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Forecasting the Economic Effects of Produced Waters Discharge Regulations on Oil and Gas Activity in Coastal Louisiana.

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FORECASTING THE ECONOMIC EFFECTS OF PRODUCED WATERS DISCHARGE REGULATIONS ON OIL AND GAS ACTIVITY IN COASTAL LOUISIANA

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ABSTRACT

Proposed regulations would restrict surface disposal of untreated produced waters by oil and gas producers in coastal south Louisiana. The regulations would impose costs on oil and gas activity. This dissertation develops an integrated model of exploration and production activities which utilizes both economic and geological concepts, in which the cost of compliance with the proposed regulations is treated as a reduction in the real net price of oil. The goal is to predict the effects of the porposed regulations on exploration and production activity in the study region.

The main findings are: (i) the proposed regulations would reinforce the trend of falling levels of exploration activity, (ii) the rate of oil production from existing fields would not be greatly affected, (iii) the minimum economic field size would increase somewhat, and (iv) the productive life of fields would be shortened by less than two years. Generally, the effects of the regulations are estimated to be rather small.

CHAPTER 1

INTRODUCTION

Any attempt to curtail domestic petroleum industry activity in the face of mounting awareness of enviromental costs is viewed by many as injurious to the national interest because of the effects on economic growth and U.S. dependence on foreign oil. The acrimony over the issue of drilling in Alaska's Arctic National Wildlife Refuge and off the coasts of both California and Florida (see Powell, 1991) illustrates the point. In order to make good decisions about optimal petroleum activity and methods we must know the costs and benefits of the various options.

The purpose of this dissertation is to develop and implement an environmental regulatory impact model for oil and gas activity in coastal south Louisiana. Specifically, it will address proposed regulations which would end the unrestricted disposal of oil and gas produced waters into the surface waters of the state. These regulations would impose compliance costs on the petroleum industry. This dissertation will determine what impact these regulations will have on exploration and production activity in coastal south Louisiana. It will not attempt to quantify the benefits engendered by these proposed regulations.

According to the Louisiana Administrative Code (LAC) 33:IX.708.B (proposed), produced waters are defined as liquids and suspended particulate waste material generated by the processing of fluids brought to the surface in conjunction with recovery of oil or natural

gas from underground geologic formations or with underground storage of hydrocarbons. The regulations would forbid discharges of produced waters directly onto "any vegetated area, soil, or intermittently exposed sediment surface" as well as into freshwater swamp or marsh areas other than "major deltaic passes" of the Mississippi and Atchafalaya Rivers. Produced waters discharged into intermediate, brackish or saline water areas inland of the territorial seas would be halted no later than 1 January 1995 unless a compliance schedule has been submitted and approved. Similar regulations are already in place in north Louisiana and Texas.

In the Fiscal and Economic Impact Statement for Administrative Rules submitted by the Department of Environmental Quality's Office of Water Resources (undated copy), the effects of produced waters discharged into surface waters are outlined. These include "significant quantities of petroleum hydrocarbons" accumulated in sediments near the discharges and the formation of oily sheens on the surface water. "Formation aromatic hydrocarbons in produced water can be ingested by fish and shellfish resulting in objectionable odor and taste" (p. 3), and "produced water is toxic to aquatic life, and has been shown to cause chromosome damage in juvenile fish". Produced water has been shown to contain benzene, ethylbenzene, toluene and other "organic toxic pollutants" which are known to be human carcinogens. Finally, "produced water may contain up to 2,800 pCi/l ^{226}Ra, a radioactive isotope known to cause bone cancer" (p. 3). A survey by DEQ's Office of Water Resources found an "average of 176 pCi/l ^{226}Ra and 180 pCi/l ^{228}Ra in 403 produced water samples", a level

which is "600% over the Nuclear Regulatory Commission limits of 30 pCi/l for unrestricted discharge of these isotops" (p. 3). The FEIS reports that it has been "repeatedly shown" that the discharge of produced waters results in the degradation of receiving waters to the extent that they fail to meet existing Louisiana water quality standards. This section of the FEIS concludes that "a human health risk may be introduced by consumption of organisms tainted through exposure to oil field waste discharges" (p. 4).

These produced waters are generated by the production of oil and gas (primarily oil). When the oil is brought to the surface, it is frequently in the form of an emulsion with water. The oil and water are separated, the oil is sent on to the refinery and the water is disposed. The proposed regulations allow for treatment of the produced water and discharge into surface waters or injection of the untreated produced waters into subsurface formations. According to the DEQ's Office of Water Resources the unanimous industry response has been that subsurface injection is the least costly method of compliance. This compliance method will be assumed throughout this dissertation.

The production of oil necessarily begins with a search for pockets of oil and/or gas. It is assumed that exploratory firms do not know a priori whether a pocket contains oil, natural gas, a combination of both in some ratio, or neither. The process begins with seismic or other surface activity in order to determine likely locations in which to drill exploratory wells. There are two types of exploratory wells distinguished by location; those drilled in areas

known to contain petroleum or very near to known fields (called infill drilling) and those drilled in relatively unexplored areas (called wildcats). Wildcat drilling will be addressed in this dissertation because this type of exploratory drilling discovers new fields, while infill drilling is usually undertaken to define the boundaries of known fields or to hasten production from known fields.

Once a new field has been found production may begin depending upon whether the producer expects the field to be profitable. Given development costs, some level of current oil prices, and expectations about future oil prices, there is a minimum field size which will be economic to develop. Fields that are at least this size will be developed; fields smaller than this will not be developed currently but may be developed in the future. As an active field is produced, production gradually falls until the field is no longer profitable and it is shut in (the producer halts production operations). The exact shut in point is dependent upon economic variables and the rate at which production declines.

The contribution of this dissertation is to develop a fully integrated exploration/production (E/P) model of oil and gas activity. This model is calibrated on coastal south Louisiana but could be applied to other regions (eg, the Gulf of Mexico Outer Continental Shelf). This integrated model is then used to compare E/P activity levels with and without the produced waters regulations. The difference between activity levels with and without the regulations will reflect the impact of the regulations.

The model incorporates the regulations by using an estimate of compliance costs on a barrel of oil equivalent basis. The estimated compliance cost will reduce the net wellhead price (assumed to be exogenous for coastal south Louisiana), and the activity levels at the two different net wellhead prices will be compared. Because of the generality of the approach, this model could be used to gauge the impact of other costly regulations or changes in the net wellhead price of oil due to exogenous shocks on coastal south Louisiana E/P activity. With minor modifications the model could also be used to assess the effects of different tax regimes on E/P activity in the study region.

The estimated compliance cost is based on work done by Farber and Dupont (1992). They examined estimates of compliance costs on a barrel of water basis from two sources and used the midpoint of those two estimates. The cost on a barrel of oil basis was derived by calculating the median produced water to oil ratio for the affected fields and using that figure to convert the cost estimate from a produced water basis to an oil basis.

Walk, Haydel (1989), in a study prepared for the Mid Continent Oil and Gas Association, estimated a $7.00 per barrel of water disposal cost. This was based on the assumptions that producers would inject produced water from their fields themselves, that new wells would be drilled specially for injection in most fields, and that one disposal well would be needed for every four producing wells (Walk, Haydel, p. 3-4). These are rather extreme assumptions. It appears that in north Louisiana and Texas most produced waters are handled by

commercial disposal (injection) operations and that considerably more than four producing wells are handled by each disposal well (see Kerr and Associates, 1990). In addition, Walk, Haydel specified elaborate pre-injection filtering and treatment systems that are not typically used in the United States (Kerr and Associates, p.2).

Kerr and Associates (1990), in a study prepared for the Louisiana Department of Environmental Quality, contacted vendors and contractors in south Louisiana and obtained estimates for the various services and equipment necessary to comply with the regulations. They estimated that compliance would cost $1.66 per barrel of water disposed, consisting of $1.32 per barrel for transportation (assuming a 3 hour round trip by truck) and $0.34 per barrel for injection. The injection cost is an average for several commercial disposal facilities in Louisiana. It should be noted that there is evidence that commercial disposal can cost as little as $0.25 per barrel of water injected. On the other hand, Kerr and Associates' estimate of transportation costs may be optimistically low. For fields which are inaccessible except by boat, truck transportation of produced water is not an option. Transportation costs may be considerably higher than that estimated by Kerr and Associates.

The heterogeneity of oil fields makes generalizations about compliance costs suspect. For fields which have ready access to commercial disposal facilities the compliance costs may be quite low. Fields which generate a higher than average volume of produced water relative to oil will experience compliance costs which may be much higher than those used in this dissertation. Stripper wells (wells

which produce fewer than 10 barrels of oil per day) will probably fall into the latter category, making them particularly susceptible to the impacts of the proposed regulations. The results of this dissertation may not be applicable to specific fields because of the heterogeneity of fields and the difficulty of generalizing about them.

CHAPTER 2

REVIEW OF LITERATURE

1. Introduction

According to Devarajan and Fisher (1981, p. 65), "there are only a few fields in economics whose antecedents can be traced to a single, seminal article. One such field is natural resource economics; . . . its origin is widely recognized as Harold Hotelling's 'The Economics of Exhaustible Resources' ". Hotelling's 1931 article will be the starting point for this literature review because most of the theoretical literature on the topic follows from his work. In addition to theoretical articles, the econometric work on oil and gas will be reviewed. Engineering and geological models of oil and gas exploration and extraction will be reviewed, followed by a review of those models that combine geologic and economic approaches (the hybrid models).

2. Theoretical Articles

Hotelling's "The Economics of Exhaustible Resources" (1931) is probably best-known for the 'r% Rule', which states that the price net of extraction costs of an exhaustible resource must rise at the rate of interest along an efficient extraction path. He also showed that this will hold in a competitive resource industry equilibrium under certain conditions. The by now familiar explanation is that if net price is rising at the rate of interest a producer will be indifferent between extracting the resource (and earning the interest r on the

money proceeds) or leaving the resource in the ground and allowing the value of the resource in the ground (the net price) to rise at the rate of interest.

Richard Gordon (1967) developed a model of industry behavior that built on the work done by Hotelling. However, Gordon concluded that "with increasing costs to cumulative output, the r per cent profits growth rule no longer holds" (p. 283). Gordon also asserted that no form of resource extracting industry will ever completely exhaust a mineral since higher expected future prices will always cause profit maximizing firms to shift production to the future (and reduce current output) in his model.

Dasgupta and Heal (1974) presented a much richer model in which the elasticity of substitution between capital and the (exhaustible) resource is explicitly taken into account. They also introduced technical change into their model, thus allowing the possibility that at some future time the resource will no longer be required in order for production to take place. While this model is not precisely a model of firm or industry behavior it does lead to some conclusions about optimal extraction and price paths. Dasgupta and Heal concluded that "the conditions under which it is optimal to exhaust the resource in finite time are really rather stringent" (p. 26). They found further that for "moderate" values of their variables, "the price of the exhaustible resource relative to output ought to be rising rather rapidly" (p. 26), something which they pointed out does not seem to be the case.

Kuller and Cummings (1974) derived an analytical management model of the petroleum reservoir that explicitly included some aspects of reservoir mechanics and engineering. Their most important contribution was the recognition in a theoretical model that the level of recoverable stock is to some extent dependent upon the time path of production. Kuller and Cummings found that the optimal rate of production is that rate at which the "marginal net income to firm j equals the user cost associated with firm j's production" (p. 73). The user cost includes not only the impact of the current production on firm j's internal future costs but also "all external effects" including "effects on the aggregate recoverable stock" (p. 73). This is obviously not the same as the Hotelling Rule, but Kuller and Cummings developed a model of reservoir management, the goal being to "characterize optimal paths for production and investment for the reservoir during all periods" (p. 71).

The studies mentioned above implicitly assume that the reserve base is fixed, although some studies allow uncertainty about the size of the reserve base. Pindyck (1978) modeled both exploration and production simultaneously and introduced the idea that the reserve base is not fixed but can be changed by exploration for and discovery of new sources of the resource in question. This paper also introduced the concept that resources such as oil and gas are best thought of as nonrenewable rather than as exhaustible because economic incentives can cause reserves to be maintained or even expanded through further exploration. Pindyck fails to point out that this is only a short run phenomenom since exploration does not create reserves

but merely moves the reserves (which must be finite) from the category of unknown to known. On a human time scale the sum of unknown plus known reserves is fixed and immutable. Because Pindyck modeled nonrenewable resource extraction as being heavily dependent upon exploration activity, and further that extraction costs are partially determined by the level of (known) reserves, he postulated several price profiles that are determined by the initial level of reserves. If reserves are initially large enough, price will rise steadily as production proceeds. In this scenario, exploration is put off until near the end of the time horizon, depending upon extraction costs. The more interesting price profile is one in which reserves start off very small. In this case, price begins at a very high level but declines steadily while exploration builds up the reserves. As exploration and reserves then decline, price begins to rise, giving overall a U-shaped price path.

In the Appendix to this model, Pindyck included a simulation model using aggregate data for the Permian Basin region of Texas. Pindyck simulated the model "repeatedly" while "varying the initial conditions until the terminal condition . . . is satisfied" (p. 857). The terminal condition is that production, exploration and average profit all become zero simultaneously at the cutoff (backstop) price of $33 per barrel.

Hartwick (1991) showed that by reformulating Pindyck's (1978) model the r% Rule holds under certain condition for resource exploration and extraction firms. Thus firms that explore and extract simultaneously may still behave as Hotelling predicted. Hartwick

claimed that "buried within the technically complicated model of the resource exploring-extracting firm of Pindyck (1978) is the classic r% rule of Gray and Hotelling" (p. 141).

An adaptation of Pindyck's (1978) model that is pertinent to this study is that of Yucel (1986). In Yucel's optimal control model, price is exogenously determined and extraction costs depend upon both current and cumulative production (p. 202). Both production and exploration functions are Cobb-Douglas, and Yucel explicitly mentioned process models in describing her exploration function. However, the most important aspect of Yucel's paper for this study is that she investigated the impact of ad valorem severance taxes on exploration and production. Her simulation study, the functions and parameters of which "were chosen to 'mimic' the Pindyck functions" (p. 217), "confirms the static results that severance taxes in a competitive market reduce production and exploration for exhaustible resources" (p. 216). The tax does not mean that the resource is conserved; new reserves are developed more slowly but known rserves are depleted more quickly. On the other hand, Yucel found that "generally, the deadweight losses are quite low" (p. 210). She attributed this to the fact that the impact of severance taxes on prices is cushioned because the tax burden is to a certain extent absorbed by producers in the form of lower rents. One caveat is that this holds only for fairly low severance tax rates (20% or less (p. 210)) since the tax becomes more distortionary as the tax rate increases.

3. Econometric Studies

Econometric models of oil and gas exploration and production began to appear regularly in the early 1970's as a response to the perceived shortage of natural gas. Although these models were geared toward explaining natural gas supply, many either included considerations of oil supply or were easily modified to include oil.

Erickson and Spann (1971) presented a model of natural gas supply that attempted to explain how natural gas exploration is carried out and how economic variables affect the success of such exploration. They modeled this process with three equations describing the number of wildcats drilled, the success ratio of those wildcats and the average size of new discoveries. They modeled all three as a function of price; in other words, as the price changes so does the average size of new discoveries and the success ratio of wildcat wells. They took no explicit account of the physical effects of continued exploration in a given region, reasoning that (in Texas, at least) the prorationing system in effect in the period under study created incentives for producers to find and develop smaller gas fields and ignore larger ones. In addition, as prices rose producers were willing to drill less likely prospects and therefore the success ratio of drilling fell. Thus everything can be explained by the wellhead price of oil and gas in this model. Oil exploration was included because the authors did not feel that there was any evidence to indicate that firms knew in advance whether a prospect would be categorized as an oil or gas field if successful. In fact, a major

point of the paper was to determine the cross price elasticities between oil and gas.

Khazzoom's (1971) approach was slightly different from that of Erickson and Spann. Khazzoom defined two broad categories of gas supply: new discoveries and extensions and revisions of existing reserves. He modeled each as functions of the ceiling price of gas, the price of oil, the price of natural gas liquids and the previous period's value of the dependent variable. Khazzoom acknowledged that new discoveries are determined by the number of wildcats, the success ratio of those wildcats and the average size of new discoveries but apparently reasoned that these factors are all functions of the prices mentioned above and so did not use these factors explicitly in his econometric work. After estimating his equations for new discoveries and extensions and revisions (he pointed out that "the quality of available data on extensions and revisions leaves much to be desired", (p. 59)), he performed a simulation of the industry in the future.

MacAvoy and Pindyck (1973) used an approach that is similar to those of Erickson and Spann and Khazzoom, but on a more comprehensive scale. MacAvoy and Pindyck modeled natural gas supply with three equations representing drilling, size of new discoveries, and extensions/revisions. They use time series data from all 18 FPC districts, giving them both cross sectional and time series data. Again, price was implicitly a primary explanatory variable since they actually use a revenue variable. Drilling costs and a risk variable were also introduced. No physical variables were used in the supply equations. However, in their production equation the explanatory

variables were the log of wellhead price and the quantity of total reserves. Their major contribution was that they also estimated wholesale demand and mainline demand. In this way, they could estimate excess demand for natural gas under various price scenarios by comparing the production to the demand. Given their reserves supply model they could forecast future long run shortages or oversupply.

Dennis Epple (1985) developed a "model in which the supply of exhaustible resources is rigorously derived from a theoretical model of optimal resource depletion" (p. 143). Unfortunately, Epple treated development and production as exogenously "determined by mechanical rules" (p. 154); in fact, in his model "a constant fraction of remaining reserves is produced each period" (p. 150). This seems to be the only way that he could convert the dynamic optimization model into an econometric model. He explicitly accounted for uncertainty about future prices and costs and drove the model from an objective function presumed to be maximized by the individual producers. This was an advance over previous econometric models because he explicitly began with a dynamic optimization framework and then fit data to his model to make it empirically operational. This paper highlighted the difficulties of using a dynamic optimization model to do empirical work. The fact that development and production are determined exogenously makes the model useless for many applications.

McDonald (1991) attempted to estimate the discount rate for producers implied by Pindyck's stochastic dynamic optimization models of natural resource production (1980, 1981, 1982). This was an

attempt to empirically test a dynamic optimization model, perhaps with a view towards applying it to policy questions. Lack of the necessary data forced McDonald to specify cost and production functions outside of the theoretical model, and his results are highly sensitive to those specifications. Nonetheless, McDonald estimated a discount rate of 90.75% based on Pindyck's models (p. 164). When he used a deterministic version of the model, the estimated discount rate was 68.66% (p. 167). These discount rates appear to be rather high. McDonald concluded that "data limitations place severe restrictions on our ability to test economic theory" (p. 167) and stated that his data limitations were "most severe when it comes to measured resource stocks and engineering cost data" (p. 167). He also wrote that his research "highlighted the dfficulty in bridging the gap between theory and empirical analysis" (p. 167).

Deacon (1993) simulated tax effects on the petroleum industry in the United States using a model that "adopts the general structure developed by Pindyck (1978) and Yucel (1986)" (p. 160). The model abstracted from all uncertainty. He found that the income tax "causes only minor deviations from the untaxed solution" (p. 172), while the severance tax "alters drilling and output to a much greater degree" (p. 173). The "dominant effect of the [severance] tax is high-grading . . . resources that would otherwise be . . . produced are rendered sub-economic by the severance tax" (p. 173). However, Deacon's results are sensitive to his estimated cost function; "a data base that would support precise econometric estimation of the cost function that applies to this industry is not presently available" (p. 184).

This article served to indicate that data restrictions on empirical work in this area are troublesome.

4. Process Approach Studies

The earliest process model, and perhaps the most consistently cited, is that of Arps and Roberts (1958). This model was only concerned with oil field discovery, not production. Arps and Roberts developed a statistical model that described the number of fields of various size classes that they expect will be found in a specific geological region. This was a purely mechanical model, involving economics only to the extent that they explicitly recognized that some fields are too small to profitably develop. These non-commercial fields will not appear in the data and therefore must be accounted for in other ways, since their absence from the data means that the sample characteristics will only reflect the population characteristics for size classes which are commercially viable. Arps and Roberts' model used a log normal distribution to estimate the remaining fields in the study region.

M. K. Hubbert (1967) developed a process model in the strictest sense. Hubbert used historical drilling and discovery data to plot the trend of increases in proved reserves per year and per foot of exploratory drilling, then assumed that those trends would continue. Depletion effects would cause the finding rate per year and per foot of exploratory drilling to decline (p. 2215 and p. 2222). Additionally, Hubbert projected annual production by observing that "cumulative production since 1925 had lagged that of cumulative

discovery by the nearly constant interval of 10-12 years" (p. 2210). In this way, Hubbert estimated both the remaining reserves in the United States and the future time path of discovery and production of those reserves. Hubbert ignored economic variables completely (although he stated that his model "is not based on assumptions of static technology" (p. 2225)) and in this way missed an important point. Proved reserves are defined as those reserves recoverable "under existing economic and operating conditions" (Cleveland and Kaufmann, 1991, p. 145). If economic conditions change, proved reserves will change even in the absence of further exploratory drilling. Hubbert ignored this. This is a serious shortcoming to his and other process models.

Eckbo, Jacoby and Smith (1978) explicitly developed a relationship between price and the minimum economic field size. This allowed them to estimate how various oil prices would affect reserves. Their discovery model, on the other hand, excluded price as an explanatory variable. The discovery model was a probabilistic one based on a lognormal field size distribution that was similar to the work of Arps and Roberts. Their "dry hole risk" was estimated based on recent drilling history and the level of exploratory drilling was based on announced plans by drilling firms. Based on their estimate of reserve additions and their calculated relationship between price and minimum economic field size, the authors were able to estimate future production for a given price of oil. Finally, they concluded that small changes in oil price will have almost no effect on overall

reserves and production because the marginal fields are so small that they contain only a tiny fraction of total reserves.

Attanasi and Haynes (1983) essentially updated the work of Arps and Roberts. They used 20 size classes in order to get more detail out of the model, but still used a lognormal field size distribution. They did not attempt to model how many exploratory wells will be drilled in a given region, but calculated how many new fields (and of what size class) will be found given some arbitrary number of wildcat wells. They estimated production from known fields on the basis of historical production profiles of similar fields. A similar study with similar results was performed by Drew, Schuenmeyer and Bawiec (1982). A further study along these lines was carried out by Drew, Attanasi and Schuenmeyer (1988).

5. Hybrid Studies

The first hybrid model was developed by Uhler (1976) to estimate a stochastic production function for the discovery of new petroleum reserves. His paper was a direct response to Erickson and Spann (1971) and the shortcomings found in that work. Uhler pointed out that Erickson and Spann ignored the effects of the accumulation of geological knowledge, the eventual exhaustion of undiscovered reserves, and the tendency for the largest fields to be found first. He overcame these problems by developing a process model and then describing how it could be adapted to the econometric model of Erickson and Spann. Uhler's main concern in this article was estimating the marginal exploration cost function. He found that the

marginal cost of finding new oil reserves (in Alberta, Canada) rose rapidly over time.

Camm, et al. (1982) developed a model of oil production that included elements of both econometric models and process models in order to quantify the effects of severance taxes on oil produced in California. They acknowledged that the price of oil determines whether or not a field will continue to operate; unprofitable fields will be shut in and profitable fields will continue to produce. However, they contended that the rate of production out of active fields is determined in large part by geological and engineering considerations rather than by economic considerations. Therefore their production model was split into two parts: an economic test to determine whether or not a field should continue to produce and then a process model to estimate the rate of production and the rate of decline of the production rate over time. Deacon, et al. (1990) developed a model that was striking in its similarity to that of Camm, et al. Deacon, et al. concluded that severance taxes of up to 9% on the value of the oil produced will reduce total production over a thirty year period by 7.7%, or about 799 mmbbl. This implies that the supply of oil in California is inelastic.

Kaufmann (1991) was also primarily concerned with production rather than exploration. He estimated a "natural" decline rate of production based on work by Hubbert (1962) and then calculated what production from a field or region would have been had it followed that estimated decline rate. This production profile "represents changes in the physical resource base that are not captured fully by economic

or political variables" (p. 113). Then he found the difference between the estimated production and actual production and called this the residual. He then used economic and political variables to explain changes in the residual. In this way, both geological and economic factors were included in his production model. Kaufmann concluded that "oil prices probably do not contain all the information that is needed to analyze oil production" and "that the U.S. has depleted reservoirs from which oil can be recovered with a profit at current prices . . . the econometric portion of the analysis indicates that large increases in real oil prices are needed to offset the decline in production that is associated with future movements in the production curve" (p. 126).

6. Summary

To summarize, there exist pure geological models of petroleum resource exploration and production that exclude any economic variables. There also exist econometric models which do not account for geophysical factors affecting oil and gas resources. Neither of these types of models is entirely satisfactory because neither employs a full spectrum of explanatory variables. Price and cost play the dominant role in the exploration for and development of oil and gas fields, while geological and engineering factors appear to determine production rates. Both types of factors influence the decision to shut down a field.

Attempts to include both physical and economic factors have been made for the most part only in production models (eg., Camm, et al.,

Deacon, et al., and Kaufmann). These models indicated that physical factors dominate economic factors in explaining oil production. Uhler's hybrid model of petroleum exploration attempted to include some geological factors in an econometric model, but did not use what is now the generally acceped premise that fields are distributed log-normally by size in geologically homogeneous regions. I could find no hybrid models that did include this stylized fact.

This literature review also indicates that attempting to operationalize a dynamic optimization model is extremely difficult, particularly in view of the data requirements. The results of studies which have been done in this manner are not very satisfactory.

This dissertation will concentrate on developing a model of petroleum exploration that explicitly recognizes the log-normal distribution of fields by size, the tendency for the largest fields to be found and developed first and the declining marginal returns to exploration. However, the model will also recognize the importance of economic variables in determining the pace of exploration. On the production side, economic variables will dominate the models of oil field development and shut down decisions, while geological variables are expected to play the largest role in the model of production from viable fields.

CHAPTER 3

EXPLORATION

1. Introduction

The exploration model consists of two interrelated systems. The overall goal of the model is to explain and predict exploratory drilling and the number of fields which will be found by the predicted exploratory drilling program. This requires a model of how oil and gas fields are distributed in the south Louisiana region and a model to explain the number of exploratory wells drilled in the region. Given profit maximizing behavior by firms engaged in exploratory drilling, the number of wells drilled will depend to some extent on the expected success of a drilling program. To predict the success of a drilling program, an estimate is needed of the number and size of remaining (undiscovered) fields in the region.

2. Explicit Cost Function Drilling Model

It is possible to estimate a model of exploratory drilling for south Louisiana which will allow a forecast not only of future exploratory drilling, but also of the success rate of the drilling and the expected sizes of the fields found. Actually, this model will attempt to explain wildcat drilling, a more narrowly defined activity than exploratory drilling. Wildcat drilling is undertaken specifically to find new fields and is usually carried out some distance from known fields. Exploratory drilling in general can

include drilling around a known field in order to determine the boundaries and size of the field. These two types of drilling and the associated risks are very different, and no doubt the economic factors which drive them are accordingly different. The following analysis is confined to wildcat drilling since the point is to estimate how the proposed regulations will affect the rate at which new fields are discovered.

Firms which are engaged in wildcat drilling wish to maximize the expected value of a drilling plan. MacAvoy and Pindyck (1975) have constructed an explicit function that begins with a series of models for the pricing of capital assets under uncertainty (see MacAvoy and Pindyck (1975), p. 67). They represent the risk inherent in any drilling program by the variance of the cash flow, so that the certainty equivalent present value of net cash flow to a firm is

$$3.1)\quad V=(1/r)(\overline{\pi}-\lambda\sigma)$$

where $\tilde{\pi}$ is the total end-of-period cash flow to the firm and $\overline{\pi}=E(\tilde{\pi})$ is the expected value of $\tilde{\pi}$, σ is the variance of $\tilde{\pi}$, λ is an index of risk aversion, and r is a long-term market interest rate.

MacAvoy and Pindyck use the following profit function:

$$3.2)\quad \overline{\pi}=E(\tilde{\pi})=W\cdot\overline{R}-C^{e}(W)$$

where W is the number of wells, $\bar{R}$ is the mean dollar receipts per well, and $C^e(W)$ is the expected cost of drilling W wells. They define the mean dollar receipts per well as

$$3.3)\ \bar{R} = (\bar{S}_G.P^e{}_G + \bar{S}_O.P^e{}_O)$$

where $\bar{S}_G$ and $\bar{S}_O$ are the mean sizes of discoveries of gas and oil per well, respectively, and P^e_G and P^e_O are the expected prices of gas and oil. By substitution into Equation 3.2

$$3.4)\ E(\tilde{\pi}) = (W \cdot \bar{S}_G.P_G{}^e + W \cdot \bar{S}_O.P_O{}^e) - C^e(W)$$

They approximate the variance of the total end-of-period cash flow to the firm by

$$3.5)\ Var(\tilde{\pi}) = (W \cdot S_G{}^{v} \cdot (P_G{}^e)^2 + W \cdot S_O{}^{v} \cdot (P_O{}^e)^2) \ = W \cdot S^v \cdot P^e$$

where S^v_G and S^v_O are the variances of the mean sizes of discoveries of gas and oil per well, respectively.

To simplify matters and to make this series of equations compatible with the reserve estimation work (Section 4) oil and gas can be combined by converting the gas on a Btu basis to barrels of oil equivalent (BOE). Gas prices will be converted to dollars per BOE ($/BOE) in a similar fashion, and the two prices will be averaged,

weighted by production volume shares. Substituting these BOE variables into Equation 3.1

$$3.6)\quad V=\frac{1}{r}\,(W\cdot\bar{S}\cdot P^{e}-C^{e}(W)-\lambda\cdot W\cdot S^{v})$$

and taking the derivative of this expression with respect to W and setting it equal to zero gives

$$3.7)\quad \frac{\partial V}{\partial W}=[\bar{S}\cdot P^{e}-\frac{\partial C^{e}}{\partial W}-\lambda\cdot S^{v}]\;/r=0$$

as the optimality condition on wildcat well drilling.

All of this is conditional upon success in drilling. In order to introduce this concept, let $\bar{S}$ now represent the mean size of discovery per successful well and let φ represent a measure of expected success in wildcat drilling (for example, MacAvoy and Pindyck use last period's success ratio).

At this point it is necessary to present a more explicit cost function. Since MacAvoy and Pindyck found that more drilling increased the costs per well (MacAvoy and Pindyck (1975), p. 70), they used a quadratic expression of the following form to represent expected cost of drilling a well:

$$3.8)\quad C^{e}(W)=W+W\cdot A\bar{T}C+\frac{1}{2}W^{2}$$

where $A\overline{T}C$ is the historical average drilling cost per well. The marginal cost for a well is then

$$3.9)\quad \frac{\partial C^{e}(W)}{\partial W}=1+A\overline{T}C+2W$$

Now substitute this expression into Equation 3.7 to obtain:

$$3.10)\quad \frac{\partial V}{\partial W}=(\varphi\cdot\overline{S}\cdot P^{e}+[-1-A\overline{T}C-2W]-W-\lambda\cdot S^{v})/r=0$$

Solving this equation for W gives the following expression for the number of wildcat wells drilled

$$3.11)\quad W^{*}=[\varphi\cdot\overline{S}\cdot P^{e}-A\overline{T}C-\lambda\cdot S^{v}-1]/3r$$

The variance expression, S^{v}, used by MacAvoy and Pindyck consists of the squared terms in the first expression in Equation 3.11, i.e., $S^{v}=\varphi^{2}\overline{S}P^{e2}$ (MacAvoy and Pindyck (1975), p. 77). The index of risk aversion drops out upon aggregating over all firms in a region, and according to MacAvoy and Pindyck (p. 71), the interest rate r from Equation 3.2 drops out because the model in order to become operational has now been converted to a one period model. However, MacAvoy and Pindyck add the interest rate back to their equation to account for the multiperiod nature of the petroleum investment

process. Their final expression, adjusted for converting gas to oil on a Btu basis, is:

$$3.12)\quad W_t = c_0 + c_1(REV) + c_2(VAR) + c_3(ATC) + c_4(INT) + \epsilon$$

where

$$REV = (\overline{S})\,(\varphi)\,((P_{-1}+P_{-2}+P_{-3})/3)$$

and

$$VAR = (\overline{S^2})\,(\varphi^2)\,((P_{-1}+P_{-2}+P_{-3})^2/9)$$

INT is the AAA corporate bond interest rate, ATC is the average total cost of drilling a well, $\overline{S}$ is the expected size of discoveries, and φ is the expected success ratio for exploratory drilling. Note that the expected price is proxied by a three year running average of past oil and gas prices.

3. An Alternative Drilling Model

A similar approach to the problem can be made which does not make an explicit assumption about the form of the cost function. We start by examining the "drilling plan", an optimal control problem which establishes an optimal drilling path for the purposes of planning. The risk-neutral firm solves this control problem:

$$3.13)\quad PV=\int_0^T \pi_t(W_t, w_t)\cdot e^{-rt}dt$$

where w_t is the number of wells drilled in period t and W_t is the cumulative number of wells drilled after t periods. The discounted profits of a future year's drilling (ie, the discounted profits of drilling w wells in period t) is

$$3.14)\quad \pi_t=\frac{1}{1+r}\{Pr(W_t, w_t)\cdot\overline{P}_t\cdot\overline{Q}(W_t, w_t)-\overline{C}_t(W_t, w_t)\}$$

where Pr(·) is the probability of success (which is a function of both cumulative and current drilling activity); $\overline{P}$ is the expected price path for oil and gas over the course of production from successful wells drilled in period t[1]; $\overline{Q}$ is the expected size of oil and gas discoveries found from drilling undertaken in period t; and $\overline{C}$ is expected exploration, development, and production costs over the course of operations of successful wells drilled in year t.

The shortcoming of the "drilling plan" approach is that costs and prices are very uncertain, and a firm would not adhere to a long-term plan under conditions different from those assumed when the plan was formulated. Thus it is appropriate to consider each period's drilling program separately. In this case, the firm would seek to

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[1] Exploratory firms' price expectations are modeled very simply in this work. This may be a serious problem, as Margaret Walls and others have pointed out (see Walls, 1992).

maximize Equation 3.14 above, the profits stemming from exploration activity undertaken next period. This can be operationalized in the following manner:

$$3.15)\quad \pi_t = \frac{1}{1+r}\{Pr(W)\cdot\overline{P}\cdot\overline{Q}(W)\cdot w - \overline{C}(w)\}$$

The derivative of this function with respect to w is:

$$3.16)\quad \frac{\partial\pi_t}{\partial w} = \frac{1}{1+r}\{Pr\cdot\overline{P}\cdot\overline{Q} - \overline{C}'\}$$

Setting this equal to zero and solving for w (and assuming that second order conditions are met) gives the optimal number of wells to be drilled in period t,

$$3.17)\quad w_t^* = w(Pr, \overline{P}, \overline{Q}, \overline{C}', r)$$

However, unless the specific form of the cost function is known (or unless we are willing to make a rather heroic assumption about the form of the cost function), we are limited to estimating a general form of Equation 3.17 that may be mis-specified.

4. Technique for Estimating Undiscovered Fields

In estimating the remaining undiscovered fields in a region, it is not enough to merely estimate total hydrocarbon reserves in the

ground. In order for the model to become operational an estimate must be made of how the reserves are distributed by size.[2] This makes a difference because the smaller a field the less profitable it is to develop and produce that field, ceteris paribus. Also, larger fields typically have a larger surface area which makes them relatively easier to find (see Arps and Roberts (1958), Drew, et al. (1982), and Attanasi and Haynes (1983)).

The process begins by dividing known fields into size classes based on the amount of physically recoverable hydrocarbons in the field at the time of discovery. Since this distribution is not readily available, it is necessary to estimate it. This is done by taking the latest year's production and multiplying it by 8.2 for oil and 8.8 for gas. This figure is then added to the cumulative production to reach the estimated field size.[3]

Following Arps and Roberts (1958), it is assumed that for any given size class in a geologically homogeneous region, the probability of discovery of a field in that class is directly proportional to the number of undiscovered fields remaining in that class in the region and to the ratio of the average surface area of fields in that class to the overall area of the region. This means that the largest fields tend to be found first (see Attanasi and Haynes (1983), p. 11). As

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[2] In this thesis, "size" means the amount of physically recoverable hydrocarbons in a field at the time of the discovery of the field.

[3] This method was suggested to me by Dr. E. D. Attanasi, an economist with the United States Geological Survey, during a telephone conversation.

drilling continues over time, smaller and smaller fields will be found as the number of undiscovered fields declines in each size class.

From Attanasi and Haynes (1983), the analytical form of the field estimating equation is:

$$3.18)\quad F_i(W) = F_i(\infty)\,(1-\exp(-(C_i \cdot A_i \cdot W)/B))$$

where $F_i(W)$ is the cumulative number of fields in size class i expected to be discovered after drilling W exploratory wells, $F_i(\infty)$ is the ultimate number of fields in size class i (including both those fields discovered to date and estimated undiscovered fields), B is the area of the region (in this case south Louisiana, a geologically homogeneous region), A_i is the average area of the fields in size class i, and C_i is the efficiency of discovery of fields in size class i.[4] $F_i(\infty)$ and C_i are parameters to be estimated.

There is one further factor which complicates this process. Generally, only those fields which are economically viable (those fields large enough to be profitably developed) are reported. Fields smaller than this may be found but not reported and thus are not (and cannot be) included in the data. Attanasi and Haynes (1983) refer to this as economic truncation. Economic truncation and the ensuing data problem will cause biased estimates of $F_i(\infty)$ and C_i for those size classes in which the economic truncation occurs. Economic truncation

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[4] When drilling is undertaken randomly, $C_i = 1$; if, for example, $C_i = 2$, then exploratory drilling is twice as efficient as drilling which is randomly undertaken. Note that $\partial F_i(W)/\partial C_i > 0$.

will occur in the size class which represents marginal fields. As real oil and gas prices increased in the 1970's and again in the early 1980's, many of these marginal fields became economically viable and were developed. They appear in the data as being "found" at this time when in fact they may have been found earlier. A further statistical complication arises from the fact that price is not the only factor which influences economic truncation. Small fields located near pipelines and other infrastructure may be developed while fields of the same size in other areas may not be developed.

To solve this problem, the work of Drew, et al. (1982) is useful. Drew, et al., assume that fields are distributed lognormally by size. They determine the size class which exhibits economic truncation. Essentially, this is the largest size class for which discovery rates did not significantly decline over the period of oil and gas activity in the study region. Drew, et al. use as the estimate of $F_i(\infty)$ for that size class the estimated ultimate number of fields in the next larger size class ($F_{i+1}(\infty)$) multiplied by 1.65 (Drew, et al. (1982), pp. 17-22). They use this factor based on the fact that in their study of the western Gulf of Mexico they found that for size classes which did not exhibit economic truncation, each size class had approximately 1.65 times as many fields as the next larger class. For size classes that do exhibit economic truncation, it is only necessary to estimate the efficiency of discovery (C_i) using Equation 3.18 after calculating $F_i(\infty)$ using an economic truncation factor. Obviously, the choice of a truncation factor will affect the

results of this procedure and therefore the results of the forecasting procedure.

Attanasi and Haynes' discovery process model will be used in conjunction with the wildcat drilling model to produce forecasts in the following manner. First, using 1986 data, an average size of discovery and a success ratio will be calculated (based on new finds in 1986) by using the number and size of new discoveries and the number of wildcat wells drilled. These values will then be used in the wildcat drilling model as the expected size of new discoveries and the expected success ratio. Using these and an expected price and average cost, along with an interest rate, a forecast value for the number of wildcat wells drilled in a year will be obtained (using the estimated parameters on Equations 3.12 and 3.17). The estimated number of wildcat wells will be used in Equation 3.18 to calculate a new $F_i(W)$, using the estimated values of $F_i(\infty)$ and C_i. The process can be repeated indefinitely.

5. Data and Data Sources

The data used in the drilling equations (Equations 3.12 and 3.17) are summarized in Table 3.1. The data run from 1960 to 1986 giving 26 observations.[5] Annual data were used because the majority of the data were not available on a monthly or quarterly basis.

[5] While some of the data were available for years following 1986, it was not in the same form and not subject to the same filtering process as the other data. They were not used. The data prior to 1960 were sketchy, incomplete and unreliable.

TABLE 3.1

DRILLING MODELS DATA SUMMARY

VARIABLE	MEAN	DESCRIPTION
WELLS	156.55	# of wildcat wells drilled annually, 1960 - 1986
PRICE	$13.04	3 year running average of weighted average price of oil and gas on BoE basis
SUCCESS	0.089	success ratio of wildcat drilling
SIZE	5742897	average size of new discoveries in BoE
REVENUE	4231591	product of size, success and price
VARIANCE	9.455×10^{12}	same as REVENUE with terms squared before multiplying
AVGCOST	$1458794	average cost to drill an exploratory well
INTEREST	3.6%	AAA corporate bond interest rate

The number of wildcat wells drilled each year in coastal south Louisiana was obtained from Louisiana Energy Statistics, 1909-1989, (see Tables I.5, I.6 and I.7 in that publication). These data also provided the success ratios for exploratory drilling as it was broken down into "Oil", "Gas" and "Dry". The simple ratio of "Oil" plus "Gas" to "Dry" was used as the success ratio. The success ratio for a given year was used as the expected probability of success for the next year.

The average size of newly discovered fields was determined by first listing all fields in the study region in order of discovery. Discovery dates were provided by the Louisiana Geological Survey (Lindstedt, et al., 1991) and checked with data from the Louisiana Office of Conservation. Then the initial size of the field was estimated using the procedure described above, and the average size of fields discovered in each year was then calculated. Again, the average size of new discoveries was used as the expected size of new discoveries in the following year. However, oil and gas were combined on a Btu basis by converting the gas from a cubic foot measure to a barrel of oil equivalent measure on the basis of the Btu content of a cubic foot of gas compared to a barrel of oil.[6] This is a reasonable approach since oil and gas are joint products of exploratory drilling.

The average cost data were obtained from publications of the Hughes Tool Company located at the Center for Energy Studies. The data consisted of nominal dollar spending on exploratory drilling (not

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[6] The factor to convert 1,000 cubic feet of natural gas to a barrel of oil equivalent measure is 0.178. This factor can be found in almost any petroleum engineering textbook or handbook.

only wildcat drilling but all exploratory drilling) in coastal south Louisiana on an annual basis. This value was divided by the number of all exploratory wells drilled in coastal south Louisiana to generate an average cost of drilling all exploratory wells. This is not precisely an average cost of drilling a wildcat well, but the differences are very likely small. While the factors driving wildcat drilling and the associated risks are not the same as those affecting other exploratory drilling activities, the actual process of drilling the wells is very similar. The actual costs of drilling are therefore assumed to be very similar.

The price data used are the price of oil and natural gas at the wellhead in south Louisiana, obtained from Louisiana Energy Statistics, 1909-1989, Table V.1. The price data were converted to an average price for oil and gas on a Btu basis (in the same manner that the volumes were converted), weighted by the shares of oil and gas discovered in each year. Expected price was proxied very simply by using a three years running average of the price per Btu. This simple price expectations process may be a serious problem and more research is needed in this area.

All of the price and cost data except for the interest rate variable were converted to real 1987 dollars using the GNP price deflator. The interest rate variable is the AAA corporate bond interest rate according to Citibase. The GNP deflator was also obtained from Citibase.

The data used in the discovery process model were collected from many of the same sources. First, the known fields were divided into

classes based on the amount of physically recoverable hydrocarbons initially in place. See Table 3.2 for the upper and lower limits of the size classes; these classes are based on those used by Attanasi and Haynes. The cumulative and annual production were obtained from the 1987 edition of the Annual Oil and Gas Report. The initial production dates were obtained from Lindstedt, et al., 1991. These initial production dates are the best available proxy for the finding date. In each size class, the fields were ordered by date of first production. The cumulative number of wells drilled up to the time of "discovery" was paired with each field. These two data points are $F_i(W)$ and W, respectively (see Equation 3.18).

The basin size (ie, the size of coastal south Louisiana in acres) was obtained from the Louisiana Almanac by adding together the areas of each parish in the region. The average size of the fields in each class was obtained from the Louisiana Geological Survey, and then fitted using a quadratic expression. This was done because of problems with the raw data (the raw data were based on the number of wells in the field and the spacing between wells required by state law). See Table 3.2 for the size classes used, the known number of fields in each class, and the average acreage (A_i) for each size class. The number of observations for each size class when estimating Equation 3.18 differed, not only because of the different number of known fields but also because before 1946 the records were rather sketchy. There are periods of several years when no fields are reported in the data as beginning production, but then a large number of fields are reported as being found (or starting production, to be

TABLE 3.2

DISCOVERY PROCESS MODEL DATA SUMMARY

SIZE CLASS	NUMBER OF KNOWN FIELDS	AVERAGE AREA OF FIELDS IN ACRES	UPPER LIMIT OF CLASS (IN MILLIONS OF BoE)	LOWER LIMIT OF CLASS (IN MILLIONS OF BoE)
1	17	7883	1137	337
2	24	6061	280	170
3	25	4041	161	85
4	48	2596	84	42
5	54	1748	41	21
6	41	1310	20	10.5
7	50	1096	10.4	5.0
8	32	979	4.8	2.5
9	33	923	2.2	1.2
10	19	900	1.2	0.66
11	15	887	0.58	0.34
12	15	880	0.30	0.17
13	11	877	0.16	0.09
14	9	875	0.07	0.04
15	8	874	0.04	0.02
16	5	874	0.019	0.010
17	5	873	0.007	0.004
18	4	873	0.004	0.0019
19	6	873	0.0019	NA

more precise) in the next year. The war years 1940 to 1946 are particularly problematic.

6. Empirical Results

While Equation 3.12 can be estimated as it is shown, Equation 3.17 cannot be estimated without ascribing some form to the equation. Without knowing the precise form of the variable functions, particularly the cost function, it is only possible to estimate a general form of Equation 3.17. In this case, a linear equation is estimated using a second-order autocorrelation model. The coefficients on the lag parameters are significant. The complete results are presented in Table 3.3.[7]

An interesting result of these regressions is that the coefficient on AVGCOST is positive. This is an unexpected result, as it implies that rising costs have a positive influence on drilling activity. One possible explanation is that the average cost data are capturing the utilization rate of drilling equipment; as drilling levels increase the price of the necessary equipment is bid up, leading to higher costs (i.e., an increasing cost industry). This parameter estimate is insignificant in the regression based on Equation 3.17.

The parameter on the price variable in Table 3.3 is 3.357. The standard error of the estimate is 1.306. Using the mean value of the

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[7] The regression model based on Equation 3.17 was also run in log form. However, the results were inferior in terms of the t-statistics and the Schwartz and Akaike information criterion. The log form resulted in a weaker estimated relationship between price and wildcat drilling but was generally similar to the results for Equation 3.17.

TABLE 3.3

DRILLING MODELS REGRESSION RESULTS

VARIABLE	PARAMETER ESTIMATE (T RATIO)	PARAMETER ESTIMATE (T RATIO)
INTERCEPT	166.25 (7.798)*	161.08 (12.239)*
PRICE	3.357 (2.569)**	
SUCCESS	252.66 (1.119)	
SIZE	0.000002 (1.835)***	
REVENUE		0.000012 (3.091)*
VARIANCE		1.97E-12 (-1.889)***
AVGCOST	0.00001 (1.071)	0.00002 (2.554)**
INTEREST	-770.35 (-2.428)**	-401.8 (-2.068)***
REG R^2	0.6	0.6
TOTAL R^2	0.5	0.5
SBC[1]	246.67	247.52
AIC[2]	236.92	238.98
DURBIN-WATSON[3]	2.2559	1.6344

* Significant at 0.01 level.
** Significant at 0.05 level.
*** Significant at 0.10 level.

[1] Schwartz Information Criterion.

[2] Akaike Information Criterion.

[3] Durbin-Watson statistic before data transformation.

wildcat well variable (156.55) and the mean of the price variable (13.04), the price elasticity of wildcat drilling is calculated to be 0.279. In other words, a 1% change in the price of oil and gas is estimated to lead to a change in wildcat drilling activity of less than 0.3% (the relationship is positive). This is an average elasticity for the full sample. This result is counter-intuitive; it is generally thought that higher oil prices greatly stimulate drilling activity. If the parameter was higher by an amount equal to the standard error (i.e., equal to 4.663) the elasticity estimated in the same manner would be 0.338.

One possible explanation for this result is the presence of multicollinearity. A collinearity diagnostic performed on this data shows that price and interest rate are linearly related (the correlation coefficient is 0.85). Average cost may be related to both the price and interest rate (correlation coefficients of (0.77 and 0.76, respectively). The presence of multicollinearity may prevent the econometric model from detecting the full impact of price on wildcat drilling. However, the parameter estimates are stable around the reported values when variables are removed from the regression.

It has been suggested that because of a changing regulatory environment, drilling firms may have changed the way in which they formed expectations about future prices. During the early part of this period prices were quite stable; after 1972, prices were less stable and regulated in a way that kept them under the world price. Since complete deregulation in 1982, prices have been very volatile. To determine the role played by these differing environments in the

relationship between price and wildcat drilling, a three regime model was estimated. The resulting coefficients on the two early regime (i.e., from the first period to 1972 and from 1973 to 1982) price parameters were negative. The third regime coefficient was positive but smaller than the estimated coefficient for the overall model. Under the assumption that during the earliest regime, when prices were most stable, the price variable used in this model most nearly represented drillers' expectations, this result is unexpected. The very stability of the prices means that there is almost no variability in the data and this fact may cause problems for the estimating program in the earliest regime.

The results of the discovery process model are presented in Table 3.4. The full work was done only for size classes 1 through 8, the largest size classes. The other classes were handled by calculating $F_i(\infty)$ using an economic truncation factor, and then calculating C_i using Equation 3.18 by plugging in the calculated values of $F_i(\infty)$. This was done because an examination of the raw data indicates that economic truncation sets in with size class 8. Table 3.2 shows that the number of known fields in each class declines steadily after size class 7, while we expect that the distribution of fields by size class is lognormal (see Attanasi and Drew, 1985). Based on the relationship between size classes 1 through 8, an economic truncation factor of 1.2 was used to estimate $F_i(\infty)$ for classes 9 through 19. The value of C_i for classes 9 through 19 is 1.00. This is in part the result of the economic truncation that is taking place; it is possible that the efficiency of discovery is

TABLE 3.4

DISCOVERY PROCESS MODEL REGRESSION RESULTS

CLASS	KNOWN FLDS	$F_i(\infty)$	C_i
1	17	17	4.48
2	24	24	3.96
3	25	25	3.48
4	48	48	4.01
5	54	54	3.24
6	41	47.8	1.48
7	50	57.7	1.98
8	32	49.6	1.17
9	33	55	1.00
10	19	66	1.00
11	15	79	1.00
12	15	95	1.00
13	11	114	1.00
14	9	137	1.00
15	8	164	1.00
16	5	197	1.00
17	5	236	1.00
18	4	284	1.00
19	6	341	1.00

For size classes 9 through 19, the ultimate number of fields ($F_i(\infty)$) is estimated using the economic truncation factor (1.2). See text for details.

greater than 1.00 for some or all of these size classes. However, I see no way to accurately estimate C_i for these classes given the limitations of the data. This problem will adversely affect the forecasts of drilling activity by understating the rate at which new fields are discovered.[8]

Given the results of the drilling models and the discovery process model, it is possible to make forecasts of drilling activity in coastal south Louisiana. This is done by using the 1986 success ratio and average size of new discoveries as the expected values of those variables for 1987. Using these values and a value for the expected price along with the parameter estimates from the two drilling models results in a forecast of the number of wildcat wells drilled in 1987.[9] By using this forecast in Equation 3.18, an estimate can be made of the average size of new discoveries and the success ratio. This allows a forecast for 1988 in the same fashion that the 1987 forecast is made. This recursive process is repeatable.

Since the number of wildcat wells drilled is known for the years 1987 through 1990, the forecasting was broken into two stages. First, forecasts were made for 1987 through 1990 using three different price paths (and average costs for the model based on Equation 3.12) so that

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[8] Other economic truncation factors were also used. The relationship between the first 8 classes was fitted using a quadratic function, and this was applied to classes 9 through 19. A factor of 1.65 was used based on the work of Drew, et al. These two factors gave very unrealistic results. For instance, using a factor of 1.65 indicates that there may be as many as 10,000 undiscovered fields in coastal south Louisiana.

[9] The average cost variable was dropped from the forecasting using Equation 3.17 since it was insignificant in that model. It was retained for forecasting using Equation 3.12.

a comparison could be made between the forecasts and the actual activity. Then a forecast was made for 1991 through 2001 using the price path that gave the best results in the first stage.

One other adjustment was made. In 1986, oil prices dropped precipitously and became more volatile. This indicates that a change in the structural equations also occurred. This fact is recognized by calibrating the model to 1987, by calculating a new intercept parameter that forces the model to accurately forecast the level of wildcat drilling in 1987. This procedure was carried out for both wildcat drilling models.

Table 3.5 shows calibrated and uncalibrated forecasting results based on Equation 3.17 for 1987 through 1990. Three different price paths were used: the actual price for each year, the real price in 1986 (used for each year), and the real price in 1986 increased 2% each year. The calibrated model using the actual price matches most closely with the actual numbers of wildcat wells drilled during the period.

In Table 3.6, the results of the same procedures carried out using Equation 3.12 are presented. In this case, the different price paths also correspond to different average cost figures. The actual average cost, the real 1986 average cost (used for each year of the forecast), and the real 1986 average cost increased 2% each year were used. Again, the calibrated model using the actual price and average cost most accurately forecasted the level of wildcat drilling.

The second stage of forecasting using the calibrated model based on Equation 3.17 and the actual real price of oil and gas in 1990

TABLE 3.5

DRILLING FORECASTING RESULTS, 1987 - 1990
Uncalibrated Model

YEAR	ACTUAL WELLS	ACTUAL P	CONSTANT P	+2%/YR P
1986	149	149	149	149
1987	79	165	170	171
1988	66	159	163	165
1989	51	151	161	164
1990	46	158	163	167

DRILLING FORECASTING RESULTS, 1987 - 1990
Model Calibrated to 1987

YEAR	ACTUAL WELLS	ACTUAL P	CONSTANT P	+2%/YR P
1986	149	149	149	149
1987	79	79	84	85
1988	66	72	77	79
1989	51	65	75	77
1990	46	73	77	82

NOTES: Actual P is the actual real price of oil and gas at the wellhead in south Louisiana; Constant P is the real price of oil and gas at the wellhead in south Louisiana in 1986 (used for all five years of the forecast); +2%/yr P is the real price of oil and gas at the wellhead in south Louisiana in 1986 increased by 2% per year over the five years of the forecast. The actual AAA corporate bond interest rate was used in all cases. The calibrated model was calibrated to 1987. See text for details.

TABLE 3.6

DRILLING FORECASTING RESULTS, 1987 - 1990
MacAvoy and Pindyck Model, Uncalibrated

YEAR	ACTUAL WELLS	ACTUAL P	CONSTANT P	+2%/YR P
1986	149	149	149	149
1987	79	149	160	161
1988	66	154	158	159
1989	51	155	157	158
1990	46	154	157	160

DRILLING FORECASTING RESULTS, 1987 - 1990
MacAvoy and Pindyck Model, Calibrated to 1987

YEAR	ACTUAL WELLS	ACTUAL P	CONSTANT P	+2%/YR P
1986	149	149	149	149
1987	79	79	90	91
1988	66	84	88	89
1989	51	84	86	87
1990	46	84	87	90

NOTES: Actual P is the actual real price of oil and gas at the wellhead in south Louisiana for each year of the forecast; Constant P is the real 1986 price of oil and gas at the wellhead in south Louisiana (used for each year of the forecast); +2%/yr P is the real 1986 price of oil and gas at the wellhead in south Louisiana increased 2% each year of the forecast. The actual AAA corporate bond interest rate was used in each case. See text for details.

resulted in the forecasts shown in Table 3.7. The results show that the number of wildcat wells, the number of new fields expected to be found, the size of those fields and the success ratio of wildcat drilling all decline more or less smoothly. This is consistent with the underlying theory, since we expect the largest fields to be found first and smaller fields to be found as drilling continues. In addition, it is expected that it will become more and more difficult to find new fields as more drilling takes place, since smaller fields are more difficult to find.

Table 3.8 shows the results of the same procedures carried out with the calibrated wildcat drilling model of Equation 3.12. Again, the actual real 1990 price and average cost are used. The forecasts are broadly similar to those presented in Table 3.7, although the Equation 3.12 model consistently predicts higher levels of wildcat drilling.

The final step is to determine how the proposed regulations will affect wildcat drilling. This requires an estimate of compliance costs on a barrel of oil equivalent basis. Several estimates of total cost of compliance exist, but it is necessary to convert them from a cost per unit of water produced to a cost per barrel of oil produced. This is difficult because for any given field the ratio of produced waters to oil and gas changes over the life of the field. It is different for every field and is not known prior to the start of production operations.

Farber and Dupont (1992) have calculated an average compliance cost on a barrel of oil equivalent (BoE) basis. They examined the

TABLE 3.7

FORECAST OF EXPLORATORY DRILLING, 1991 - 2001
Model Calibrated to 1987

YEAR	WELLS	NEW FIELDS	SUCCESS	SIZE
1991	67	5	0.084	251460
1992	67	6	0.084	251360
1993	66	5	0.083	251261
1994	67	6	0.082	251162
1995	66	5	0.082	251065
1996	66	5	0.081	250968
1997	66	6	0.080	250872
1998	66	5	0.079	250777
1999	65	5	0.079	250683
2000	65	5	0.078	250589
2001	66	5	0.077	250496

NOTES: New Fields is the number of new fields predicted to be found of all size classes, rounded to the nearest whole number; Success is the success ratio (number of new fields before rounding divided by the number of wells predicted to be drilled); Size is the average size of the predicted new discoveries in barrels of oil equivalent; Wells is the predicted number of wildcat exploratory wells drilled in each year. The actual real 1990 price ($12.56/BoE) and the actual 1990 AAA corporate bond interest rate were used for each year.

TABLE 3.8

FORECAST OF EXPLORATORY DRILLING, 1991 - 2001
MacAvoy and Pindyck Model, Calibrated to 1987

YEAR	WELLS	NEW FIELDS	SUCCESS	SIZE
1991	85	7	0.084	251396
1992	84	7	0.083	251271
1993	84	7	0.082	251147
1994	85	7	0.081	251023
1995	84	7	0.080	250900
1996	84	6	0.080	250779
1997	85	7	0.079	250658
1998	84	6	0.078	250537
1999	84	7	0.077	250418
2000	84	6	0.076	250300
2001	84	6	0.075	250182

NOTES: New Fields is the number of new fields predicted to be found of all size classes, rounded to the nearest whole number; Success is the success ratio (number of new fields before rounding divided by the number of wells predicted to be drilled); Size is the average size of the predicted new discoveries in barrels of oil equivalent; Wells is the predicted number of wildcat exploratory wells drilled in each year. The actual real 1990 price ($12.56/BoE) and Avgcost ($1229786) were used, as well as the 1990 AAA corporate bond interest rate, for each year.

ratio of produced waters to produced hydrocarbons for fields in south Louisiana and then chose the median value of these ratios. They used this median value to convert two compliance cost estimates to a cost per barrel of oil basis. The two compliance cost estimates were from a study by Walk, Haydel and Associates (1989) and Kerr and Associates. The Walk, Haydel study indicated a cost per BoE of $1.13, based on the assumptions that the regulations would require one injection well for every four active wells and that all injection wells would have to be drilled (as opposed to using existing but abandoned wells). The Kerr study indicated a cost of $0.27/BoE based on the cost of subsurface injection of produced waters at commercial injection facilities. Neither of these estimates is without problems (see Chapter 1), but given that no other estimates are available Farber and Dupont used the average of these two estimates, $0.70 per barrel of oil equivalent, as their compliance cost. This estimate of the compliance cost is also used in this study.

A sensitivity analysis was carried out to compare the impact of the various compliance cost estimates and different parameter estimates for the price variable. The results are presented in Table 3.9. The columns represent the parameter estimates: in the center is the reported estimate (3.357), on the right is the parameter plus the standard error (4.663), while on the left is the parameter minus the standard error (2.051). The rows represent the different compliance cost estimates discussed previously, starting with the Walk, Haydel estimate at the top. The numbers inside the table are the changes in the number of wildcat wells drilled in a year, reported as negative

TABLE 3.9

SENSITIVITY ANALYSIS SUMMARY

β = 2.051		β = 3.357		β = 4.663	
COST	EFFECT	COST	EFFECT	COST	EFFECT
$1.13	-2.26	$1.13	-3.79	$1.13	-5.2
0.70	-1.4	0.70	-2.35	0.70	-3.22
0.27	-0.48	0.27	-0.8	0.27	-1.1

β is the parameter estimate on Price in the drilling model. Cost is the estimated compliance cost from the Walk, Haydel study, Farber and Dupont (1992), and the Kerr and Associates study, respectively. Effect is the decrease in wildcat drilling activity associated with the respective compliance cost estimate and price parameter. The actual estimate of the Price parameter is 3.357.

numbers since these are all reductions over the number that would be drilled in the absence of the regulations.

Table 3.10 shows the forecasting results based on the real 1990 price of oil and gas reduced by $0.70/BoE in order to examine the effects of the regulations. In every other respect, the forecasts in Table 3.10 are identical to the results in Table 3.7. By comparing the two, it can be seen that the regulations reduce the level of wildcat drilling, which slows the decline in the success ratio and average size of new discoveries. In other words, the drilling activity is delayed and future discoveries are therefore also delayed. Table 3.11 repeats the procedures outlined above for the drilling model based on Equation 3.12. By comparing this table with Table 3.8, one can see how this model predicts that the regulations will affect drilling in south Louisiana. The same broad conclusions apply, namely that the drilling activity and discovery is delayed.

7. Summary and Conclusions

Two different approaches to modelling oil and gas drilling activity in coastal south Louisiana have been utilized. Both of these models provide broadly similar results, and it appears that wildcat drilling is fairly insensitive to the price of oil and gas. The drilling models in combination with a discovery process model form an overall model that can be used to forecast future levels of wildcat drilling activity. These forecasts indicate that drilling activity will continue to decline even if real oil and gas prices are constant. This may result from the fact that the study area (coastal south

TABLE 3.10

FORECAST OF EXPLORATORY DRILLING WITH REGULATIONS
Model Calibrated to 1987

YEAR	WELLS	NEW FIELDS	SUCCESS	SIZE
1991	65	5	0.085	251460
1992	64	6	0.084	251363
1993	64	5	0.083	251268
1994	64	5	0.082	251173
1995	64	5	0.082	251079
1996	64	5	0.081	250985
1997	64	5	0.080	250893
1998	63	5	0.080	250801
1999	63	5	0.079	250710
2000	63	5	0.078	250619
2001	63	5	0.078	250529

NOTES: New Fields is the predicted number of new fields to be found, rounded to the nearest whole number; Success is the success ratio of drilling (the predicted number of new fields before rounding divided by the predicted number of exploratory wells); Size is the average size of predicted new fields; Wells is the predicted number of wildcat exploratory wells. The actual real 1990 price of oil and gas less compliance costs ($11.86/BoE) and the actual 1990 AAA corporate bond interest rate were used for each year.

TABLE 3.11

FORECAST OF EXPLORATORY DRILLING WITH REGULATIONS
MacAvoy and Pindyck Model Calibrated to 1987

YEAR	WELLS	NEW FIELDS	SUCCESS	SIZE
1991	85	7	0.084	251396
1992	84	7	0.083	251271
1993	84	7	0.082	251147
1994	84	7	0.081	251023
1995	85	7	0.081	250901
1996	84	6	0.080	250779
1997	84	7	0.079	250658
1998	84	6	0.078	250538
1999	84	7	0.077	250419
2000	84	6	0.076	250301
2001	84	6	0.075	250183

NOTES: New Fields is the predicted number of new fields to be found, rounded to the nearest whole number; Success is the success ratio of drilling (the predicted number of new fields before rounding divided by the predicted number of exploratory wells); Size is the average size of predicted new fields; Wells is the predicted number of wildcat exploratory wells. The actual real 1990 price of oil and gas less compliance costs ($11.86/BoE), the actual real 1990 Avgcost ($1229786) and the actual 1990 AAA corporate bond interest rate were used for each forecast year.

Louisiana) has been thoroughly explored and it is assumed that only small fields remain to be found and developed.

The proposed regulations would impose costs on firms engaged in the petroleum industry, and these costs would reinforce these trends. The drilling will be spread farther into the future, as would the discovery of new fields and the corresponding production from those fields.

CHAPTER 4

PRODUCTION

1. Introduction

Regulatory changes, as well as tax and price changes, can affect the production of oil and gas in three ways: the rate at which oil and gas is produced may be altered, the productive life of a well or field may be changed, or in the case of newly discovered oil whether the field is developed. This chapter will address all three issues and attempt to develop models that explain producing firms' responses to costly new regulations.

2. Models of Production from Existing Fields

There are essentially two types of models that seek to describe the rate of production of hydrocarbons from a reservoir. First are the geophysical (engineering) models, pioneered by M. King Hubbert in 1962. These models explain oil production solely on the basis of engineering concepts and ignore any economic or regulatory variables. Production is modelled as rising quickly to a peak level, followed by a long decline in production rates as the natural drive mechanism slowly loses its energy. These models focus on estimating the decline rate and estimate ultimate production from a field or well as a function of that decline rate.

In response to changes in the oil industry in the early 1970's, economists unleashed a flood of oil models (see, eg, MIT Energy Laboratory, 1974 and National Petroleum Council, 1971). These models

stood on the premise (whether explicit or implicit) that oil prices reflect all relevant data. Kaufmann (1991) reports that these models performed very poorly and in general tended to overestimate the response of oil supply to changes in oil price. More recent econometric models of oil supply and production do not seem to have improved matters much (see Hall, et al., 1986).

Kaufmann (1991) attempts to combine the engineering and econometric models by arguing that geophysical factors impose severe constraints on a firm's ability to respond to economic variables. He calculates a "natural" decline rate using a model developed by Hubbert (1962), and then calculates what production would have been each year had production declined at that "natural" rate. Then he finds the difference between actual production and the calculated production, and proposes that this residual represents the response of oil production to changes in economic and political variables. It is the residual (not the actual production level) which is explained by prices and other variables.

Kaufmann uses Equation 4.1 to describe the "natural" decline rate (Kaufmann, 1991, p. 114):

$$4.1)\ \ln[(Q_\infty/Q_t)-1] = \ln a - b(t-t_0)$$

where Q_∞ is the (separately estimated) ultimate production of oil, Q_t is the cumulative production at time t, and t_0 is the start date of production. Given an estimate of this equation, it is possible to backcast annual production at the "natural" decline rate noting that Q_t

is cumulative production. The difference between this estimated backcast production and the actual production is R_t, the residual at time t. Kaufmann models the residual as follows:

$$4.2)\ R_t = \alpha + \beta_1(P_{o(1,2)}) + \beta_2(P_{o(3,4,5)}) + \beta_3(P_o/P_g) + \beta_4(TRC) + \beta_5(\Delta\hat{Q}_t)$$

in which $P_{o(1,2)}$ and $P_{o(3,4,5)}$ are the average real price of oil 1 and 2 years ago and 3, 4, and 5 years ago respectively. P_o/P_g is the ratio of the real price of oil and the real price of natural gas. Using Texas as the source of his observations, TRC represents the fraction of production capacity shut in by the Texas Railroad Commission. $\Delta\hat{Q}_t$ is the first difference of the backcast production after the peak but zero before the peak. Kaufmann uses this variable to test the symmetry of the backcast production curve.

An alternative specification to Equation 4.2 is one that recognizes Hotelling's (1931) analysis of natural resource production. Hotelling argued that the expected change in price net of production costs (net price) and the expected interest rate would jointly influence the production of a natural resource such as oil. The Hotelling model tells us that the real (net) price of oil will rise at the rate of interest, assuming a perfectly competitive industry, no rule of capture, no uncertainty, and constant demand. If the percentage change in real net price of oil ($\%\Delta P_o$) is greater than the real interest rate (I), a decrease in production is expected as firms leave the oil in the ground awaiting the higher future prices. If $\%\Delta P_o < I$, firms will increase production, increasing current revenues

(relative to future revenues at lower prices) and earning the relatively higher rate of interest. A Hotelling variable is created by taking the difference between the percentage change in the real price of oil and the real interest rate. It is possible to test Hotelling's theory. For this reason, the following alternative specification was tested:

$$
\begin{aligned}
&4.3)\ R_t = f(\%\Delta P_o - I) \\
&\textit{where } R_t > 0 \quad \textit{if } (\%\Delta P_o - I) < 0 \\
&R_t < 0 \quad \textit{if } (\%\Delta P_o - I) > 0 \\
&R_t = 0 \quad \textit{if } (\%\Delta P_o - I) = 0
\end{aligned}
$$

Hotelling's thesis can also be tested by using the actual production rates and the same explanatory variable on the right hand side.

Finally, a piece-wise continuous form of Equation 4.3 can be tested wherein the dependent variable is the residual and the independent variable is the natural log of the absolute value of the Hotelling variable multiplied by a dummy variable equal to 1 when the Hotelling variable is positive and 0 otherwise plus the natural log of the absolute value of the Hotelling variable multiplied by a dummy variable equal to 1 if the Hotelling variable is negative and zero otherwise. The sign of the parameters is expected to be negative when the Hotelling variable is positive and positive when the Hotelling variable is negative. However, the response of producers may be asymmetric in that it is no doubt easier to lower production than to raise production. For that reason, it is expected that more parameters will be significant when the Hotelling variable is positive

than when it is negative. Unfortunately, without knowing what producers' price expectations were at the time that these production decisions were being made, the percentage changes in actual historical prices were used in calculating the Hotelling variables.

The best test of Hotelling's theory would take into account producer price expectations. Therefore, a model was tested in which the Hotelling variable was constructed using future prices as if producers knew with perfect foresight what oil prices would be next period. The parameter estimates obtained were significant in some cases, primarily for the medium to large fields. This type of model is obviously not useful for forecasting purposes is mentioned here only to illustrate that expectations do play a role in producer firm decision making.

Hotelling's comparative statics indicate that an expected increase in the cost of production which will reduce net price will cause production to increase (since the higher production costs will cause $\%\Delta P_0$ to fall below I). If the increase in production cost is expected to be temporary and the net price is expected to return to current real levels over time, the current net price will fall relative to future net price causing $\%\Delta P_0 > I$ and a decrease in current production. However, if the increase in production costs and the corresponding fall in net price is a one time discrete change, this will not affect the percentage change in net price and thus will not affect production rates at all.

One serious problem with Kaufmann's approach is the use of an estimated "natural" decline rate. The firm has some influence over

the decline rate through decisions about initial capital investment in a field or well. A larger investment in the field will lead to a higher initial capacity and a higher decline rate (production will fall more quickly from one period to the next). Two factors will mitigate the tendency for the firm to produce the oil as quickly as possible. The marginal cost of initial capacity is increasing, but additionally (and more importantly) the more quickly a field or well is produced (ie, the higher the initial capacity) the less oil that is ultimately recovered. Thus the firm will choose the optimal initial capacity and simultaneously choose (within the geophysical limits defined by the reservoir and its drive mechanism) the decline rate. There may be no "natural" decline rate in the sense that Kaufmann apparently uses the word.

A different approach to synthesizing the engineering and econometric approaches is that of Camm, et al. (1982) and Deacon, et al. (1990). These studies examine the impact of new or higher state severance taxes on oil produced in California and are very relevant to this thesis. Camm, et al. argue that the decline rate is fixed by the initial capacity and that therefore production does not deviate significantly from the path dictated by the decline rate. Camm, et al. do not include production as a choice variable for firms in their model. They reason further that even in the face of rising real oil prices costs must rise faster than revenues, else no well or field would ever be shut down for economic reasons. Thus net revenues from a field or well decline at a constant rate in their model, and the effects of a change in the level of net price (resulting from the

imposition of costly regulations, for instance) will affect production only in the choice of the period in which the well or field will be shut down. The change will not affect the rate of production in Camm, et al.'s model.[10]

If decline rates are fixed by the choice of initial capacity, as asserted by Camm, et al. and Deacon, et al., then changes in the net price of oil will only affect the minimum economic field size and the shut down point (discussed in the following Section) but not the rate at which oil is produced from existing fields. If, on the other hand, the extracting firm has control over the decline rate, then changes in the real net price of oil will affect production from current on-line wells. This question of whether or not decline rates of on-line wells (ie, production rates) respond to changes in economic variables is testable empirically.

In addition to Equation 4.2 and the two forms of Equation 4.3, two other specifications of firm production decisions can be tested. First, actual production could be specified as a function of the three price variables which appear in Equation 4.2. In addition, actual production could be specified as a function of the current real price of oil. These five specifications generally stem from the assumption that firms adjust their output (production) in response to price changes (or changes in net price) in order to maximize profits.

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[10] Note that the Hotelling model suggests that production is affected only by changes in net price, not the absolute price (except when the absolute price falls so low that the decision is made to shut in a well or when it rises so high that no sales are made). In this very narrow sense, the model of Camm, et al. follows the Hotelling model.

3. Models of Field Development and Shut Down Decisions

There are several major approaches to determining the firm's shut down point and the related question of the minimum size of a field which may be profitably developed (the minimum economic field size). That these two issues are the same is clear when it is considered that for a field which is not sufficiently large to profitably develop, the shut down time is identical to the initial period. A well or field is shut down (or shut in) if production ceases. However, this is not the same as abandonment. Abandonment is a permanent destruction of a well, usually by plugging it with cement and removing all surface equipment. A firm can shut in a well for a period of time and then restart production at a later date, but this appears to be a relatively rare event. Clarke and Reed (1990) point out that the shut down decision is quite complex and the outcome is dependent on the firm's expectations of future prices. Clarke and Reed develop an elegant model of the shut down decision[11], but are unable to carry out any empirical work because of the data requirements of their model.[12]

A simpler model of the shut down decision is developed by Camm, et al. (Deacon, et al. develop a similar model). It builds on the results of their production model in that it is assumed that the decline rate is partly determined by the initial investment in capacity but that it is not sensitive to price changes. Further, the

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[11] They actually develop a model of the abandonment decision, but the shut down decision is implicit in this.

[12] For further evidence of the extreme difficulty of applying dynamic models of natural resource production, see McDonald, 1991.

authors assume that there is some cost that is related to initial capacity but that is not related to production (ie, a fixed cost). Finally, they assume that production will continue so long as "revenues net of taxes can cover annual operating costs" (Camm, et al., p. 180).

In the face of some irreducible level of uncertainty about future prices it is reasonable to model the firm as making the decision whether to continue production or to shut down as a discrete, periodic decision. Camm, et al. start by specifying current production (in period t_c) as:

$$4.4)\quad K(t_0)\, e^{-\delta(t_c-t_0)}$$

where $K(t_0)$ is initial capacity, δ is the decline rate and t_0 is the initial production date. Now, revenue net of production related costs and taxes is:

$$4.5)\quad p\cdot K(t_0)\, e^{-\delta(t_c-t_0)}$$

where p is the price net of production related costs and taxes, and other variables are defined as before. Production continues until time t_c when:

$$4.6) \quad (p \cdot e^{-\delta(t_c - t_0)} - b_0) K(t_0) = 0$$

where b_0 are non-production related, but non-sunk, fixed costs measured in dollars per barrel of initial capacity and other variables are defined as before.

By examining Equation 4.6 it can be shown that the change in the productive life of a field is represented by the following relationship,

$$4.7) \quad T' - T = \frac{1}{\delta} \ln\left(\frac{p'}{p}\right)$$

where net price changes from p to p′ and field life changes from T to T′ (Camm, et al., p. 182). Equation 4.7 will lead to estimates of the change in productive life of any given field in the face of a change in the price of oil.

The assumption of price exogeneity allows a calculation of the profit maximizing firm's shut down point and thus leads to a calculation of lost production due to the regulations. The firm will continue to produce oil until the price of the oil is equal to the marginal cost of production. Since the production by an individual firm in coastal south Louisiana is assumed to have no effect on the price of oil we have only to estimte the marginal cost. This is done by calculating the direct operating costs for future years based on the estimated cost function (see Section 4.4). For each year, the operating cost is the increase in total cost of producing the field

while the production is the increase in total output from the field. The marginal cost for the year's production is derived by dividing these two.

Since the costs are steadily increasing and production is steadily decreasing, it is seen that the marginal cost is increasing from year to year. This is due primarily to the effect of depletion; each barrel of oil is more costly to extract than the previous one. However, readers should keep in mind that several assumptions are being made here. It is assumed that the marginal costs are constant for each year and only change from one year to the next rather than being a smoothly continuous function. This implies that the results of the procedure just outlined will only provide an upper bound on the lost production volume. For instance, if the calculated marginal cost is $18 in one year and $22 the next and the price is assumed to be $20 per barrel (all in constant dollars), we can say that production will continue through the first year but will not take place in the second year. With the regulations in place at an estimated cost of $0.70 per barrel, the upper bound on the lost production is the production from the first year even though we still predict production to continue through the first year but not the second. The model cannot provide precise estimates of lost production. In addition, no enhanced oil recovery is allowed in the model.

To calculate the minimum economic field size and its sensitivity to changes in net price, it is recalled that firms wish to maximize the net present value (NPV) of production from a field. The NPV of production can be expressed in the following form:

$$4.8)\ NPV = -SC + P_o \cdot K \cdot \int_0^T e^{-(r+\delta-\pi)t} dt - OC \cdot \int_0^T e^{-(r-c)t} dt$$

where SC are sunk costs (drilling expenses and production equipment), P_0 is the real 1987 price of oil, K is the initial production level, r is the interest rate, δ is the decline rate, π is the rate of real price increase, OC are annual real operating costs and c is the annual rate of increase of real operating costs. T is the expected life of the field. If the NPV is negative no production will take place. By setting NPV equal to zero and solving for K we get minimum economic field size.

4. Data and Data Sources

Data used in this chapter are summarized in Table 4.1. The data run from 1953 to 1987 giving 35 observations unless otherwise noted. Annual data were used because much of it is not available on any other basis.

Annual production from selected fields was obtained from the 1953 through 1987 editions of Annual Oil and Gas Report. A description of how the ultimate production of oil for individual fields was estimated can be found in Chapter 3. The time variable used in Equation 4.1 is simply a column of index numbers.

The economic variables were obtained from Louisiana Energy Statistics, 1909-1989. These prices were adjusted for inflation using the GNP deflator (obtained from Citibase). The interest rate is the AAA corporate bond rate (also obtained from Citibase), which was also

TABLE 4.1

PRODUCTION MODELS DATA SUMMARY

VARIABLE	MEAN	DESCRIPTION
RESIDUAL		Difference between production estimated using "natural" decline rate and actual production
PRODUCTION		Annual production
TIME		Years of production between 1953 and 1987
$PRICE_{1,2}$	\$15.74	Two year running average of net real price of oil
$PRICE_{3,5}$	\$14.53	Running average of net real oil price 3, 4, and 5 years previous
O/G PRICE	3.11	Ratio of real oil to real natural gas price
HOTEL		Hotelling variable; equal to percent change in net price less the real interest rate
PRICE	\$16.03	net real price of oil; south Louisiana onshore, at wellhead

adjusted to real values. In every case, the prices used are the wellhead price in south Louisiana.

Production cost data are only available from 1976 (see Deacon, 1993). The available data were obtained directly from Mr. Ralph Russell of the Dallas field office of the Department of Energy's Energy Information Administration. A cost series from 1953 to 1987 was constructed by regressing the natural logarithm of the available cost data against an index. The available cost data are in the form of four series (one for each of four depths) of average annual direct operating costs for a coastal south Louisiana oil field with 10 producing wells. This was converted to a cost per barrel of oil basis by dividing the annual cost by the annual oil production from the fields used in the study. This resulted in an average production cost of $0.50/bbl, with a high of $9.76/bbl and a low of $0.12/bbl (all using 1987 cost and production data). The high value resulted from a field which had very little production in 1987.

Only recently has the Louisiana Department of Natural Resources begun to keep statistics on the number of wells active in fields, so it was not possible to adjust this cost series to reflect different numbers of operating wells in the fields in the study. However, average production depths for the fields in the study were obtained from the Production Audit Reporting System (PARS) and the appropriate cost series was used based on the average producing depth for each field.

Field level data were used rather than less aggregrated data because of problems encountered obtaining and utilizing lease level

production reports. The lease level data are not as complete as the field level data, particularly for periods preceding 1978. In general, relationships not observed at the field level are not expected to be observable at a more disaggregated level.

Sunk costs of production were obtained from the DOE-EIA publication Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations, 1987 through 1989.

5. Empirical Results

Equation 4.1 was estimated for thirteen fields in south Louisiana, selected from various areas and the seven largest class sizes (see Chapter 3). Fields from smaller class sizes were not selected because, for many of them, their productive lives were so short that considerably fewer than 35 years of data exist. As it is, several of the fields actually used in the estimate ceased production before 1987. The results of these thirteen regressions are presented in Table 4.2. The regressions were run using a two period autoregressive model.

Note that in every case the intercept parameter and the parameter on the TIME variable (ie, the decline rate) are significant at the 0.01 level. These results should be viewed with some caution since the Durbin-Watson statistics indicate that the hypothesis that autocorrelation is present cannot be rejected despite the use of a second order autoregressive model.

In order to obtain net prices, it is necessary to obtain a real operating cost series. This was done using a log-linear equation as

TABLE 4.2

RESULTS OF EQUATION 4.1 FOR SELECTED FIELDS

FIELD NAME	INTERCEPT (t RATIO)	TIME (t RATIO)	DW	REG R^2	TOTAL R^2
LAFITTE	3.424 (18.546)*	-0.135 (-15.95)*	1.104	0.888	0.989
BELL ISLE	3.831 (13.071)*	-0.183 (-13.65)*	1.076	0.854	0.988
AVERY ISLAND	2.461 (11.451)*	-0.110 (-10.99)*	0.998	0.791	0.971
DEER ISLAND	3.929 (12.291)*	-0.191 (-12.52)*	1.327	0.831	0.938
BLACK BAY SE	6.607 (19.423)*	-0.282 (-17.37)*	1.235	0.904	0.968
CONSTANCE BAYOU	6.302 (2.986)*	-0.554 (-5.93)*	1.495	0.524	0.959
BAYOU SALE	3.051 (12.848)*	-0.136 (-12.72)*	1.084	0.835	0.989
JEANERETTE	2.678 (10.848)*	-0.108 (-9.41)*	1.109	0.735	0.967
POINTE A LA HACHE	1.942 (11.949)*	-0.104 (-13.55)*	1.109	0.852	0.972
LAKE LONG	2.678 (11.233)*	-0.099 (-9.01)*	1.102	0.718	0.966
BOUTTE	3.858 (12.428)*	-0.196 (-13.58)*	1.166	0.852	0.980
HOUMA SOUTH	3.621 (15.304)*	-0.156 (-11.44)*	1.101	0.840	0.974
BAYOU PEROT	2.009 (10.773)*	-0.072 (-6.68)*	0.950	0.641	0.919

* Denotes significance at the 0.01 level.

DW is the Durbin-Watson statistic after data transformation.
REG R^2 is the R^2 for the structural part of the model (ie, excluding the autoregressive parameters).
TOTAL R^2 is the R^2 for the total model, including the autoregressive parameters.

described in Section 4.4. These regressions were also run using a two period autoregressive model. The results are shown in Table 4.3. Note that the intercepts are significant at the 0.01 level in all four series, while the parameters on the index are in no case significant. These parameters were used to create four series of costs from 1953 through 1987. The absence of significance on the index parameters suggests that the reliability of the constructed cost series is low. This may affect the estimates of models that use this series.

The estimated decline rates (Table 4.2) were used to backcast production (as described in Section 4.2). The difference between actual and backcast production (the residual, R_t) was used as the dependent variable for two different regressions for each of the thirteen fields. The explanatory variables used are given in the text, except that neither the TRC variable nor the first difference of the backcast production was used. Kaufmann used the first difference of the backcast production as a test of the symmetry of his model, not as an explanatory variable. Louisiana had no system of production allowables similar to that of the Texas Railroad Commission. The exact form of the relationships is not known, so a linear model was used in each case, following Kaufmann. Thus for each field five different regression results are reported. Each regression was run using a two period autoregressive model. These results are presented in Tables 4.4(a) through 4.4(m).

Eight of the fields in this study exhibit at least one price parameter that is significant using a one tail t-test. One tail tests were utilized since there are very strong theoretical reasons for

TABLE 4.3

REGRESSION RESULTS FOR COST FUNCTION

DEPTH	INTERCEPT (t RATIO)	INDEX (t RATIO)	DW	REG R^2	TOTAL R^2
2000'	11.6327 (74.20)*	0.0148 (0.63)	2.998	0.053	0.875
4000'	11.9941 (93.21)*	0.0146 (0.74)	2.898	0.072	0.942
8000'	12.1704 (68.60)*	0.0076 (0.31)	2.868	0.011	0.916
12000'	12.3581 (85.91)*	0.0225 (1.03)	2.859	0.130	0.880

* denotes significance at the 0.01 level. Note that the dependent variable is the natural logarithm of the direct operating cost for each depth classification.

TABLE 4.4(a)

LAFITTE OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT (t ratio)	-115918 (-0.026)	-1E+6 (-0.40)	6560521 (2.202)**	4455829 (2.28)**	4769664 (2.57)**
$PRICE_{1,2}$ (t ratio)	-5787 (-0.078)		-24156 (-0.39)		
$PRICE_{3,5}$ (t ratio)	-50175 (-0.376)		-90704 (-0.95)		
O/G PRICE (t ratio)	115215 (0.423)		32193 (0.12)		
HOTEL (t ratio)		296954 (0.60)		308293 (0.624)	
PRICE (t ratio)					-8395 (-0.027)
DW	2.434	2.180	2.206	2.347	2.198
REG R^2	0.021	0.013	0.042	0.014	0.003
TOTAL R^2	0.967	0.967	0.955	0.954	0.953

In this and the following sub-tables, the conventions described below will be used.

*** denotes significance at the 0.01 level.
** denotes significance at the 0.05 level.
* denotes significance at the 0.10 level.

DW is the Durbin-Watson statistic after transformation.
REG R^2 is the R^2 for the structural part of the model (ie, excluding the autoregressive parameters).
TOTAL R^2 is the R^2 for the total model, including the autoregressive parameters.

TABLE 4.4(b)

BELL ISLE OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	160618 (0.19)	-68342 (-0.17)	1593251 (2.22)**	805143 (1.91)*	834903 (1.93)**
$PRICE_{1,2}$	-6379 (-0.37)		-16999 (-1.04)		
$PRICE_{3,5}$	4473 (0.20)		-12357 (-0.59)		
O/G PRICE	-61659 (-0.81)		-94075 (-1.24)		
HOTEL		-75071 (-0.52)		-70772 (-0.49)	
PRICE					-3596 (-0.41)
DW	2.090	2.108	2.244	2.177	2.191
REG R^2	0.031	0.001	0.071	0.009	0.006
TOTAL R^2	0.933	0.932	0.925	0.919	0.920

TABLE 4.4(c)

AVERY ISLAND OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	-253891 (-0.000)	136301 (0.064)	-172177 (-0.00)	1896443 (1.81)*	1489429 (0.84)
$PRICE_{1,2}$	24334 (0.780)		18891 (0.58)		
$PRICE_{3,5}$	66979 (1.37)*		59388 (1.06)		
O/G PRICE	193291 (1.027)		114502 (0.60)		
HOTEL		188470 (0.493)		192948 (0.49)	
PRICE					26639 (1.20)
DW	1.790	1.739	1.754	1.764	1.857
REG R^2	0.203	0.010	0.095	0.010	0.057
TOTAL R^2	0.908	0.885	0.843	0.824	0.838

TABLE 4.4(d)

DEER ISLAND OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	-201157 (-1.23)	-3785 (-0.05)	189043 (1.18)	215344 (3.67)***	243954 (3.58)***
$PRICE_{1,2}$	6471 (1.74)**		3461 (0.89)		
$PRICE_{3,5}$	1555 (0.33)		-3119 (-0.64)		
O/G PRICE	23174 (0.92)		3694 (0.14)		
HOTEL		51433 (0.95)		56617 (1.04)	
PRICE					-1726 (-0.58)
DW	1.992	2.020	1.938	1.911	1.934
REG R^2	0.110	0.031	0.039	0.037	0.012
TOTAL R^2	0.777	0.756	0.689	0.677	0.680

TABLE 4.4(e)

BLACK BAY SE OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	-592439 (-0.52)	-39197 (-0.19)	190478 (0.22)	438240 (0.95)	528676 (1.16)
$PRICE_{1,2}$	10303 (0.84)		4156 (0.33)		
$PRICE_{3,5}$	25141 (1.52)**		18417 (1.10)		
O/G PRICE	-18598 (-0.30)		-42218 (-0.66)		
HOTEL		-189612 (-1.69)		-175320 (-1.57)	
PRICE					-4901 (-0.67)
DW	1.926	2.113	2.198	2.134	2.041
REG R^2	0.144	0.093	0.079	0.081	0.015
TOTAL R^2	0.872	0.870	0.927	0.926	0.924

TABLE 4.4(f)

CONSTANCE BAYOU OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	82628 (0.80)	-17545 (-0.52)	167722 (1.33)	67632 (1.10)	54497 (1.44)
$PRICE_{1,2}$	16942 (1.13)		19491 (1.53)*		
$PRICE_{3,5}$	-16948 (-1.13)		-19496 (-1.53)		
O/G PRICE	-27373 (-1.10)		-37084 (-1.55)		
HOTEL		167 (0.42)		297 (0.49)	
PRICE					4 (0.16)
DW	2.444	2.363	1.962	1.671	2.056
REG R^2	0.113	0.009	0.201	0.012	0.001
TOTAL R^2	0.779	0.774	0.704	0.662	0.655

TABLE 4.4(g)

BAYOU SALE OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	598830 (0.19)	-420550 (-0.21)	5787811 (2.38)**	3643223 (2.15)**	3811335 (2.33)**
$PRICE_{1,2}$	4215 (0.08)		-14168 (-0.30)		
$PRICE_{3,5}$	-63399 (-0.65)		-106848 (-1.27)		
O/G PRICE	60233 (0.34)		27041 (0.16)		
HOTEL		135895 (0.41)		140144 (0.43)	
PRICE					-5872 (-0.29)
DW	2.417	2.237	2.286	2.304	2.284
REG R^2	0.045	0.006	0.088	0.006	0.003
TOTAL R^2	0.980	0.980	0.976	0.975	0.975

TABLE 4.4(h)

JEANERETTE OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	-413975 (-0.00)	-74318 (-0.08)	682403 (0.55)	748484 (1.37)	788904 (1.28)
$PRICE_{1,2}$	3227 (0.22)		-2640 (-0.20)		
$PRICE_{3,5}$	15980 (0.84)		6833 (0.42)		
O/G PRICE	12837 (0.21)		878 (0.01)		
HOTEL		19840 (0.19)		20952 (0.19)	
PRICE					-141 (-0.02)
DW	2.111	1.918	2.190	1.990	2.238
REG R^2	0.046	0.001	0.017	0.001	0.000
TOTAL R^2	0.969	0.967	0.945	0.944	0.944

TABLE 4.4(i)

POINTE A LA HACHE OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	4E+8 (0.03)	859567 (0.30)	3215983 (0.00)	1192756 (0.00)	1057224 (0.00)
$PRICE_{1,2}$	10046 (0.76)		5305 (0.65)		
$PRICE_{3,5}$	14346 (0.68)		4526 (0.35)		
O/G PRICE	93122 (1.51)*		87652 (2.24)**		
HOTEL		51641 (0.70)		50067 (0.65)	
PRICE					2421 (0.52)
DW	1.954	2.536	1.745	2.351	1.992
REG R^2	0.258	0.017	0.216	0.016	0.010
TOTAL R^2	0.919	0.948	0.960	0.943	0.954

TABLE 4.4(j)

LAKE LONG OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	4E+7 (0.00)	-61345 (-0.09)	285942 (0.03)	281694 (1.26)	273844 (0.56)
$PRICE_{1,2}$	987 (0.32)		578 (0.20)		
$PRICE_{3,5}$	2457 (0.64)		2454 (0.68)		
O/G PRICE	-7915 (-0.38)		-14427 (-0.72)		
HOTEL		-3756 (-0.69)		-3594 (-0.65)	
PRICE					2001 (0.96)
DW	1.828	1.880	2.054	1.822	2.109
REG R^2	0.137	0.017	0.044	0.015	0.032
TOTAL R^2	0.974	0.973	0.945	0.945	0.944

TABLE 4.4(k)

BOUTTE OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	-336757 (-2.1)**	-4221 (-0.07)	103705 (0.61)	210194 (4.27)***	244084 (3.71)***
$PRICE_{1,2}$	4819 (0.94)		330 (0.06)		
$PRICE_{3,5}$	5061 (0.80)		-299 (-0.04)		
O/G PRICE	61483 (2.19)**		30960 (1.04)		
HOTEL		45587 (0.73)		43959 (0.70)	
PRICE					-2560 (-0.74)
DW	2.110	1.962	2.113	2.026	2.096
REG R^2	0.162	0.019	0.046	0.017	0.018
TOTAL R^2	0.774	0.740	0.701	0.688	0.691

TABLE 4.4(1)

HOUMA SOUTH OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	-365139 (-0.27)	-26586 (-0.41)	-21742 (-0.61)	104675 (11.62)***	73937 (2.38)**
$PRICE_{1,2}$	11016 (3.06)***		838 (0.26)		
$PRICE_{3,5}$	17835 (4.03)***		14245 (3.80)***		
O/G PRICE	9415 (1.59)*		-2635 (-0.70)		
HOTEL		10107 (0.54)		4579 (0.24)	
PRICE					2982 (0.98)
DW	2.047	1.717	1.985	2.005	1.823
REG R^2	0.595	0.014	0.529	0.003	0.042
TOTAL R^2	0.971	0.932	0.747	0.491	0.573

TABLE 4.4(m)

BAYOU PEROT OIL FIELD REGRESSION RESULTS

DEPENDENT	RESID	RESID	PROD	PROD	PROD
INTERCEPT	-17179 (-0.08)	803049 (0.27)	58116 (0.62)	323073 (0.88)	135688 (0.68)
$PRICE_{1,2}$	1428 (0.33)		1442 (0.33)		
$PRICE_{3,5}$	-1423 (-0.32)		-1435 (-0.33)		
O/G PRICE	12934 (1.60)*		13519 (1.69)*		
HOTEL		281 (0.81)		281 (0.79)	
PRICE					-1147 (-0.36)
DW	1.892	2.396	1.833	1.921	1.766
REG R^2	0.116	0.031	0.127	0.029	0.006
TOTAL R^2	0.968	0.969	0.952	0.949	0.946

believing that the price parameters are positive (ie, that production should increase given an increase in prices). In general, only the smaller fields had any significant price parameters. This may indicate that smaller fields (with less production) are more sensitive to price changes than are the more productive larger fields. Note that none of the parameters on the Hotelling variables (in this case constructed using past price changes as a proxy for expected future price changes) are significant using a one tail t-test.

For each significant price parameter an elasticity was calculated using average values for both the dependent and independent variables. The derivative of R_t with respect to Q_t is equal to 1, so for the regressions in which the residual is the dependent variable the mean value of actual production was used in conjunction with the parameter estimate and the elasticity was calculated in the usual manner. The economic interpretation does not change in this case. For a summary of the calculated elasticities, see Table 4.5. The largest elasticity is 5.81, indicating a strong relationship between price and production. The smallest is 0.27, which indicates that production is rather insensitive to changes in price. The simple mean of the elasticities in Table 4.5 is 1.24.

The piece-wise continuous form of Equation 4.3 was also run using a two period autoregressive model but the results are reported separately in Table 4.6. The parameter estimates are significant in some cases, primarily for the smaller fields in the study. This implies that the ability of producers to adjust output is greater in smaller fields than in larger fields. Consistent with expectations,

TABLE 4.5

SELECTED ELASTICITY CALCULATIONS

FIELD	MEAN PRODUCTION	PRODUCTION (IND VAR)	RESIDUAL (IND VAR)
CONSTANCE BAYOU	52,798	5.81 ($P_{1,2}$)	
POINTE A LA HACHE	1,001,435	0.27 ($P_{O/G}$)	
POINTE A LA HACHE	"		0.29 ($P_{O/G}$)
HOUMA, S	105,011	1.97 ($P_{3,5}$)	
HOUMA, S	"		1.65 ($P_{1,2}$)
HOUMA, S	"		2.47 ($P_{3,5}$)
HOUMA, S	"		0.28 ($P_{O/G}$)
BAYOU PEROT	80,404	0.52 ($P_{O/G}$)	
BAYOU PEROT	"		0.50 ($P_{O/G}$)
AVERY ISLAND	1,969,648		0.49 ($P_{3,5}$)
DEER ISLAND	235,863		0.43 ($P_{1,2}$)
BLACK BAY SE	664,328		0.55 ($P_{3,5}$)
BOUTTE	216,170		0.88 ($P_{O/G}$)

The independent variable associated with the significant parameter with which the elasticity calculation has been made is given in parentheses below the reported elasticity.

TABLE 4.6

PIECE-WISE CONTINUOUS REGRESSION

FIELD	LN|H|, H>0	LN|H|, H<0	DW	REG R^2	TOT R^2
LAFITTE	-47742 (-0.611)	3802 (0.075)	2.145	0.027	0.969
BELL ISLE	-16228 (-0.945)	-26070 (-1.546)	2.060	0.082	0.937
AVERY ISL	2980 (0.046)	-9759 (-0.185)	1.733	0.002	0.889
DEER ISL	-6959 (-0.519)	-6556 (-0.631)	1.997	0.014	0.755
BLACK BAY	-26070 (-2.46)**	-28578 (-1.94)*	2.200	0.178	0.883
CONSTANCE BAYOU	-18473 (-3.20)***	-2351 (-0.712)	2.236	0.356	0.850
BAYOU SALE	3703 (0.067)	9251 (0.238)	2.240	0.003	0.980
JEANERETT	8838 (0.457)	8548 (0.486)	1.934	0.009	0.969
POINTE A LA HACHE	-5424 (-0.441)	7940 (0.834)	2.372	0.091	0.953
LAKE LONG	-13369 (-1.89)*	-16236 (-2.18)**	1.902	0.156	0.979
BOUTTE	-20709 (-1.311)	2554 (0.223)	2.030	0.115	0.765
HOUMA S	-2190 (-1.433)	-1221 (-0.735)	1.796	0.090	0.943
BAYOU PEROT	-3457 (-1.99)*	-2203 (-1.67)	2.606	0.198	0.976

* - Indicates significance at the 0.10 level.
** - Indicates significance at the 0.05 level.
*** - Indicates significance at the 0.01 level.

more of the parameters on the natural log of the absolute value of the Hotelling variable are significant when the Hotelling variable is positive than when it is negative. For the two significant parameters on the independent variable when the Hotelling variable is negative, the sign is not the expected sign.

The change in the productive life of a field can be quantified using Equation 4.7. The estimated decline rates for the thirteen fields studied here are given in Table 4.2 (the parameter estimates on the TIME variable). These range from a low value of -0.072 to a high of -0.554, and the mean value is -0.179. The average of the real oil prices used in this study is $16.03 per barrel (see Table 4.1), although the current wellhead price is approximately $20 per barrel. Using the three values for the decline rate and the two values for the price of oil, in addition to the three values of production cost per barrel (see the previous Section) and the estimated cost of compliance with the proposed regulations of $0.70 per barrel of oil (see Farber and Dupont, 1992), a range of possible values can be calculated for the change in productive life of a field in the face of these regulations. The results of these calculations are shown in Table 4.7. Note that the largest calculated loss of productive life for a field is 1.6 years. This occurs for the lowest decline rate, lowest price and largest production cost. Since Equation 4.7 is structured such that the percentage change in price is the driving factor (rather than the absolute price or absolute change in price), the $0.70 per barrel of oil compliance cost is calculated to have a larger impact at lower absolute net oil prices and lower decline rates. The production

TABLE 4.7

LOSS OF PRODUCTIVE FIELD LIFE IN YEARS
T' - T, see Equation 4.7

Cost = $9.76/bbl

p	δ = -0.072	δ = -0.179	δ = -0.554
$20	-0.983	-0.396	-0.128
$16.03	-1.644	-0.661	-0.214

Cost = $0.50/bbl

p	δ = -0.072	δ = -0.179	δ = -0.554
$20	-0.508	-0.204	-0.066
$16.03	-0.641	-0.258	-0.083

Cost = $0.12/bbl

p	δ = -0.072	δ = -0.179	δ = -0.554
$20	-0.498	-0.200	-0.065
$16.03	-0.625	-0.251	-0.081

T' is the life of the field after the change in net price, while T is the initial life of the field (both in years). The initial price is p (shown), while p' = p - $0.70 - Cost. See the text for further details.

cost per barrel for these calculations was based on the reported costs (rather than the constructed cost series) and production for 1987. The rather large upper value obtained ($9.76/bbl) was for a field with very little production in 1987. The loss of 1.6 years in productive life for such a field will have little impact on the overall production of oil in south Louisiana.

A sensitivity analysis was carried out using the three compliance cost estimates. The results are in Table 4.8. For the lowest price, highest production cost and highest compliance cost (Walk, Haydel's $1.13/barrel of oil estimate), the estimated loss of productive field life is 2.8 years. Again, this represents a field with very little production so that the actual loss of oil production is not likely to be significant.

The lost production calculation described in Section 4.3 was carried out for each field in the study for which production continued through 1987. If a real oil price of $16.03 per barrel (the average of the real oil prices for 1953 through 1987) is assumed then the mean of the upper bounds on lost production volume due to the regulations is 21,400 barrels and the median is 25,300 barrels (see Tables 4.9 and 4.10). Of course, this production is lost at the end of the life of the field and for 7 of the 11 fields this is after the turn of the century. In no case did it appear that the productive life of a field would be shortened by more than one year. In total, there are 421 fields in the coastal zone (see Table 3.2) which indicates that just over 9 million barrels of oil will not be produced because of the shortened lives of fields due to the regulations if the mean for the

TABLE 4.8

LOSS OF PRODUCTIVE FIELD LIFE IN YEARS

SENSITIVITY ANALYSIS

$1.13/barrel compliance cost

p	δ = -0.072	δ = -0.179	δ = -0.554
$20	-0.83	-0.33	-0.11
$16.03	-1.05	-0.42	-0.14

$0.27/barrel compliance cost

p	δ = -0.072	δ = -0.179	δ = -0.554
$20	-0.19	-0.08	-0.03
$16.03	-0.24	-0.10	-0.03

Note: This sensitivity analysis was carried out assuming a production cost of $0.50/barrel. It is directly comparable to the middle table in Table 4.7 (p. 93).

TABLE 4.9

SELECTED RESULTS FOR COST AND PRODUCTION FORECASTS

LAFITTE FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
2018	17,951	$14.93
2019	15,515	$17.40
2020	13,409	$20.29
2021	11,589	$23.65
2022	10,016	$27.58

BELL ISLE FIELD (8,000')

YEAR	PRODUCTION (EST)	AVERAGE COST
1999	18,716	$12.38
2000	15,290	$15.27
2001	12,492	$18.84
2002	10,206	$23.24
2003	8,338	$28.66

BELL ISLE FIELD (12,000')

YEAR	PRODUCTION (EST)	AVERAGE COST
1997	28,040	$13.62
1998	22,908	$17.05
1999	18,716	$21.34
2000	15,290	$26.71
2001	12,492	$33.44

AVERY ISLAND FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
2010	35,689	$14.33
2011	31,761	$16.47
2012	28,264	$18.93
2013	25,153	$21.75
2014	22,384	$25.00

DEER ISLAND FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
1996	16,963	$13.35
1997	13,718	$16.64
1998	11,093	$20.73
1999	8,971	$25.84
2000	7,254	$32.19

BLACK BAY, SE FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
1996	14,889	$15.21
1997	10,685	$21.36
1998	7,668	$30.00
1999	5,503	$42.12
2000	3,949	$59.14

BAYOU SALE FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
2013	19,662	$13.12
2014	16,986	$15.30
2015	14,674	$17.85
2016	12,676	$20.82
2017	10,951	$24.28

JEANERETTE FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
2010	18,776	$13.43
2011	16,756	$15.16
2012	14,953	$17.12
2013	13,345	$19.33
2014	11,909	$21.82

POINT A LA HACHE FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
2010	35,151	$14.55
2011	31,506	$16.60
2012	28,238	$18.95
2103	25,310	$21.62
2014	22,685	$24.67

LAKE LONG FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
2005	17,555	$13.82
2006	15,814	$15.46
2007	14,246	$17.29
2008	12,833	$19.34
2009	11,561	$21.64

BOUTTE FIELD

YEAR	PRODUCTION (EST)	AVERAGE COST
1992	27,324	$12.49
1993	21,961	$15.89
1994	17,650	$20.22
1995	14,185	$25.73
1996	11,401	$32.75

TABLE 4.10

SUMMARY RESULTS, LOST PRODUCTION ESTIMATES

SAMPLE	PRICE	MEAN	TOTAL	MEDIAN	TOTAL
FULL	$16.03	21,400	9 million	25,300	10.6 mil
BIG	$16.03	21,695	1.4 mil	21,665	1.4 mil
LITTLE	$16.03	21,063	4.1 mil	25,289	4.9 mil
FULL	$20.00	18,350	7.7 mil	20,400	8.6 mil
BIG	$20.00	18,130	1.2 mil	20,365	1.3 mil
LITTLE	$20.00	18,615	3.6 mil	20,991	4.0 mil

fields in the study applies to all fields. The corresponding figure for the median value is 10.6 million barrels. By comparison, total south Louisiana oil production in 1989 was over 79 million barrels (DNR-OTA, Table II.1) and cumulative production between 1926 and 1989 was 9.4 billion barrels (Lindstedt, et al., p. 58). These mean and median figures probably will not hold for all fields since the fields used in this study were all in the seven largest size classes. This was done precisely because the largest fields (while fewest in number) contain most of the oil and the smallest fields (while numerous) contain relatively little of the total reserves.

If a real oil price of $20 per barrel is assumed the estimated losses are smaller. In this case, estimated mean losses of production are 18,350 barrels and the median value is 20,400 barrels. This leads to a total estimated loss for south Louisiana of 7.7 million barrels using the mean value and 8.6 million barrels using the median value (see Table 4.10). These estimates are upper bounds as explained in the previous section and the actual losses quite possibly could be smaller.

By dividing the sample into "big" fields (from the three largest size classes) and "little" fields (from the next four largest size classes) we can perform the same calculations and compare the differences. Assuming a price of $16.03 per barrel, the mean lost production from "big" fields is 21,695 barrels while the mean from "little" fields is 21,063 barrels. There are 66 "big" fields in south Louisiana and 193 "little" fields, so that total losses from "big" fields are 1.4 million barrels and from "little" fields, 4.1 million

barrels. This translates to overall losses from the seven largest size classes of 5.5 million barrels, compared to an overall estimated loss from all fields of 9 million barrels. The lost production from the "big" fields will be much later in time than the lost production from the "little" fields. The corresponding median value results are 21,665 barrels lost from "big" fields and 25,289 barrels lost from "little" fields. The little field losses are somewhat higher because they tend to have a higher decline rate. Estimated total losses from "big" fields based on the median value are 1.4 million barrels, while "little" field losses are estimated to be 4.9 million barrels. This gives a total lost production estimate from the seven largest size classes of 6.3 million barrels compared to total south Louisiana losses of 10.6 million barrels under these assumptions.

Under the $20 per barrel price assumption, mean losses of production are 18,130 barrels for "big" fields and 18,615 barrels for "little" fields. Total "big" field losses are 1.2 million barrels and total "little" field losses are 3.6 million barrels, which sum to 4.8 million barrels. This compares to total south Louisiana losses for mean values under this scenario of 7.7 million barrels. The median "big" field losses are 20,365 barrels and median "little" field losses are 20,991 barrels. These give total estimated losses from "big" fields of 1.3 million barrels and from "little" fields of 4.0 million barrels, for a total of 5.3 million barrels. This compares to an estimated loss of 8.6 million barrels from all south Louisiana fields. See Table 4.10 for a summary of these results.

Unfortunately, because of the imprecise nature of the method used to estimate lost production from premature shutdown it was not possible to use this method to carry out a sensitivity analysis. Using the Walk, Haydel estimate of compliance cost resulted in no change in the estimated losses. The method used is simply not sensitive enough to detect these changes.

The MEFS calculation described in Section 4.3 was carried out using values for the decline rate and operating cost appreciation rate gained from other calculations in this study. The decline rates used were the average (δ = -0.179) and an arbitrarily chosen faster decline rate (δ = -0.25) because this calculation concerns small fields, and the cost appreciation rate used was the value for 8,000′ wells (c = 0.007). The rate of increase in real oil prices was arbitrarily set at zero; any positive value would tend to make the MEFS less sensitive to price changes and thus less sensitive to the regulations. T was arbitrarily chosen to be 20 years. The operating costs are averages for a 10 well field, so they were reduced by a factor of 10 since a very small field (the smallest field that is economically viable) will presumably have only one well. Results of this calculation are reported in Table 4.11. Using a price of $20 per barrel without regulations and $19.30 per barrel with regulations and δ = -0.179 leads to a change in MEFS of only 434 barrels per year or 3.63%. With the same decline rate and price at $16.03 per barrel with regulations and $15.33 per barrel without regulations, the change is 681 barrels per year or 4.57%. To put this in perspective, these changes amount to less than 1.5 barrels and 2 barrels of oil per day, respectively.

TABLE 4.11

MINIMUM ECONOMIC FIELD SIZE CALCULATION SUMMARY

PRICE	DECLINE RATE	MEFS (INITIAL PRODUCTION)
$20.00	-0.179	11,951
$19.30	-0.179	12,385
$16.03	-0.179	14,911
$15.33	-0.179	15,592
$20.00	-0.250	15,013
$19.30	-0.250	15,558
$16.03	-0.250	18,732
$15.33	-0.250	19,587

Using the higher decline rate but the same prices, the resulting changes in minimum initial capacity are 545 barrels per year (3.63%) and 855 barrels per year (4.56%). The absolute changes are larger but the percentage changes are identical. On a daily basis, these changes are 1.5 barrels and 2.3 barrels, respectively. See Table 4.11 for a summary of these calculations.

A sensitivity analysis carried out on the MEFS calculation using a different estimated compliance cost indicates that using the Walk, Haydel estimate increases the MEFS by 7.6% when using the $16.03/barrel mean price and 6.0% when using the $20/barrel price. This increase will not push the MEFS into the next larger size class, however, so the change in the loss of production due to the use of the higher compliance cost estimate will not be dramatic. See Table 4.12 for a summary of this sensitivity analysis.

The compliance costs used in this study are average costs that abstract away from considerations of fixed costs versus variable costs. If the fixed costs are high enough to offset the quasi-rents the producer will shut down even if the increase in the marginal cost due to the regulations is quite low. Because this model does not consider this aspect of compliance costs the results will not capture these effects if they are present. This question of fixed and variable cost magnitudes has implications for producer decision making. If, as the Walk, Haydel study assumes, producers will provide their own capital equipment for injection of produced water, the fixed costs would be very large and any fixed cost effect would be important. The Kerr and Associates study implicitly assumes that

TABLE 4.12

MINIMUM ECONOMIC FIELD SIZE CALCULATION SUMMARY

SENSITIVITY ANALYSIS

PRICE	DECLINE RATE	MEFS (INITIAL PRODUCTION)
$20.00	-0.179	11,951
$18.87	-0.179	12,667
$16.03	-0.179	14,911
$14.90	-0.179	16,042
$20.00	-0.250	15,013
$18.87	-0.250	15,913
$16.03	-0.250	18,732
$14.90	-0.250	20,152

Note: This sensitivity analysis was performed assuming that the Walk, Haydel estimated compliance cost ($1.13/barrel of oil) is the true compliance cost.

producers will use commercial disposal facilities and that the cost will be preponderantly variable with very low fixed costs. In that case, the fixed cost effect would be insignificant.

6. Summary and Conclusions

Two approaches to modeling oil production have been examined. The traditional econometric technique downplays the geophysical aspects of oil production and emphasizes the response of firms to changes in economic variables (primarily price). The engineering approach takes the opposite tack, in most cases ignoring economic variables altogether. An attempt has been made in this chapter to synthesize the two views.

The results of the empirical work suggest that economic variables, while playing a significant role in decisions about whether or not a field should be developed and when a field should be shut down, for the most part have little effect on decisions about how much oil will be produced each period from a producing field. The weak significance of the estimated parameters on economic variables for the large fields in the regression results reported in Tables 4.4(a) through 4.4(m) lead to the conclusion that net price does not significantly influence production levels. This is consistent with the work of Camm, et al. and Deacon, et al. However, the results of Table 4.4 indicates that price does have some influence on output decisions in smaller fields. Additionally, the piece-wise regressions using the Hotell variables indicate that for some fields this relationship is significant. These results are mixed.

The elasticity calculations in Table 4.5 are also mixed. Nine of the relationships are indicated to be inelastic while only four are indicated to be elastic. However, one of the relationships is found to be extremely elastic.

Net price does play a role in the shut down decision and it does influence minimum economic field size. However, Table 4.7 indicates that the shut down time will be brought forward only marginally, by as much as 19 months or less (out of a total productive life that can run from 20 to 30 years), if the net price of oil received by producers falls by $0.70 per barrel due to regulations. The lost production volumes are estimated to be 10.6 million barrels in a worst case scenario. These results suggest that small price changes and the imposition of the proposed regulations will have very little effect on the production of oil from existing wells in coastal south Louisiana.

Net price also plays a role in the determination of whether or not a field of a given size will be developed. The results in Table 4.11 show that the produced waters regulations will have an effect on the minimum economic field size of as little as 2.5 barrels per day initial production.

CHAPTER 5

OVERALL SUMMARY AND CONCLUSIONS

This dissertation has analyzed and quantified the economic effects of proposed produced waters discharge regulations. Produced waters are those fluids brought to the surface when oil is produced, and have been shown to harm marine life when disposed into inland waters and swamps. This study has not attempted to estimate either the economic value of the harm done by surface disposal of untreated produced waters or the economic benefits of oil and gas activity. Proposed regulations would require producers of oil to either treat the produced waters before surface disposal or to inject the untreated produced waters into underground formations. Complying with the regulations will increase the costs of production. The present analysis has been carried out by modelling the oil industry in coastal south Louisiana and incorporating the cost of compliance with the regulations into the model.

The oil industry participates in two broad phases of activities. Exploration is the process of looking for deposits of oil, primarily by drilling exploratory wells (including wildcat wells). Once a deposit of oil has been found that can profitably be developed and produced, production begins. These are very broad categorizations but they capture the most important aspects of oil industry activity. Correspondingly, this study has been divided into two analyses: a study of the exploration activity of firms, and a study of the production of oil from existing fields. This dissertation also

estimates how the regulations will affect the decision whether or not to develop a field and the related decision of when to shut down a producing field.

The exploration analysis was further broken down into two related objectives. The first objective was to estimate how various explanatory variables impact the number of wildcat wells drilled in a year. Two different models were used, both based on an objective function which firms engaged in oil exploration are assumed to maximize. The second objective was to estimate the number and size of remaining undiscovered oil fields in the study area. This was modeled by making the widely accepted assumption that fields are distributed log normally by size in a geologically homogeneous region. By dividing known fields into size classes, one can draw conclusions about the remaining fields in the region which are undiscovered.

The two models for the objectives in the exploratory drilling section can be used together recursively. In this way, it is possible to use as explanatory variables in the wildcat drilling model the wellhead price of oil and gas, the expected success rate for drilling based on the estimate of the number of remaining undiscovered fields and an estimate of finding rates relative to the cumulative number of wildcat wells, and the size of the fields expected to be found (also based on the model for the second objective). This recursive procedure allows both economic theory and variables and geological factors to be analyzed simultaneously, and a much richer model of exploratory activity is obtained.

The empirical estimates of the parameters on the explanatory variables in the exploratory model indicate that the impact of the regulations will be slight. However, the presence of multicollinearity requires that this conclusion be advanced cautiously. More definitive statements about the regulatory impact cannot be made until such time as more and better data is available. The estimated net price elasticity of wildcat drilling is 0.279 using the mean values of the price and wildcat drilling variables over all years in the sample.

The estimated parameters were used to forecast future wildcat drilling activity. These forecasts show that wildcat drilling activity will continue to decline in coastal south Louisiana under current economic and technological conditions even in the absence of new regulations. This is primarily due to the fact that coastal south Louisiana is a very mature area, has been thoroughly explored, and only the most expensive oil remains in place. The imposition of costly regulations will reinforce this trend, but the effects may be small and more in the nature of delays in the timing of exploratory drilling and discovery of new fields. Again, the presence of multicollinearity requires caution in interpreting and using these results.

The section of this study devoted to production was similarly divided into two objectives. The first objective was to estimate the relationship between price and production so that a supply elasticity could be calculated. This was approached by way of two different but parallel models. The first model is an attempt to combine economic

and geological factors in the analysis by estimating a "natural" decline rate and then using economic variables to explain deviations in actual production from the production expected based on the "natural" decline rate. This approach implies that oil producing firms have limited control over the production from their fields and thus are limited in how they can respond to changes in the net price of oil. The other approach is to say simply that firms directly vary the amount of oil produced in response to changes in net price.

Empirical results reported in Chapter 4 suggest that oil production is rather insensitive to net price. The estimated price parameters are significant in relatively few cases. Generally, they are significant for regressions involving smaller fields but insignificant for those involving larger fields. In addition, there are more significant parameters when the residual is the dependent variable than when actual production is the dependent variable. This lends support to the view that producers are constrained in their responses to changes in price insofar as altering production is concerned, particularly in large fields. Estimated price elasticities of oil production range from a high of 5.81 to a low of 0.27. The simple mean of the elasticities is 1.24. None of the parameters on the simple Hotelling variable were significant, but a piece-wise regression using the Hotelling variable indicates that producers may respond asymmetrically to changes in the Hotelling variable, primarily in smaller fields. In the absence of a good model of producer price expectations, however, this is not a true test of Hotelling's theory.

The second part of the production study attempts to estimate lost production volumes caused by early shut down of existing wells, and to quantify the effects of the regulations on the minimum economic field size. Using a model developed by Camm, et.al., an estimate was made of lost production given the reduction in net price caused by costly regulations. The worst case scenario estimate was that 1.6 years of production would be lost. This 1.6 years is at the end of the productive life of the field when produced oil volumes are very low. Forecasts of production using the decline rates and of costs using the estimated cost function were made to determine how average marginal cost would behave over time and at what point this cost would become greater than price. This procedure led to estimated losses between 10.6 million barrels of oil and 4.8 million barrels of oil, depending upon the assumptions made. The corresponding dollar values are $170 million and $96 million (these are future values). These losses will occur at the end of the life of the fields, in most cases estimated to be after the turn of the century. This estimate is based on econometric results that are counter-intuitive and should be used and interpreted cautiously.

Minimum economic field size was estimated using a net present value function, setting it equal to zero and solving for initial production. By comparing the initial production calculated at some benchmark price with the initial production calculated at the benchmark price less the cost of compliance, the impact of the regulations can be quantified. The impact of the regulations on MEFS is estimated to be quite small. The cost of compliance with the

regulations will increase MEFS by less than 5%, or 855 barrels of oil in the first year of production in a worst case scenario. That is roughly 2.4 barrels of oil per day over and above what would be needed in the absence of the regulations to make a field commercially viable. The initial production level required in this worst case scenario with the regulations in place is 19,587 barrels per year (first year). According to knowledgeable petroleum engineers that is a plausible but by no means exceptional initial production for a well in south Louisiana.

The most important aspect of this dissertation which needs further work is that of producer price expectations (see also Walls, 1992). It is crucial to an understanding of the oil and gas industry that a good model of how producers' price expectations are formed is available. This is not a simple task but it is a most important one because of the dynamic nature of this non-renewable resource extraction problem.

It will also be helpful to incorporate a more realistic and sophisticated model of the tax regime under which producers in coastal south Louisiana operate. This would allow comparisons between various fiscal systems' effects on the petroleum industry. In the current atmosphere of fiscal uncertainty in Louisiana this aspect of the model could become very attractive.

An interest in the economics of enhanced oil recovery (EOR) activity has been expressed by outside parties. Analysis of EOR economics appears to be a rather straightforward adaptation of the present model. If domestic oil and gas fields continue to decline and

the United States becomes more dependent upon foreign oil, EOR will become the focus of a great deal of attention. An estimate of the conditions under which EOR activity is profitable and how environmental regulations will affect EOR activity will be very important for policy makers.

An area for research which is not strictly a part of this effort but which is an adjunct to it is that of the demand side. A model of the demand for domestic petroleum would coincide with the current work and provide an estimate of the price of oil endogenous to the model, given some level of production in the rest of the world. This effort would not only make the model richer but would make it possible to estimate the effects of increasing corporate average fuel economy (CAFE) standards or other demand side factors on the petroleum industry in south Louisiana.

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VITA

Allen Paul Dupont was born in Houma, Louisiana on March 3, 1965. He grew up in south Louisiana, primarily Houma and Thibodaux, except for short periods in New Orleans and Stillwater, Oklahoma. He graduated from Thibodaux High School in May, 1983 and entered Rice University in Houston, Texas that fall. Mr. Dupont received his B.A. in Economics from Rice in May, 1987 and immediately went to work for Transco Energy Company in their home office in Houston. While at Transco, he worked first in the Supply Economics Group and then in the Region II Customer Services Group, giving him broad experience with natural gas pipeline operations. Mr. Dupont began his graduate studies in Economics at Louisiana State University in the fall semester of 1988. He received his M.S. in Economics in May, 1990 and will receive the Doctor of Philosophy in Economics in December, 1993.

DOCTORAL EXAMINATION AND DISSERTATION REPORT

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Major Field: Economics

Title of Dissertation: Forecasting the Economic Effects of Produced Waters Discharge Regulations on Oil and Gas Activity in Coastal Louisiana

Approved:

Major Professor and Chairman

Dean of the Graduate School

EXAMINING COMMITTEE:

Date of Examination:

July 26, 1993