Documentation of the Oil and Gas Supply Module (OGSM)

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1. Introduction

The purpose of this report is to define the objectives of the Oil and Gas Supply Model (OGSM), to describe the model's basic approach, and to provide detail on how the model works. This report is intended as a reference document for model analysts, users, and the public. It is prepared in accordance with the Energy Information Administration's (EIA) legal obligation to provide adequate documentation in support of its statistical and forecast reports (Public Law 93-275, Section 57(b)(2).

Projected production estimates of U.S. crude oil and natural gas are based on supply functions generated endogenously within National Energy Modeling System (NEMS) by the OGSM. OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes enhanced oil recovery (EOR), and unconventional gas recovery (UGR) from tight gas formations, Devonian/Antrim shale and coalbeds. Crude oil and natural gas projections are further disaggregated by geographic region. OGSM projects U.S. domestic oil and gas supply for six Lower 48 onshore regions, three offshore regions, and Alaska. The general methodology relies on forecasted profitability to determine exploratory and developmental drilling levels for each region and fuel type. These projected drilling levels translate into reserve additions, as well as a modification of the production capacity for each region.

OGSM also represents foreign trade in natural gas, imports and exports by entry region. Foreign gas trade may occur via either pipeline (Canada or Mexico), or via transport ships as liquefied natural gas (LNG). These import supply functions are critical elements of any market modeling effort.

OGSM utilizes both exogenous input data and data from other modules within NEMS. The primary exogenous inputs are resource levels, finding rate parameters, costs, production profiles, and tax rates - all of which are critical determinants of the expected returns from projected drilling activities. Regional projections of natural gas wellhead prices and production are provided by the Natural Gas Transmission and Distribution Module (NGTDM). From the Petroleum Market Model (PMM) come projections of the crude oil wellhead prices at the OGSM regional level. Important economic factors, namely interest rates and GNP(GDP) deflators flow to OGSM from the Macroeconomic Module. Controlling information (e.g., forecast year) and expectations information (e.g., expected price paths) come from the integrating, or system module.

Outputs from OGSM go to other oil and gas modules (NGTDM and PMM) and to other modules of NEMS. NGTDM employs short-term supply functions, the parameters for which are provided by OGSM for nonassociated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. The short-term supply functions reflect potential oil or gas flows to the market for a one year period. The gas functions are used by NGTDM and the oil volumes are used by PMM for the determination of equilibrium prices and quantities of crude oil and natural gas at the wellhead. OGSM also provides projections of natural gas production to PMM to estimate the corresponding level of natural gas liquids production. Other NEMS modules receive projections of selected OGSM variables for various uses. Oil and gas production and resultant emissions are forwarded to the Systems Module. Forecasts of oil and gas production, go to the Macroeconomic Module to assist in forecasting aggregate measures of output.

OGSM is archived as part of the National Energy Modeling System (NEMS). The archival package of NEMS is located under the model acronym NEMS98. The version is that used to produce the *Annual Energy Outlook 1999 (AEO99)*. The package is available through the National Technical Information Service. The model contact for OGSM is:

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This OGSM documentation report presents the following major topics concerning the model.

- Model purpose

- Model overview and rationale

- Model structure

- Inventory of input data, parameter estimates, and model output

- Detailed mathematical description.

2. Model Purpose

OGSM is a comprehensive framework with which to analyze oil and gas supply potential and related issues. Its primary function is to produce forecasts of crude oil, natural gas production, and natural gas imports and exports in response to price data received endogenously (within NEMS) from the Natural Gas Transmission and Distribution Model (NGTDM) and the Petroleum Market Model (PMM). The OGSM does not provide nonassociated gas production forecasts per se, but rather parameter estimates for short-term domestic gas production functions that reside in the NGTDM.

The NGTDM utilizes the OGSM supply functions during a solution process that determines regional wellhead market-clearing prices and quantities. After equilibration is achieved in each forecast year, OGSM calculates revised parameter estimates for the supply functions for the next year of the forecast based on equilibrium prices from the PMM and NGTDM and natural gas quantities received from the NGTDM. OGSM then sends the revised parameters to NGTDM, which updates the short-term supply functions for use in the following forecast year. The determination of the projected natural gas and crude oil wellhead prices and quantities supplied occurs within the NGTDM and OGSM. As the supply component only, OGSM cannot project prices, which are the outcome of the equilibration of demand and supply. The basic interaction between OGSM and the other oil and gas modules is represented in Figure 1. Controlling information and expectations come from the System Module. Major exogenous inputs include resource levels, finding rate parameters, costs, production profiles, and tax rates - all of which are critical determinants of the oil and gas supply outlook of the OGSM.

OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 2). The primary fuel types are crude oil and natural gas, which are further disaggregated based on type of deposition, method of extraction, or geologic formation. Crude oil supply comprises production from conventional and enhanced oil recovery techniques. Natural gas is differentiated by nonassociated and associated-dissolved gas.[1] Nonassociated natural gas is categorized by conventional and unconventional types. Conventional crude oil and natural gas recovery is differentiated by depth between formations up to 10,000 feet and those at greater than 10,000 feet (in the context of OGSM, these depth categories are referred to as shallow or deep). The unconventional gas category in OGSM consists of resources in tight sands, Devonian/Antrim shale, and coal bed methane formations.

OGSM provides mid-term (15 to 25 year) forecasts, as well as serving as an analytical tool for the assessment of various policy alternatives. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues OGSM can address involve policies that affect the profitability of drilling through impacts on certain variables including:

- drilling costs,

- production costs,

- regulatory or legislatively mandated environmental costs,

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[1]Nonassociated (NA) natural gas is gas not in contact with significant quantities of crude oil in a reservoir. Associated-dissolved natural gas consists of the combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Figure 1. OGSM Interface with Other Oil and Gas Modules
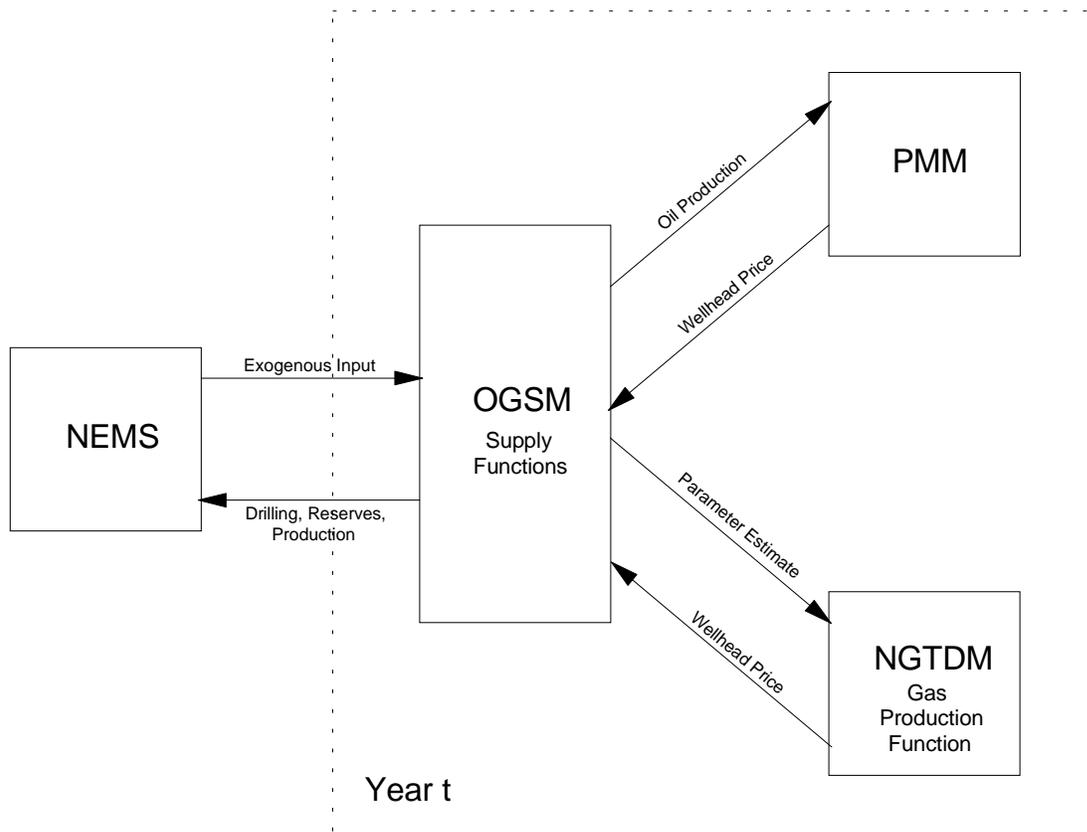
- key taxation provisions such as severance taxes, State or Federal income taxes, depreciation schedules and tax credits, and

- the rate of penetration for different technologies into the industry by fuel type.

The cash flow approach to the determination of drilling levels enables OGSM to address some financial issues. In particular, the treatment of financial resources within OGSM allows for explicit consideration of the financial aspects of upstream capital investment in the petroleum industry.

OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). This feature allows the model to be used for the analysis of issues involving:

- the uncertainty surrounding the technically recoverable oil and gas resource estimates, and

- access restrictions on much of the offshore Lower 48 states, the wilderness areas of the onshore Lower 48 states, and the 1002 Study Area of the Arctic National Wildlife Refuge (ANWR).

In general, OGSM will be used to foster a better understanding of the integral role that the oil and gas extraction industry plays with respect to the entire oil and gas industry, the energy subsector of the U.S. economy, and the total U.S. economy.

Figure 2. Oil and Gas Supply Regions
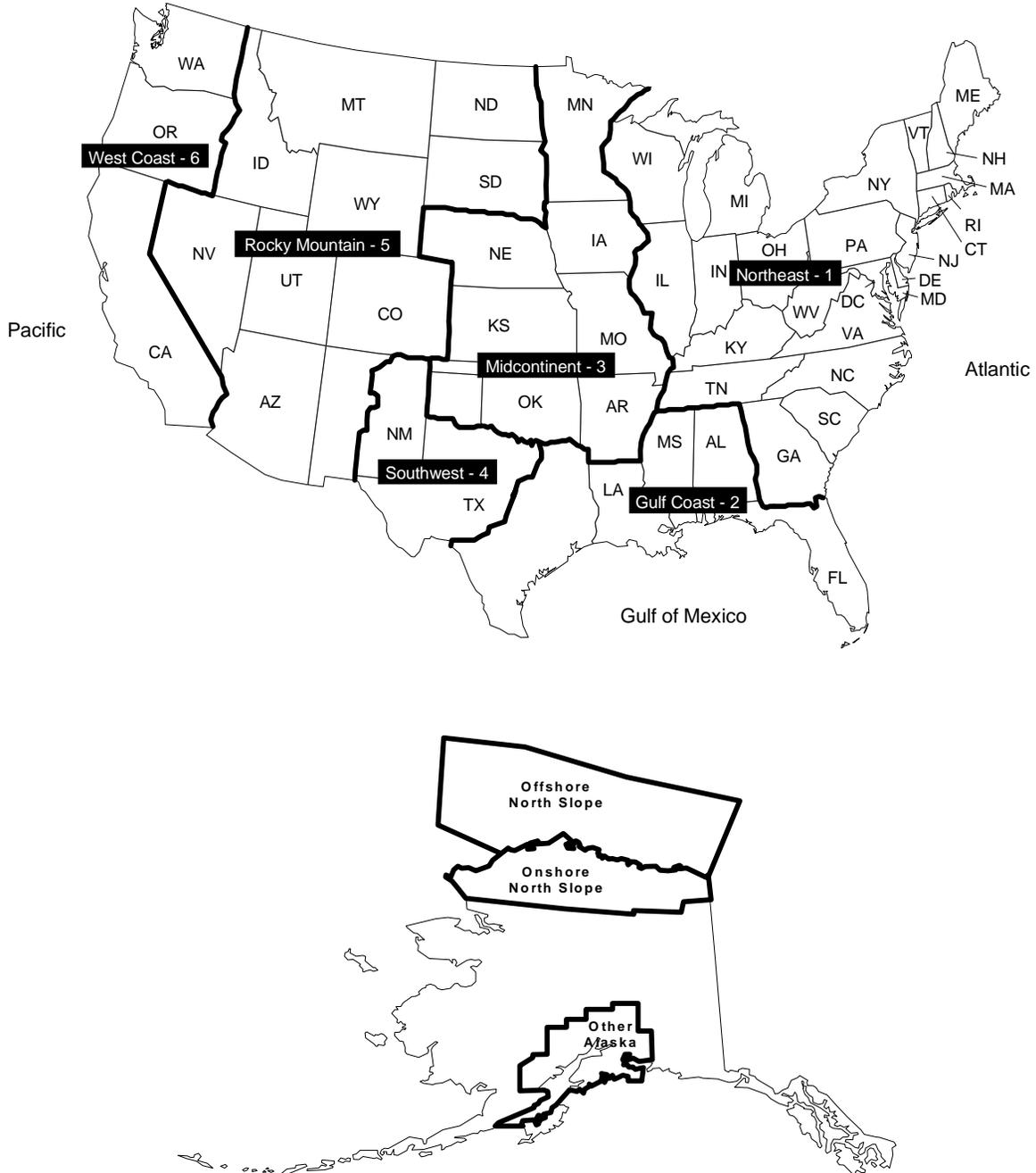
3. Model Rationale and Overview

Introduction

This chapter provides a brief overview of the rationale and theoretical underpinnings of the methodology chosen for the Oil and Gas Supply Module (OGSM). First a classification of previous oil and gas supply modeling methodologies is discussed, with descriptions of relevant supply models and comments on their advantages and disadvantages. This leads to a discussion of the rationale behind the methodology adopted for OGSM and its various submodules, including the onshore and offshore Lower 48 states, the foreign natural gas supply submodule, and the Alaska submodule.

Overview of Oil and Gas Supply Modeling Methods

Oil and gas supply models have relied on a variety of techniques to forecast future supplies. These techniques can be categorized generally as geologic/engineering, econometric, "hybrid" -- an approach that combines geologic and econometric techniques, and market equilibrium. The geologic/engineering models are further disaggregated into play analysis models and discovery process models.

Geologic/Engineering Models

Play Analysis

According to the U.S. Geological Survey (USGS), a play is a group of geologically related, known or undiscovered accumulations (prospects) having similar hydrocarbon sources, reservoirs, traps, and geologic histories. A prospect is a geologic feature having the potential for the trapping and accumulation of hydrocarbons. Prospects are the targets of exploratory drilling. Play analysis relies on detailed geologic data and subjective probability assessments of the presence of oil and gas. Seismic information, expert assessments, and information from analog areas are combined in a Monte Carlo simulation framework to generate a probability distribution of the total volume of oil or gas present in the play. These models are primarily used as a source assessment tool, but they have been used with an economic component to generate oil and gas reserve additions and production forecasts.

An example of a play analysis model is EIA's Outer Continental Shelf Oil and Gas Supply Model (OCSM)[1], which was developed during the late 1970s and early 1980s. The OCSM used a field-size-distribution approach to evaluate Federal offshore supply (including production from the Gulf of Mexico, Pacific, and Atlantic offshore regions). The OCSM drew on a series of Monte Carlo models based on the work of Kaufman and Barouch.[2] These models started with lognormal field-size distributions and examined the order in which fields are discovered. The OCSM also drew on an alternative approach taken by Drew et al.,[3] which

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[1]*Outer Continental Shelf (OCS) Oil and Gas Supply Model, Volume 1, Model Summary and Methodology Description*, Energy Information Administration, Washington, D.C., December 1982, DOE/EIA-0372/1. and Farmer, Richard D., Harris, Carl M., Murphy, Frederic H., and Damuth, Robert J., "The Outer continental Shelf Oil and gas Supply model of the Energy Information Administration," *North-Holland European Journal Of Operation Research*, 18 (1984), pages 184-197.

[2]Kaufman, G.M., and Barouch, E., "The Interface Between Geostatistical Modeling of Oil and Gas Discovery and Economics," *Mathematical Geology*, 10(5), 1978.

[3]Drew, L.J., Schuenemeyer, J.H., and Bawiec, W.J., *Estimation of the Future Rate of Oil and Gas Discovery in the Gulf of Mexico*, U.S. Geologic Survey Professional Paper, No. 252, Reston, VA, 1982.

was an extension of the Arps and Roberts approach to resource assessment,[4] falling between simple extrapolation and Monte Carlo simulation. This alternative approach explicitly represented an exponentially declining exploration efficiency factor (in contrast to that of Kaufman and Barouch, in which declining efficiency was related solely to the assumed decline in field size). Under this approach, finding rates for the number of fields in a collection of size categories were estimated (as opposed to determining an aggregate finding rate)--an approach involving massive data requirements.

Key differences between the OCSM and other field-size-distribution models included the fact that OCSM was based on (a) geological data on undiscovered structures obtained from the U.S. Department of the Interior (as opposed to data simulated from aggregate regional information), (b) a highly detailed characterization of the supply process, (c) a relatively sophisticated treatment of uncertainty, and (d) explicit consideration of investment decisions at the bidding, development, and production stages, in addition to the exploration stage.

Although the OCSM had many superior qualities, it was highly resource intensive. In particular, the OCSM required (a) maintenance of a large database on more than 2000 prospects in thirty offshore plays, (b) considerable mainframe CPU time to execute completely, reflecting the highly complex algorithmic and programming routines, and (c) maintenance of a wide range of staffing skills to support both the model and the underlying data. Since all these problems violate basic key attributes required of an oil and gas supply model operating in the NEMS environment, adopting a similar play analysis approach for the OGSM was rejected.

Discovery Process

Kaufman, Balcer and Kruyt described discovery process modeling as "building a model of the physics of oil and gas field discovery from primitive postulates about discovery that are individually testable outside the discovery model itself." Unlike play analysis models, discovery process models can only be used in well developed areas where information on exploration activity and oil and gas discovery sizes is readily available. Discovery process models reflect the dynamics of the discovery process and do not require detailed geologic information. They rely instead on historical exploratory drilling and discoveries data.

Although the details of discovery process models vary, they all rely on the assumption that the larger the oil or gas field, the more likely it will be discovered. This assumption leads to discovery rates (the amount of oil or gas found per unit of exploratory effort) that typically decline as more of an area is explored. Discovery process models usually specify a finding rate equation using a functional form such that discoveries decline with cumulative drilling.

Discovery process models have generally been applied to specific geologic basins, such as the Denver-Julesburg basin (Arps and Roberts 1959). They have also been used in studies of the Permian Basin[5] and the North Sea. Discovery process models do not usually incorporate economic variables such as costs, profits, and risk. Returns to exploratory effort are represented in terms of wells drilled or reserves discovered.

Since there are generally no economic components, discovery process models cannot project time paths of future drilling and reserve additions without using ad hoc constraints (for example constraints on rigs or expenditures). The constraints chosen become to some extent deciding factors in the model outcome.

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[4]Arps, J.J., and Roberts, T.G., "Economics of Drilling for Cretaceous Oil on East Flank of Denver-Julesburg Basin," *American Association of Petroleum Geologists Bulletin 42*, 1958.

[5]*Future Supply of Oil and Gas from the Permian Basin of West Texas and Southeastern New Mexico*, U.S. Geological Survey, Washington DC, 1980

Typically factors such as cash flow or the availability of rigs are constrained to enable the model to forecast satisfactorily.

The OGSM is intended to support the market analysis requirements of NEMS, thus it includes both an economic and a geologic component. A model of industry activity was developed for the OGSM that predicts expenditure and drilling levels each period of the forecast horizon. The estimated levels of drilling are used to determine oil and gas reserve additions in each period through a finding rate function. The modular nature of OGSM does allow for future consideration of an alternate geologic approach such as a pure discovery process model. Whereas many discovery process models specify one finding rate function, OGSM uses three to capture the varying influences of new field wildcat, other exploratory, and development drilling on the discovery process.

Econometric Models

Many econometric models do not include a description of geologic trends or characteristics -- for example, average discovery sizes do not vary systematically with cumulative exploratory drilling as in discovery process models. Additionally, these models, for the most part, have not been based on a dynamic optimization model of firm behavior and do not incorporate expectations of future economic variables -- a limitation that also applies, for the most part, to the geologic/engineering models.

Recent econometric models have made some inroads in overcoming these problems. Rational expectations econometric models have been developed by Hendricks and Novales and by Walls which are based on intertemporal optimization principles that incorporate uncertainty and inherently attempt to capture the dynamics of the exploration process.[6] Geologic trends also are accounted for, though not in as much detail as they are in play analysis and discovery process models.

These improvements are not without cost. The theoretical specifications of rational expectations econometric models must be highly simplified in order to obtain analytic solutions to the optimization problems. This feature of these models means that it is impossible to describe the oil supply process with the level of detail that the more *ad hoc* approaches allow. In addition, a long time series of historical data is necessary in order to obtain consistent parameter estimates of these models. Such a time series does not exist in many cases, especially for frontier areas such as the offshore or at the regional levels required for NEMS. Finally, because of the degree of mathematical complexity in the models, forecasting and policy analysis often turn out to be intractable.

Econometric methods have been employed primarily for studies of a single region, either a relatively limited area such as a single state or more broad-based such as the entire Lower 48 states. An example of the former is the work by Griffin and Moroney (1985), which was used to study the effects of a state severance tax in Texas. Recent work on large scale aggregate data appear in studies by Epple (1985) and Walls (1989). These studies link models of individual dynamic optimizing behavior under uncertainty to the use of econometric techniques. In general, the firm is assumed to maximize a quadratic objective function subject to linear constraints on the processes governing the stochastic variables that are outside the firm's control. In the Walls model, an oil exploration firm chooses the number of exploratory wells to drill in each period to maximize the expected discounted present value from exploration, providing a clear link between a theory of the exploration firm's dynamic behavior under uncertainty and the econometric equations of the model. However, in addition to other considerations, the model is so mathematically complicated that "...it is impossible to

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[6]Hendricks, Kenneth and Alfonso Novales, 1987, Estimation of dynamic investment function in oil exploration, Draft manuscript. Walls, Margaret A., 1989, Forecasting oil market behavior: Rational expectations analysis of price shocks, Paper EM87-03 (Resources for the Future, Washington, D.C.)

describe the oil supply process with the same level of detail as the *ad hoc* models. In other words, it is difficult, if not impossible, to model all of the stages of supply in a realistic way."[7] Such a model would not be appropriate for the intended role of NEMS, although it can be quite useful in other applications.

Hybrid Models

Hybrid models are an improvement in some ways over both the pure process models and the econometric models. They typically combine a relatively detailed description of the geologic relationship between discoveries and drilling with an econometric component that estimates the response of drilling to economic variables. In this way, a time path of drilling may be obtained without sacrificing an accurate description of geologic trends. Such a hybrid approach has been directly implemented (or incorporated indirectly, using the results of hybrid models) under a variety of methodological frameworks. Such frameworks include the system dynamics methodology used in the FOSSIL2 model, which underlies the *National Energy Strategy* and numerous related studies.

The Energy and Environmental Analysis's (EEA) Hydrocarbon Supply Model (HSM) is one example of a hybrid model. The HSM employs an enhanced discovery process component to estimate discoveries from the underlying resource base and an economic component to provide costs for exploration, development and production of oil and gas accumulations. Overall industry activity is subject to an econometrically determined financial constraint.

The American Gas Association's Total Energy Resource Analysis model (TERA) employs an econometric approach to determine changes in aggregate Lower 48 onshore drilling based on a profitability index. Offshore Lower 48 supply is evaluated offline for inclusion in the outlook. New supplies flow from discoveries that depend on a finding rate. This finding rate does not rely on an explicit resource estimate, but does reflect resource depletion given cumulative increases in reserves. Technology influences the finding rate, but it primarily manifests itself in lower costs by reducing the number of dry holes experienced in the supply process.

Data Resources Inc's oil and gas supply model also employs a hybrid approach. Lower 48 exploratory drilling depends on projected net revenues. Developmental drilling is a function of lagged exploratory wells. New supplies occur from discoveries that depend on a finding rate. The finding rate itself is based on an analysis of recent trends in observed data. The extrapolative technique used does not incorporate an explicit estimate for economically recoverable resources. Technology is not explicit within the model, but it is treated on an *ad hoc* basis.

Market Equilibrium Models

Market-equilibrium models connect supply and demand regions via a transportation network and solve for the most efficient regional allocation of quantities and corresponding prices. Market-equilibrium models tend to be single energy market models that concentrate on the economic forces that efficiently balance markets across regions without explicit representation of other fuel market conditions. Consideration of the processes that alter supply and demand are not necessarily modeled in detail; stylized regional supply and demand curves are postulated.

An example of a market-equilibrium model is Decision Focus Incorporated's North American Regional Gas Model (NARG). Regional supplies of indigenous production are based on a representation of the gas resource

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[7]Walls, Margaret A., *Modeling and forecasting the supply of oil and gas: A survey of existing approaches*, Resources and Energy 14 (1992), North Holland, p 301.

base as a continuous, ordered stream of reserve increments that will be discovered and developed over a range of prices. As prices rise, thus covering increasing costs, additional portions of the resource base systematically become available to the market. Regional supply curves also reflect an assessment of the expected cost characteristics of the technically recoverable resource base.

Supply regions are linked to demand regions throughout the United States and Canada by a network of existing and prospective pipelines, with specified capacity constraints and tariffs. Within the framework of this model, 17 supply regions are specified: 12 in the United States and 5 in Canada.[8] Each region has its own gas supply curve based on estimates of the resource base and associated costs of discovery and development from the Potential Gas Committee (United States), the Canadian Energy Research Institute, and the Canadian National Energy Board.

The partial equilibrium nature of these models is contrary to the requirements of an oil and gas supply model operating within the integrated environment of NEMS. Moreover, the solution from a market equilibrium model consists of a volume of gas produced, rather than a supply schedule as required by the Natural Gas Transmission and Demand Model. Finally, the forecasting capabilities of this approach are open to question given that many of the key parameters are not subjected to the discipline of validation against historical data.

OGSM Rationale

None of the models described are able to address all the issues that would be required of the OGSM. For example, some models might have reasonable representations of the onshore supply process, but completely lack an offshore or unconventional fuel component. Some models only provide a representation of the gas supply industry while almost completely ignoring oil supplies. Some models provided only limited ability to be simulated under different fiscal and policy environments. OGSM had to be developed keeping in mind the overall goal of NEMS - the ability to address many of the likely physical and policy variables that might affect future U.S. oil and gas supplies.

An important consideration regarding many of the models discussed above is that they typically tend to be highly resource intensive, both (a) in terms of personnel requirements for development and maintenance and (b) in terms of execution time and other computational resource requirements. It was for these reasons that the OCSM model, the EIA's offshore play-analysis model, was ultimately retired.

Another difficulty with many of these models is that the relationships in the models are typically not subjected to the discipline of validation against historical data--in fact, there are usually too many parameters in the models to estimate econometrically. As a result, the models cannot project time paths of future oil and gas supply without the use of ad hoc constraints that turn out to be important determinants of the forecasts generated by the models.

Accordingly, the OGSM lower 48 conventional onshore and shallow offshore submodules use some features of the discovery-process approach, but do not employ any of the traditional discovery process models discussed earlier because they are too data intensive. This design helps to satisfy some of the specification requirements set forth for the NEMS,[9] which emphasize, among other attributes, model transparency and model efficiency. These submodules, which constitute the major part of the OGSM, do not determine activity levels on the basis of an explicit economic evaluation of discrete production units, such as individual

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[8]Mexico has been introduced into the model as a net import flow in recent work for the National Petroleum Council's Natural Gas Study.

[9]See, for example, *Requirements for a National Energy Modeling System*, December 1991, and *Recommended Design for the National Energy Modeling System*, October 1991.

producing fields. The requirements for performing a disaggregated field analysis were prohibitive in the context of the time and resources needed to develop and maintain such an approach, without necessarily affecting the modeling results appreciably. There does exist here, however, an endogenous simulation of separate discretionary levels for exploratory and developmental drilling in contrast to the fixed relationship between exploratory and developmental drilling that characterizes many other models.

The Alaska Oil and Gas Supply Submodule (AOGSS), the Unconventional Gas Recovery Supply Submodule (UGRSS), the Deep Water Offshore Supply Submodule (DWOSS), and the liquefied natural gas (LNG) component of the Foreign Natural Gas Supply Submodule (FNGSS) are treated differently from the conventional lower 48 onshore and shallow offshore. These methodologies take more of an engineering approach. In the case of Alaska this is because of the relative low number of fields (compared to the Lower 48 states) expected to be economically viable in Alaska. For unconventional gas, the paucity of historical data and the expected future importance of technology were the major determinants of this decision. For the deep water offshore, the historical data problems were even more significant and played a similar role. The representation of LNG in OGSM is unique because field production is not part of domestic operations. The stages of the LNG process to be modeled primarily concern the receipt of LNG at importation facilities and its subsequent conversion into gaseous natural gas.

The remainder of this section provides a brief discussion of the rationales and methodologies of the OGSM's submodules.

Lower 48 Oil and Gas Supply

A hybrid econometric/discovery process approach was used to model Lower 48 states conventional oil and gas supply and UGR supply in the OGSM.[10] The geology is represented in the model's discovery-process components, while the economics of exploration, development, and production are captured by the model's econometric equations component. The methodology was designed for two basic purposes: (1) to generate forecasts of future drilling activity, and oil and gas supplies under alternative scenarios and (2) to provide a framework for analyzing the potential impacts of policy changes on future drilling activities and oil and gas supplies. The OGSM was designed to meet these two requirements in a transparent and efficient manner, while simulating the supply behavior of the oil and gas industry and incorporating essential behavioral and physical relationships without resorting to extraordinarily complex functional forms and/or algorithms.

Conventional Lower 48 Onshore and Shallow Offshore Supply

Relying on basic research on the determinants of business investment, it is assumed that the industry's level of domestic exploration and developmental drilling is determined by several major factors, including: the expected oil and gas prices, the expected profitability of domestic exploration and developmental drilling and the economic and geologic risk associated with exploration and developmental drilling. The drilling equations are econometrically based. Specifically, the levels of exploration and developmental drilling are forecast on the basis of econometrically estimated equations that relate historical exploration and developmental drilling to the explanatory variables given above.

The econometric approach was chosen over a linear programming approach or a hybrid linear programming/econometric approach of the type used in PROLOG, the OGSM's predecessor, for two major reasons. First, incurring the additional computational burden associated with solving a linear programming problem with multiple constraints seemed inefficient relative to forecasting directly from the estimated

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[10]A slightly different approach was employed to represent EOR and deep water offhore supply activities and these methods are described in the following sections.

historical relationships. This is especially critical given that NEMS requirements include the goals of quick execution and the efficient utilization of computer resources. Second, the linear programming approach requires the explicit specification of the objective function while an econometrically based approach does not. If the true objective function is unknown or cannot be specified without adding undue complexity and computational burden to the model, then an econometric approach is more sensible. For empirical purposes, implementation of the econometric approach does not require specification of an explicit objective function, but only the identification of explanatory variables whose movements can be related, on average, to changes in investment that are driven by a particular behavioral objective, e.g, profit maximization.

The econometric method of determining drilling activity levels on the basis of expected profitability, is certainly in line with the methodologies of several other respected oil and gas supply models. For example, overall industry drilling activity in the Hydrocarbon Supply Model (HSM) of the Energy and Environmental Analysis (EEA) is subject to an econometrically determined financial constraint. The Total Energy Resource Analysis (TERA) model of the American Gas Association (AGA) employs an econometric approach to determine changes in aggregate lower 48 onshore drilling based on a profitability index. The DRI/McGraw-Hill (DRI) model forecasts exploratory drilling on the basis of projected net revenues. Though the specific details differ across the models, their unifying trait is an explicit recognition of the important linkages among profitability, exploration and developmental drilling expenditures (financial resources), and drilling activity levels.

The total number of wells drilled for each specific drilling activity is converted to expenditure levels by multiplying the drilling levels by estimates of drilling costs per well, which vary by region and fuel type. Based on historical proportions, exploratory wells are separated into new field wildcats and other exploratory wells. Differentiation between types of exploratory drilling is a feature that is not found in most other hybrid models. It enables the discovery process component to more realistically model the reserves additions process.

Proved reserves comprise the only source for production, and the discovery process is the means by which nonproducing resources (i.e., undiscovered economically recoverable resources or inferred reserves) are converted into proved reserves. The discovery process component in OGSM consists of a set of finding rate equations that relate the volume of reserve additions to drilling levels. Three discovery processes are specified: new field discoveries from new field wildcats, field extension volumes from other exploratory drilling, and reserve revisions due to developmental drilling. New field wildcat discovery volumes are separated into proved and inferred reserves based on the historical relationship between a field's ultimate recovery and its initial discovery size. Inferred reserves are converted into proved reserves in later periods through other exploratory and developmental drilling. This differentiation in finding rates provides a more accurate representation of the reserves discovery process in the oil and gas industry. Exogenous estimates of the undiscovered economically recoverable resource base are incorporated in the new field wildcat finding rates. This allows user assumptions concerning the resource base to be specified for purposes of policy analysis, such as offshore drilling moratoria. The distinction between proved and inferred reserves is also found in EEA's HSM, though the separate impacts of new field wildcats and other exploratory wells on the reserves discovery process is not modeled there.

Conventional Deep Water Offshore Supply

While the hybrid econometric/discovery process approach is a significant improvement over purely process models or econometric models, it is still inherently inadequate when if comes to determining exploration and development activity from predominantly frontier areas. This is due to the reliance of the hybrid model on significant historical information being available to forecast future activity based on historical performance. deep water offshore Gulf of Mexico has become active only during the last 5 years and very little information to develop equations for the discovery process/econometric type models exists. Due to significant

differences in technology, costs, and productivity of fields in the Deep water areas compared to those from shallow water areas, it would be incorrect to extrapolate the data from shallow water areas to the deep water fields.

An alternative, field-based engineering and economic analysis approach allows for the explicit characterization of the undiscovered resource base in the Deep water areas, and the evaluation of the technology options, project scheduling and expenditures for exploration, development and production activities as a function of the water depth and field size. It also makes use of a discounted cash flow algorithm to characterize project profitability. A positive net present value for each prospect is directly associated with the minimum acceptable supply price (MASP) for that prospect.

The production timing algorithm explicitly makes choices for field exploration and development based on relative economics of the project profitability compared with the equilibrium crude oil and natural gas prices determined by PMM and NGTDM in OGSM. Development of inferred (economic) reserves into proved reserves is constrained by drilling activity. Proved reserves are translated into production based on reserves-to-production (R/P) ratio. The drilling activity and the R/P ratio are both determined by extrapolating the historical information.

This approach not only permits analysis of each and individual prospect, but also permits the possibility of looking at the impact of various regulatory, policy, and financial issues by evaluating these impacts at the individual prospect level. Thus, the field-based engineering and economic analysis approach utilized to project supply potential from deepwater offshore Gulf of Mexico OCS significantly enhances OGSM's analytical capabilities. The model, due to its modular construction, can be easily adapted to address other economic issues, and also to address other potential deepwater offshore areas in the future.

Enhanced Oil Recovery Supply

The Enhanced Oil Recovery Supply Submodule (EORSS) uses a modified form of the previously described methodology, which is used for conventional oil supply and all natural gas recovery types. A more thorough description of the EORSS methodology is presented in Chapter 4 of this report. All submodules in the OGSM share the similar basic attributes, but the representation may differ in the particulars. This section presents a discussion of the general differences between the methodologies.

The basic supply process for both EOR and the other sources of crude oil and natural gas consists of essentially the same stages. The physical stages of the supply process involve the conversion of unproven resources into proved reserves, and then the proved reserves are extracted as flows of production. A key element of economics on the supply side is that investment funds are directed more heavily to exploration and development opportunities that have greater expected profitability.

The significant differences between the methodology of the EORSS and the other submodules of OGSM concern the conversion of unproven resources to proved reserves and the determination of supply activities. The transfer of resource stocks from unproven to proved status in OGSM is handled by use of finding rate functions that relate reserve additions to cumulative drilling levels. The EORSS uses discovery factors that convert a specified fraction of unproven resources into proved reserves. These factors depend on the expected profitability of EOR investment opportunities, and not on drilling levels.

Greater expected financial returns motivate the conversion of larger fractions of the resource base into proved reserves. This is consistent with the principle that funds are directed toward projects with relatively higher returns. An explicit determination of expenditures for supply activities does not occur within the EORSS as it does in the OGSM. Given the role of the discovery factors in the supply process, the implicit working assumption is that EOR investment opportunities with positive expected profit will attract sufficient financial

development capital. EOR investment does not compete with other oil and gas opportunities. EOR recovery is sufficiently different, and its product not entirely similar to the less heavy oil most often yielded by conventional projects, that this assumption is considered appropriate.

Unconventional Gas Recovery Supply

Prior to the current UGRSS, unconventional gas recovery actitivities were treated the same as conventional. The current UGRSS replaced the previous econometric based UGRSS with a geology/engineering based submodule. The previous UGRSS was based on econometric equations estimated from rather incomplete data that reflect historical trends during a period in which the relative importance of UGR was probably significantly less than it will be in future decades. With the eventual depletion of conventional resources, there is likely to be considerable pressure to develop the relatively abundant unconventional gas resource base much more intensively in order to meet projected increases in natural gas demand. In the future development of the unconventional gas resource base, technology is expected to play a prominent role, and a geology/engineering based module is much more capable of portraying that role. The UGRSS provides an internal, integrated methodology for estimating the impact of future advances in technology on unconventional gas production.

The UGRSS is a play level model that specifically analyzes the three major unconventional resources - coalbed methane, tight gas sands, and gas shales. The UGRSS calculates the economic feasibility of individual plays based on locally specific wellhead prices and costs, resource quantity and quality, and the various effects of technology on both resources and costs. In each year an initial resource characterization determines the expected ultimate recovery (EUR) for the wells drilled in a particular play. Resource profiles are adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play. Subsequently, prices received from the NGTDM and endogenously determined costs adjusted to reflect technological progress are utilized to calculate the economic profitability (or lack thereof) for the play. If the play is profitable, drilling occurs according to an assumed schedule, which is adjusted annually to account for technological improvements, as well as varying economic conditions. This drilling results in reserve additions, the quantities of which are directly related to the EUR's for the wells in that play. Given these reserve additions, reserve levels and ("expected") production-to-reserves (P/R) ratios are recalculated at the NGTDM regional level. The resultant values are sent to OGSM, where they are aggregated with similar values from the other submodules. The aggregate P/R ratios and reserve levels are then passed to the NGTDM, which determines through market equilibration the prices and production for the following year.

Foreign Natural Gas Supply

The Foreign Natural Gas Supply Submodule consists of three key components: Canadian gas trade, liquefied natural gas (LNG) trades and gas trade with Mexico. Different methodological approaches were taken for each component in recognition of inherent differences between the various modes of import and the different circumstances affecting both supply capacity in the source country and its potential availability to the United States. The process by which Canadian gas flows to the United States is essentially the same process as that for U.S. supplies in the Lower 48 states. LNG imports are very different however, with available regasification capacity and the unit costs of transportation, liquefaction, and regasification being the most important determinants of import volumes. Production costs in countries currently or potentially providing LNG are a relatively small portion of total unit costs for gas delivered into the U.S. transmission network. Gas has not been imported from Mexico in the eight year period ending in 1992. Mexico began exporting very small volumes of gas to the United States in 1993. Further development of Mexican gas production capability depends more on institutional rather than economic factors. Consequently a third, scenario-based approach was chosen to model gas imports from this source.

It is a recursive type model, with oil and gas prices as the principal driving variables. Regional oil and gas prices are determined exogenously from the OGSM and are received from the Petroleum Market Module and the Natural Gas Transmission and Distribution Module respectively.

Canadian Gas Imports

Gas imports from Canada are modeled using a hybrid approach similar to the one taken for the Lower 48 States. The model has two key components, a discovery process component and an economic component. The economic component forecasts drilling activity as a function of oil and natural gas wellhead prices. The discovery process component relates reserve additions per period to wells drilled.

A hybrid method was chosen for modeling Canadian gas supplies since this approach most effectively meets the numerous analytical requirements of OGSM. Also, sufficient data are available for the Canadian oil and gas industry. Finally, although this approach is a somewhat simplified version of the Lower 48 methodology, the two models are methodologically consistent.

Liquefied Natural Gas

LNG has been included as an explicit element of some natural gas models. LNG is represented in one of two ways, depending on the basic nature of the model. It has been included as a basic element in models such as the World Gas Trade Model (WGTM).[11] It also has been added to an expanded version of the Hydrocarbon Supply Model (HSM) that was used for the National Petroleum Council Natural Gas Study (1992).

Global trade models are based on a disaggregation of the world, in which countries or groups of countries are separated into consuming and producing regions. Each region has a stylized representation of supply and demand. Regions are connected via a transportation network, characterized by interregional transportation costs and flow constraints. LNG is incorporated into global trade models as possible gas trade between two noncontiguous countries. The model solves for the most efficient regional allocation of quantities and corresponding prices. The extensive scope of these models (and commonly encountered limitations of the necessary data) does not allow for detailed representations of gas supply or demand.

The incorporation of LNG trade into each model generally has occurred as an enhancement of established models. Both LNG imports and exports are included, with LNG exports from Alaska as an exogenous factor. LNG imports are represented as gas supply available to the appropriate U.S. regions according to a prespecified schedule reflecting industry announcements. The model solution includes an endogenous determination of flows through LNG facilities and new capacity in response to price.

The LNG algorithm in OGSM differs from the OGSM supply approaches for domestic and Canadian production. It utilizes supply curves for LNG imports, but it does not model explicitly the exploration and development process. These supply curves are based on the estimated cost of delivering LNG into the pipeline network in the United State and include all costs associated with production, liquefaction, shipping, and regasification. The supply curves mark the unit costs, which serve as economic thresholds that must be attained before investment in potential LNG projects will occur. Extensive operational assumptions were made on current import terminal capacity and the timing of planned capacity expansions.

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[11]The World Gas Trade Model (WGTM) basically is a global expansion of the NARG, using the Generalized Equilibrium Modeling System (GEMS). This model will not be described in detail because of the extreme similarity of the two models.

Gas Trade with Mexico

Gas trade between the United States and Mexico tended to be overlooked in earlier modeling efforts. This treatment (or lack thereof) seemed justified for a number of reasons. Except for a brief 5 year period in the early 1980s, neither gross nor net flows of gas between the United States and Mexico were significant. Additionally, reliable data regarding Mexican gas potential were not readily available.

A scenario basis was chosen to handle gas imports from Mexico because of uncertainty and the significant influence of noneconomic factors that affect Mexican gas trade with the United States. Many of the models described previously make use of such exogenous offline analyses to forecast certain variables. For example, DRI's offshore oil and gas production forecasts are handled offline and integrated later into their main forecasting model.

Alaskan Oil and Gas Supplies

Alaska has a limited history as a source of significant volumes of crude oil and natural gas. Initial commercial flows of crude oil from the Alaskan North Slope began on June 17, 1977. Interest in analyzing the volumetric potential of Alaska as a source of oil or gas supplies arose after the late 1960s discovery of the Prudhoe Bay field, which is the largest in North America. During the years since the mid 1970s, there have been numerous special studies of either a one-time nature or limited in scope. An early study by Mortada (1976) projected expected oil production through 2002.[12] The results of this analysis were used in Congressional hearings regarding the construction and operation of the Trans-Alaska Pipeline System (TAPS). A Department of the Interior (DOI) study (1981) analyzed the supply potential of the National Petroleum Reserve - Alaska (NPRA). This work was used in the consideration of leasing the NPRA for exploration and development.

Generalized models that deal with both oil and gas potential for Alaska are not as common as those for the Lower 48 states. Most forecasting agencies, including the EIA, have not devoted a large amount of resources towards the development and maintenance of a detailed Alaskan oil and gas representation in their domestic production models. Generally, forecasting groups either adopted a projection from another agency, or utilized other projections as the basis for selected *ad hoc* modifications as appropriate. The latter approach occurs in EIA's previous modeling work regarding Alaskan supply in PROLOG.

This seeming inattention to building an Alaska oil and gas supply model arose from the limited extent of the projection horizon that was needed until recently. Projections in EIA had been for periods of 10 to 15 years, and up to 20 years only recently. This period length limits the flexibility in Alaskan activities, where lags of 10 to 15 years affect the discovery and development process. Thus, the bulk of oil production for at least 15 years under virtually any scenario depends almost wholly on the recovery from currently known fields. Marketing of natural gas from the Alaskan North Slope is not expected prior to the beginning of the next decade at the earliest, because of the lack of facilities to move the gas to Lower 48 markets and the interest of the operators and the State of Alaska in using the natural gas to maximize recovery of oil from Prudhoe Bay.

The present methodology for the Alaska Oil and Gas Supply Submodule (AOGSS) differs from that of the Lower 48 States representation. A discovery process approach with ad hoc constraints was chosen for the AOGSS. This method was chosen because of the unique nature of industry operations in Alaska and the limited number of fields do not lend themselves readily to application of the Lower 48 approach.

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[12]Mortada International, *The Determination of Equitable Pricing Levels for North-Slope Alaskan Crude Oil*, (October 1976).

The AOGSS is divided into three components: new field discoveries, development projects, and producing fields. A discounted cash flow method is used to determine the economic viability of each project at netback price. The netback price is determined as the market price less intervening transportation costs. The continuation of the exploration and development of multi-year projects, as well as the discovery of a new field, is dependent on profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and development projects, and historical production patterns and announced plans for currently producing fields.

Oil and gas prices are the principal driving variables and are received from the Petroleum Market Module and the Natural Gas Transmission and Distribution Module respectively.

4. Model Structure

Introduction

This chapter describes the Oil and Gas Supply Module (OGSM), which consists of a set of submodules (Figure 3) that perform supply analysis regarding domestic oil and gas production and foreign trade in natural gas between the United States and other countries via pipeline or as liquefied natural gas. The OGSM provides crude oil production and parameter estimates representing natural gas supplies by selected fuel types on a regional basis to support the market equilibrium determination conducted within other modules of the National Energy Modeling System (NEMS). The oil and gas supplies in each period are balanced against the regional derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the disjoint wellhead and enduse markets. The description of the market analysis models may be found in the separate methodology documentation reports for the Petroleum Market Module (PMM) and the Natural Gas Transmission and Distribution Model (NGTDM).

Figure 3. Submodules within the Oil and Gas Supply Module
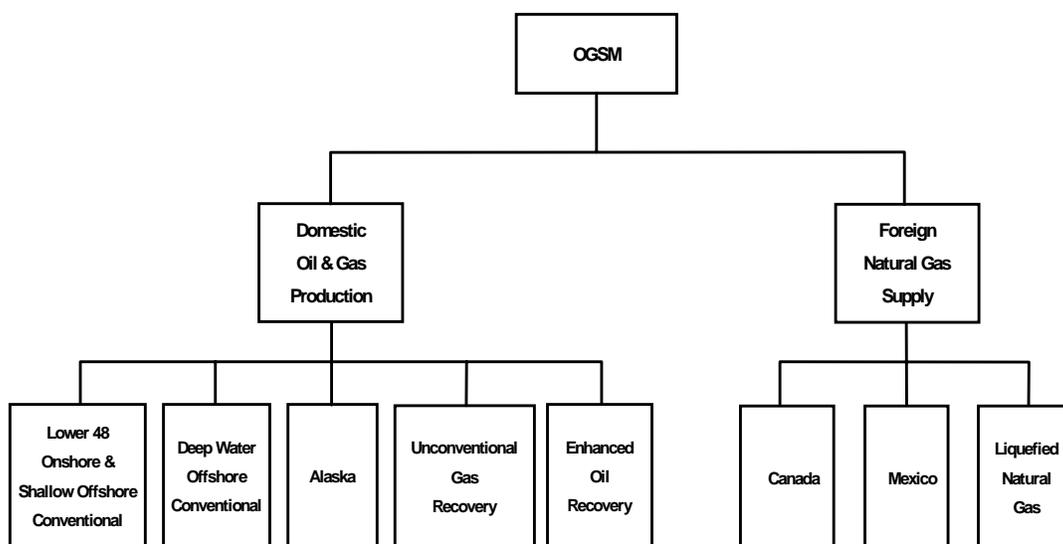
The OGSM mirrors the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States or acquire natural gas from foreign producers for resale in the United States or sell U.S. gas to foreign consumers. The OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes enhanced oil recovery (EOR), and unconventional gas recovery (UGR) from tight gas formations, Devonian/Antrim shale and coalbeds. Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM represents foreign trade in natural gas as imports and exports by entry region of the United States. These foreign transactions may occur via either pipeline (Canada or Mexico), or via ships transported as liquefied natural gas (LNG).

The model's methodology is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. In particular, the model assumes that investment in

exploration and development drilling, by fuel type and geographic region, is a function of the expected profitability of exploration and development drilling, disaggregated by fuel type and geographic region.

The OGSM includes an enhanced methodology for estimating short-term oil and gas supply functions. Short-term is defined as a one year period in the OGSM. This enhancement improves the procedure for equilibrating the natural gas and oil markets by allowing for the determination of regional market clearing prices for each fuel, as opposed to the previous modeling system that only equilibrates markets at a national market clearing price.

Output prices influence oil and gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the PMM and NGTDM are determined as a direct result of the observed market price in that period. Longer-term supply responses are related to investments required for subsequent production of oil and gas. Output prices affect the expected profitability of these investment opportunities as determined by use of a discounted cash flow evaluation of representative prospects.

The OGSM, compared to the previous EIA midterm model, incorporates a more complete and representative description of the processes by which oil and gas in the technically recoverable resource base[1] convert to proved reserves.[2] The previous model treated reserve additions primarily as a function of undifferentiated exploratory drilling. The relatively small amount of reserve additions from other sources was represented as coming from developmental drilling.

The OGSM distinguishes between drilling for new fields and that for additional deposits within old fields. This enhancement recognizes important differences in exploratory drilling, both by its nature and in its physical and economic returns. New field wildcats convert resources in previously undiscovered fields[3] into both proved reserves (as new discoveries) and inferred reserves.[4] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves. The phenomenon of reserves appreciation is the process by which initial assessments of proved reserves from a new field discovery grow over time through extensions and revisions. This improved resource accounting approach is more consistent with recent literature regarding resource recovery.[5]

The breadth of supply processes that are encompassed within OGSM results in methodological differences between the lower 48 methodology and that for Alaska oil and gas production and foreign gas trade. The present OGSM consequently comprises a set of three distinct approaches and corresponding submodules. The label OGSM as used in this report generally refers to the overall framework and the implementation of lower 48 oil and gas conventional supply in both onshore and shallow offshore regions. The Unconventional Gas Recovery Supply Submodule (UGRSS) models gas supply from tight gas formations, Devonian/Antrim

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[1]*Economically recoverable resources* are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current conventional technologies, under specified economic assumptions. Economically recoverable volumes include proved reserves, inferred reserves, as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional. Economically recoverable resources are a subset of *technically recoverable resources*, which are those volumes producible with current recovery technology and efficiency but without reference to economic viability.

[2]*Proved reserves* are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3]*Undiscovered resources* are located outside of oil and gas fields in which the presence of resources has been confirmed by exploratory drilling, and thus exclude reserves and reserve extensions; however, they include resources from undiscovered pools within confirmed fields to the extent that such resources occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[4]*Inferred reserves* are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

[5]See, for example, *An Assessment of the Natural Gas Resource Base of the United States*, R.J. Finley and W.L. Fisher, *et al*, 1988, and *The Potential for Natural Gas in the United States*, Volume II, National Petroleum Council, 1992.

shale and coalbeds. The Deepwater Offshore Supply Submodule (DWOSS) models oil and gas production in the deep offshore Gulf of Mexico. The Alaska Oil and Gas Supply Submodule (AOGSS) represents industry supply activity in Alaska. The Foreign Natural Gas Supply Submodule (FNGSS) models trade in natural gas between the United States and other countries. These distinctions are reflected in the presentation of the methodology in this chapter.

Several changes were made to OGSM for the AEO99. Most significant is the debut of the Unconventional Gas Recovery Supply Submodule (UGRSS). The UGRSS has the potential to significantly improve EIA's ability to model activity using unconventional recovery techniques in that it captures the dynamic changes in this area and provides a link between R&D programs and future technology progress and benefits. Another change for AEO99 was the division of crude oil activity into two depth categories, shallow (up to 10,000 feet) and deep (greater than 10,000 feet). New finding rate functions from conventional oil and natural gas resources were also incorporated. Because of the new depth category for oil and the substantially revised historical oil and gas well counts, drilling and cost equations were re-estimated. Finally, the Canadian supply submodule was simplified to reduce maintenance costs and improve performance. The discounted cash flow algorithm was eliminated and drilling activity was estimated as a function of wellhead prices.

The following sections describe OGSM grouped into six conceptually distinct divisions. The first section describes conventional oil and gas supply in the lower 48 states, including onshore lower 48 conventional oil and gas supply and shallow offshore oil and gas supply. This is followed by the methodology of the Deep Water Offshore Supply Submodule, the Unconventional Gas Recovery Supply Submodule, the Enhanced Oil Recovery Supply Submodule, and then the Alaska Oil and Gas Supply Submodule. The chapter concludes with the presentation of the Foreign Natural Gas Supply Submodule. A set of five appendices are included following the chapter. These separate reports provide additional detail on special topics relevant to the methodology. The appendices present extended discussions on the discounted cash flow (DCF) calculation, the determination of unit costs for delivered LNG, unconventional gas recovery, technologies for unconventional gas recovery, and deep offshore Gulf of Mexico supply.

Lower 48 Onshore and Shallow Offshore Supply Submodule

Introduction

This section describes the structure of the models that comprise the lower 48 onshore (excluding EOR and UGR) and the lower 48 shallow offshore submodule of the Oil and Gas Supply Module (OGSM). The general outline of the lower 48 submodule of the OGSM is provided in Figure 4. The overall structure of the submodule can be best described as recursive. The structure implicitly assumes a sequential decision making process. A general description of the submodule's principal features and relationships computations is provided first. This is followed by a detailed discussion of the key mathematical formulas and computations used in the solution algorithm.

The OGSM receives regional oil and gas prices from the PMM and NGTDM, respectively. Using these prices in conjunction with data on production profiles, co-product ratios, drilling costs, lease equipment costs, platform costs (for offshore only), operating costs, severance tax rates, ad valorem tax rates, royalty rates, state tax rates, federal tax rates, tax credits, depreciation schedules, and success rates, the discounted cash flow (DCF) algorithm calculates expected DCF values in each period associated with representative wells for each region, well type (exploratory, developmental), and fuel type (shallow oil, deep oil, shallow gas, and deep gas).

Exploratory and development wells by fuel type and region are predicted as functions of the expected profitabilities of the fuel and region-specific drilling activity. Based on region-specific historical patterns, exploration wells are broken down into new field wildcats and other exploratory wells.

Figure 4 . Flowchart for Loweer 48 States Onshore and Offshore Oil and Gas Submodules

```
                              ( 1 )
                                │
                                ▼
                    ┌───────────────────────┐
                    /  Economic Data          /
                    /  Physical Data          /
                    └───────────────────────┘
              ┌──────────────┼──────────────┐
              ▼              ▲              ▼
  ┌──────────────────┐  ┌──────────────┐  ┌──────────────────┐
  │ Exploration DCF by│  │ Drilling &   │  │ Development DCF by│
  │ Fuel Type and     │  │ Equiping     │  │ Fuel Type and    │
  │ Region            │  │ Costs        │  │ Region           │
  └──────────────────┘  └──────────────┘  └──────────────────┘
           │           ↗         ↖          │
           ▼         ↙             ↘        ▼
  ┌──────────────┐  ┌──────────────┐  ┌──────────────┐
  │ Exploration  │  │  Rig Stock   │  │ Development  │
  │ Wells        │  │              │  │ Wells        │
  └──────────────┘  └──────────────┘  └──────────────┘
        │       │                            │
        ▼       ▼                            │
 ┌──────────┐  ┌────────────────┐            │
 │New Field │  │Other Exploratory│           │
 │Wildcats  │  │Wells            │           │
 └──────────┘  └────────────────┘            │
     │              │                         │
     ▼              │                         │
 ┌──────────┐       │    ┌──────────┐         │
 │Discovery │───────────▶│ Inferred │         │
 │Rate      │       │    │ Reserves │         │
 └──────────┘       │    └──────────┘         │
     │              ▼        │    ╲            ▼
     │         ┌──────────┐  │     ┌──────────┐
     │         │ Finding  │◀─┘     │ Finding  │
     │         │ Rate     │        │ Rate     │
     │         └──────────┘        └──────────┘
     ▼              │                    │
 ┌──────────┐       │    ┌────────────┐  │
 │New Reserve│      └───▶│ Extensions │◀─┘
 │Discoveries│          │ and Revisions│
 └──────────┘          └────────────┘
       │                    │
       └────────┬───────────┘
                ▼
        ┌────────────────┐
        │ Total Reserve  │
        │ Additions      │
        └────────────────┘
                │
                ▼
        ┌────────────────┐
        │   Reserves     │
        └────────────────┘
         │      │      │
         ▼      ▼      ▼
 ┌───────┐ ┌──────────┐ ┌───────┐
 │ NGTDM │▶│Production │◀│ PMM   │
 │       │ │Prices     │ │       │
 └───────┘ └──────────┘ └───────┘
                │  t+1
                ▼
              ( 1 )
```

The forecasted numbers of new field wildcats, other exploratory wells, and developmental wells are used in a set of finding rate equations to determine additions to oil and gas reserves each period. New field wildcats determine new field discoveries. Based on the historical relationship between the initial quantity of proved reserves discovered in a field and the field's ultimate recovery, reserves from new field discoveries are categorized into additions to proved reserves and inferred reserves. Inferred reserves are converted into proved reserves (extensions and revisions) in later periods by drilling other exploratory wells and development wells.

Reserve additions are added to the end-of-year reserves for the previous period while the current period's production (determined in the NGTDM and the PMM) is subtracted to yield the end of year reserves for the current period. These reserves along with an estimate of the expected production to reserves ratio for the next period are passed to the NGTDM and the PMM for use in their short-run supply functions.

The Expected Discounted Cash Flow Algorithm

For each year t, the algorithm calculates the expected DCF for a representative well of type I, in region r, for fuel type k. The calculation assumes only one source of uncertainty--geology. The well can be a success (wet) or a failure (dry). The probability of success is given by the success rate; the probability of failure is given by one minus the success rate. For expediency, the model first calculates the discounted cash flow for a representative project, conditional on a requisite number of successful wells. The conditional project discounted cash flow is then converted into the expected discounted cash flow of a representative well as shown below.

Onshore Lower 48 Development

A representative onshore developmental project[6] consists of one successful developmental well along with the associated number of dry holes. The number of dry developmental wells associated with one successful development well is given by [(1/SR) - 1] where SR represents the success rate for a development well in a particular region r and of a specific fuel type. Therefore, (1/SR) represents the total number of wells associated with one successful developmental well. All wells are assumed to be drilled in the current year with production from the successful well assumed to commence in the current year.

For each year of the project's expected lifetime, the net cash flow is calculated as:

$$NCFON_{i,r,k,s} = (REV - ROY - PRODTAX - DRILLCOST - EQUIPCOST - OPCOST - DRYCOST - STATETAX - FEDTAX)_{i,r,k,s}, \text{ for } i$$
$$r = 1 \text{ thru } 6, \ k = 1 \text{ thru } 4, \ s = t \text{ thru } t+L \tag{1}$$

where,

NCFON	=	annual undiscounted net cash flow for a representative onshore development project
REV	=	revenue from the sale of the primary and co-product fuel
ROY	=	royalty taxes

---

[6]Equations (1) through (6) in this section and the following one describe the computation of the expected discounted cash flow estimate for a representative onshore exploratory or developmental well, denoted as $DCFON_{i,r,k,t}$ in equations (4) and (6). An equivalent set of calculations determine $DCFOFF_{i,r,k,t}$, the expected discounted cash flow estimate for a representative offshore exploratory or developmental well. In these equations, the suffix "ON" is replaced everywhere by "OFF," with all other particulars remaining the same. These alternate equations are not shown to avoid redundancy in the presentation.

PRODTAX	=	production taxes (severance plus ad valorem)
DRILLCOST	=	the cost of drilling the successful developmental well
EQUIPCOST	=	lease equipment costs
OPCOST	=	operating costs
DRYCOST	=	cost of drilling the dry developmental wells
STATETAX	=	state income tax liability
FEDTAX	=	federal income tax liability
I	=	well type (1 = exploratory, 2 = development)
r	=	subscript indicating onshore regions (see Figure 5 for OGSM region codes)
k	=	subscript indicating fuel type
s	=	subscript indicating year of project life
t	=	current year of forecast
L	=	expected project lifetime.[7]

The calculation of REV depends on expected production and prices. Expected production is calculated on the basis of individual wells. Flow from each successful well begins at a level equal to the historical average for production over the first 12 months. Production subsequently declines at a rate equal to the historical

Figure 5. Lower 48 Oil and Gas Supply Regions with Region Codes

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[7]Abandonment of a project is expected to occur in that year of its life when the expected net revenue is less than expected operating costs. When abandonment does occur, expected abandonment costs are added to the calculation of the project's discounted cash flow.

average production to reserves ratio. The default price expectation is that real prices will remain constant over the project's expected lifetime. The OGSM also can utilize an expected price vector provided from the NEMS system that reflects a user-specified assumption regarding price expectations. The calculations of STATETAX and FEDTAX account for the tax treatment of tangible and intangible drilling expenses, lease equipment expenses, operating expenses, and dry hole expenses. The algorithm also incorporates the impact of unconventional fuel tax credits and has the capability of handling other forms of investment tax credits. For a detailed discussion of the discounted cash flow methodology, the reader is referred to Appendix 4-A at the end of this chapter.

The undiscounted net cash flows for each year of the project, calculated by Equation (1), are discounted and summed to yield the discounted cash flow for the representative onshore developmental project (PROJDCFON). This can be written as:

$$PROJDCFON_{i,r,k,t} = SUCDCFON_{i,r,k,t} + [(\frac{1}{SR_{i,r,k}}) - 1] * DRYDCFON_{i,r,k,t},$$

for $i = 2$

(2)

where,

SUCDCFON $=$ the discounted cash flow associated with one successful onshore developmental well

DRYDCFON $=$ the discounted cash flow associated with one dry onshore developmental well (dry hole costs).

Since the expected discounted cash flow for a representative onshore developmental well is equal to:

$$DCFON_{i,r,k,t} = SR_{i,r,k} * SUCDCFON_{i,r,k,t} + (1 - SR_{i,r,k}) * DRYDCFON_{i,r,k,t}, \text{ for } i = 2$$

(3)

it is easily calculated as:

$$DCFON_{i,r,k,t} = PROJDCFON_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 2, r = 1 \text{ thru } 6, k = 1 \text{ thru } 4$$

(4)

where,

DCFON $=$ expected discounted cash flow for a representative onshore developmental well.

Onshore Lower 48 Exploration

A representative onshore exploration project consists of one successful exploratory well, $[(1/SR_{1,r,k})-1]$ dry exploratory wells, m_k successful development wells, and $m_k*[(1/SR_{2,r,k})-1]$ dry development wells. All exploratory wells are assumed to be drilled in the current year with production from the successful exploratory well assumed to commence in the current year. The developmental wells are assumed to be drilled in the second year of the project with production from the successful developmental well assumed to begin in the second year.

The calculations of the yearly net cash flows and the discounted cash flow for the exploratory project are identical to those described for the developmental project. The discounted cash flow for the exploratory project can be decomposed as:

$$
\begin{aligned}
PROJDCFON_{1,r,k,t} = {} & SUCDCFON_{1,r,k,t} + m_k * \left[SUCDCFON_{2,r,k,t} + \left(\left(\frac{1}{SR_{2,r,k}} \right) - 1 \right) * \right. \\
& \left. DRYDCFON_{2,r,k,t} \right] + \left(\left(\frac{1}{SR_{1,r,k}} \right) - 1 \right) * DRYDCFON_{1,r,k,t}
\end{aligned}
\tag{5}
$$

where,

$$m_k \quad = \quad \text{number of successful developmental wells in a representative project.}$$

The first two terms on the right hand side represent the discounted cash flows associated with the successful exploratory well drilled in the first year of the project and the successful and dry developmental wells drilled in the second year of the project. The third term represents the impact of the dry exploratory wells drilled in the first year of the project.

Again, as in the development case, the expected DCF for a representative onshore exploratory well is calculated by:

$$
DCFON_{1,r,k,t} = PROJDCFON_{1,r,k,t} * SR_{1,r,k}
\tag{6}
$$

Shallow Offshore Exploration and Development

The calculations of the expected discounted cash flows for the lower 48 offshore regions (i.e., $DCFOFF_{i,r,k,t}$) are identical to those described for the lower 48 onshore. In addition, the economic assessment of an offshore development well matches that in the onshore. The sole difference relates to the specific characterization of an offshore exploration project, which is reflected in the input data for the offshore.

Specifically, an offshore exploration project consists of: (1) two successful new field wildcat wells drilled in the first year of the project from which there is no production; (2) three successful other exploratory wells that delineate the new field and begin producing in the second year of the project along with the requisite number of dry other exploratory wells; (3) eight successful developmental wells that are drilled and begin producing in the third year of the project along with the requisite number of dry developmental wells; and (4) one successful developmental well that is drilled and begins producing in each of the next seven years of the project along with the requisite number of dry holes.

Calculation of Alternative Expected DCF's as Proxies for Expected Profitability

In some instances, the forecasting equations employ alternative, usually more aggregated, forms of the expected DCF. For example, the deep oil well data for some regions is sparse thus an aggregate expected oil DCF is calculated . This aggregate expected DCF for oil is calculated as a weighted average of the expected DCF's for shallow and deep oil. Specifically,

$$
woil_{i,r,k,t} = \frac{WELLS_{i,r,k,t-1}}{\sum_k WELLS_{i,r,k,t-1}}, \quad \text{for } k = 1 \text{ to } 2
\tag{7}
$$

and

$$\text{ODCFON}_{i,r,t} = \sum_{k=1}^{2} \text{woil}_{i,r,k,t} * \text{DCFON}_{i,r,k,t} \qquad (8)$$

where,

$$\begin{aligned}
\text{WELLS} &= \text{wells drilled} \\
\text{ODCFON} &= \text{expected DCF for oil.}
\end{aligned}$$

For some onshore well equations, a regional exploratory or development expected DCF is used as a proxy for expected profitability. These are calculated as weighted averages of the fuel specific expected DCF's in each region. The weights are equal to the share of total wells of type I drilled in region r of fuel type k in the previous period. Specifically,

$$w_{i,r,k,t} = \frac{\text{WELLS}_{i,r,k,t-1}}{\sum\limits_{k} \text{WELLS}_{i,r,k,t-1}}, \quad \text{for each } i,\ r,\ k \qquad (9)$$

where,

$$\text{WELLS} = \text{wells drilled.}$$

The expected DCF's are then derived using the following equation:

$$\text{RDCFON}_{i,r,t} = \sum_{k} w_{i,r,k,t} * \text{DCFON}_{i,r,k,t}, \quad \text{for } i = 1, 2, r = \text{onshore regions}, k = 1 \text{ thru } 4 \qquad (10)$$

where,

$$\text{RDCFON} = \text{onshore regional expected discounted cash flow per well}$$

Finally, in several cases, the expected profitability of a representative onshore shallow oil and/or shallow gas well is proxied by a combined shallow oil/shallow gas expected DCF for the specific region, denoted by the variable name OSGDCFON. Analogous to the alternatives described above, this measure is calculated as a weighted average of the exploratory oil and shallow gas expected DCF's in the region. The weights are equal to the shares of the total number of oil and shallow gas exploratory wells drilled in the region in the previous period. Algebraically:

$$\text{OSGDCFON}_{i,r,t} = \sum_{k} \text{wcon}_{i,r,k,t} * \text{DCFON}_{i,r,k,t}, \quad \text{for } i,\ r,\ k = 1,3 \qquad (11)$$

where,

$$\text{wcon}_{i,r,k,t} = \frac{\text{WELLS}_{i,r,k,t-1}}{\sum\limits_{k} \text{WELLSON}_{i,r,k,t-1}}, \quad \text{for } i,\ r,\ k = 1,3 \qquad (12)$$

Lower 48 Wells Forecasting Equations

For each onshore Lower 48 region, the shallow Gulf offshore region, and the Pacific offshore region, the number of wells drilled by well class and fuel type is forecasted generally as a function of the expected profitability, proxied by the expected DCF, of a representative well of class I, in region r, for fuel type k, in year t. In some specific cases, however, the forecasting equations may use the lagged value of the expected DCF or a more aggregate form of the expected DCF and may incorporate dummy variables to capture the effects of structural changes.[8] For the Pacific offshore, only oil development wells are forecasted.

The specific forms of the equations used in forecasting wells are given in Appendix B. These equations can be expressed in the following generalized form.[9]

$$\text{WELLSON}_{i,r,k,t} \; = \; m0_{i,r,k} \; + \; m1_{i,r,k} * \text{DCFON}_{i,r,k,t} \; + \; m2_{i,r,k} * \text{DUMXX}_t \; + \; m3_{i,r,k} * \text{DUMAABB}_t \tag{13}$$

$$\text{WELLSOFF}_{i,r,k,t} \; = \; \alpha0_{i,r,k} \; + \; \alpha1_{i,r,k} * \text{DCFOFF}_{i,r,k,t} \; + \; \alpha2_{i,r,k} * \text{DUMZZ}_t \; + \; \alpha3_{i,r,k} * I \tag{14}$$

where,

WELLSON	=	lower 48 onshore wells drilled by class, region, and fuel type
WELLSOFF	=	lower 48 offshore wells drilled by class, region, and fuel type
DCFON	=	expected DCF for a representative onshore well of class I, in region r, for fuel type k, in year t
DCFOFF	=	expected DCF for a representative offshore well of class I, in region r, for fuel type k, in year t
DUMXX	=	1 if year $\geq$ 19XX; 0 otherwise
DUMZZ	=	1 if year $\geq$ 19ZZ; 0 otherwise
DUMAABB	=	1 if year > 19AA and year < 19BB; 0 otherwise
DUMCCDD	=	1 if year > 19CC and year < 19DD; 0 otherwise
m's, α"s	=	estimated parameters
i	=	well type
r	=	lower 48 regions
k	=	fuel type
t	=	year.

Other variables not defined above that appear in specific equations are defined in Appendix E. Additionally, a number of the forecasting equations include a correction for first order serial correlation. The general form is given below with the onshore notation used for exposition purposes only. The form for the offshore equations is identical.

---

[8]Some of these dummy variables are only applied to historical years and will appear in the estimation description in Appendix E but, because they are equal to zero in the projection period, will not appear in the mathematical description in Appendix B.

[9]For the shallow gas exploratory wells in onshore region 2 and for the oil and gas development wells in the offshore Gulf, the forecasting equations took the general exponential form given by:

$$\text{WELLS} = \exp{(\beta_0 + \beta_1 * \text{DCF} + \beta_2 * \text{DUMXX})}$$

where exp represents the exponential function and the β's are estimated parameters.

$$\begin{aligned} WELLSON_{i,r,k,t} = \ & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUMXX_t + \rho_{i,r,k} * WELLS \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUMXX_{t-1}) \end{aligned} \tag{15}$$

where,

ρ = estimated serial correlation parameter.

Successful and Dry Wells Determination

The number of successful wells in each category is determined by multiplying the forecasted number of total wells drilled in the category by the corresponding success rates. Specifically,

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, \ r = \text{onshore regions}, \ k = 1 \text{ thru } 4 \tag{16}$$

$$SUCWELSOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, \ r = \text{offshore regions}, \ k = 1, 2 \tag{17}$$

where,

SUCWELSON	=	successful onshore lower 48 wells drilled
SUCWELSOFF	=	successful offshore lower 48 wells drilled
WELLSON	=	onshore lower 48 wells drilled
WELLSOFF	=	offshore lower 48 wells drilled
SR	=	drilling success rate
i	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 regions, onshore and offshore
k	=	fuel type (1 = oil, 2 = shallow gas, 3 = deep gas, 4 = tight sands gas)
t	=	year.

Dry wells by class, region, and fuel type are calculated by:

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t}, \text{ for } i = 1, 2, \\ r = \text{onshore regions}, \ k = 1 \text{ thru } 4 \tag{18}$$

$$DRYWELOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} - SUCWELSOFF_{i,r,k,t}, \text{ for } i = 1, 2, \\ r = \text{offshore regions}, \ k = 1, 2 \tag{19}$$

where,

DRYWELON	=	number of dry wells drilled onshore
DRYWELOFF	=	number of dry wells drilled offshore
SUCWELSON	=	successful lower 48 onshore wells drilled by fuel type, region, and well type
SUCWELSOFF	=	successful lower 48 offshore wells drilled by fuel type, region, and well type
WELLSON	=	onshore lower 48 wells drilled by fuel type, region, and well type
WELLSOFF	=	offshore lower 48 wells drilled by fuel type, region, and well type
i	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 regions, onshore and offshore
k	=	fuel type (1 = shallow oil, 2 = deep oil, 3 = shallow gas, 4 = deep gas)
t	=	year.

Drilling, Lease Equipment, and Operating Cost Calculations

Three major costs classified within the OGSM are drilling costs, lease equipment costs, and operating costs (including production facilities and general/administrative costs). These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The successful drilling and dry hole cost equations capture the impacts of complying with environmental regulations, drilling to greater depths, rig availability, and technological progress.

One component of the drilling equations that causes costs to increase is the number of wells drilled in the given year. But within the framework of the OGSM, the number of wells drilled cannot be determined until the costs are known. Thus, drilling is estimated as a function of price as generalized below:

$$\text{ESTWELLS}_t = \exp(b0) * \exp(b1 * \text{LPOIL}_t * \text{LPGAS}_t) * \exp(b2 * \text{LPOIL}_t * \text{LPGAS}_t * \text{PRE91}_t) \tag{20}$$

$$\text{ESTSUCWELLS}_t = \exp(c0) * \exp(c1 * \text{LPOIL}_t * \text{LPGAS}_t) * \exp(c2 * \text{LPOIL}_t * \text{LPGAS}_t * \text{PRE91}_t) \tag{21}$$

where,

ESTWELLS	=	estimated total onshore lower 48 wells drilled
ESTSUCWELLS	=	estimated successful onshore lower48 wells drilled
LPOIL	=	logarithm of the average wellhead price of crude oil
LPGAS	=	logarithm of the average wellhead price of natural gas
b0,b1,b2,c0,c1,c2	=	estimated parameters
t	=	year.

The estimated level of drilling is then used to calculate the rig availability. The calculation is given by:

$$\text{RIGSL48}_t = \exp(b0) * \text{RIGSL48}_{t-1}^{b1} * \text{REVRIG}_{t-1}^{b2} \tag{22}$$

where,

RIGSL48	=	onshore lower 48 rigs
REVRIG	=	total drilling expenditures per rig
b0, b1, b2	=	estimated parameters
t	=	year.

Drilling Costs

Onshore
In each period of the forecast, the drilling cost per successful well is determined by:

$$\text{DRILLCOST}_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_{d,k}) * \exp(b2_{r,k}) * \text{ESTWELLS}_t^{b3_k} * \\ \text{RIGSL48}_t^{b4_k} * \exp(b5 * \text{TIME}_t) \tag{23}$$

$$\text{DRYCOST}_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_{d,k}) * \exp(b2_{r,k}) * \text{ESTWELLS}_t^{b3_k} * \\ \text{RIGSL48}_t^{b4_k} * \exp(b5 * \text{TIME}_t) \tag{24}$$

where,

DRILLCOST	=	drilling cost per well
DRYCOST	=	drilling cost per dry well

ESTWELLS	=	estimated total onshore lower 48 wells drilled
RIGSL48	=	onshore lower 48 rigs
TIME	=	time trend - proxy for technology
r	=	OGSM lower 48 onshore region
k	=	fuel type (1 = shallow oil, 2 = deep oil, 3 = shallow gas, 4 = deep gas)
d	=	depth class
b0, b1, b2, b3, b4, b5	=	estimated parameters
t	=	year.

Shallow Offshore

In each period of the forecast, the drilling cost per well is determined by:

$$DRILLCOST_k = \exp(\delta 0_k) * GOMWELLS_t^{\delta 1_k} * \exp(\delta 2_{d,k}) * RIGSOFF_{t-2}^{\delta 3_k} * \exp(\delta 4_k * TIME_t) \tag{25}$$

$$DRYCOST_k = \exp(\delta 0_k) * GOMWELLS_t^{\delta 1_k} * \exp(\delta 2_{d,k}) * RIGSOFF_{t-2}^{\delta 3_k} * \exp(\delta 4_k * TIME_t) \tag{26}$$

where,

DRILLCOST	=	drilling cost per successful well
DRYCOST	=	drilling cost per dry hole
GOMWELLS	=	total gulf of mexico offshore wells drilled
RIGSOFF	=	total offshore rigs
TIME	=	time trend - proxy for technology
d	=	depth per well
k	=	fuel type (1 = oil, 2 = gas)
$\delta 0, \delta 1, \delta 2, \delta 3, \delta 4$	=	estimated parameters
t	=	year.

In each period of the forecast, the total number of wells is determined by:

$$GOMWELLS_t = \exp(\alpha) * \exp(\beta * \log(POIL_t) * \log(PGAS_t)) \tag{27}$$

where,

POIL	=	average wellhead price of crude oil
PGAS	=	average wellhead price of natural gas
α, β, ρ	=	estimated parameters.

In each period of the forecast, the total rigs available is determined by:

$$RIGSOFF_t = \exp(\alpha) * RIGSOFF_{t-1}^{\beta} * REVRIG_{t-2}^{\gamma} \tag{28}$$

where,

RIGSOFF	=	number of rigs available in year t
REVRIG	=	total drilling expenditures per rig
α, β, γ	=	estimated parameters
t	=	year.

Lease Equipment Costs

In each period of the forecast, lease equipment costs per successful well are determined by:

$$LEQC_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_k * DEPTH_{r,k,t}) * ESTSUCWELLS_t^{b2_k} * \exp(b3_k * TIME_t) \qquad (29)$$

where,

LEQC	=	oil and gas well lease equipment costs
DEPTH	=	average well depth
ESTSUCWELLS	=	estimated lower 48 successful onshore wells
TIME	=	time trend - proxy for technology
$\epsilon 0, \epsilon 1, \epsilon 2$	=	estimated parameters
r	=	OGSM lower 48 onshore region
k	=	fuel type (1=shallow oil, 2=deep oil, 3=shallow gas, 4=deep gas)
t	=	year.

Operating Costs

In each period of the forecast, operating costs per successful well are determined by:

$$OPC_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_k * DEPTH_{r,k,t}) * ESTSUCWELLS_{t-1}^{b2_k} * \exp(b3_k * TIME_t) \qquad (30)$$

where,

OPC	=	oil and gas well operating costs
ESTSUCWELLS	=	estimated lower 48 successful onshore wells
DEPTH	=	average well depth
TIME	=	time trend - proxy for technology
b0, b1, b2, b3	=	estimated parameters
r	=	OGSM lower 48 onshore region
k	=	fuel type (1=shallow oil, 2=deep oil, 3=shallow gas, 4=deep gas)
t	=	year.

The estimated wells, rigs, and cost equations are presented in their generalized form but the forecasting equations include a correction for first order serial correlation as shown in Appendix E.

Reserve Additions

The Reserve Additions algorithm calculates units of oil and gas added to the stocks proved and inferred reserves. Reserve additions are calculated through a set of equations accounting for new field discoveries, discoveries in known fields, and incremental increases in volumetric recovery that arise during the development phase. There is a 'finding rate' equation for each phase in each region and for each fuel type.

Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. Proved reserves are reserves that can be certified using the original discovery wells, while inferred reserves are those hydrocarbons that require additional drilling before they are termed proved. Additional drilling takes the form of other exploratory drilling and development drilling. Within the model, other exploratory drilling accounts for proved reserves added through new pools or extensions, and development drilling accounts for reserves added through revisions.

The volumetric yield from a successful new field wildcat well is divided into proved reserves and inferred reserves. The proportions of reserves allocated to these categories are based on historical reserves growth statistics. Specifically, the allocation of reserves between proved and inferred reserves is based on the ratio of the initial reserves estimated for a newly discovered field relative to ultimate recovery from the field.[10]

Functional Forms

Oil or gas reserve additions from new field wildcats are a function of the cumulative new field discoveries, the initial estimate of recoverable resources for the fuel, and the rate of technological change.

Total successful exploratory wells are disaggregated into successful new field wildcats and other exploratory wells based on a historical ratio. For the rest of the chapter, successful new field wildcats will be designated by the variable SW1, other successful exploratory wells by SW2, and successful development wells by SW3.

The major inputs to the new field reserve addition equation are new reserve discoveries and the resource base.

This approach relies on the finding rate equation:

$$FR1_{r,k,t} = FR1O_{r,k,t} * \left(1 - \frac{CUM\_U_{r,k,t}}{BIG\_U_{r,k}} \right)^{DELTA\_B_{r,k}} \tag{31}$$

where

$$FR1O_{r,k,t} = INITFR1_{r,k,t} * FRTECH_{r,k,t} * ECON_{r,k,t} \tag{32}$$

and

FR1	=	new field wildcats finding rate
FR1O	=	initial finding rate for new field wildcats
CUM_U	=	cumulative new field discoveries
BIG_U	=	ultimate recovery resource estimate
DELTA_B	=	hyperbolic decline rate
FR1O	=	initial finding rate adjusted for technology and economics
INITFR1	=	initial finding rate
FRTECH	=	technology adjustment
ECON	=	economic adjustment
r	=	region
k	=	fuel type (oil or gas)
t	=	year.

Under the above specification, the yield from new fieldcat drilling in the absence of technological and economic change declines with cumulative discoveries. Technological progress is split into four regimes (2 past, 1 current, and 1 future) and is of the form

---

[10]A more complete discussion of the topic of reserve growth for producing fields can be found in Chapter 3 of *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy*.

$$FRTECH_{r,k,t} = 1 + \frac{\alpha_{r,k}}{1 + e^{\beta 1_{r,k} *(t - \beta 2)}}$$

(33)

where

$$
\begin{array}{rcl}
\alpha & = & \text{peak impact} \\
\beta 1 & = & \text{rate of change} \\
\beta 2 & = & \text{peak year} \\
r & = & \text{region} \\
k & = & \text{fuel type} \\
t & = & \text{year.}
\end{array}
$$

The economic impact is defined by

$$ECON_{r,k,t} = \frac{OFE_{r,k} * \dfrac{CUM\_U_{r,k,t}}{CUM\_NFW_{r,k,t}} + POA_{r,k}}{OFE_{r,k} * \dfrac{CUM\_U_{r,k,t}}{CUM\_NFW_{r,k,t}} + WHP_{r,k,t}}$$

(34)

where

$$
\begin{array}{rcl}
OFE & = & \text{assumed economic impact coefficient} \\
CUM\_U & = & \text{cumulative new field discoveries} \\
CUM\_NFW & = & \text{cumulative new field wildcats drilled} \\
POA & = & \text{historical average wellhead price} \\
WHP & = & \text{wellhead price.}
\end{array}
$$

The above equations provide a rate at which undiscovered resources convert into proved and inferred reserves as a function of cumulative new field discoveries. Given an estimate for the ratio of ultimate recovery from a field relative to the initial proved reserve estimate, $X_{r,k}$, the $X_{r,k}$ reserve growth factor is used to separate newly discovered resources into either proved or inferred reserves. Specifically, the change in proved reserves from new field discoveries for each period is given by integrating the finding rate with respect to wells drilled each period.

$$\Delta R_{r,k,t} = \frac{1}{X_{r,k}} \int_{0}^{SW1_{r,k,t}} FR1_{r,k,t} \; d(SW1)$$

$$\frac{1}{X_{r,k}} \int_{0}^{SW1_{r,k,t}} FR1_{r,k,t-1}(1 + \beta 1) * \exp(-\delta 1_{r,k,t} * SW1_{r,k,t}) d(SW1)$$

(35)

where,

$$
\begin{array}{rcl}
X & = & \text{reserves growth factor} \\
\Delta R & = & \text{additions to proved reserves.}
\end{array}
$$

The terms in equation (28) are all constants in period t, except for the SW1. X is derived from historical data and it is assumed to be constant during the forecast period. $FR1_{r,k,t-1}$ and $\delta 1_{r,k,t}$ are calculated, prior to period t, based on lagged variables and fixed parameters as shown in equations (26) and (27).

Reserves are converted from inferred to proved with the drilling of other exploratory wells and developmental wells. The finding rate for other exploratory wells is modeled as a function of cumulative successful other exploratory wells drilled, current successful other exploratory wells drilled, cumulative new field discoveries, and a time trend to proxy the impact of technological progress. Algebraically, the general form of the other exploratory wells finding rate equation is given by: [11]

$$FR2_{r,k,t} = \delta0_{r,k} + \delta1_k * CUMSW1_{r,k,t-1} + \delta2_k * CUMSW2_{r,k,t-1} + \delta3_k * SW2_{r,k,t} \dashv \tag{36}$$

where:

FR2	=	other exploratory wells finding rate;
CUMSW1	=	cumulative successful new field wildcats wells drilled at the start of year t;
CUMSW2	=	cumulative other exploratory drilling at the start of year t-1;
SW2	=	the average of successful other exploration wells drilled in year t and t-1;
YEAR	=	time trend.

Similarly, the finding rate for developmental wells is modeled as a function of cumulative successful developmental wells drilled, current successful developmental wells drilled, cumulative reserve additions from other exploratory drilling, and a time trend to proxy the impact of technological progress. Algebraically, the general form of the equation is given by:[12]

$$FR3_{r,k,t} = \delta0_k + \delta1_k * CUMSW3_{r,k,t-1} + \delta2_k * CUMRES2_{r,k,t-1} + \delta3_k * SW3_{r,k,t} \dashv \tag{37}$$

where:

FR3	=	developmental wells finding rate;
CUMSW3	=	cumulative successful developmental wells drilled at the start of year t;
CUMRES2	=	cumulative reserve additions from other exploratory drilling at the start of year t;
SW3	=	successful developmental wells drilled in year t;
YEAR	=	time trend.

Total reserve additions in period t are given by the following equation:

$$RA_{r,k,t} = \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t}d(SW1) + \int_0^{SW2_{r,k,t}} FR2_{r,k,t}d(SW2) + \int_0^{SW3_{r,k,t}} FR3_{r,k,t}d(SW3) \tag{38}$$

Finally, total end of year proved reserves for each period equals:

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \tag{39}$$

where,

---

[11] In some cases, the variables CUMSW1 did not contribute any explanatory power to the estimated equation. In these cases, the variable was dropped from the regression. See appendicies for details.

[12] For all fuel types, the FR3 equation is estimated and implemented with a correction for first order serial correlation. In some cases, the estimated and implemented equations also include region-specific constant terms. The FR3 equation for deep gas (k = 4) does not include CUMRES2 as an explanatory variable. See appendices B and E for details.

$$R \quad = \quad \text{reserves measured as of the end-of-year}$$
$$Q \quad = \quad \text{production}$$

Production to Reserves Ratio

The production of nonassociated gas in NEMS is modeled at the "interface" of NGTDM and OGSM while oil production is determined within the OGSM. In both cases, the determinants of production include the lagged production to reserves (PR) ratio and price. The PR ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves. The user has an option of three different approaches to determine the PR ratio.

Option 1

For each year t, the PR ratio is calculated as:

$$PR_t = \frac{Q_t}{R_{t-1}} \tag{40}$$

where,

$$PR_t \quad = \quad \text{production to reserves ratio for year t}$$
$$Q_t \quad = \quad \text{production in year t (received from the NGTDM and the PMM)}$$
$$R_{t-1} \quad = \quad \text{end of year reserves for year (t-1) or equivalently, beginning of year reserves}$$
$$\text{for year t.}$$

PR_t represents the rate of extraction from all wells drilled up to year t (through year t-1). To calculate the expected rate of extraction in year (t+1), the model combines production in year t with the reserve additions and the expected extraction rate from new wells drilled in year t. The calculation is given by:

$$PR_{t+1} = \frac{(R_{t-1} * PR_t * (1 - PR_t)) + (PRNEW * RA_t)}{R_t} \tag{41}$$

where,

$$PR_{t+1} \quad = \quad \text{expected production to reserves ratio for year (t+1)}$$
$$PRNEW \quad = \quad \text{long-term expected production to reserves ratio for all wells drilled in forecast}$$
$$R_t \quad = \quad \text{end of year reserves for year t or equivalently, beginning of year reserves for}$$
$$\text{year (t+1).}$$

The numerator, representing expected total production for year t+1, comprises the sum of two components. The first represents production from proved reserves as of the beginning of year t. This production is the expected production in year t, $R_{t-1}*PR_t$, adjusted by $1-PR_t$ to reflect the normal decline from year t to t+1. The second represents production from reserves discovered in year t. No production in year t+1 is assumed from reserves discovered in year t+1.

Under this option, PR_t is constrained not to vary from PR_{t-1} by more than 5 percent. It is also constrained not to exceed 30 percent.

The values for R_t and PR_{t+1} are passed to the NGTDM and the PMM for use in their market equilibration algorithms which solve for equilibrium production and prices for year (t+1) of the forecast using the following short-term supply function:

$$Q_{r,k,t+1} = [R_{r,k,t}] * [PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})] \tag{42}$$

where,

$$
\begin{array}{rcl}
R_t & = & \text{end of year reserves in period t} \\
PR_t & = & \text{extraction rate in period t} \\
\beta & = & \text{estimated short run price elasticity of supply} \\
\Delta P_{t+1} & = & (P_{t+1}\text{-}P_t)/P_t, \text{ proportional change in price from t to t+1.}
\end{array}
$$

The P/R ratio for period t, PR_t, is assumed to be the approximate extraction rate for period t+1 under normal operating conditions. The product ($R_{r,k,t}$ * PR_t is the expected, or normal, operating level of production for period t+1. Actual production in t+1 will deviate from expected depending on the proportionate change in price from period t and on the value of short run price elasticity. The OGSM passes estimates of β to the NGTDM and PMM that can be used in solving for the market equilibria. Documentation of the equations used to estimate β is provided in Appendix E.

Option 2

Options 2 is an econometric alternative to the approach presented under option 1. The determinants of the production to reserves ratio in a given region include the regional wellhead price and unobserved regional specific effects such as geology. The relationship between the PR ratio and price as well as other factors is not linear given that ratio is bounded between zero and one. For this reason, a logistic transformation of the PR ratio was the dependent variable in the regression equation. Given this approach, the estimated PR equation for region r in year t is

$$PR_{r,k,t} = \frac{X_{r,k,t}}{1 + X_{r,k,t}} \tag{43}$$

where $X_{r,k,t}$ is defined as follows.

Natural Gas

$$
\begin{aligned}
X_{r,k,t} = {} & \exp((1-\rho gas)*cgas_r) \ * \ \exp(h*CARRIAGE_t) \ * \ \exp(-\rho gas*h*CARRIAGE_{t-1}) * \\
& \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}} \right)^{\rho gas} * \ PGAS_{r,t}^{\alpha} \ * \ PGAS_{r,t-1}^{-\rho gas*\alpha}
\end{aligned} \tag{44}
$$

where,

$$
\begin{array}{rcl}
CARRIAGE & = & \text{share of pipeline deliveries transported for others} \\
PR & = & \text{production to reserves ratio} \\
PGAS & = & \text{average wellhead price of natural gas} \\
r & = & \text{region} \\
k & = & \text{fuel type (1=oil, 2=gas)} \\
t & = & \text{year}
\end{array}
$$

cgas, h, α, ρgas   =   estimated parameters.

The variable CARRIAGE is equal to one over the forecast period. It was included in the equation to account for the transition to open access over the sample period.

Crude Oil

$$X_{r,k,t} = \exp((1-\rho oil)*coil_r) * \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}} \right)^{\rho oil} * \exp(\beta*POIL_{r,t}) * \exp(-\rho oil*\beta*POIL_{r,t-1}) \tag{45}$$

where,

$$
\begin{aligned}
PR &= \text{production to reserves ratio} \\
POIL &= \text{average wellhead price of crude oil} \\
r &= \text{region} \\
t &= \text{year} \\
coil, \beta, \rho oil &= \text{estimated parameters.}
\end{aligned}
$$

The PR ratio is multiplied by the beginning-of-year crude oil reserves to get production by region. This volume is then passed to the PMM for use in their market equilibration.

Option 3

Options 3 is another econometric alternative to the approach presented under option 1. The determinants of the production to reserves ratio include the same variables as in option 2 as well as a ratio of reserve additions relative to reserves. Specifically, the estimated PR equation for region r in year t is

$$PR_{r,k,t} = \frac{X^{\circ}_{r,k,t}}{1 + X^{\circ}_{r,k,t}} \tag{46}$$

where $X^{\circ}_{r,k,t}$ is defined as follows.

Natural Gas

$$X^{\circ}_{r,k,t} = \exp((1-\rho gas)*cgas_r) * \exp(h*CARRIAGE_t) * \exp(-\rho gas*h*CARRIAGE_{t-1}) *$$
$$\left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}} \right)^{\rho gas} * \exp(fgas_r*RA_{r,k,t-1}) * \exp(-\rho gas*fgas_r*RA_{r,k,t-2}) \tag{47}$$

where,

$$
\begin{aligned}
CARRIAGE &= \text{share of pipeline deliveries transported for others (reflects the industry's} \\
&\quad \text{transition to open access)} \\
PR &= \text{production to reserves ratio} \\
RA &= \text{reserve additions to reserves ratio} \\
r &= \text{region} \\
k &= \text{fuel type (1=oil, 2=gas)} \\
t &= \text{year}
\end{aligned}
$$

cgas, h, fgas, ρgas $\quad=\quad$ estimated parameters.

The NGTDM uses the following function to determine the wellhead prices given the production to reserves ratios.

$$PGAS_{r,t} = PGAS_{r,t-1}^{\rho} * \left(\frac{PR_{r,t}}{1-PR_{r,t}}\right)^{\frac{1}{B}} * \left(\frac{PR_{r,t-1}}{1-PR_{r,t-1}}\right)^{-\frac{\rho}{B}} * Z^{\circ}{}_{r,t}^{\frac{1}{B}} \tag{48}$$

where,

$$Z^{\circ}{}_{r,t} = \exp((\rho gas-1)*cgas(r)) * \exp(-h*CARRIAGE(t)) * \exp(\rho gas*h*CARRIAGE(t-1)) *$$
$$\exp(-fgas_r*RA_{r,k,t-1}) * \exp(\rho gas*fgas_r*RA_{r,k,t-2}) \tag{49}$$

Crude Oil

$$X^{\circ}{}_{r,k,t} = \exp((1-\rho oil)*coil_r) * \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho oil} * \exp(\beta *POIL_{r,t}) * \exp(-\rho oil*\beta *POIL_{r,t-1}) *$$
$$\exp(foil_r*RA_{r,k,t-1}) * \exp(-\rho oil*foil_r*RA_{r,k,t-2}) \tag{50}$$

where,

PR	=	production to reserves ratio
POIL	=	average wellhead price of crude oil
RA	=	reserve additions to reserves ratio
r	=	region
t	=	year
coil, β, ρoil	=	estimated parameters.

The PR ratio is multiplied by the beginning-of-year crude oil reserves to get production by region. This volume is then passed to the PMM for use in their market equilibration.

Associated Dissolved Gas

Associated dissolved (AD) gas production is estimated as a function of crude oil production. The basic form of the equation is given as:

$$ADGAS_{r,t} = e^{\ln(\alpha)_r} * OILPROD_{r,t}^{\beta} \tag{51}$$

where,

ADGAS	=	associated dissolved gas production
OILPROD	=	crude oil production
r	=	OGSM region
t	=	year
α,β	=	estimated parameters.

This simple regression function is used in the estimation of AD gas production in onshore regions 1 through 4. A time dummy is introduced in onshore regions 5 and 6 and offshore regions of California and the Gulf of Mexico to represent loosening of restrictions on capacity and changes in regulation. Specifically,

$$ADGAS_{r,t} = e^{\ln(\alpha 0)_r + \ln(\alpha 1)_r * DUM86_t} * OILPROD_{r,t}^{\beta 0_r + \beta 1_r * DUM86_t} \tag{52}$$

where,

$$
\begin{aligned}
DUM86 \quad &= \quad \text{dummy variable (1 if t>1985, otherwise 0)} \\
\alpha 0, \alpha 1, \beta 0, \beta 1 \quad &= \quad \text{estimated parameters.}
\end{aligned}
$$

Unconventional Gas Recovery Supply Submodule

This section describes the basic structure of the Unconventional Gas Recovery Supply Submodule (UGRSS). The UGRSS is designed to project gas production from unconventional gas deposits. This section provides an overview of the basic modeling approach. A more detailed description of the methodology is presented in Appendix 4-C and an in depth view of the treatment of technology in the UGRSS is provided in Appendix 4-D.

The UGRSS is a play level model that specifically analyzes the three major unconventional resources - coalbed methane, tight gas sands, and gas shales. The UGRSS calculates the economic feasibility of individual plays based on locally specific wellhead prices and costs, resource quantity and quality, and the various effects of technology on both resources and costs. In each year an initial resource characterization determines the expected ultimate recovery (EUR) for the wells drilled in a particular play. Resource profiles are adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play. Subsequently, prices received from the NGTDM and endogenously determined costs adjusted to reflect technological progress are utilized to calculate the economic profitability (or lack thereof) for the play. If the play is profitable, drilling occurs according to an assumed schedule, which is adjusted annually to account for technological improvements, as well as varying economic conditions. This drilling results in reserve additions, the quantities of which are directly related to the EUR's for the wells in that play. Given these reserve additions, reserve levels and ("expected") production-to-reserves (P/R) ratios are recalculated at the NGTDM region level. The resultant values are sent to OGSM, where they are aggregated with similar values from the other submodules. The aggregate P/R ratios and reserve levels are then passed to the NGTDM, which determines through market equilibration the prices and production for the following year.

Deep Water Offshore Supply Submodule

This section describes the basic structure of the Deep Water Offshore Supply Submodule (DWOSS). The DWOSS is designed to project oil and gas production from the deep water region of the Gulf of Mexico. This section provides an overview of the basic approach. A more detailed description of the methodology is presented in Appendix 4E as well as a discussion of the characterization of the undiscovered resource base and the rationale behind the various technology options for deep water exploration, development and production practices incorporated in the DWOSS.

The DWOSS was developed offline from the OGSM. A methodology was developed within OGSM to enable it to readily import and manipulate the DWOSS output, which consists essentially of detailed price/supply tables disaggregated by Gulf of Mexico planning regions (Eastern, Central, and Western) and fuel type (oil, natural gas). At the most fundamental level, therefore, it is useful to identify the two structural components that make up the DWOSS, as defined by their relationship (exogenous vs. endogenous) to the OGSM:

Exogenous Component. A methodology for developing deepwater offshore undiscovered resource price/supply curves, employing a rigorous field-based discounted cash-flow (DCF) approach,[15] was constructed exogenously from OGSM. This offline portion of the model utilizes key field properties data, algorithms to determine key technology components, and algorithms to determine the exploration, development and production costs, and computes a minimum acceptable supply price (MASP) at which the discounted net present value of an individual prospect equals zero. The MASP and the recoverable reserves for the different fields are aggregated by planning region and by resource type to generate resource-specific price-supply curves. In addition to the overall supply price and reserves, cost components for exploration, development drilling, production platform, and operating expenses, as well as exploratory and development well requirements, are also carried over to the endogenous component.

Endogenous Component. After the exogenous price/supply curves have been developed, they are transmitted to and manipulated by an endogenous program within OGSM. The endogenous program contains the methodology for determining the development and production schedule of the deepwater offshore Gulf of Mexico OCS oil and gas resources from the price/supply curves. The endogenous portion of the model also includes the capability to estimate the impact of penetration of advanced technology into exploration, drilling, platform, and operating costs as well as growth of reserves.

Enhanced Oil Recovery Supply Submodule

This section describes the structure of the Enhanced Oil Recovery Supply Submodule (EORSS). The EORSS is designed to project regional oil production in the onshore lower 48 states extracted by use of tertiary recovery techniques. This section provides an overview of the basic approach including a discussion of the procedure for projecting production from base year reserves and the methodology for development and subsequent production from previously unproven reserves.

Introduction

All submodules in the OGSM share similar basic attributes, but the EOR representation differs in the particulars. The EORSS uses a modified form of the previously described methodology, which is used for conventional oil supply and all natural gas recovery types in the lower 48 states. This section presents a discussion of the general differences in the EOR methodology.

The basic supply process for both EOR and the other sources of crude oil and natural gas consists of essentially the same stages. The physical stages of the supply process involve the conversion of unproven resources into proved reserves, and then the proved reserves are extracted as flows of production. The significant differences between the methodology of the EORSS and the other submodules of OGSM concern the conversion of unproven resources to proved reserves, the extraction of proved reserves for production, and the determination of supply activities.

The EORSS uses discovery factors that convert a specified fraction of unproven resources into proved reserves. These factors depend on the expected profitability of EOR investment opportunities. This approach is a substitute for the approach used elsewhere in OGSM in which the transfer of resource stocks from unproven to proved status is accomplished by use of finding rate functions that relate reserve additions to

cumulative drilling levels. Greater expected financial returns motivate the conversion of larger fractions of the resource base into proved reserves. This is consistent with the principle that funds are directed toward projects with relatively higher returns.

An explicit determination of expenditures for supply activities does not occur within the EORSS as it does elsewhere in the OGSM. Given the role of the discovery factors in the supply process, the implicit working assumption is that EOR investment opportunities with positive expected profit will attract sufficient financial development capital. The exploitation of economic EOR resources without an explicit budget constraint is consistent with the view that EOR investment does not compete directly with other oil and gas opportunities. This assumption is considered acceptable because EOR extraction is unlike the other oil and gas production processes, and its product differs sufficiently from the less heavy oil most often yielded by conventional projects.

EOR Production from Proved Reserves
Input: reserves differentiated by unit operating costs (constitutes price-supply table)[13]

For every year of the forecast horizon, the remaining proved reserves in the price-supply table that continue to be economic are identified. Proved reserves that have unit operating costs that exceed the current net price do not contribute to current production. The net price is the current price less royalty payments and severance taxes, which are unavoidable costs per unit. Thus, the net price measures the unit revenue that accrues to the producing firms. Production from a given stock of proved reserves is determined by the application of an assumed production-to-reserves ratio (Figure 6).

Figure 6. Procedure for EOR Production from Proved Reserves

Depictions of Processing steps in each period

Identify remaining economic
proved reserves

Conduct comparison test
between current net price and
unit variable costs

Extract fraction of economic
reserves using P/R ratio

---
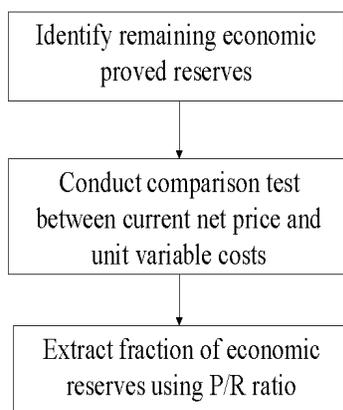
[13]The EOR price-supply tables used in this submodule are of critical importance to any outlook. The estimates provided in these tables are generated exogenously from an elaborate preprocessor routine, that performs economic evaluations intended to be consistent with the detailed geological, engineering, and economic information maintained in the Tertiary Oil Recovery Information System (TORIS). TORIS is a large analysis system maintained by the Bartlesville Project Office of the DOE Office of Fossil Energy (OFE). TORIS originally was developed for use in the analysis sponsored by the National Petroleum Council in their comprehensive 1984 study on EOR. A complete description of the EORSS preprocessor and its relationship to the EORSS was published in the spring of 1997 as a special appendix to this document.

New EOR Projects

Input: reserves differentiated by unit operating costs (constitutes price-supply table)Use current year price to identify the economic portion of remaining unproven inferred reserves (Figure 7). Economic projects are transferred to undeveloped inferred reserves status. The economic portion of undeveloped inferred reserves become proved reserves based on net difference between price and unit cost. The rate of conversion is a fraction determined as the inverse of the expected number of years for development (see table below). The new additions to this stock are economic given the current price as indicated by the economic test in the previous step. Subeconomic portions of the preexisting undeveloped stock are not developed, because the development fractions (i.e., the inverse of the expected years for development) are zero if unit costs exceed the net current price.

Expected Development Schedule for Economic Undeveloped Inferred Reserves EOR Projects

Difference in Price over Unit Cost	Expected Years for Development
$0-1.00	40
$1.01-2.00	36
$2.01-3.00	32
$3.01-4.00	28
$4.01-5.00	24
> $5.00	20

The conversion of the appropriate volume of undeveloped reserves into proved reserves is followed by the extraction of a fraction of proved reserves as production. Production from a given stock of proved reserves is determined by use of the assumed production-to-reserves ratio.

Figure 7. Development of New EOR Projects

Depictions of Processing steps in each period
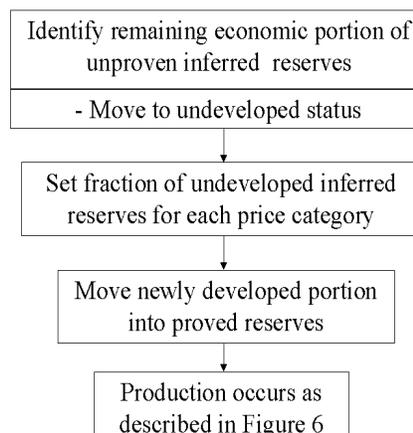
Cogeneration

Cogeneration of electricity by EOR projects is determined by a streamlined algorithm. This method assigns a level of new cogeneration capacity based on the EOR expansion from new projects. Electricity from existing capacity occurs according to assumed utilization factors.

Alaska Oil and Gas Supply Submodule

This section describes the structure for the Alaska Oil and Gas Supply Submodule (AOGSS). The AOGSS is designed to project field-specific oil and gas production from the Onshore North Slope, Offshore North Slope, and Other Alaska (primarily the Cook Inlet area.) This section provides an overview of the basic approach including a discussion of the discounted cash flow (DCF) method.

AOGSS Overview

The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 8).Transportation costs are used in conjunction with the relevant market price of oil or gas to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow (DCF) method is used to determine the economic viability of each project at the netback price. Alaskan oil and gas supplies are modeled on the basis of discrete projects, in contrast to the Onshore Lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multi-year projects, as well as the discovery of a new field is dependent on its profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, and historical production patterns and announced plans for currently producing fields.

Calculation of Costs

Costs differ within the model for successful wells and dry holes. Costs are categorized functionally within the model as:

- Drilling costs

- Lease equipment costs

- Operating costs (including production facilities and general and administrative costs).

All costs in the model incorporate the estimated impact of environmental compliance. Whenever environmental regulations preclude a supply activity outright, that provision is reflected in other adjustments to the model.

Figure 8. Flowchart for the Alaska Oil and Gas Supply Module

For each period t:

```
                        ┌─────────────────────────┐
                        │ Economic & Physical Data│
                        └────────────┬────────────┘
                                     │
                        ┌────────────┴────────────┐
                        │ Estimate transportation costs│
                        └────────────┬────────────┘
```

NEW FIELDS

```
                ┌──────────────────────────────────────┐
                │   Determine DCF for next discovery size│
                └────────────────┬─────────────────────┘
                                 │
                            ╱ DCF > 0 ╲  ── False ──┐
                            ╲         ╱              │
                                 │ True              │
           ┌─────────────────────┴──────────────────────────────┐
           │ Determine outcome for allowable number of New Field Wildcats│
           │ Add any successes to inventory of development projects│
           │ Record                                              │
           │    - Drilling                                       │
           │    - Reserve additions                              │
           │    - Financial expenditures                         │
           └─────────────────────┬──────────────────────────────┘
```

DEVELOPMENT
PROJECTS

```
        ┌───────────────────────────────────┐
        │      Compute DCF for project       │◄───
        └────────────────┬──────────────────┘
                         │
                    ╱ DCF > 0 ╲ ── False ──►┌──────────────────┐
                    ╲         ╱              │ Suspend operation │
                         │ True              └──────────────────┘
              ┌──────────┴───────────┐
              │ Continue project, record│
              │    - Drilling          │
              │    - Financial expenditures│
              └──────────┬───────────┘
                         │
         False      ╱ Project ╲
        ◄───────────╲ complete ╱
                         │ True
              ┌──────────┴────────────┐
              │ Add project to producing fields│
              └──────────┬────────────┘
                         │
                    ╱   All    ╲
  ┌──────────────┐ False ╱ projects ╲
  │Go to next project│◄──╲ evaluated ╱
  └──────────────┘        │ True
```

PRODUCING FIELDS

```
        ┌─────────────────────────────────────┐
        │ For all fields, compute production (PROD)│
        └────────────────┬────────────────────┘
                         │
                    ╱ PROD>QMIN ╲ ── False ──┐
                    ╲           ╱             │
                         │ True              │
              ┌──────────┴──────┐   ┌────────┴─────────────┐
              │ Record production│   │ Shut down, remove field│
              └─────────────────┘   └──────────────────────┘
```

For example, environmental regulations that preclude drilling in certain locations within a region is modeled by reducing the recoverable resource estimates for the total region.

Each cost function includes a variable that reflects the cost savings associated with technological improvements. Such declines would be relative to what costs would otherwise be. Technological improvements lower average costs of the affected phase of activity. As such, the lower costs reflect changes in the cost of either the supply activity or environmental compliance. The value of this variable is a user option in the model. The equations used to estimate the costs are similar to those used for the lower 48 but include costs of elements that are particular to Alaska. For example, lease equipment includes gravel pads.

Drilling Costs

Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through the "Christmas tree", the valves and fittings assembled at the top of a well to control the fluid flow. Elements that are included in drilling costs are labor, material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Drilling costs for exploratory wells include costs of support equipment such as ice pads. Lease equipment required for production is included as a separate cost calculation, and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in any field located within region r in year t is given by:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1) ** (t - T_b) \tag{53}$$

where,

$$
\begin{array}{rcl}
I & = & \text{well class(exploratory=1, developmental=2)} \\
r & = & \text{region} \\
k & = & \text{fuel type (oil=1, gas=2)} \\
t & = & \text{forecast year} \\
DRILLCOST & = & \text{drilling costs} \\
T_b & = & \text{base year of the forecast} \\
TECH1 & = & \text{annual decline in drilling costs due to improved technology.}
\end{array}
$$

The above function specifies that drilling costs decline at the annual rate TECH1. Observe that drilling costs are not modeled as a function of the activity level as they are in the Onshore Lower 48 methodology. The justification for this is the relative constancy of activity in Alaska as well as the specialized nature of drilling inputs in Alaska.

Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Costs include: producing equipment, the gathering system, processing equipment, and production related infrastructure such as gravel pads. Producing equipment costs include tubing and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells. The lease equipment cost estimate for a new oil or gas well is given by:

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2)**(t - T_b)$$

$$(54)$$

where,

$$
\begin{array}{rcl}
r & = & \text{region} \\
k & = & \text{fuel type (oil=1, gas=2)} \\
t & = & \text{forecast year} \\
EQUIP & = & \text{lease equipment costs} \\
T_b & = & \text{base year of the forecast} \\
TECH2 & = & \text{annual decline in lease equipment costs due to improved technology.}
\end{array}
$$

Operating Costs

EIA operating cost data, which are reported on a per well basis for each region, include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The estimated operating cost curve is:

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3)**(t - T_b)$$

$$(55)$$

where,

$$
\begin{array}{rcl}
r & = & \text{region} \\
k & = & \text{fuel type (oil=1, gas=2)} \\
t & = & \text{forecast year} \\
OPCOST & = & \text{operating cost} \\
T_b & = & \text{base year of the forecast} \\
TECH3 & = & \text{annual decline in operating costs due to improved technology.}
\end{array}
$$

Drilling costs, lease equipment costs, and operating costs are integral components of the following discounted cash flow analysis. These costs are assumed to be uniform across all fields within a region.

Treatment of Costs in the Model for Income Tax Purposes

All costs are treated for income tax purposes as either expensed or capitalized. The tax treatment in the DCF reflects the applicable provisions for oil and gas producers. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts. The following assumptions, reflecting current tax law, are used in the calculation of costs.

- All dry-hole costs are expensed.

- A portion of drilling costs for successful wells are expensed. The specific split between expensing and amortization is determined on the basis of the data.

- Operating costs are expensed.

- All remaining successful field development costs are capitalized.

- The depletion allowance for tax purposes is not included in the model, because the current regulatory limitations for invoking this tax advantage are so restrictive as to be insignificant in the aggregate for future drilling decisions.

- Successful versus dry-hole cost estimates are based on historical success rates of successful versus dry-hole footage.

- Lease equipment for existing wells is in place before the first forecast year of the model.

Tariff Routine

In general, tariffs are designed to enable carriers to recover operating and capital costs for a given after-tax rate of return. The Trans Alaska Pipeline System (TAPS) tariff is determined by dividing the total revenue requirement for a year by the projected throughput for that year. The total revenue requirement is composed of eight elements as defined in the Settlement Agreement dated June 28, 1985 between the State of Alaska and ARCO Pipe Line Company, BP Pipelines Inc., Exxon Pipeline Company, Mobil Alaska Pipeline Company, and Union Alaska Pipeline Company. The determination of costs conforms to the specification as provided in the Settlement Agreement.

$$\begin{aligned} TRR_t = {} & OPERCOST_t + DRR_t + TOTDEP_t + MARGIN_t + DEFRETREC_t + TXALLW_t \\ & NONTRANSREV_t + CARRYOVER_t \end{aligned}$$

(56)

where,

TRR	=	total revenue requirement
OPERCOST	=	total operating costs (fixed and variable)
DRR	=	dismantling, removal, and restoration allowance
TOTDEP	=	total depreciation (original and new property)
MARGIN	=	total after-tax margin (original and new property)
DEFRETREC	=	total recovery of deferred return (original and new property)
TXALLW	=	income tax allowance
NONTRANSREV	=	non-transportation revenues
CARRYOVER	=	net carryover.

Four of the elements are associated with the recovery of a TAPS carrier's costs: (1) operating expenses, (2) dismantling, removal, and restoration (DR&R) allowance, (3) depreciation, and (4) income tax allowance. Two elements, after-tax margin and recovery of deferred return, provide for a return on unrecovered capital and an incentive to continue to operate the pipeline. The last two components, non-transportation revenues and net carryover are adjustment items.

Operating Costs. Operating costs include both the fixed and variable operating costs. The fixed portion is based on an assumed cost of $325 million (in 1991 dollars). If the expected throughput for the year is greater than 1.4 million barrels per day, the variable cost is $0.28 per barrel in 1991 dollars; otherwise, the variable cost is $0.24 per barrel in 1991 dollars.[14] These assumed costs exclude any incurred or expected DR&R expenses, any depreciation or amortization of capitalized cost, and any settlements with shippers for lost or undelivered oil due to normal operations during transportation.

---

[14]The variable cost was converted from 1983 dollars as specified in the Settlement Agreement to 1991 dollars.

DR&R Allowance. The annual DR&R allowance to be included in the revenue requirement calculation for years 1984 through 2011 is given in Exhibit E: DR&R Allowance Schedule of the Settlement Agreement.

Depreciation. Total depreciation is the sum of depreciation from original property and depreciation from new property as given by

$$\text{TOTDEP}_t = \text{DEP}_t * \left(\text{DEPPROP}_{t-2} + \text{ADDS}_{t-1} - \text{PROCEEDS}_{t-1} - \text{TOTDEP}_{t-1}\right) \tag{57}$$

where,

TOTDEP	=	total depreciation
DEP	=	depreciation factor
DEPPROP	=	total (original and new) depreciable property in service
ADDS	=	additions to both original and new property in service
PROCEEDS	=	proceeds from both original and new depreciable property in service.

After-Tax Margin. The after-tax margin is designed to provide the TAPS carrier with an after-tax real return on capital. This margin has two components: (1) the product of the allowance per barrel and the projected throughput and (2) the allowed rate of return on the rate base associated with new property in service. The allowance per barrel is set at $0.35 in 1983 dollars and the allowed rate of return at 6.4 percent.

$$\text{MARGIN}_t = \text{ALLOW}_t * \text{THRUPUT}_t + 0.064 * \left(\text{DEPPROP}_{\text{NEW},t} + \text{DEFRET}_{\text{NEW},t} - \text{DEFTAX}_{\text{NEW},t}\right) \tag{58}$$

where,

MARGIN	=	total after-tax margin
ALLOW	=	allowance per barrel
THRUPUT	=	projected net deliveries
DEPPROP$_{\text{NEW}}$	=	new depreciable property in service
DEFRET$_{\text{NEW}}$	=	new deferred return
DEFTAX$_{\text{NEW}}$	=	new deferred tax.

Recovery of Deferred Return. Deferred returns represent amounts which could be rightfully collected and turned over to the owners but, for tariff profile purposes, are collected at a later date. For example, Construction Work in Progress (CWIP) is not added in the company's rate base until the end of the construction period. As a result, it is not included in the return on capital and not recovered in current rates. Instead, an Allowance for Funds Used During Construction (AFUDC) is added to the book value of the construction. This deferred return is then recovered through depreciation of the pipeline's cost over its economic life. The recovery of this deferred return has two components, the conventional AFUDC and the inflation portion of the return on rate base. The calculation of the recovery of deferred returns is given by

$$\text{DEFRETREC}_t = \text{DEP}_t * \left(\text{DEFRET}_{t-2} + \text{INFLADJ}_{t-1} + \text{AFUDC}_{t-1} - \text{DEFRETREC}_{t-1}\right) \tag{59}$$

where,

DEFRETREC	=	total recovery of deferred return (original and new property)
DEP	=	depreciation factor
DEFRET	=	total deferred return (original and new property)
INFLADJ	=	inflation adjustment (original and new property)
AFUDC	=	allowance for funds used during construction.

Income Tax Allowance. The income tax allowance is equal to the income tax allowance factor multiplied by the sum of the after-tax margin and recovery of deferred return. The income tax allowance factor is the amount of tax allowance necessary to provided a dollar of after tax income at the composite Federal and State tax rates, adjusted for the deductibility of State income tax in Federal tax calculations.

$$\text{TXALLW}_t = \text{TXRATE} * \left(\text{MARGIN}_t + \text{DEFRETREC}_t\right) \tag{60}$$

where,

TXALLW	=	income tax allowance
TXRATE	=	income tax allowance factor
MARGIN	=	total after-tax margin
DEFRETREC	=	total recovery of deferred return.

Non-transportation Revenues. A TAPS owner receives revenues from the use of carrier property in addition to the tariff revenue. These incidental revenues include payments received directly or indirectly from penalties paid by shippers who were delinquent in taking delivery of crude oil at Valdez. By subtracting these revenues from the total revenue requirement, the economic benefit to these non-transportation revenues is passed on to other shippers through the lower tariff for TAPS transportation.

Net Carryover. The net carryover reflects any difference between the expected revenues calculated by this tariff routine and revenues actually received.

Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil and gas projects.[15] A positive DCF is necessary to continue operations for a known field, whether exploration, development, or production. Selection of new prospects for initial exploration occurs on the basis of the profitability index which is measured as the ratio of the expected discounted cash flow to expected capital costs for a potential project.

A key variable in the DCF calculation is the transportation cost to lower 48 markets. Transportation costs of either oil or gas reflect delivery costs to an oil import facility or the citygate for natural gas. Transportation costs for oil include both pipeline and tanker shipment costs, and natural gas transportation costs are pipeline costs (tariffs). Transportation costs are specified for each field, although groups of fields may be subject to uniform transportation costs for that region. This cost directly affects the expected revenues from the production of a field as follows:[16]

$$\text{REV}_{f,t} = Q_{f,t} * (\text{MP}_t - \text{TRANS}_{f,t}) \tag{61}$$

where,

f	=	field
t	=	year
REV	=	expected revenues
Q	=	expected production volumes
MP	=	market price in the lower 48 states
TRANS	=	transportation cost.

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[15]See Appendix 4.A at the end of this chapter for a detailed discussion of the DCF methodology.

[16]This formulation assumes oil production only. It can be easily expanded to incorporate the sale of natural gas.

The expected discounted cash flow associated with a representative oil or gas project in a field f at time t is given by:

$$DCF_{f,t} = (PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP - PVOPCOST - PVPRODTAX - PVSIT - PVFIT - PVWPT)_{f,t}$$ (62)

where,

PVREV	=	present value of expected revenues
PVROY	=	present value of expected royalty payments
PVDRILLCOST	=	present value of all exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity
PVOPCOST	=	present value of operating costs
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes
PVWPT	=	present value of expected windfall profits tax[17]

The expected capital costs for the proposed field f located in region r are:

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t}$$ (63)

where,

PVEXPCOST	=	present value exploratory drilling costs
PVDEVCOST	=	present value developmental drilling costs
PVEQUIP	=	present value lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity

The profitability indicator from developing the proposed field is therefore equal to:

$$PROF_{f,t} = DCF_{f,t} / COST_{f,t}$$ (64)

The field with the highest positive PROF in time t is then eligible for exploratory drilling in the same year. The profitability indices for Alaska also are passed to the basic framework module of the OGSM.

New Field Discovery

Development of estimated recoverable resources, which are expected to be in currently undiscovered fields, depends on the schedule for the conversion of resources from unproved to reserve status. The conversion of resources into reserves requires a successful new field wildcat well. The discovery procedure requires needed information, which can be determined endogenously or supplied at the option of the user. The procedure requires data regarding:

- technically recoverable oil and gas resource estimates by region

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[17]Since the Windfall Profits Tax was repealed in 1988, this variable would normally be set to zero. It is included in the DCF calculation for completeness.

- distribution of technically recoverable field sizes[18] within each region

- the maximum number of new field wildcat wells drilled in any year

- new field wildcat success rate

- any restrictions on the timing of drilling.

The endogenous procedure generates:

- the set of individual fields to be discovered, specified with respect to size and location

- an order for the discovery sequence

- a schedule for the discovery sequence.

The new field discovery procedure divides the estimate for technically recoverable oil and gas resources into a set of individual fields. The field size distribution data was gathered from the U.S. Geological Survey work for the national resource assessment.[19] The field size distribution is used to determine a largest field size based on the volumetric estimate corresponding to an acceptable percentile of the distribution. The remaining fields within the set are specified such that the distribution of estimated sizes conform to the characteristics of the input distribution. Thus, this estimated set of fields is consistent with the expected geology with respect to expected aggregate recovery and the relative frequency of field sizes.

New field wildcat drilling depends on the estimated expected DCF for the set of remaining undiscovered recoverable prospects. If the DCF for each prospect is not positive, no new drilling occurs. Positive DCF's motivate additional new field wildcat drilling. Drilling in each year matches the maximum number of new field wildcats. A discovery occurs as indicated by the success rate; i.e., a success rate of 12.5 percent means that there is one discovery in each sequence of 8 wells drilled. By assumption, the first new field well in each sequence is a success. The requisite number of dry holes must be drilled prior to the next successful discovery.

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil deposits. This refinement is implemented by declaring a start date for possible exploration. For example, development of the West Sak field is expected to be delayed until technology can be developed that will enable the heavy crude oil of that field to be economically extracted.

Development Projects

Development projects are those projects in which a successful new field wildcat has been drilled. As with the new field discovery process, the DCF calculation plays an important role in the timing of development and exploration of these multi-year projects.

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[18]"Size" of a field is measured by the volume of recoverable oil or gas.

[19]*Estimates of Undiscovered Conventional Oil and Gas Resources in the United States -- A Part of the Nation's Energy Endowment*, USGS (1989).

Every year, the DCF is calculated for each development project. Initially, the drilling schedule is determined by the user or some set of specified rules. However, if the DCF for a given project is negative, then exploration and development of this project is suspended in the year in which this occurs. The DCF for each project is evaluated in subsequent years for a positive value; at which time, exploration and development will resume.

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[20] The specific assumptions used in this work are as follows:

- a two to four year build-up period from initial production to peak rate,

- peak rate sustained for three to eight years, and

- production rates decline by 12 or 15 percent after peak rate is no longer maintained.

The pace of development and ultimate number of wells drilled for a particular field is based on the historical field-level profile adjusted for field size and other characteristics of the field (e.g. API gravity.)

After all exploratory and developmental wells have been drilled for any given project, development of the project is complete. For this version of the AOGSS, no constraint is placed on the number of exploratory or developmental wells that can be drilled for any project. All completed projects are added to the inventory of producing fields.

Producing Fields

Oil and natural gas production from fields producing as of the base year (including Prudhoe Bay, Kuparuk, Lisburne, Endicott, and Milne Point) are based on historical production patterns, remaining estimated recovery, and announced development plans. Production ceases when flow becomes subeconomic; i.e., attains the assumed minimum economic production level.

Natural gas production from the North Slope for sale to end-use markets is dependent on the construction of a major transportation facility to move natural gas to lower 48 markets.[21] In addition, the reinjection of North Slope gas for increased oil recovery poses an operational/economic barrier limiting its early extraction. Nonetheless, there are no extraordinary regulations or legal constraints interfering with the recovery and use of this gas. Thus, the modeling of natural gas production for marketing in the lower 48 states recognizes the expected delay to maximize oil recovery, but it does not require any further modifications from the basic procedure.[22]

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[20]*Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge*, EIA (1987) and *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/0570-H1 (January 1991).

[21]Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction.

[22]The currently proposed version of AOGSS does not include plans for an explicit method to deal with the issue of marketing ANS gas as liquefied natural gas (LNG) exports to Pacific Rim countries. The working assumption is that sufficient recoverable gas resources are present to support the economic operation of both a marketing system to the Lower 48 states and the LNG export project.

Foreign Natural Gas Supply Submodule

This section describes the structure for the Foreign Natural Gas Supply Submodule (FNGSS) within the Oil and Gas Supply Module (OGSM). FNGSS includes U.S. trade in foreign natural gas via either the North American pipeline network or ocean-going tankers.[23] Gas is traded with Canada and Mexico via pipelines. The border crossing locations are identified in Figure 9. Gas trade with other, nonadjacent, countries is in the form of liquefied natural gas (LNG) and involves liquefaction, transportation by tanker and subsequent regasification. To date, the United States has imported LNG almost exclusively from Algeria.

A representation of Canadian gas reserves accounting and well development has been established. Since forecasts of fixed volumes are not adequate for the purposes of equilibrating supply and demand, this submodule provides the Natural Gas Transmission and Distribution Module (NGTDM) with a supply function of Canadian gas at the eastern Canadian supply point. With the help of these supply parameters, Canadian imports to the United States are defined by the North American market equilibration that occurs in the NGTDM. Natural gas imports via pipeline from Mexico are handled with less detail. LNG imports are modeled on the basis of importation costs, including production, liquefaction, transportation, and regasification. Projected pipeline imports of LNG are subject to user assumptions regarding the timing and

Figure 9. Foreign Natural Gas Trade via Pipeline

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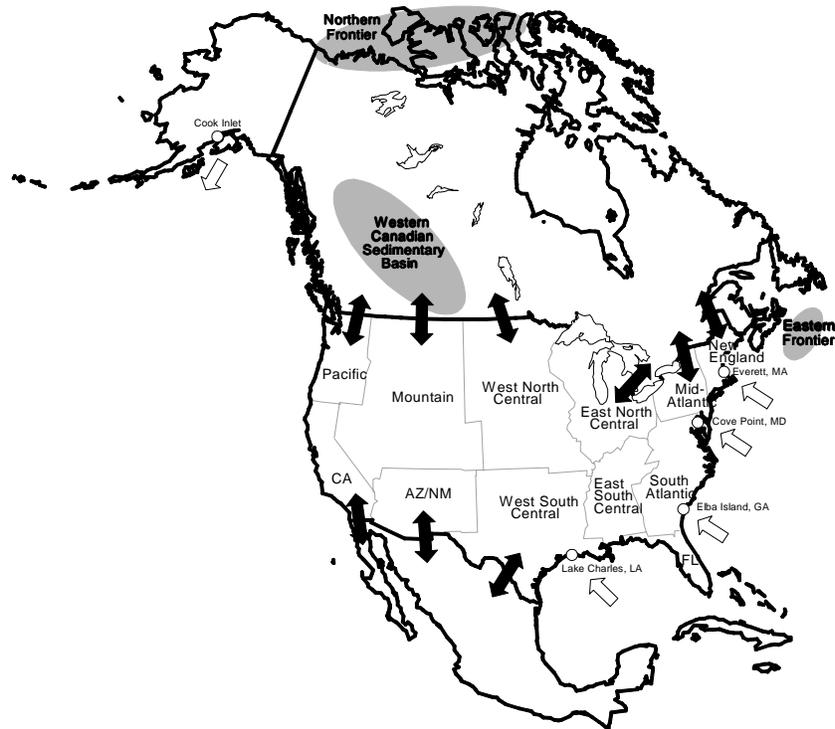
[23]The issue of foreign gas trade generally is viewed as one of supply (to the United States) because the United States is currently a net importer of natural gas by a wide margin, a situation that is expected to continue.

size of available import capacity. Natural gas exports, via pipeline or as LNG, are included in the National Energy Modeling System (NEMS) as a set of exogenous assumptions. This section presents descriptions of the separate methodological approaches for Canadian, Mexican, and LNG natural gas trade.

Canadian Gas Trade

This submodule determines the components and the subsequent parameters needed to define the Canadian price/supply curve used by the NGTDM to help determine Canadian import levels. The approach taken to determine Canadian gas supply differs from that used in the domestic submodules of the OGSM. Drilling activity, measured as the number of successful wells drilled, is estimated directly as a function of Canadian natural gas wellhead price rather than as a function of expected profitability proxied by the expected DCF. No distinction is made between exploration and development. Production from three Canadian regions is estimated -- the Western Canadian Sedimentary Basin (WCSB, including Alberta, British Columbia, and Saskatchewan), the Northern Frontier (Arctic Islands and mackenzie Delta), and Eastern Canada. Drilling activity for the WCSB is determined using an econometric model. For this region, finding rate equations are used to determine reserve additions; a reserves accounting prodecure yields reserve estimates (beginning of year reserves); and an estimated extraction rate determines production potential [(production to reserves ratio (PRR)]. Production from the Northern Frontier and Eastern Canada regions, for which there are very limited data, is determined exogenously from resource supply curves that relate resource availability to price. Annual production from these regions is combined with WCSB production, yielding total Canadian domestic production. Total Canadian supply includes natural gas received from the United States. The general methodology employed for estimating Canadian gas trade is depicted in Figure 10.

The determination of the import volumes into the U.S. occurs in the equilibration process of the NGTDM, utilizing the Canadian supply curve parameters as well as Canadian demand estimates. Forecasts of Canadian demand are based on estimates made by the Canadian National Energy Board.

Western Canadian Sedimentary Basin

Wells Determination

The total number of successful natural gas wells drilled in Western Canada each year is forecasted econometrically as a function of the Canadian natural gas wellhead price and the number of wells in the previous year. Thus,

$$
\text{WELLS}_t = \text{OGPRCIMP}_{\text{gas},1}^{\text{B1WELLS}} * \text{OGPRCIMPL}^{-\text{BRHO}*\text{B1WELLS}} * \text{WELLAG}^{\text{BRHO}} *
$$
$$
e^{(\text{B0WELLS}*(1-\text{BRHO})) + (\text{B2WELLS} * \text{DUM7080}) + (\text{B3WELLS} * \text{DUM8192})}
$$

(65)

where,

|		
gas	=	index for gas prices (gas=2)
WELLS	=	total gas wells completed in Western Canada
WELLAG	=	previous year gas wells completed in Western Canada

Figure 10. A General Outline of the Canadian Algorithm of the FNGSS

```
      ╱─────────────────────╲
     ╱    Wellhead Prices     ╲
    ╱───────────────────────────╲
                  │
                  ▼
      ┌───────────────────────┐
      │     Wells Drilled      │
      └───────────────────────┘
                  │
                  ▼
      ┌───────────────────────┐
      │     Finding Rate       │
      └───────────────────────┘
                  │
                  ▼
      ┌───────────────────────┐
      │   Reserve Additions    │
      └───────────────────────┘
                  │
                  ▼
      ┌───────────────────────┐
      │       Reserves         │
      └───────────────────────┘
                  │
                  ▼
      ┌───────────────────────┐
      │      Production        │
      └───────────────────────┘
```
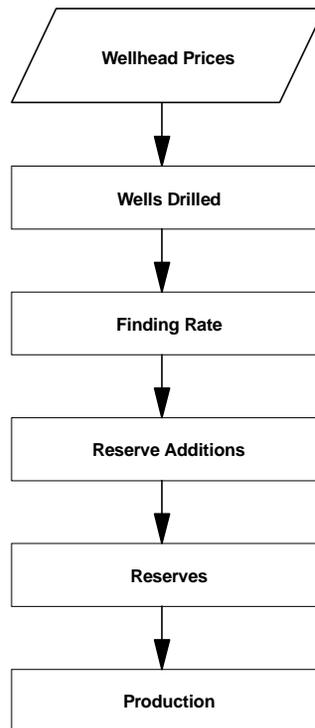
OGPRCIMP	=	average wellhead price per Mcf, in 1987 dollars
OGPRCIMPL	=	previous year average wellhead price per Mcf, in 1987 dollars
B0WELLS, B1WELLS	=	econometrically estimated parameters (Appendix B)
B2WELLS, B3WELLS	=	econometrically estimated parameters (Appendix B)
BRHO	=	econometrically estimated parameter (Appendix B)
DUM7080	=	1 if year between 1970-1980, otherwise 0
DUM8192	=	1 if year between 1981-1992, otherwise 0

(Note: the dummy variables were added to include what seemed to be structural shifts in the relationships according to visual inspection of residual plots as well as Chow tests for structural stability. However, these are defined to be zero during the forecast years.)

Reserve Additions

The Reserve Additions algorithm calculates units of gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which gas becomes proved reserves is a highly complex one. This section presents a methodology that is representative of the major phases that occur; although, by necessity, it is a simplification from a highly complex reality.

Gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to wells or feet drilled in such a way that the rate of reserve additions declines as more wells are drilled. The reason for this is, all else being constant, the larger prospects typically are drilled first. Consequently, the finding rate can be expected to decline as a region matures, although the rate of decline and the functional forms are a subject of considerable debate.

Functional Forms. The model adopts the basic structure of the previous EIA Canadian supply model to determine Canadian reserve additions. Specifically, Canadian gas reserve additions are a function of the cumulative number of successful wells drilled, the estimated economically recoverable resource base for the fuel, and the rate of technological change.

The finding rate equation for gas is defined by:

$$FR_t = FR_{t-1} * e^{(-\delta_t * WELLS_t * SR)} * (1 + FRTECH) \tag{66}$$

where,

$$
\begin{array}{rcl}
FR & = & \text{finding rate} \\
WELLS_t & = & \text{successful gas wells drilled in time period t} \\
SR & = & \text{success rate} \\
\delta & = & \text{finding rate decline parameter } (\delta > 0) \\
FRTECH & = & \text{finding rate technology factor.}
\end{array}
$$

In this specification, the yield from successful drilling begins at the initial finding rate for each period, FR_{t-1}, and declines exponentially as drilling continues, but technological progress can reduce or even reverse this decline. This form is consistent with the methodology presented in Appendix 4C. The decline parameter, δ, is estimable from the finding rate equation, given an estimate for ultimate recovery. A smaller estimate for the economically recoverable resource base would result in a more rapid decrease in productivity for the same level of cumulative drilling: a larger value of δ.

$$\delta_t = \frac{(FR_{t-1} - FRMIN) * RSVGR}{Q * (1.0 + TECH)^{t-T} - CUMRES_{t-1}} \tag{67}$$

where,

$$
\begin{array}{rcl}
\delta & = & \text{finding rate decline parameter } (\delta > 0) \\
t & = & \text{forecast year} \\
FR & = & \text{finding rate (billion of cubic feet)} \\
FRMIN & = & \text{minimum economic finding rate} \\
RSVGR & = & \text{reserves growth factor} \\
Q & = & \text{economically recoverable resource estimate} \\
TECH & = & \text{technology factor} \\
T & = & \text{base year of the forecast} \\
CUMRES & = & \text{cumulative reserve discoveries over the projection period (initial value = 0).}
\end{array}
$$

The denominator is the *remaining* economically recoverable resource estimate in a given period, so the cumulative reserves found over time must be deducted.

$$CUMRES_t = \sum_{T=1}^{t} RA_T \tag{68}$$

The minimum economic finding rate, FRMIN, is incorporated into equation (67) so that the cumulative reserve discoveries match the *economically* recoverable resource estimate when the yield from wells drilled falls to the economic minimum. Equation (67) also incorporates the benefits of technological change. Technological change is expected to improve the productivity of drilling by increasing the physical returns per drilling unit from what it otherwise would have been. Technological change is introduced through

modifications of the initial economically recoverable resource estimate, thus affecting the value of the finding rate decline parameter, δ. It reflects the assumptions that technological change occurs over time and its effect is realized in the expansion of the resource estimate, thus lessening the decline rate of productivity and resulting in higher yields to drilling, relative to what they otherwise would have been. The growing recoverable volume necessitates recomputing δ in each period.

Total reserve additions in period t is given by:

$$RA_t = \int_{WELLS_{t-1}}^{WELLS_t} FR_t \ d(WELLS)$$

(69)

-or-

$$RA_t = \frac{FR_{t-1}}{\delta_t} * (1 - e^{-\delta_t * WELLS_t * SR})$$

(70)

where,

RA	=	reserve additions
FR	=	finding rate (billion cubic feet)
$WELLS_t$	=	successful gas wells drilled in time period t
SR	=	success rate
δ	=	finding rate decline parameter (δ>0)

Finally, total end-of-year proved reserves for each period equals proved reserves from the previous period plus new reserve additions less production.

$$R_t = R_{t-1} + RA_t - Q_t$$

(71)

where,

t	=	forecast year
R	=	end-of-year reserves
Q	=	production
RA	=	reserve additions.

(All volumes in billion cubic feet of gas.)

Gas Production

Production is commonly modeled using a production to reserves ratio. A major advantage to this approach is its transparency. Additionally, the performance of this function in the aggregate is consistent with its application on the micro level. The production to reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

Canadian gas production in year t is given by:

$$Q_t = R_{t-1} * PR_t * (1 + \beta * \frac{\Delta P_t}{P_{t-1}})$$

(72)

where,

R_{t-1} = end-of-year gas reserves in period t-1

PR_t = gas extraction rate in period t-1 (measured as the production to reserves ratio at the end of period t-1)

P_t = gas netback price at the wellhead in period t

β = estimated short run price elasticity of extraction

ΔP_t = $(P_t - P_{t-1})$, the change in price from t-1 to t.

The proposed production equation relies on price induced variation in the extraction rate to determine short run supplies. The producible stock of reserves equals reserves at the end of the previous period. The extraction rate for the current period, PR_t, is assumed as the approximate extraction rate for the current period under normal operating conditions. The product of R_{t-1} and PR_t is the expected, or normal, operating level of production for period t. The extraction rate (PR_{t+1}) is defined as:

$$PR_{t+1} = \frac{Q_t * (1 - PR_t) + PRNEW * RA_t}{R_t}$$

(73)

where,

PR_{t+1} = gas extraction rate in period t+1 (measured as the production to reserves ratio at the end of period t)

R_t = end-of-year gas reserves in period t

Q = production

RA = reserve additions

PRNEW = new production to reserves ratio

Supplies from the Northern Canadian Frontier and Eastern Canada

Frontier production in FNGSS was to be determined as a sequence of predetermined estimates drawn from analysis of other analysis groups, such as the National Energy Board (NEB) of Canada[24] and the National Petroleum Council (NPC). The NEB work published in June 1991 indicates that the economics of frontier gas recovery and transportation prevent the occurrence of frontier flows until at least 2004. Subsequent communication with NEB staff indicate that their reassessment of frontier potential would delay frontier development until after 2010. Similarly, NPC analysis[25] showed that northern frontier gas would not be developed until after 2010 under most scenarios. The present implementation of OGSM reflects the assumption that the northern frontier Canadian gas sources will not be developed until after 2020. This assumption appears reasonable in light of the results that other productive areas show sufficient productive potential to meet expected internal Canadian as well as U.S. demands. As for eastern Canada gas, estimates are handled by the NGTDM, with details included in the associated methodology documentation.

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[24]See, for example, *Supply and Demand: 1990-2010*, June 1991.

[25]*The Potential for Natural Gas in the United States*, December 1992.

Allocation of Canadian Natural Gas Production to Canada and the United States

The purpose of Canadian natural gas production is to meet both Canadian demands and exports to the United States. The methodology used to define Canadian natural gas production and exports is intrinsic in the North American market equilibrium that occurs in the NGTDM. Thus, the details of this procedure are provided in the methodology documentation for that module.

Mexican Gas Trade

Mexican gas trade is a highly complex issue. A range of noneconomic factors will influence, if not determine, future flows of gas between the United States and Mexico. Uncertainty surrounding Mexican/U.S. trade is so great that not only is the magnitude of flow for any future year in doubt, but also the direction of flow. Reasonable scenarios have been developed and defended in which Mexico may be either a net importer or exporter of hundreds of billions of cubic feet of gas by 2010.[26]

The vast uncertainty and the significant influence of noneconomic factors that influence Mexican gas trade with the United States suggest that these flows should be handled on a scenario basis. A method to handle user-specified path of future Mexican imports and exports has been incorporated into FNGSS. This outlook has been developed from an assessment of current and expected industry and market circumstances as indicated in industry announcements, or articles or reports in relevant publications. The outlook, regardless of its source, is fixed, and so it will not be price responsive.

Liquefied Natural Gas

Liquefaction is a process whereby natural gas is converted into a liquid that can be shipped to distant markets that otherwise are inaccessible. Prospects for expanded imports of LNG into the United States are beginning to improve in spite of difficulties affecting the industry until recent years. Various factors contributed to the recent reemergence of LNG as an economically viable source of energy, including contracts with pricing and delivery flexibility, a growing preference toward natural gas due to the lesser environmental consequences for burning it versus other fossil fuels, and diversification and security of energy supply. The outlook for LNG imports also depends on customers' perceptions regarding supply reliability and price uncertainty.

Determining U.S. Imports and Exports of LNG

Supply costs are input to the FNGSS. These supply, or delivery, costs of LNG measure all costs including regasification; that is, gas made ready for delivery into a pipeline. These values serve as economic thresholds that must be achieved before investment in the potential LNG projects occurs.

Imported LNG costs do not compete with the wellhead price of domestically produced gas; rather, these costs compete with the purchase price of gas prevailing in the vicinity of the import terminal. This is a significant element in evaluating the competitiveness of LNG supplies, since LNG terminals vary greatly in their proximity to domestic producing areas. Terminals closer to major consuming markets have an inherent economic advantage over distant competing producing areas because of the lower transportation costs incurred.

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[26]For example, the National Petroleum Council study, *The Potential for Natural Gas in the United States*, December 1992.

In addition to the cost estimates, however, certain operational assumptions are required to complete the picture. Dominant factors affecting the outlook are: expected use of existing capacity, expansion at sites with existing facilities, and construction at additional locations. The FNGSS requires specification of a combination of factors: available gasification capacity, scheduled use of existing capacity, schedules for and lags between constructing and opening a facility, expected utilization rates, and worldwide liquefaction capacity. The current version of the FNGSS implicitly assumes that tanker capacity becomes available as needed to meet the transportation requirements.

A key assumption for any LNG outlook from FNGSS is that all major operational or institutional difficulties have been incorporated into the recognized allowable schedule for capacity operation and expansion. No other difficulties arise that are not resolved expeditiously.

LNG Imports from Existing Capacity

There are four existing LNG terminal facilities in the United States, one each at Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; and Elba Island, Georgia. The latter two terminals are currently idle (Figure 9).

Given the rather low variable costs (generally under $1.00 for liquefaction, tanker transportation, and regasification, but not including production), one can argue that the import volumes for these facilities have not been, and are not expected to be, determined on the basis of full cost recovery. The schedule for reopening these facilities are drawn from the announced plans for each import terminal, and modifications can be readily introduced at the user's request.

LNG Imports from Capacity Expansion

Capacity expansion refers to additional capacity at the four sites that have capacity at present. The presence of a facility may be judged as reliable evidence that the local community has demonstrated tolerance for the facility and associated operations. The continuation of such tolerance is accepted as a working assumption.

The costs of capacity expansion are assumed to be consistent with those for new construction. Required operational assumptions include the lag in capacity expansion and the buildup period for full utilization of the incremental capacity. The difference in timing between the attainment of prices adequate to initiate capacity expansion and the initial operation of that expanded capacity is assumed to be one year. Given a required construction period likely exceeding one year, this assumption is consistent with some degree of anticipation of the growth in prices by the operators of the facility.

New Construction

Increases in LNG deliveries beyond expanded capacity at existing sites require capacity expansion at sites other than those where facilities are currently located. New capacity construction requires a set of working assumptions that are either user specified or default parameters. Major operational assumptions include:

- Selected start dates before which construction of LNG terminals on new sites would not be allowed

- Design capacity and utilization rates for the newly constructed capacity

- Regional locations for new construction sites[27]

- Price increments that would bring forth additional LNG import capacity.

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[27]The siting of new facilities in the United States is a controversial issue that is not addressed analytically.

Appendix 4-A. Discounted Cash Flow Algorithm

Introduction

The basic DCF methodology used in the Oil and Gas Supply Module (OGSM) is applied for a broad range of oil or natural gas projects, including single well projects or multiple well projects within a field. It is designed to capture the affects of multi-year capital investments (eg., offshore platforms). The expected discounted cash flow value associated with exploration and/or development of a project with oil or gas as the primary fuel in a given region evaluated in year T may be presented in a stylized form (Equation (1)).

$$DCF_T = (PVTREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP - PVKAP - PVOPCOST - PVABANDON - PVSIT - PVFIT)_T \tag{1}$$

where,

T	=	year of evaluation
PVTREV	=	present value of expected total revenues
PVROY	=	present value of expected royalty payments
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVDRILLCOST	=	present value of expected exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
PVKAP	=	present value of other expected capital costs (i.e., gravel pads and offshore platforms)
PVOPCOST	=	present value of expected operating costs
PVABANDON	=	present value of expected abandonment costs
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes.

Costs are assumed constant over the investment life but vary across both region and primary fuel type. This assumption can be changed readily if required by the user. Relevant tax provisions also are assumed unchanged over the life of the investment. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

The following sections describe each component of the DCF calculation. Each variable of Equation (1) is discussed starting with the expected revenue and royalty payments, followed by the expected costs, and lastly the expected tax payments.

Present Value of Expected Revenues, Royalty Payments, and Production Taxes

Revenues from an oil or gas project are generated from the production and sale of both the primary fuel as well as any co-products. The present value of expected revenues measured at the wellhead from the production of a representative project is defined as the summation of yearly expected net wellhead price[1]

---

[1]The DCF methodology accommodates price expectations that are myopic, adaptive, or perfect. The default is myopic expectations, so prices are assumed to be constant throughout the economic evaluation period.

times expected production[2] discounted at an assumed rate. The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$PVREV_{T,k} = \sum_{t=T}^{T+n} \left[Q_{t,k} * \lambda * P_{t,k} * \left[\frac{1}{1+disc} \right]^{t-T} \right], \; \lambda = \begin{cases} 1 & \text{if primary fuel} \\ COPRD & \text{if secondary fuel} \end{cases} \tag{2}$$

where,

$$
\begin{array}{rcl}
k & = & \text{fuel type (oil or natural gas)} \\
t & = & \text{time period} \\
n & = & \text{number of years in the evaluation period} \\
disc & = & \text{expected discount rate} \\
Q & = & \text{expected production volumes} \\
P & = & \text{expected net wellhead price} \\
COPRD & = & \text{co-product factor.[3]}
\end{array}
$$

Net wellhead price is equal to the market price minus any transportation costs. Market prices for oil and gas are defined as: the price at the receiving refinery for oil, the first purchase price for onshore natural gas, the price at the coastline for offshore natural gas, and the price at the Canadian border for Alaskan gas.

The present value of the total expected revenue generated from the representative project is:

$$PVTREV_T = PVREV_{T,1} + PVREV_{T,2} \tag{3}$$

where,

$$
\begin{array}{rcl}
PVREV_{T,1} & = & \text{present value of expected revenues generated from the primary fuel} \\
PVREV_{T,2} & = & \text{present value of expected revenues generated from the secondary fuel.}
\end{array}
$$

Present Value of Expected Royalty Payments

The present value of expected royalty payments (PVROY) is simply a percentage of expected revenue and is equal to:

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{4}$$

where,

$$ROYRT \quad = \quad \text{royalty rate, expressed as a fraction of gross revenues.}$$

---

[2]Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 4.

[3]The OGSM determines coproduct production as proportional to the primary product production. COPRD is the ratio of units of coproduct per unit of primary product.

Present Value of Expected Production Taxes

Production taxes consist of ad valorem and severance taxes. The present value of expected production tax is given by:

$$PVPRODTAX_T = PVREV_{T,1} * (1 - ROYRT_1) * PRODTAX_1 + PVREV_{T,2} * (1 - ROYRT_2) * PRODTAX_2 \tag{5}$$

where,

$PRODTAX$ = production tax rate.

PVPRODTAX is computed as net of royalty payments because the investment analysis is conducted from the point of view of the operating firm in the field. Net production tax payments represent the burden on the firm because the owner of the mineral rights generally is liable for his/her share of these taxes.

Present Value of Expected Costs

Costs are classified within the OGSM as drilling costs, lease equipment costs, other capital costs, operating costs (including production facilities and general/administrative costs) and abandonment costs. These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The present value calculations of the expected costs are computed in a similar manner as PVREV (i.e., costs are discounted at an assumed rate and then summed across the evaluation period.)

Present Value of Expected Drilling Costs

Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through the Christmas tree installation.[4] Elements included in drilling costs are labor, material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals.

The present value of expected drilling costs is given by:

$$PVDRILLCOST_T = \sum_{t=T}^{T+n} \left[COSTEXP_T * SR_1 * NUMEXP_t + COSTDEV_T * SR_2 * NUMDEV_T + COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \right] * \left(\frac{1}{1 + disc} \right)^{t-T} \tag{6}$$

where,

$COSTEXP$ = drilling cost for a successful exploratory well
SR = success rate (1=exploratory, 2=developmental)

---

[4]The Christmas tree refers to the valves and fittings assembled at the top of a well to control the fluid flow.

COSTDEV	=	drilling cost for a successful developmental well
COSTDRY	=	drilling cost for a dry hole (1=exploratory, 2=developmental).
NUMEXP	=	number of exploratory wells drilled in a given period
NUMDEV	=	number of developmental wells drilled in a given period.

The number and schedule of wells drilled for a oil or gas project are supplied as part of the assumed production profile. This is based on historical drilling activities.

Present Value of Expected Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Three categories of costs are included: producing equipment, the gathering system, and processing equipment. Producing equipment costs include tubing, rods, and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells. The present value of expected lease equipment cost is

$$PVEQUIP_T = \sum_{t=T}^{T+n} \left[EQUIP_T * \left(SR_1 * NUMEXP_t + SR_2 * NUMDEV_t \right) * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \tag{7}$$

where,

$\qquad$ EQUIP $\quad = \quad$ lease equipment costs per well.

Present Value of Other Expected Capital Costs

Other major capital expenditures include the cost of gravel pads in Alaska, and offshore platforms. These costs are exclusive of lease equipment costs. The present value of other expected capital costs is calculated as:

$$PVKAP_T = \sum_{t=T}^{T+n} \left[KAP_t * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \tag{8}$$

where,

$\qquad$ KAP $\quad = \quad$ other major capital expenditures, exclusive of lease equipment.

Present Value of Expected Operating Costs

Operating costs include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

Total operating cost in time t is calculated by multiplying the cost of operating a well by the number of producing wells in time t. Therefore, the present value of expected operating costs is as follows:

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[OPCOST_T * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left(\frac{1}{1 + disc} \right)^{t-T} \right]$$

(9)

where,

OPCOST   =   operating costs per well.

Present Value of Expected Abandonment Costs

Producing facilities are eventually abandoned and the cost associated with equipment removal and site restoration is defined as

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[COSTABN_T * \left[\frac{1}{1 + disc} \right]^{t-T} \right]$$

(10)

where,

COSTABN   =   abandonment costs.

Drilling costs, lease equipment costs, operating costs, abandonment costs and other capital costs incurred in each individual year of the evaluation period, are integral components of the following determination of State and Federal corporate income tax liability.

Present Value of Expected Income Taxes

An important aspect of the DCF calculation concerns the tax treatment. All expenditures are divided into depletable[5], depreciable, or expensed costs according to current tax laws. All dry hole and operating costs are expensed. Lease costs (i.e., lease acquisition and geological and geophysical costs) are capitalized and then amortized at the same rate at which the reserves are extracted (cost depletion). Drilling costs are split between tangible costs (depreciable) and intangible drilling costs (IDC's) (expensed). IDC's include wages, fuel, transportation, supplies, site preparation, development, and repairs. Depreciable costs are amortized in accord with schedules established under the Modified Accelerated Cost Recovery System (MACRS).

Key changes in the tax provisions under the tax legislation of 1988 include:

- Windfall Profits Tax on oil was repealed.

- Investment Tax Credits were eliminated.

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[5]The DCF methodology does not include lease acquisition or geological & geophysical expenditures because they are not relevant to the incremental drilling decision.

Table 1. Tax Treatment in Oil and Gas Production by Category of Company Under Current Tax Legislation

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	**Cost Depletion**	**Cost Depletion**[b]	**Maximum of Percentage or Cost Depletion**
	G&G[a]	G&G	G&G
	Lease Acquisition	Lease Acquisition	Lease Acquisition
Depreciable Costs	**MACRS**[c]	**MACRS**	**MACRS**
	Lease Acquisition	Lease Acquisition	Lease Acquisition
	Other Capital Expenditures	Other Capital Expenditures	Other Capital Expenditures
	Successful Well Drilling Costs Other than IDC's	Successful Well Drilling Costs Other than IDC's	Successful Well Drilling Costs Other than IDC's
	5-year SLM[d]		
	20 percent of IDC's		
Expensed Costs	Dry Hole Costs	Dry Hole Costs	Dry Hole Costs
	80 percent of IDC's	80 percent of IDC's	80 percent of IDC's
	Operating Costs	Operating Costs	Operating Costs

[a]Geological and geophysical.
[b]Applicable to marginal project evaluation; firsst 1,000 barrels per day depletable under percentage depletion.
[c]Modified Accelerated Cost Recovery System; the period of recovery for depreciable costs will vary depending on the type of depreciable asset.
[d]Straight Line Method.

● Depreciation schedules shifted to a Modified Accelerated Cost Recovery System.

Tax provisions vary with type of producer (major, large independent, or small independent) as shown in Table 1. A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users. An independent is any oil and gas producer or owner of an interest in oil and gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and gas equivalent). The present DCF methodology reflects the tax treatment provided by current tax laws for large independent producers.

The resulting present value of expected taxable income (PVTAXBASE) is given by:

$$PVTAXBASE_T = \sum_{t=T}^{T+n} \left[(TREV_t - ROY_t - PRODTAX_t - OPCOST_t - ABANDON_t - XIDC_t - \right.$$
$$\left. AIDC_t - DEPREC_t - DHC_t) \ * \ \left(\frac{1}{1 + disc} \right)^{t-T} \right]$$

(11)

where,

T	=	year of evaluation
t	=	time period
n	=	number of years in the evaluation period
TREV	=	expected revenues
ROY	=	expected royalty payments
PRODTAX	=	expected production tax payments
OPCOST	=	expected operating costs
ABANDON	=	expected abandonment costs
XIDC	=	expected expensed intangible drilling costs
AIDC	=	expected amortized intangible drilling costs[6]
DEPREC	=	expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC	=	expected dry hole costs
disc	=	expected discount rate.

$TREV_t$, ROY_t, $PRODTAX_t$, $OPCOST_t$, and $ABANDON_t$ are the nondiscounted individual year values as defined in equations (6), (7), (8), (12), and (13) respectively. The following sections describe the treatment of expensed and amortized costs for purpose of determining corporate income tax liability at the State and Federal level.

Expected Expensed Costs

Expensed costs are intangible drilling costs, dry hole costs, operating costs, and abandonment costs. Expensed costs and taxes (including royalties) are deductible from taxable income.

Expected Intangible Drilling Costs

For large independent producers, all intangible drilling costs are expensed. However, this is not true across the producer category (as shown in Table 1). In order to maintain analytic flexibility with respect to changes in tax provisions, the variable XDCKAP (representing the portion of intangible drilling costs that must be depreciated) is included. Expected expensed IDC's are defined as follows:

$$XIDC_t = COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t + $$
$$COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t$$

(12)

where,

COSTEXP $\quad$ = $\quad$ drilling cost for a successful exploratory well

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[6]This variable is included only for completeness. For large independent producers, all intangible drilling costs are expensed.

EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
XDCKAP	=	fraction of intangible drilling costs that must be depreciated[7]
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells.

If only a portion of IDC's are expensed (as is the case for major producers), the remaining IDC's must be depreciated. These costs are recovered at a rate of 10 percent in the first year, 20 percent annually for four years, and 10 percent in the sixth year, referred to as the 5-year Straight Line Method (SLM) with half year convention. If depreciable costs accrue when fewer than 6 years remain in the life of the project, then costs are recovered using a simple straight line method over the remaining period.

Thus, the value of expected depreciable IDC's is represented by:

$$
\begin{aligned}
AIDC_t = \sum_{j=\beta}^{t} & \Big[\big(COSTEXP_T*(1-EXKAP)*XDCKAP*SR_1*NUMEXP_j + \\
& COSTDEV_T*(1-DVKAP)*XDCKAP*SR_2*NUMDEV_j\big) * \\
& DEPIDC_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j}\Big], \\
\beta = & \begin{cases} T & \text{for } t \leq T+m-1 \\ t-m+1 & \text{for } t > T+m-1 \end{cases}
\end{aligned}
\tag{13}
$$

where,

j	=	year of recovery
β	=	index for write-off schedule
DEPIDC	=	for t ≤ n+T-m, 5-year SLM recovery schedule with half year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[8]
disc	=	expected discount rate
m	=	number of years in standard recovery period.

AIDC will equal zero by default since the DCF methodology reflects the tax treatment pertaining to large independent producers.

Expected Dry Hole Costs

All dry hole costs are expensed. Expected dry hole costs are defined as

---

[7]The fraction of intangible drilling costs that must be depreciated is set to zero as a default to conform with the tax perspective of a large independent firm.

[8]The write-off schedule for the 5-year SLM give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

Table 2. MACRS Schedules
(Percent)

Year	3-year Recovery Period	5-year Recovery Period	7-year Recovery Period	10-year Recovery Period	15-year Recovery Period	20-year Recovery Period
1	33.33	20.00	14.29	10.00	5.00	3.750
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Source: U.S. Master Tax Guide.

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \tag{14}$$

where,

COSTDRY   =   drilling cost for a dry hole (1=exploratory, 2=developmental).

Total expensed costs in any year equals the sum of $XIDC_t$, $OPCOST_t$, $ABANDON_t$, and DHC_t.

Expected Depreciable Tangible Drilling Costs, Lease Equipment Costs and Other Capital Expenditures

Amortization of depreciable costs, excluding capitalized IDC's, conforms to the Modified Accelerated Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in Table 2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

The expected tangible drilling costs, lease equipment costs, and other capital expenditures is defined as

$$DEPREC_t = \sum_{j=\beta}^{t} \left[(COSTEXP_T * EXKAP + EQUIP_T) * SR_1 * NUMEXP_j + \right.$$

$$(COSTDEV_T * DVKAP + EQUIP_T) * SR_2 * NUMDEV_j + KAP_j \Big] *$$

$$DEP_{t-j+1} * \left(\frac{1}{1+infl} \right)^{t-j} * \left(\frac{1}{1+disc} \right)^{t-j} \Bigg], \tag{15}$$

$$\beta = \begin{cases} T \text{ for } t \le T+m-1 \\ t-m+1 \text{ for } t > T+m-1 \end{cases}$$

where,

j	=	year of recovery
β	=	index for write-off schedule
m	=	number of years in standard recovery period
COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
EQUIP	=	lease equipment costs per well
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells drilled in a given period
KAP	=	major capital expenditures such as gravel pads in Alaska or offshore platforms, exclusive of lease equipment
DEP	=	for $t \le n+T-m$, MACRS with half year convention; otherwise, $1/(n+T-t)$ in each period
infl	=	expected inflation rate[9]
disc	=	expected discount rate.

Present Value of Expected State and Federal Income Taxes

The present value of expected state corporate income tax is determined by

$$PVSIT_T = PVTAXBASE_T * STRT \tag{16}$$

where,

PVTAXBASE	=	present value of expected taxable income (Equation (14))
STRT	=	state income tax rate.

The present value of expected federal corporate income tax is calculated using the following equation:

---

[9]Each of the write-off schedules give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \tag{17}$$

where,

> FDRT = federal corporate income tax rate.

Summary

The discounted cash flow calculation is a useful tool for evaluating the expected profit or loss from an oil or gas project. The calculation reflects the time value of money and provides a good basis for assessing and comparing projects with different degrees of profitability. The timing of a project's cash inflows and outflows has a direct affect on the profitability of the project. As a result, close attention has been given to the tax provisions as they apply to costs.

The discounted cash flow is used in each submodule of the OGSM to determine the economic viability of oil and gas projects. Various types of oil and gas projects are evaluated using the proposed DCF calculation, including single well projects and multi-year investment projects. Revenues generated from the production and sale of co-products also are taken into account.

The DCF routine requires important assumptions, such as costs and tax provisions. Drilling costs, lease equipment costs, operating costs, and other capital costs are integral components of the discounted cash flow analysis. The default tax provisions applied to the costs follow those used by independent producers. Also, the decision to invest does not reflect a firm's comprehensive tax plan that achieves aggregate tax benefits that would not accrue to the particular project under consideration.

Appendix 4-B. LNG Cost Determination Methodology

Introduction

The expected LNG import volumes will respond to the projected gas prices at the point of delivery into the U.S. pipeline network. That is, the unit cost of imported LNG[1] will be compared to the cost of other gas available to the pipeline network at that location. Unit LNG costs will be computed as the project revenue at the breakeven point, averaged over expected throughput. The proposed methodology comprises a generalized computation of LNG project costs. These costs serve as the minimum price at which the associated volumes would flow.

The LNG project investment will have a positive expected discounted cash flow when the price exceeds the computed delivered cost (including taxes), which is comprised of three components distinguished with respect to the separate operational phases: liquefaction, shipping, and regasification. Each cost component will be expressed as the cost incurred at each phase to supply a unit of LNG.

The proposed method is intended to be transparent, representative of economic costs, and accounting for some degree of tax liability. The specific level of costs may be affected by local factors that vary costs or tax liability between countries. The sole operational phase on U.S. soil is the regasification terminals. The cost of taxes for these facilities will be determined on the basis of the relevant tax law provisions, including the Modified Accelerated Cost Recovery System (MACRS). Operational phases involving non-U.S. capital (liquefaction facilities and tankers) will represent the tax liability associated with these facilities as property taxes.[2]

$$DCST_t = LIQCST_t + SHPCST_t + RGASCST_t \tag{1}$$

where,

t	=	forecast year
$DCST_t$	=	delivered cost per unit of LNG
$LIQCST_t$	=	liquefaction cost per unit of LNG
$SHPCST_t$	=	shipping cost per unit of LNG
$RGASCST_t$	=	regasification cost per unit of LNG.

A brief description of these components is presented below, followed by the actual formulas used for these estimations.

Liquefaction

The liquefaction revenue requirement is composed of capital costs, operation and maintenance costs, and miscellaneous costs, as follows:

---

[1]A unit of LNG will be measured as a thousand cubic feet equivalent of the regasified LNG.

[2]This approach, while a severe simplification of a highly complex reality, is a practical alternative that is consistent with the method used in a Gas Research Institute study (1988) and the recent National Petroleum Council study (1992).

$$LIQCST_t = \frac{CAPCSTS_{L,t} + OMCSTS_{L,t} + MSCSTS_{L,t}}{UTIL_{L,t} * CPCTY_{L,t}}$$ (2)

where,

$$
\begin{aligned}
LIQCST_t &= \text{liquefaction cost per unit of LNG} \\
CAPCSTS_{L,t} &= \text{capital costs (millions of dollars)} \\
OMCSTS_{L,t} &= \text{operation and maintenance costs (millions of dollars)} \\
MSCSTS_{L,t} &= \text{miscellaneous costs (including production costs) (millions of dollars)} \\
UTIL_{L,t} &= \text{utilization rate (percent)} \\
CPCTY_{L,t} &= \text{gas input capacity (billion cubic feet).}
\end{aligned}
$$

Capital costs are derived from a rate base that includes equipment costs for gas pretreatment, liquefaction process, utilities, storage, loading facilities, marine facilities, overhead, engineering, fees, and infrastructure costs. The debt/equity ratio, cost of capital, and the tax rate are essential in calculating these costs. Additionally, a method of depreciation, such as the straight line method, must be established for the investment. Capital costs are represented by the following equation:

$$CAPCSTS_{L,t} = DEP_{L,t} + INTR_{L,t} + ROE_{L,t} + TAX_{L,t}$$ (3)

where,

$$
\begin{aligned}
CAPCSTS_{L,t} &= \text{capital costs} \\
DEP_{L,t} &= \text{depreciation } (INVST_L/n_L) \\
INVST_L &= \text{capital investment (millions of dollars)} \\
n_L &= \text{useful life of investment} \\[6pt]
INTR_{L,t} &= \text{interest on debt } (RBASE_{L,t} * d_L * kd_L) \\
RBASE_{L,t} &= \text{rate base } (INVST_L - ACCDEP_{L,t}) \\[6pt]
ACCDEP_{L,t} &= \text{accumulated depreciation } (\textstyle\sum_{y=1}^{t} DEP_{L,y}) \\
d_L &= \text{debt financing amount (fraction)} \\
kd_L &= \text{cost of debt (percent)} \\
y &= \text{year of investment} \\[6pt]
ROE_{L,t} &= \text{return on equity } (RBASE_{L,t} * e_L * ke_L) \\
e_L &= \text{equity financing amount } (1 - d_L) \text{ (fraction)} \\
ke_L &= \text{cost of equity (percent)} \\[6pt]
TAX_{L,t} &= \text{tax on capital } (INVST_L * TRATE_L) \\
TRATE_L &= \text{tax rate (percent).}
\end{aligned}
$$

Operation and maintenance costs include raw materials, labor, materials, general plant, direct costs, and insurance. Miscellaneous costs include production and feed gas costs.

The utilization rate is represented as a percentage of the sustainable capacity. For both liquefaction and regasification, a buildup period toward the maximum utilization rate may be included as an assumption to reflect a scenario that is more consistent with the historical experience of LNG projects.

Shipping

The shipping component of the delivered cost also consists of capital costs, operation and maintenance costs, and miscellaneous costs, as represented by the following:

$$SHPCST_t = \frac{CAPCSTS_{s,t} + OMCSTS_{s,t} + MSCSTS_{s,t}}{VOLYR_{s,t}}$$

(4)

where,

$SHPCST_t$	=	shipping cost per unit of LNG
$CAPCSTS_{s,t}$	=	capital costs (millions of dollars)
$OMCSTS_{s,t}$	=	operation and maintenance costs (millions of dollars)
$MSCSTS_{s,t}$	=	miscellaneous costs (millions of dollars)
$VOLYR_{s,t}$	=	shipping volume per year (billion cubic feet).

Again, key components in calculating capital costs are the type of financing and the cost of financing. Capital costs are represented as follows:

$$CAPCSTS_{s,t} = DEP_{s,t} + INTR_{s,t} + ROE_{s,t} + TAX_{s,t}$$

(5)

where,

$CAPCSTS_{s,t}$	=	capital costs
$DEP_{s,t}$	=	depreciation ($INVST_s/n_s$)
$INVST_s$	=	capital investment (millions of dollars)
n_s	=	useful life of investment
$INTR_{s,t}$	=	interest on debt ($RBASE_{s,t} * d_s * kd_s$)
$RBASE_{s,t}$	=	rate base ($INVST_s - ACCDEP_{s,t}$)
$ACCDEP_{s,t}$	=	accumulated depreciation ($\sum_{y=1}^{t} DEP_{s,y}$)
d_s	=	debt financing amount (fraction)
kd_s	=	cost of debt (percent)
y	=	year of investment
$ROE_{s,t}$	=	return on equity ($RBASE_{s,t} * e_s * ke_s$)
e_s	=	equity financing amount ($1 - d_s$) (fraction)
ke_s	=	cost of equity (percent)
$TAX_{s,t}$	=	tax on capital ($INVST_s * TRATE_s$)
$TRATE_s$	=	tax rate (percent).

Operation and maintenance costs for shipping include those for crew, repair, administrative and general overhead, and insurance.

A key element in the operating costs for shipping is the distance that the LNG must travel. This distance will affect the amount of LNG that can be transported annually, and ultimately will affect the annual unit cost of transporting gas. Assumptions about average speed, operating days per year, and boiloff LNG used for fuel also affect the calculation of shipping volume per year. The calculation for finding the volume that can be shipped per year is represented as follows:

$$VOLYR_{s,t} = VLTRIP_{s,t} * TRIPS_{s,t} \tag{6}$$

where,

$$
\begin{aligned}
VOLYR_{s,t} &= \text{shipping volume per year (billion cubic feet)} \\
VLTRIP_{s,t} &= \text{volume per trip } (CPCTY_{s,t} - BOILTRP_{s,t}) \text{ (billion cubic feet)} \\
CPCTY_{s,t} &= \text{shipping capacity (billion cubic feet)} \\
BOILTRIP_{s,t} &= \text{boiloff per trip } [BOILDAY_{s,t} * (HOURS_{s,t}/24)] \text{ (billion cubic feet)} \\
BOILDAY_{s,t} &= \text{boiloff per day (billion cubic feet)} \\
HOURS_{s,t} &= \text{hours per round-trip } (2 * MILES_{s,t}/SPEED_{s,t}) \\
MILES_{s,t} &= \text{one-way distance (nautical miles)} \\
SPEED_{s,t} &= \text{average speed of trip (nautical miles per hour)} \\
TRIPS_{s,t} &= \text{trips per year } (OPDAYS_{s,t}/DAYS_{s,t}) \\
OPDAYS_{s,t} &= \text{operating days per year.} \\
DAYS_{s,t} &= \text{days per trip } (HOURS_{s,t}/24 + PORT_{s,t}) \\
PORT_{s,t} &= \text{port days per round-trip}
\end{aligned}
$$

Miscellaneous costs include tankers fuel costs (nitrogen and bunker) and port costs.

Regasification

Regasification terminals consist of capital and operation and maintenance costs, as shown in the following:

$$RGASRR_t = \frac{CAPCSTS_{r,t} + OMCSTS_{r,t}}{UTIL_{r,t} * CPCTY_{r,t}} \tag{7}$$

where,

$$
\begin{aligned}
RGASRR_t &= \text{regasification cost per unit of LNG} \\
CAPCSTS_{r,t} &= \text{capital costs (millions of dollars)} \\
OMCSTS_{r,t} &= \text{operation and maintenance costs (millions of dollars)} \\
UTIL_{r,t} &= \text{utilization rate (percent)} \\
CPCTY_{r,t} &= \text{terminal capacity (billion cubic feet).}
\end{aligned}
$$

For existing terminals, original capital expenditures are considered sunk costs. The capital outlays for both re-activation and expansion are examined, along with costs of capital, method of financing, and tax rates. These capital costs can be represented as follows:

$$CAPCSTS_{r,t} = RSCAP_{r,t} + EXCAP_{r,t} \tag{8}$$

where,

$$RSCAP_{r,t} = \text{restart capital costs}$$
$$EXCAP_{r,t} = \text{expansion capital costs.}$$

Both of these capital expenditures[3] can be represented in the same way as the capital costs for liquefaction or shipping. The formulae are as follows:

$$RSCAP_{r,t} = RSDEP_{r,t} + RSINTR_{r,t} + RSROE_{r,t} + RSTAX_{r,t} \tag{9}$$

where,

$RSDEP_{r,t}$	$=$	depreciation $(RSINVST_r * RSDRATE_{r,t})$
$RSINVST_r$	$=$	capital investment in re-activation (millions of dollars)
$RSDRATE_{r,t}$	$=$	depreciation rate
$RSINTR_{r,t}$	$=$	interest on debt $(RSRBASE_{r,t} * d_r * kd_r)$
$RSRBASE_{r,t}$	$=$	rate base $(RSINVST_r - RSACCDEP_{r,t})$
$RSACCDEP_{r,t}$	$=$	accumulated depreciation $(\sum_{y=1}^{t} RSDEP_{r,y})$
d_r	$=$	debt financing amount (fraction)
kd_r	$=$	cost of debt (percent)
y	$=$	year of re-activation
$RSROE_{r,t}$	$=$	return on equity $(RSRBASE_{r,t} * e_r * ke_r)$
e_r	$=$	equity financing amount $(1 - d_r)$ (fraction)
ke_r	$=$	cost of equity (percent)
$RSTAX_{r,t}$	$=$	tax on capital $(RSINVST_r * RSTRATE_r)$
$RSTRATE_r$	$=$	tax rate (percent).

and,

$$EXCAP_{r,t} = EXDEP_{r,t} + EXINTR_{r,t} + EXROE_{r,t} + EXTAX_{r,t} \tag{10}$$

where,

$EXDEP_{r,t}$	$=$	depreciation $(EXINVST_r * EXDRATE_{r,t})$
$EXINVST_r$	$=$	capital investment in expansion (millions of dollars)
$EXDRATE_{r,t}$	$=$	depreciation rate
$EXINTR_{r,t}$	$=$	interest on debt $(EXRBASE_{r,t} * d_r * kd_r)$
$EXRBASE_{r,t}$	$=$	rate base $(EXINVST_r - EXACCDEP_{r,t})$
$EXACCDEP_{r,t}$	$=$	accumulated depreciation $(\sum_{y=1}^{t} EXDEP_{r,y})$

---

[3]In practice, it is not expected that both restarting an existing facility and capacity expansion at the same site would occur in the same year. Thus, RSCAP and EXCAP are not expected to both be nonzero in the same year.

$$d_r = \text{debt financing amount (fraction)}$$
$$kd_r = \text{cost of debt (percent)}$$
$$y = \text{year of expansion}$$

$$EXROE_{r,t} = \text{return on equity } (EXRBASE_{r,t} * e_r * ke_r)$$
$$e_r = \text{equity financing amount } (1 - d_r) \text{ (fraction)}$$
$$ke_r = \text{cost of equity (percent)}$$

$$EXTAX_{r,t} = \text{tax on capital } (EXINVST_r * EXTRATE_r)$$
$$EXTRATE_r = \text{tax rate (percent).}$$

Operating and maintenance costs for a regasification terminal include: terminaling and processing, labor, storage, administrative and general overhead.

Appendix 4-C. Unconventional Gas Recovery Supply Submodule

INTRODUCTION

The UGRSS is the unconventional gas component of the EIA's Oil and Gas Supply Module (OGSM), one component of EIA's National Energy Modeling System (NEMS). The UGRSS is a play level model that specifically analyzes the three major unconventional resources - coalbed methane, tight gas sands, and gas shales. This appendix describes the UGRSS in detail. The following major topics are presented concerning the model:

- Model purpose;
- Model overview and rationale;
- Model structure
- Inventory of input data, technological variables, model output;

The first section discusses the purpose of the UGRSS. The second section explains the rationale for developing the UGRSS, and how the model allows OGSM to address various issues associated with unconventional natural gas exploration and production. The third section discusses the actual modeling structure in detail. The unconventional gas resource base is defined and quantified in the first part of this section. The second part discusses costs and prices in detail, offering justification from various sources. The final part illustrates the model output and how this output data allows the model to progress yearly.

MODEL PURPOSE

The Unconventional Gas Recovery Supply Submodule (UGRSS) offers EIA the ability to analyze the unconventional gas resource base and its potential for future economic production under differing technological circumstances. The UGRSS was built exogenously from the National Energy Modeling System (NEMS) but now functions as a submodule within the NEMS Oil and Gas Supply Module (OGSM). The UGRSS uses pricing data from EIA's NGTDM, resource data from the USGS's 1995 National Assessment, and cost data from various sources including the API's JAS. An illustration of how the UGRSS interfaces with the EIA/NEMS energy modules is shown in Figure 4C-1.

Figure 4C-1. UGRSS Interfaces with EIA/NEMS Modules
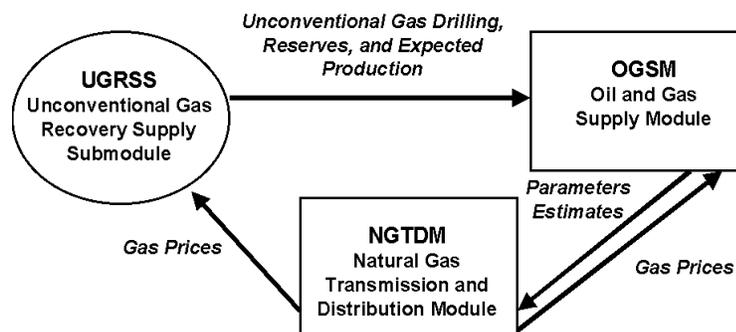
Unconventional natural gas -- natural gas from coal seams, natural gas from organic shales, and natural gas from tight sands -- was thought of as an "interesting concept" or "scientific curiosity" not long ago. To spur interest in the development of unconventional gas, the U.S. Government offered tax credits (Section 29) for any operator attempting to develop this type of resource. Indeed, this did interest many operators and unconventional gas resources began to be developed. Through research and development (R&D), individual technology was developed to enable unconventional resources to be economically developed and placed on production. These technologies began to be applied in different regional settings yielding successful results.

Today, according to the USGS's 1995 National Assessment, unconventional gas represents the largest onshore technically recoverable natural gas resource.(Table 4C-1) Figures 4C-2 through 4C-4 illustrate the current basins in which each type of resource exists. Since 1992, production in each unconventional gas resource has increased and in 1996 unconventional gas made up 20 percent of natural gas production and 30percent of natural gas reserves in the United States. The increase in the contribution of unconventional natural gas to the U.S. production and reserve baseline is apparent and growing. This fact makes the capability to understand the present unconventional gas resource base and the ability to predict future energy scenarios involving unconventional gas an invaluable element in future DOE/EIA energy modeling.

Prior to the development of the new UGRSS, the estimates of unconventional gas production in the Annual Energy Outlook (AEO) were based on the results of econometric equations. OGSM forecasted representative drilling costs and drilling activities (wells) by region and resource type, including unconventional gas. Based on historical trends in reserve additions per well and a series of discovery process equations, these projected drilling levels generated reserve additions, and thereby production, for each resource type. This approach is somewhat limited when applied to unconventional gas, however. Because significant exploration and development in this resource has been realized only recently, there exists minimal historical activity to effectively establish a trend from which to extrapolate into the future. Furthermore, technological changes have substantially changed the productivity and economics of this resource area in recent years. Consequently, the development of a specialized, geology and engineering based unconventional gas model that accounts for technological advances was deemed necessary.

Table 4C-1. USGS 1995 National Assessment

Background

- The 1995 National Assessment of U.S. Oil and Gas Resources by the USGS established unconventional gas (continuous-type deposits) as the largest undiscovered onshore technically recoverable natural gas resource:

  - <u>Continuous-Type Deposits</u> 358 Tcf

    - CBM   (50 Tcf)

    - Gas Shales (49 Tcf)

    - Tight Sands* (260 Tcf)

  - <u>Reserve Growth</u> 322 Tcf

  - Undiscovered Conventional 259 Tcf

    Resources

  *Includes low permeability chalks

- **Significantly, the 1995 Assessment did not quantitatively assess many large, already producing unconventional gas deposits, such as:**
  - Wind River Basin, Tertiary and Upper Cretaceous Tight Sands
  - Fort Worth Basin, Barnett Shale
  - Green River Basin, Deep Coalbed Methane

Figure 4C-2: Resources of U.S. Lower 48 Coalbed Methane Basins

Western Washington
24 Tcf

Powder River
30 Tcf

Illinois
21 Tcf

Northern
Appalachian
61 Tcf

Wind River
2 Tcf

Greater
Green River
84 Tcf

Forest City

Uinta
10 Tcf

Cherokee

Central
Appalachia
5 Tcf

Piceance
84 Tcf

San Juan
Fruitland Coal = 50 Tcf
Menefee Coal = 34 Tcf

Raton
11 Tcf

Arkoma
4 Tcf

Warrior
20 Tcf

Established CBM Basin
Emerging CBM Basin
Frontier CBM Basin
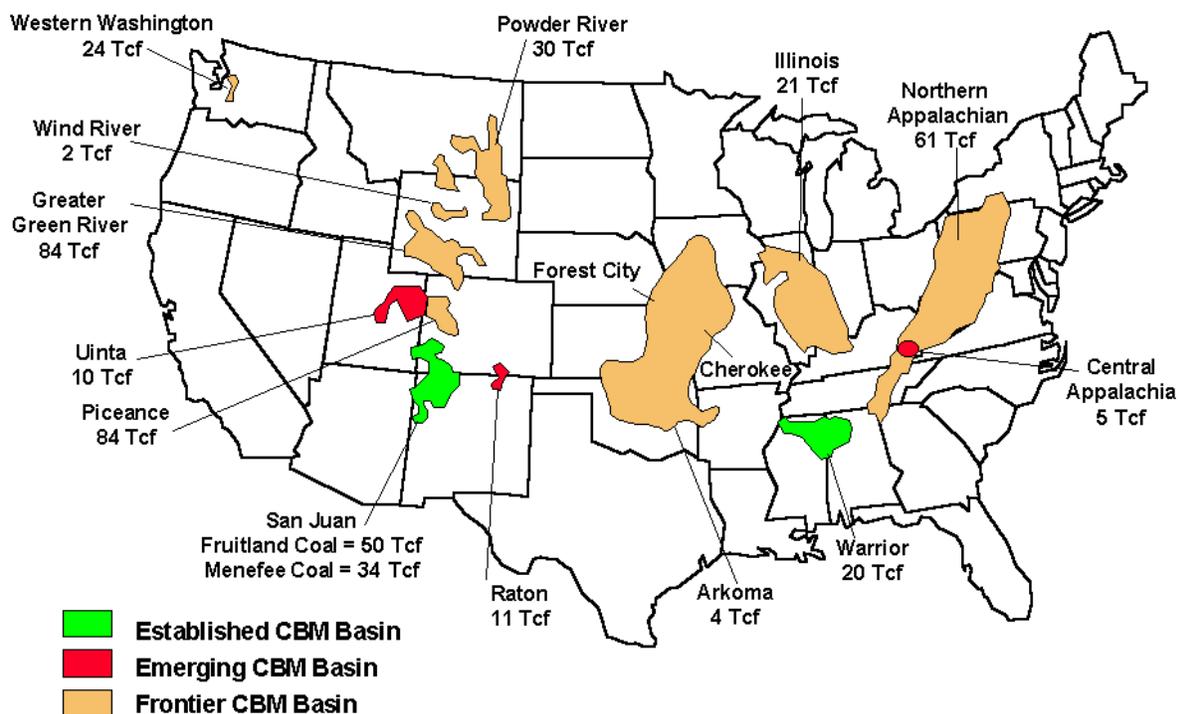
JAF00568.PPT

Figure 4C- 3: Principal U.S. Tight Gas Basins
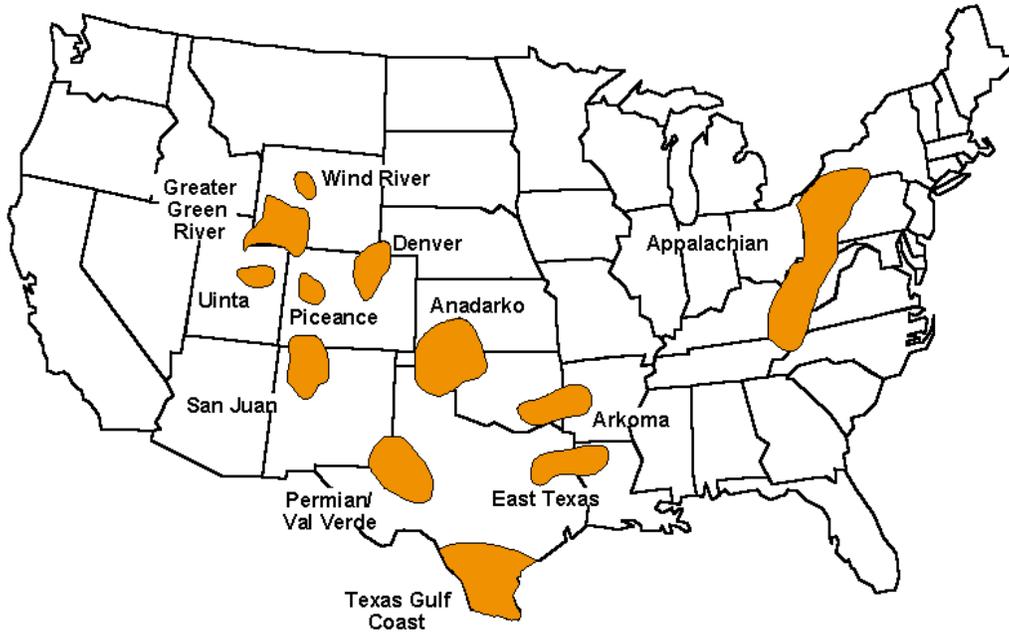
JAF00568.PPT

Figure 4C-4: Locations of U.S. Gas Shale Basins

Basins where GRI has conducted R&D programs

Basins where productive shales are present
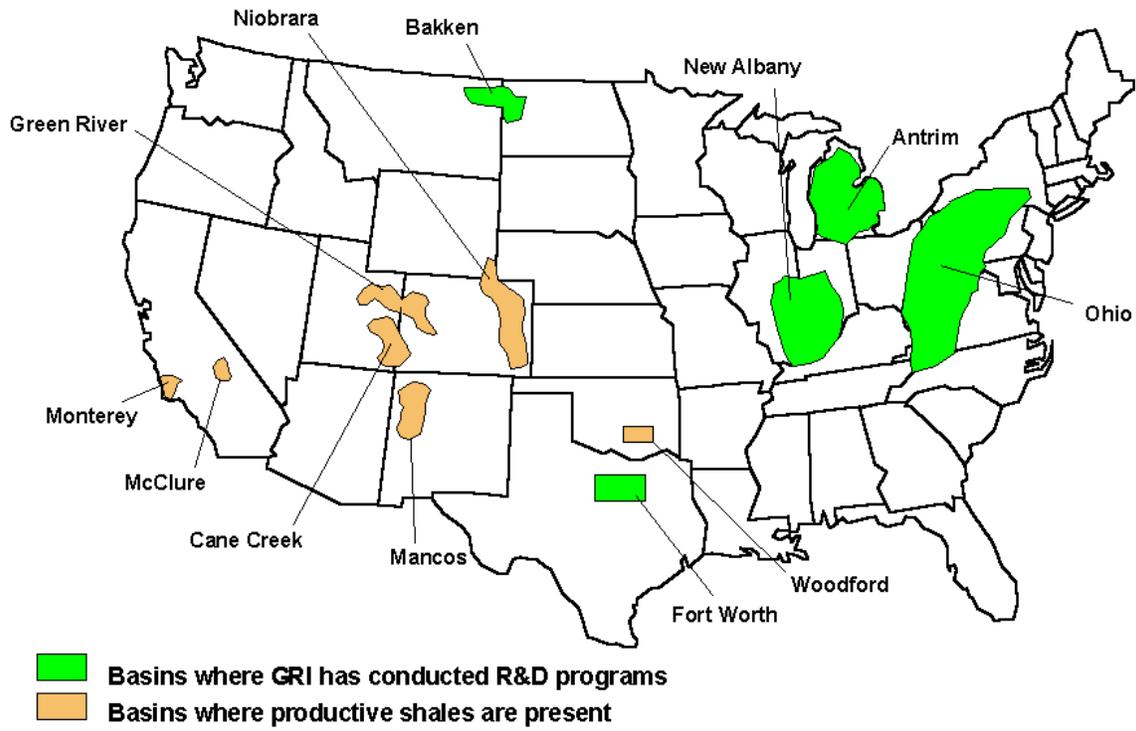
JAF00568.PPT

MODEL OVERVIEW & RATIONALE

The growth of unconventional gas activities in the last five years has been so significant that DOE/EIA needed a better understanding of the quantity of unconventional resources and the technologies associated with its production. Figures 4C-5 to 4C-7 illustrate growth in coalbed methane, tight gas and gas shales production. By 1996, unconventional gas made up 20 percent of US natural gas production and 30 percent of US natural gas reserves. Much of this growth can be attributed to technological advances from R&D in unconventional gas supported by the DOE, the Gas Research Institute (GRI) and industry in the late 1980's and early 1990's.

The USGS included unconventional natural gas in their 1995 National Assessment. However, their estimates did not take into account future changes in technologies effecting unconventional gas. Because much of the unconventional gas resource is "technology constrained" rather than "resource constrained," it is important to quantify the existing unconventional gas resource base and explore the technologies that are needed to enhance the development of unconventional natural gas. The UGRSS incorporates the effect of different technologies in different forward-looking scenarios to quantify the future of unconventional gas.

Figure 4C-5
Growth in Coalbed Methane
Wells and Production

Producing Wells

- 1992*: 5,278
- 1993: 5,926
- 1994: 6,287
- 1995: 6,700(e)
- 1996: 7,000(e)

Annual Production (Bcf)

- 1992*: 562
- 1993: 748
- 1994: 862
- 1995: 956
- 1996: 1003
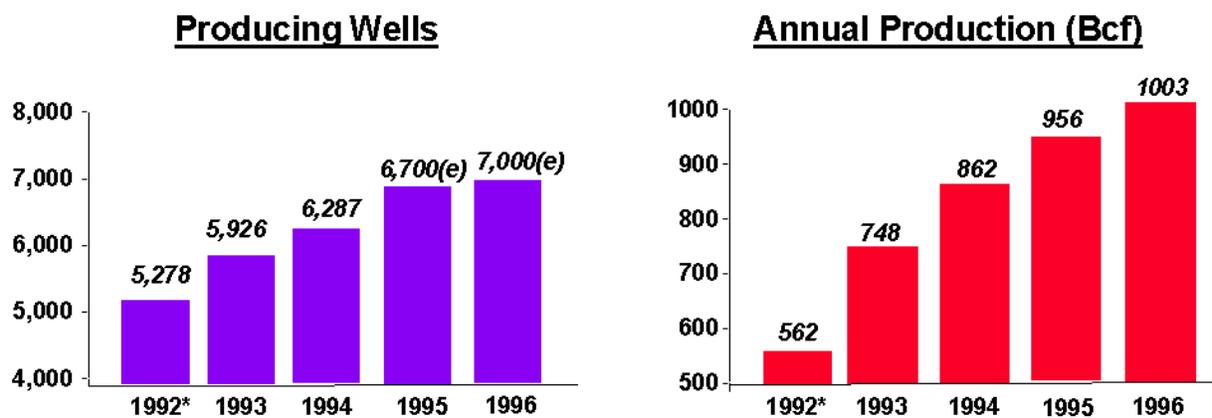
1992 was the end of the Sec. 29 tax credit.

Figure 4C-6

Gas Shales Production and Well Completions

Annual Production

Well Completions

Basins	1992	1993	1994	1995
Michigan (Antrim)	1,193	418	507	850
Appalachian (Devonian)	462	411	336	300
Fort Worth (Barnett)	19	40	41	60
Other*	35	71	28	90
Total	1,709	940	912	1,300
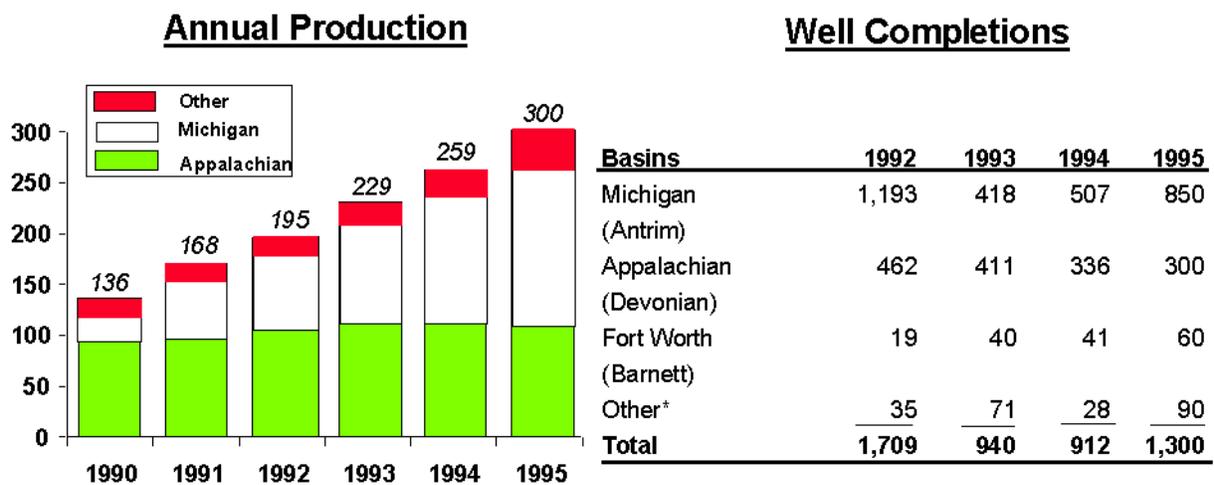
*Illinois (New Albany) and Denver (Niobrara).

Table 4C-2

Tight Gas Production -- 1992-1996

Basins/Regions	Annual Production (Bcf)				
	1992	1993	1994	1995	1996
Arkla	48	51	52	50	50
East Texas	339	365	370	370	370
Texas Gulf Coast	435	468	474	500	520
Wind River	11	11	11	20	30
Green River	231	295	335	327	360
Denver	71	76	77	75	75
Uinta	35	66	59	56	60
Piceance	31	33	34	32	41
Anadarko	213	230	232	220	220
Permian Basin	235	253	255	260	260
San Juan	321	350	342	330	340
Williston	8	8	8	8	20
Appalachian	419	396	396	390	397
TOTALS	**2,397**	**2,603**	**2,645**	**2,638**	**2,743**

DATA SOURCES

The UGRSS borrows much of its resource data from the USGS's 1995 National Assessment. (Advanced Resources International (ARI) prepared much of the resources assessment for coalbed methane within that study). Further sources for unconventional gas resource data were the National Petroleum Council's (NPC) 1992 study (*The Potential for Natural Gas in the United States*) and ARI's own internal database. The UGRSS incorporates all of the USGS designated continuous-type plays into the model structure (continuous-type deposits is the USGS term for unconventional gas) and adds some frontier plays that were not quantitatively assessed by the USGS. Because of the geologic and engineering base for the models structure, many ARI internal basin and play level evaluations, reservoir simulations and history-matching based well performances were included to modify the existing data. These modifications provide the UGRSS with up-to-date and expert resource evaluation to base its future projections upon. Comparisons between the resource base in the USGS's 1995 National Assessment and the UGRSS are provided in Tables 4C-3 to 4C-5.

The estimates used for current and expected activity in production and reserves within the UGRSS were derived from in-depth analysis of state survey data, industry inputs, Petroleum Information /Dwights Energy Data (PI/Dwights) completion and production records and EIA's annual reserves report. These data are linked to the NEMS historic accounting module.

The data concerning costs and economics were developed by ARI from extensive work with industry producers in tight gas, coalbed methane and gas shale basins, plus the API's JAS. These data are also linked to the main NEMS price module.

The determinations of how technology will impact the model, the timing of these technology impacts and current and future environmental constraints are the significant variables that determine the output of the UGRSS. These variables were developed by ARI to incorporate R&D programs being conducted by the DOE, GRI and industry that lead to significant technology progress. These variables will each be explained in detail in the next section.

Drilling allocations establish a pace of well drilling for economically feasible gas plays based on relative profitability and associated drilling schedules. The baseline data and these determinations are linked to the other drilling projections within OGSM.

The model outputs to be incorporated into EIA's AEO are: annual production, drilling and reserves, by OGSM regions. These outputs are linked to NEMS integrating module and output reports.

Table 4C-3

Tight Sand Resource Base

Tight Sand Basins	No. Plays	Undeveloped Recoverable Resources (Tcf)* USGS	ARI	Comments
Appalachian Basin	6	43.9	22.6	Reduced Area
Arkoma	1	N/A	0.8	New Assessment
Columbia	1	12.6	6.3	Reduced Area; Success Rates
Louisiana-Miss Salt	1	6.2	12.7	Improved Performance
Mid-Continent (Anadarko)	3	N/A	14.0	New Assessment
Northern Great Plains	3	39.9	24.8	Reduced Performance
Rocky Mountain Basins				
- *Denver*	*1*	*0.8*	*0.8*	*Comparable Assessment*
- *San Juan*	*3*	*21.7*	*21.7*	*Comparable Assessment*
- *Uinta*	*4*	*7.9*	*6.2*	*Comparable Assessment*
- *Green River*	*7*	*86.7*	*96.3*	*Added Deep Gas Resource*
- *Piceance*	*3*	*12.8*	*16.4*	*Improved S. Basin Assessment*
- *Wind River*	*4*	*N/A*	*18.3*	*New Assessment*
Permian	2	N/A	14.0	New Assessment
Texas Gulf	3	N/A	4.6	New Assessment
TOTAL		**232.5**	**259.5**	

Table 4C-4

Gas Shales Resource Base

Gas Shales Basins	No. Plays	Undeveloped Recoverable Resources (Tcf)* USGS	ARI	Comments
Appalachian Basin	4	24.4	24.4	Comparable Assessment
- *Big Sandy Central*	*1*	*9.1*	*9.1*	
- *Big Sandy Extension*	*1*	*9.1*	*9.0*	
- *Greater Siltsone Area*	*1*	*2.8*	*2.8*	
- *Low Thermal Maturity*	*1*	*3.4*	*3.5*	
Michigan Basin	2	18.9	18.8	Comparable Assessment
Illinois Basin	1	1.9	2.0	Comparable Assessment
Cincinnatti Arch	1	1.4	1.4	Comparable Assessment
Williston Basin	1	1.9	1.6	Comparable Assessment
Fort Worth Basin	1	-	3.3	USGS Did Not Assess
TOTAL	**10**	**48.5**	**51.5**	

Table 4C-5

Coalbed Methane Resource Base

CBM Basins	No. Plays	Undeveloped Recoverable Resources (Tcf)* USGS	ARI	Comments
Appalachian Basin	3	14.9	8.6	Reduced Area for Northern Basin
- Central	(1)		(3.7)	
- Northern	(2)		(3.9)	
- Cahaba	(1)		(1.0)	
Black Warrior Basin	2	2.3	1.5	Reduced Well EUR's
Illinois Basin	1	1.6	0.6	Reduced Area
Mid-Continent	2	5.0	2.9	Reduced Well EUR's
Rocky Mountain Basins				
- San Juan	5	7.5	12.9	*Infill Development/Menefee Coals*
- Raton	3	1.8	3.6	*Expanded Area*
- Uinta	3	3.2	7.5	*New Plays; Expanded Area*
- Powder River	2	1.1	1.8	*Improved Well EURs*
- Green River	2	3.9	7.8	*Added Deep Coals (3.9 Tcf)*
- Piceance	4	7.5	7.7	*Comparable Assessment*
Others (Wind River, etc.)	2	1.1	-	Small Resources, Little Data
TOTAL	**28**	**49.9**	**54.9**	

UGRSS MODEL STRUCTURE

The UGRSS is a FORTRAN-based modeling system developed in a spreadsheet format. The UGRSS projects future unconventional natural gas production for the U. S. onshore lower 48 states. An overview of the rationale for designing the model, the model's strategy and the model's ultimate purpose were presented in Sections 1.0, 2.0, and 3.0.

This chapter discusses in detail the programming structure, design, model inputs and technology variables that allow the UGRSS to function. The first section provides a brief introduction of the UGRSS and a description of the interface between the UGRSS, NEMS, and OGSM. The resource base is categorized in detail in the next section. The justification is detailed for the modifications made by ARI to the existing USGS data, and some background is provided for the new plays that are introduced in the new model. An explanation of how the total resource is derived through equations is summarized and described more fully in the section dealing with technologies. The third section deals with the price and cost components of the UGRSS. Justifications are provided for each price and cost variable that effects the model output. The fourth section describes the output of the model and how the model's output in the base year is built upon and either grows or shrinks over time. Further description of how the equations of the model change from the base case year to subsequent years is provided in this section. The final section describes the technology variables. This section illustrates how different technologies apply to different plays and unconventional gas resource types and how adjustments to these technologies affect the output of the model.

INTRODUCTION

The UGRSS was developed offline from EIA's mainframe OGSM as a standalone model entitled Model of Unconventional Gas Supply (MUGS). It was then programmed as a submodule of the OGSM. A methodology was developed within OGSM to enable it to readily import and manipulate the UGRSS output, which consists essentially of detailed production/reserve/drilling tables disaggregated by the 17 regions within the Natural Gas Transmission and Distribution Module (NGTDM) and by the 6 onshore regions of the OGSM.

The general process flow diagram for the UGRSS is provided in Figure 4C-7. Within each of the 6 Lower-48 State regions, as defined by OGSM; reservoir, cost and technology information were collected to analyze the economics of producing unconventional gas. The UGRSS utilizes price information received from the NGTDM via the OGSM to generate reserve additions and production response based on economic and supply potential.

Figure 4C-7. UGRSS General Process Flow Diagram

Energy Information Administration/Oil and Gas Supply Module Documentation
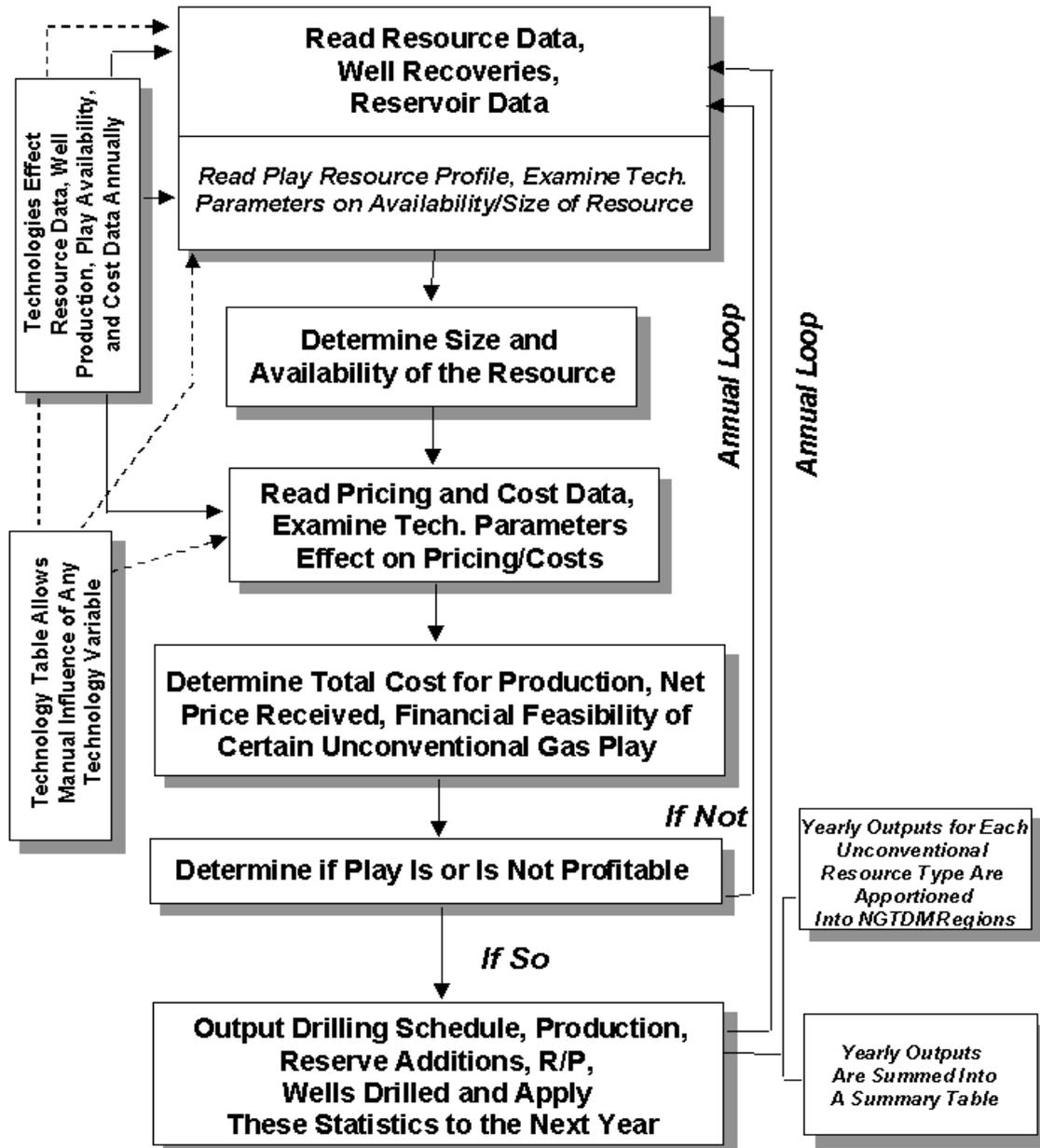
The USGS estimates 352 trillion cubic feet (TCF) of continuous-type resources for the onshore US, allocating 50 TCF to coalbed methane, 39 TCF to gas shales and 263 TCF to gas in tight sands. Based on these estimates unconventional gas (the USGS uses the term continuous-type resources) holds about 100 TCF more technically recoverable resources than conventional gas. Other studies also quantified the amount of unconventional gas resources. The National Petroleum Council (NPC) allocated 1,065 TCF to unconventional gas resources in its 1992 study.

Advanced Resources International (ARI) incorporated much of the resource information used in The UGRSS from the 1995 USGS US Oil and Gas Resource Assessment. ARI also used the NPC and it own studies as reference data to track historical unconventional resource data and to illustrate how the outlook concerning unconventional gas has changed over the last ten years. After analyzing these studies, ARI chose the specific basins and plays it viewed as important producing or potential unconventional gas areas. Some of these plays included in The UGRSS were not quantitatively assessed in the USGS study. These plays include the deep coalbed methane in the Green River Basin, the Barnett Shale of the Fort Worth Basin and the Tertiary-age and Upper Cretaceous-age tight sands of the Wind River Basin. For these resource estimates, ARI gathered basin and play information from expert sources and added these specific plays to the resource base.

RESOURCE BASE

The resource base is established in the first year of the UGRSS and is built upon in each year to produce model outputs. The underlying resource base does not change but it is affected specifically by technology. The static resource base elements and the definitions are presented here:

PNUM	=	Play Number: The play number established by ARI
BASLOC	=	Basin Location: The basin and play name
BASAR	=	Basin Area: Area in square miles
DEV_CEL	=	Developed Cells: Number of locations already drilled
WSPAC_CT	=	Well Spacing - Current Technology: Current spacing in acres
WSPAC_AT	=	Well Spacing - Advanced Technology: Spacing in acres under Advanced Technology
SZONE	=	Stimulation Zones: Number of times a single well is stimulated in the play
AVGDPTH	=	Average Depth: Average depth of the play
CTUL	=	Undrilled Locations - Current Technology: Current umber of locations available to drill

$$CTUL = (BASAR*WSPAC\_CT) - (DEV\_CEL)$$

(1)

ATUL = Undrilled Locations - Advanced Technology: Number of locations available to drill under advanced technology

$$ATUL = (BASAR*WSPAC\_AT) - (DEV\_CEL)$$

(2)

WELL PRODUCTIVITY

This section of the unconventional gas model concerns well productivity. The Estimated Ultimate Recovery (EUR) numbers were taken directly from (with some modifications) the USGS 1995 Assessment. ARI placed the base case year estimates in as hard-wire figures and then extrapolated these figures throughout the model as formulas.

For future years, much of the input resource and production numbers in the UGRSS are derived from equations. Year 1 includes many actual measured values because they offer a base of historic information to forecast from. Each is noted in this documentation and the actual number and forecast equation are described.

$RW10_1$ = Reserves per Well for the best 10 percent of the play (year 1): an EUR estimate

$RW20_1$ = Reserves per Well for the next (lesser) 20 percent of the play (year 1): an EUR estimate

$RW30_1$ = Reserves per Well for the next (lesser) 30 percent of the play (year 1): an EUR estimate

$RW40_1$ = Reserves per Well for the worst 40 percent of the play (year 1): an EUR estimate

Though each of these EUR values is an input value in Year 1, future forecasting turns these inputs into formulas that capture the effects of technology on the resource base. These equations will be explained in the technology section.

$MEUR1_{1,1}$ = A weighted average for the EUR values for each (entire) basin

$$MEUR1_{1,1} = (0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1) \qquad (3)$$

$MEUR1_{1,2}$ = A weighted average for the best 30 percent of the wells in the basin
$MEUR1_{1,2}$ = $(0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$

$MEUR1_{1,3}$ = A weighted average for the middle 30 percent of the wells in the basin
$MEUR1_{1,3}$ = $(0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$

$MEUR1_{1,4}$ = A weighted average for the worst 40 percent of the wells in the basin
$MEUR1_{1,4}$ = $(0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$

Where,

Subscript 1 = year count, with 1996=1; years = 1,25
Subscript 2 = basin area
　　1 = total area of basin
　　2 = designated "best area" of the basin
　　3 = designated "average area" of the basin
　　4 = designated "worst area" of the basin

As mentioned above, the equations change for MEUR after the first year. After Year 1, technology enables the basin to be better understood geologically and from a potential productive aspect. As time and technology move forward the model high grades each basin into a best, average, and worst area. As the understanding of the basin develops over time and technological advancement, the best area moves toward the best 10 percent and 20 percent EUR value, the average area stays consistent with the middle 30 percent EUR value and the worst part of the basin slowly downgrades to the bottom 40 percent EUR value. This process uses the following equations:

$MEUR1_{iyr,2}$ for the best 30 percent of the wells in the basin :

$$MEUR1_{iyr,2} \quad =MEUR1_{iyr,1}+(((((RW10_1*(1/3))+(RW20_1*(2/3)-MEUR1_{1,1}))/DEVPER) \\ *TECHYRS)*(TECHYRS*(REDAM\ percent/20)+TECHYRS* \\ (FRCLEN\%/20)+TECHYRS*(PAYCON\%/20)+1))$$

(4)

$MEUR1_{iyr,3}$ for the middle 30 percent of the wells in the basin :

$$MEUR1_{iyr,3} \quad = \quad RW30_{iyr}$$

(5)

$MEUR1_{iyr,4}$ for the worst 40 percent of the wells in the basin :

$$MEUR1_{iyr,4} \quad = \quad MEUR1iyr,1)-(((RW30_1-RW40_1)/DEVPER)*TECHYRS) \\ *(TECHYRS*(REDAM\%/20)+TECHYRS*(FRCLEN\%/20) \\ +TECHYRS*(PAYCON\%/20)+1)$$

(6)

MEUR2	=	For Coalbed Methane, "MEUR1" adjusted for technological progress in the development of New Cavity Fairways (explained in more detail in the Technology Section - Appendix 4-D)
MEUR3	=	For Enhanced Coalbed Methane, "MEUR2" adjusted for technological progress in the commercialization of Enhanced Coalbed Methane (explained in more detail in the Technology Section - Appendix 4-D)
$SCSSRT_1$	=	Success Rate : The ratio of successful wells over total wells drilled (This can also be called the dry hole rate if you use the equation 1 - SCSSRT). Though each of these SCSSRT values is an input value in Year 1, future forecasting turns these inputs into formulas that capture the effects of technology on the resource base. These equations will be explained in the technology section.
DEVPER	=	Development period for "Favorable Settings" technological advances
REDAM%	=	Total percentage increase over development period due to advances in "Reduced Damage D&S" technology

<table>
<tr><td>FRCLEN%</td><td>=</td><td>Total percentage increase over development period due to advances in "Increased Fracture Length L&C" technology</td></tr>
<tr><td>PAYCON%</td><td>=</td><td>Total percentage increase over development period due to advances in "Improved Pay Contact" technology</td></tr>
<tr><td>TECHYRS</td><td>=</td><td>Number of years (from base year) over which incremental advances in indicated technology have occurred</td></tr>
<tr><td>PLPROB</td><td>=</td><td>The play probability: Only hypothetical plays have a PLPROB < 100 percent.</td></tr>
<tr><td>PLPROB2</td><td>=</td><td>The play probability adjusted for technological progress, if initial play probability less than 1</td></tr>
<tr><td>TRW</td><td>=</td><td>The amount of technically recoverable wells available regardless of economic feasibility. Though each of these TRW values is an input value in Year 1, future forecasting turns these inputs into formulas that capture the effects of technology on the resource base. These equations will be explained in the technology section.</td></tr>
</table>

$$\text{TRW} \quad = \quad (\text{ATUL*SCSSRT*PLPROB2}) \tag{7}$$

UNDEV_RES =   Undeveloped resources: This formula remains constant throughout the model.

$$\text{UNDEV\_RES} = \quad (\text{MEUR3*TRW}) \tag{8}$$

RESNPROD_{iyr} =   Reserves and Production: This is an input number for Year 1 but changes into the following formula for subsequent years.

$$\text{RESNPROD}_{iyr} = \quad \text{RESNPROD}_{iyr-1} + \text{RESADD}_{iyr-1} \tag{9}$$

URR =   Ultimate Recoverable Resources: This formula remains constant throughout the model.

$$\text{URR} \quad = \quad (\text{RESNPROD+UNDEV\_RES}) \tag{10}$$

ECONOMICS AND PRICING

The next section of the unconventional gas model focuses on economic and pricing of the different types of unconventional gas. The pricing section involves many variables and is impacted by technology. Prices, though put in as absolute numbers, are able to be changed to suit the desired economic conditions of the user.

DIS_FAC = Discount Factor: This is the discount factor[1] that is applied to the EUR for each well. The discount factor is based on the Present Value of a production stream from a typical coalbed methane, tight sands, or gas shales well over a 20 year period. The stream is discounted at a rate of 15 percent. Both the production stream and the discount rate are variables that are easily modified.

DISCRES = Discounted Reserves: The mean EUR per well multiplied by the discount factor.

$$DISCRES = (DIS\_FAC * MEUR3)$$ (11)

WHGP = Wellhead Gas Price: The price stream is a variable provided by EIA. This variable is input for each year.

BASNDIF = Basin Differential: This is a sensitivity on the gas price at a basin level. Depending on their proximity to market and infrastructure, the price varies throughout the country. The numbers are constant throughout the model.

ENPVR = Expected NPV Revenues: Gives the value of the entire discounted production stream for one well in real $.

$$ENPVR = (WHGP + BASNDIF) * DISCRES * 1,000,000$$ (12)

DAC = Drilling and completion costs

DACC = IF AVGDPTH less than 2000 feet:
DACC = AVGDPTH*DCC_L2K+DCC_G&G
IF AVGDPTH equal to or greater than 2000 feet:
DACC = 2000*DCC_L2K+(AVGDEPTH-2000)
*DCC_G2K)+DCC_G&G   (13)

DCC_L2K = Cost per foot, well is less than 2000 feet.
DCC_G2K = Cost per foot, well is greater than 2000 feet.
DCC_G&G = Land / G&G Costs

---

[1]The definition for the discount factor is found in the appendix.

The following table represents drilling costs for Coalbed Methane:

Table 4C-6. Drilling Costs for Coalbed Methane

Well Depth	Well Cost	Land / G&G Costs
< 2000 feet	$60.00 / foot	$10,000
> 2000 feet	$80.00 / foot	$10,000

Drilling Costs were calculated by basin for Tight Sands and Gas Shales because of the differing depths among basins and differing state regulations. The formulas for drilling cost equations are similar for tight sands and gas shales; the average depth of the play is established and at that depth a calculation is made adding a fixed cost to a variable cost per foot.

The following tables represent drilling costs for Tight Sands and Gas Shales:

Table 4C-7. Drilling Costs for Tight Sands

UTAH - Uinta Basin		
Depth	fixed cost	variable cost $/ft
0-2500	20000	40
2500-5000	50000	50
5000-7500	50000	60
7500-10000	50000	70
10000-12500	50000	80
12500-15000	50000	95
15000-20000	50000	240
WYOMING - Wind River, Greater Green River Basins		
Depth	fixed cost	variable cost $/ft
0-2500	20000	50
2500-5000	50000	40
5000-7500	50000	50
7500-10000	50000	60
10000-12500	50000	65
12500-15000	50000	95
15000-20000	50000	242

Table 4C-7. Drilling Costs for Tight Sands

COLORADO - Piceance, Denver Basins			
	Depth	fixed cost	variable cost $/ft
	0-2500	20000	46
	2500-5000	50000	34
	5000-7500	50000	43
	7500-10000	50000	48
	10000-12500	50000	73
	12500-15000	50000	150
	15000-20000	50000	200
NEW MEXICO - WEST (Rockies) - San Juan Basin			
	Depth	fixed cost	variable cost $/ft
	0-2500	20000	47
	2500-5000	50000	53
	5000-7500	50000	54
	7500-10000	50000	75
	10000-12500	50000	-
	12500-15000	50000	-
	15000-20000	50000	-
NEW MEXICO - East - AZ, SW			
	Depth	fixed cost	variable cost $/ft
	0-2500	20000	-
	2500-5000	50000	45
	5000-7500	50000	65
	7500-10000	50000	67
	10000-12500	50000	70
	12500-15000	50000	89
	15000-20000	50000	117

Table 4C-7. Drilling Costs for Tight Sands

APPALACHIA - Appalachian Basin			
	Depth	fixed cost	variable cost $/ft
	0-2500	30000	30
	2500-5000	30000	25
	5000-7500	30000	25
	7500-10000	30000	25
	10000-12500	30000	-
	12500-15000	30000	-
	15000-20000	30000	-
LA/MS/TX Salt Basins - Cotton Valley / Travis Peak			
	Depth	fixed cost	variable cost $/ft
	0-2500	10000	30
	2500-5000	20000	32
	5000-7500	20000	53
	7500-10000	20000	90
	10000-12500	20000	90
	12500-15000	20000	95
	15000-20000	20000	-
ARKANSAS/OKLAHOMA/TEXAS - Arkoma / Anadarko Basins			
	Depth	fixed cost	variable cost $/ft
	0-2500	10000	63
	2500-5000	20000	47
	5000-7500	20000	50
	7500-10000	20000	57
	10000-12500	20000	73
	12500-15000	20000	87
	15000-20000	20000	88

Table 4C-7. Drilling Costs for Tight Sands

MONTANA - Northern Great Plains Basins			
	Depth	fixed cost	variable cost $/ft
	0-2500	20000	30
	2500-5000	20000	30
	5000-7500	20000	-
	7500-10000	20000	-
	10000-12500	20000	-
	12500-15000	20000	-
	15000-20000	20000	-
TX - Texas Gulf Basins -- Wilcox/Lobo, Vicksburg, Olmos			
	Depth	fixed cost	variable cost $/ft
	0-2500	10000	24
	2500-5000	20000	26
	5000-7500	20000	37
	7500-10000	20000	63
	10000-12500	20000	122
	12500-15000	20000	163
	15000-20000	20000	217
TX / NM - Permian Basin -- Canyon Sands			
	Depth	fixed cost	variable cost $/ft
	0-2500	10000	-
	2500-5000	20000	44
	5000-7500	20000	50
	7500-10000	20000	50
	10000-12500	20000	67
	12500-15000	20000	110
	15000-20000	20000	188

Table 4C-7. Drilling Costs for Tight Sands

TX / NM - Permian Basin -- Abo		
Depth	fixed cost	variable cost $/ft
0-2500	10000	-
2500-5000	20000	54
5000-7500	20000	70
7500-10000	20000	71
10000-12500	20000	72
12500-15000	20000	91
15000-20000	20000	119

Table 4C- 8. Drilling Costs for Gas Shales

MI - Antrim Shale Wells		
Depth	fixed cost	variable cost $/ft
0-2500	20000	60
2500-5000	20000	100
5000-7500	20000	120
7500-10000	20000	130
10000-12500	20000	-
12500-15000	20000	-
15000-20000	20000	-

STIMC   =   Stimulation Costs: Provides the cost of stimulating a well in the specific basin by multiplying the given average stimulation cost by the number of stimulation zones.

STIM_CST   =   Variable average cost of stimulating one zone. (Number of zones is a variable)

$$STIMC \quad = \quad (SZONE*STM\_CST) \tag{14}$$

PASE   =   Pumping and Surface Equipment Costs: Determines if the play requires H_2O disposal, adds the variable pumping and surface equipment cost, and multiplies the average depth (if so) to the variable tubing cost of $5 / foot. If not, a flat variable is added.

$$
\begin{aligned}
\text{PASE} \quad = \quad &\text{IF WATR\_DISP equal to 1:} \\
&\text{PASE} \;=\; \text{BASET}+5*\text{AVGDPTH} \\
&\text{IF WATR\_DISP not equal to 1:} \\
&\text{PASE} \;=\; 10{,}000
\end{aligned}
\tag{15}
$$

BAS

ET = Variable cost of Pumping and Surface equipment when H_2O disposal is required.

    LSE_EQ = Lease Equipment Costs: Established if H2O disposal is needed and adds this fee (if so) to the variable Lease Equipment costs depending on MEUR.

$$
\begin{aligned}
\text{LSE\_EQ} \quad = \quad &\text{IF WATR\_DISP equal to 1:} \\
&\quad \text{IF MEUR3 less than 0.5:} \\
&\quad \text{LSE\_EQ} \;=\; \text{WOMS\_LE}+\text{WOML\_WTR} \\
&\quad \text{IF MEUR3 greater than or equal to 0.5:} \\
&\qquad \text{IF MEUR3 less than or equal to 1:} \\
&\qquad \text{LSE\_EQ} \;=\; \text{WOMM\_LE}+ \\
&\qquad\qquad\qquad\qquad \text{WOML\_WTR} \\
&\qquad \text{IF MEUR3 greater than 1:} \\
&\qquad \text{LSE\_EQ} \;=\; \text{WOML\_LE}+ \\
&\qquad\qquad\qquad\qquad \text{WOML\_WTR} \\
&\text{IF WATR\_DISP equal to 0:} \\
&\quad \text{IF MEUR3 less than 0.5:} \\
&\quad \text{LSE\_EQ} \;=\; \text{WOMS\_LE} \\
&\quad \text{IF MEUR3 greater than or equal to 0.5:} \\
&\qquad \text{IF MEUR3 less than or equal to 1:} \\
&\qquad \text{LSE\_EQ} \;=\; \text{WOMM\_LE} \\
&\qquad \text{IF MEUR3 greater than 1:} \\
&\qquad \text{LSE\_EQ} \;=\; \text{WOML\_LE}
\end{aligned}
\tag{16}
$$

    WATR_DISP = Establishes whether or not (and degree to which) water disposal is required (No Disposal=0; Maximum Disposal=1)
    WOMS_LE = Small Well Lease Equipment Costs
    WOMM_LE = Medium Well Lease Equipment Costs
    WOML_LE = Large Well Lease Equipment Costs
    WOML_WTR = Water Producing Well Lease Equipment Costs

The matrix for Lease Equipment costs and EUR is shown below:

Table 4C-9. Lease Equipment Costs Matrix

Well Size (EUR)	Lease Equip	Water
Well O&M Small Well - <0.5 Bcf	$ 50,000	$ 50,000
Well O&M Medium Well - <1.0 Bcf	$ 75,000	$ 50,000
Well O&M Large Well - >1.0 Bcf	$ 120,000	$ 50,000

GAA10   =   G&A Costs: Adds on a variable G&A cost

$$ GAA10 \quad = \quad RST*(LSE\_EQ+ PASE+ STIMC+ DACC) \tag{17} $$

RST   =   Variable G&A Cost - Currently 10 percent

TCC   =   Total Capital Costs: The sum of Stimulation Costs, Pumping and Surface Equipment Costs, Lease Equipment Costs, G&A Costs and Drilling and Completion Costs

$$ TCC \quad = \quad DACC+STIMC+PASE+LSE\_EQ+GAA10 \tag{18} $$

DHC   =   Dry Hole Costs: Calculates the dry hole costs

$$ DHC \quad = \quad (DACC+STIMC) * ((1/SCSSRT)-1) \tag{19} $$

CCWDH   =   Capital Costs with Dry Hole Costs: Combines these two costs and converts into $/Mcf

$$ CCWDH \quad = \quad (TCC+DHC)/(DISCRES*1,000,000) \tag{20} $$

VOC	=	Variable Operating Costs: Establishes if the play requires H_2O disposal and adds the appropriate cost (\$/Mcf)

$$
\begin{aligned}
\text{VOC} \quad = \quad & \text{IF WATR\_DISP greater than 0.4:} \\
& \text{VOC} \quad = \quad (\text{WTR\_DSPT}*(\text{TECHYRS})*(\text{WDT\%}/20)) \\
& \qquad\qquad\qquad +((\text{WOMS})*(\text{TECHYRS})*(\text{PUMP\%}/20)) \\
& \qquad\qquad\qquad +((\text{GASTR})*(\text{TECHYRS})*(\text{GTF\%}/20)) \\
& \qquad\qquad\qquad +(\text{OCWW\$}) \\
& \text{IF WATR\_DISP less than or equal to 0.4:} \\
& \text{VOC} \quad = \quad (\text{WTR\_DSPT}*(\text{TECHYRS})*(\text{WDT\%}/20)) \\
& \qquad\qquad\qquad +((\text{WOMS})*(\text{TECHYRS})*(\text{PUMP\%}/20)) \\
& \qquad\qquad\qquad +((\text{GASTR})*(\text{TECHYRS})*(\text{GTF\%}/20)) \\
& \qquad\qquad\qquad +(\text{OCNW\$})
\end{aligned}
\qquad (21)
$$

WTR_DSPT	=	Water Disposal Fee: \$0.05
WDT%	=	Total percentage decrease in H_2O disposal and treatment costs over the development period due to technological advances
WOMS	=	H_2O Costs, Small Well
PUMP%	=	Total percentage decrease in pumping costs over the development period due to technological advances
TECHYRS	=	Number of years (from base year) over which incremental advances in indicated technology have occurred
GASTR	=	Gas Treatment and Fuel costs - \$0.25
GTF%	=	Total percentage decrease in gas treatment and fuel costs over the development period due to technological advances
OCWW\$	=	Operating Costs with H_2O - \$0.30
OCNW\$	=	Operating Costs without H_2O - \$0.25
VOC2	=	Variable Operating Costs: Establishes an extra operating cost for plays that will incorporate the technology of Enhanced CBM in the future

$$
\begin{aligned}
\text{VOC2} \quad = \quad & \text{If ECBMR is equal to 1:} \\
& \text{VOC2} \quad = \quad (\text{VOC}+((\text{ECBM\_OC}+\text{VOC})*(\text{ENH\_CBM\%}))/ \\
& \qquad\qquad\qquad (1+\text{ENH\_CBM\%})) \\
& \text{If ECBMR is not equal to 1:} \\
& \text{VOC2} \quad = \quad \text{VOC}
\end{aligned}
\qquad (22)
$$

ECBM_OC	=	Enhanced CBM Operating Costs Variable - \$1.00
ENH_CBM%	=	Enhanced CBM EUR Percentage gain

FOMC = Fixed Operating and Maintenance Costs: (1) Establish whether or not the play requires H2O disposal; (2) determine the size of the reserves / well (EUR); (3) calculate the Fixed O&M Costs for the well

$$
\begin{aligned}
\text{FOMC} = \quad &\text{If WATR\_DISP is greater than or equal to 0.5:} \\
&\quad \text{If MEUR3 is less than or equal to .5:} \\
&\quad\quad \text{FOMC} = \text{DIS\_FACT*WOMS\_OMW+} \\
&\quad\quad\quad\quad\quad\quad \text{VOC* (DISCRES*1,000,000)} \\
&\quad \text{If MEUR3 is greater .5 and less than or equal to 1:} \\
&\quad\quad \text{FOMC} = \text{DIS\_FACT*WOMM\_OMW} \\
&\quad\quad\quad\quad\quad\quad \text{+VOC*(DISCRES*1,000,000)} \\
&\quad \text{If MEUR3 is greater than 1:} \\
&\quad\quad \text{FOMC} = \text{DIS\_FACT*WOML\_OMW} \\
&\quad\quad\quad\quad\quad\quad \text{+VOC*(DISCRES*1,000,000)} \\
&\text{If WATR\_DISP is less than 0.5:} \\
&\quad \text{If MEUR3 is less than or equal to .5:} \\
&\quad\quad \text{FOMC} = \text{.6*DIS\_FACT*WOMS\_OMW+VOC*} \\
&\quad\quad\quad\quad\quad\quad \text{(DISCRES*1,000,000)} \\
&\quad \text{If MEUR3 is greater .5 and less than or equal to 1:} \\
&\quad\quad \text{FOMC} = \text{.6*DIS\_FACT*WOMM\_OMW+VOC*} \\
&\quad\quad\quad\quad\quad\quad \text{(DISCRES*1,000,000)} \\
&\quad \text{If MEUR3 is greater than 1:} \\
&\quad\quad \text{FOMC} = \text{.6*DIS\_FACT*WOML\_OMW+VOC*} \\
&\quad\quad\quad\quad\quad\quad \text{(DISCRES*1,000,000)}
\end{aligned}
$$

(23)

Table 4C-10. Operation and Maintenance Costs Matrix

Operation & Maintenance Costs	WOM*_OMW H_2O	WOM*_OM No H_2O
Well O&M <0.5 Bcf	$ 180,000	$ 108,000
Well O&M <1.0 Bcf	$ 270,000	$ 162,000
Well O&M >1.0 Bcf	$ 360,000	$ 216,000

WOMS_OMW = Operating & Maintenance - Small well with H_2O disposal
WOMM_OMW = Operating & Maintenance - Medium well with H_2O disposal
WOML_OMW = Operating & Maintenance - Large well with H_2O disposal
WOMS_OM = Operating & Maintenance - Small well without H_2O disposal
WOMM_OM = Operating & Maintenance - Medium well without H_2O disposal
WOML_OM = Operating & Maintenance - Large well without H_2O disposal

TOTL_CST = Total Costs ($/Mcf): Calculates the total costs of producing the gas in ($/Mcf)

TOTL_CST = CCWDH+FOMC/(DISCRES*1,000,000)

(24)

NET_PRC   =   Net Price ($/Mcf): Calculates the Royalty & Severance Tax on the gas price

$$NET\_PRC = (1-RST)*(WHGP+BASNDIF) \tag{25}$$

RST   =   Variable Royalty and Severance Tax - Set at 17 percent

NET PROFITABILITY

The next section of the unconventional gas model focuses on profitability. The profitability of the play drives the model outputs. The better the economics of the play, the faster it will be developed so that the operator will maximize the potential economic profit.

NET_PROF   =   Net Profits ($/Mcf): Calculates whether or not the play is profitable under the current variable conditions

$$NET\_PROF = NET\_PRC - TOTL\_CST \tag{26}$$

NET_PROF2   =   Net Profits: Allows only the profitable plays to become developed.

NET_PROF2   =   If NET_PROF is greater than 0:
NET_PROF2   =   NET_PROF
If NET_PROF is less than or equal to 0:
NET_PROF2   =   0   (27)

MODEL OUTPUTS

The last section of the unconventional gas model supplies the user with yearly model outputs by basin.

UNDV_WELS = Undeveloped Wells: (1) Establish whether or not the play is profitable and therefore ready for development; (2) establish whether or not environmental or pipeline regulations exist for the play; (3) If regulations exist, restrict a certain percentage (50 percent) of the play from development; (4) If regulations do not exist, allow the entire play can be developed.

UNDV_WELLS   =   If NET_PROF is greater than 0:
                          IF ENPRGS   =   1:
                          UNDV_WELLS   =   TRW*(ENV%+
                                                                      LOW%/LOWYRS
                                                                      *TECHYRS)
                          IF ENPRGS   =   0:   (28)
                          UNDV_WELLS   =   TRW
                      If NET_PROF is less than or equal to 0:
                      UNDV_WELLS   =   0

ENPRGS   =   Establishes if the play is pipeline or environmentally regulated.
ENV%   =   The percentage of the play that is not restricted from development due to environmental or pipeline regulations
LOW%   =   The percentage of the play that is restricted from development due to environmental or pipeline regulations
LOWYRS   =   The number of years the environmental and or pipeline regulation will last.

MEUR4   =   Mean EUR: This variable establishes whether or not the play is profitable and if so, allows the EUR to appear for development.

MEUR4   =   If NET_PROF is greater than 0:
                    MEUR4   =   MEUR3
                    If NET_PROF is less than or equal to 0:   (29)
                    MEUR4   =   0

PROV_RES   =   Proved Reserves: This variable is a plugged number in the first year to equate with the EIA published figure
RP_RAT   =   Reserves-to-Production (R/P) Ratio: This variable is the current R/P ratio. For some plays this is a plugged number in the first year.

PROD   =   Current Production: This variable is a plugged number in the first year to equate with the EIA published figure

DRL_SCHED =   Drilling Schedule: This variable determines the drilling schedule for the play. The drilling schedule is dependent upon the profitability of the play.

```
DRL_SCHED  =  If HYP% is equal to 0:
                    If NET_PROF2 is less than or equal to 0:
                    DRL_SCHED  =       0
                    If NET_PROF2 is greater than 0:
                            If NET_PROF2 is less than LOW$:
                            DRL_SCHED  =       USLOW
                            If NET_PROF2 is greater than or equal to LOW$:
                                    If NET_PROF2 is less than SMAL$:
                                    DRL_SCHED  =       SLOW
                                            If NET_PROF2 is greater thanor equal to SMAL$:
                                                    If NET_PROF2 is less than MED$:
                                                    DRS_SCHED   =MED
                                                    If NET_PROF2 is greater than or equal
                                                    to MED$:
                                                            If NET_PROF2 is less than LAR$:
                                                            DRL_SCHED=FAST
                                                            If NET_PROF2 is greater than or
                                                            equal to LAR$:
                                                            DRL_SCHED=UFAST
                    If HYP% is not equal to 0:
                    DRL_SCHED          =       0
```
(30)

HYP% = Establishes whether or not the play is hypothetical

Table 4C-11. Drilling Rules Matrix

	Drilling Rules		
Net Profitability		Drilling Schedule in Years	
LOW$	0.25	USLOW	40
SMAL$	0.5	SLOW	30
MED$	0.75	MED	20
LAR$	1	FAST	10
XLAR$	>1.00	UFAST	10

DRL_SCHED2 =   Drilling Schedule: This variable allows technology advancement to effect the drilling schedule

DRL_SCHED2   =   If DRL_SCHED is greater than 0:
        If EMRG is equal to 1:
        DRL_SCHED2 =   (DRL_SCHED+
        EMERG%)-
        EMERG#
        If EMRG is not equal to 1:
        DRL_SCHED2 =   DRL_SCHED
If DRL_SCHED is less than or equal to 0:
DRL_SCHED2 =   0

(31)

EMRG   =   The parameter that determines if the play is an emerging basin. This designation was made by ARI.
EMERG%   =   The number of years added onto the drilling schedule because of the hindrance of the play being an emerging basin.
EMERG#   =   The number of years taken off the drilling schedule for an advancement in technology.

DRL_SCHED3 =   Drilling Schedule: This variable calculates and justifies the technology impacts of the previous two Drilling Schedule variables to ensure that the proper drilling schedule is positive.

DRL_SCHED3 =   If DRL_SCHED2 is less than DRL_SCHED:
        DRL_SCHED3 =   DRL_SCHED
        If DRL_SCHED2 is greater than or equal to DRL_SCHED:
        DRL_SCHED3 =   DRL_SCHED2

(32)

NW_WELLS   =   New Wells: The amount of wells drilled for the play in that year

NW_WELLS   =   If DRL_SCHED3 is greater than 0:
        NW_WELLS   =   UNDV_WELLS/DRL_SCHED3
        If DRL_SCHED3 is less than or equal to 0:
        NW_WELLS   =   0

(33)

NW_WELLS2 = New Wells2: This variable ensures the wells drilled is a positive number

NW_WELLS2 =	If UNDV_WELLS is less than NW_WELLS: NW_WELLS2 = UNDV_WELLS If UNDV_WELLS is greater than or equal to NW_WELLS: NW_WELLS2 = NW_WELLS	(34)

DRA = Drilled Reserve Additions: This variable establishes the existence of reserve additions in plays that have had development in that year.

DRA = NW_WELLS2*MEUR4		(35)

RGA = Reserve Growth Additions: This variable establishes if the play will have reserve growth and then allocates an appropriate amount for the play.

RGA =	If RES_GR is equal to 1: RGA = RGR*PROV_RES: If RES_GR is not equal to 1: RGA = 0	(36)

RES_GR = Establishes whether or not the play will have reserve growth. These parameters are explained in the technology section.

RGR = Reserve Growth Rate

R_ADD = Total Reserve Additions:This variable sums the Drilled Reserves and the Reserve Growth

R_ADD = DRA+RGA		(37)

PROV_RES2 = Proved Reserves for the next year: This variable calculates the reserves for the coming year from the calculation of occurrences during the year. This variable is an input in Year 1 but then turns into a formula.

$$
\boxed{
\begin{array}{lll}
\text{PROV\_RES2} & = & \text{If (PROV\_RES+R\_ADD-PROD) is greater than 0:} \\
& & \text{PROV\_RES2} \quad = \quad \text{PROV\_RES+R\_ADD-PROD} \\
& & \text{If (PROV\_RES+R\_ADD-PROD) is less than or equal to 0:} \\
& & \text{PROV\_RES2} \quad = \quad 0
\end{array}
}
\tag{38}
$$

RP_RAT2 = R/P Ratio for the next year: This variable establishes the R/P ratio for the next year by subtracting one from the current R/P, not allowing the R/P to drop under a specified limit.

$$
\boxed{
\begin{array}{lll}
\text{RP\_RAT2} & = & \text{If R/P is greater than 10:} \\
& & \text{RP\_RAT2} \quad = \quad \text{RP\_RAT-1} \\
& & \text{If R/P is less than or equal to 10:} \\
& & \text{RP\_RAT2} \quad = \quad \text{RP\_RAT}
\end{array}
}
\tag{39}
$$

PROD2 = Production for the next year: This variable establishes production for the next year using the new R/P ratio

$$
\boxed{
\begin{array}{lll}
\text{PROD2} & = & \text{If R/P2 is equal to 0:} \\
& & \text{PROD2} \quad = \quad 0 \\
& & \text{If R/P2 is not equal to 0:} \\
& & \text{PROD2} \quad = \quad \text{PROV\_RES2/(RP\_RAT2)}
\end{array}
}
\tag{40}
$$

UNDV_WELLS2 = Undeveloped wells available to be drilled for the next year

$$
\boxed{
\begin{array}{lll}
\text{UNDV\_WELLS2} & = & \text{If ENPRGS is equal to 1:} \\
& & \text{UNDV\_WELLS2} \quad = \quad \text{TRW-NW\_WELLS2} \\
& & \text{If ENPRGS is not equal to 1:} \\
& & \qquad \text{If UNDV\_WELLS is equal to 0:} \\
& & \qquad \text{UNDV\_WELLS2} \quad = \quad 0 \\
& & \qquad \text{If UNDV\_WELLS is not equal to 0:} \\
& & \qquad\qquad \text{If (UNDV\_WELLS-NW\_WELLS2) is} \\
& & \qquad\qquad \text{equal to 0:} \\
& & \qquad\qquad \text{UNDV\_WELLS2} \quad = \quad 0.1 \\
& & \qquad\qquad \text{If (UNDV\_WELLS-NW\_WELLS2) is} \\
& & \qquad\qquad \text{not equal to 0:} \\
& & \qquad\qquad \text{UNDV\_WELLS2} \quad = \\
& & \qquad\qquad\qquad\qquad\qquad \text{UNDV\_WELLS} \\
& & \qquad\qquad\qquad\qquad\qquad \text{-NW\_WELLS2}
\end{array}
}
\tag{41}
$$

Appendix 4-D. Unconventional Gas Recovery Supply Technologies

I.   INTRODUCTION

The Unconventional Gas Recovery Supply Submodule (UGRSS), shown in **Figure 4D-1**, relies on the Technology Impacts and Timing functions to capture the effects of technology progress on the costs and rates of gas production from Coalbed Methane, Gas Shales, and Tight Sands. The numerous research and technology initiatives are grouped into eleven specific "technology packages," that encompass the full spectrum of key disciplines -- geology, engineering, operations and the environment. The enclosed materials define these eleven technology packages for unconventional gas exploration and production (E&P).

The technology packages are grouped into four distinct technology cases -- Reference Case, Low Technology, High Technology, and Reference Case without Department of Energy (DOE) research and development (R&D)-- that capture four different futures for technology progress, as further described below:

- **Reference Case** captures the current status and trends in the E&P technology for unconventional gas. A limited amount of R&D on Tight Sand reservoirs is directly supported by the DOE, particularly on advanced macro-exploration, seismic technologies and matching of technology to reservoir settings. The Gas Research Institute (GRI) R&D program funds valuable studies of emerging and future gas plays and supports advanced well stimulation technology. Also, direct R&D on CBM has been funded by the DOE SBIR program for CBM cavitation technology. In addition to the directly funded R&D, considerable indirect R&D by DOE, GRI and others contributes to unconventional gas E&P, particularly on drilling cost reductions, re-stimulation opportunities, produced gas and water treatment, and environmental mitigation. However, overall technology progress in unconventional gas has slowed noticeably with the phase-out of formal R&D on this topic by GRI and the United States Geological Survey (USGS).

- **Low Technology** captures the pace of technology progress assuming only industry supported R&D and continuing reductions in corporate R&D budgets. With the scale-back in major company R&D outlays and the dominance of independent producers, who fund little R&D in unconventional gas, the pace of technology progress under Low Technology would be, as expected, modest.

- **High Technology** defines strong, focused and integrated industry, DOE and GRI R&D programs in unconventional gas. It reflects the levels of investment and progress achieved during the late 1980's and early 1990's when DOE and GRI R&D programs and industry's own commitment to unconventional gas were high and highly productive.

Figure 4D-1

NEMS Unconventional Gas Recovery Supply Submodule
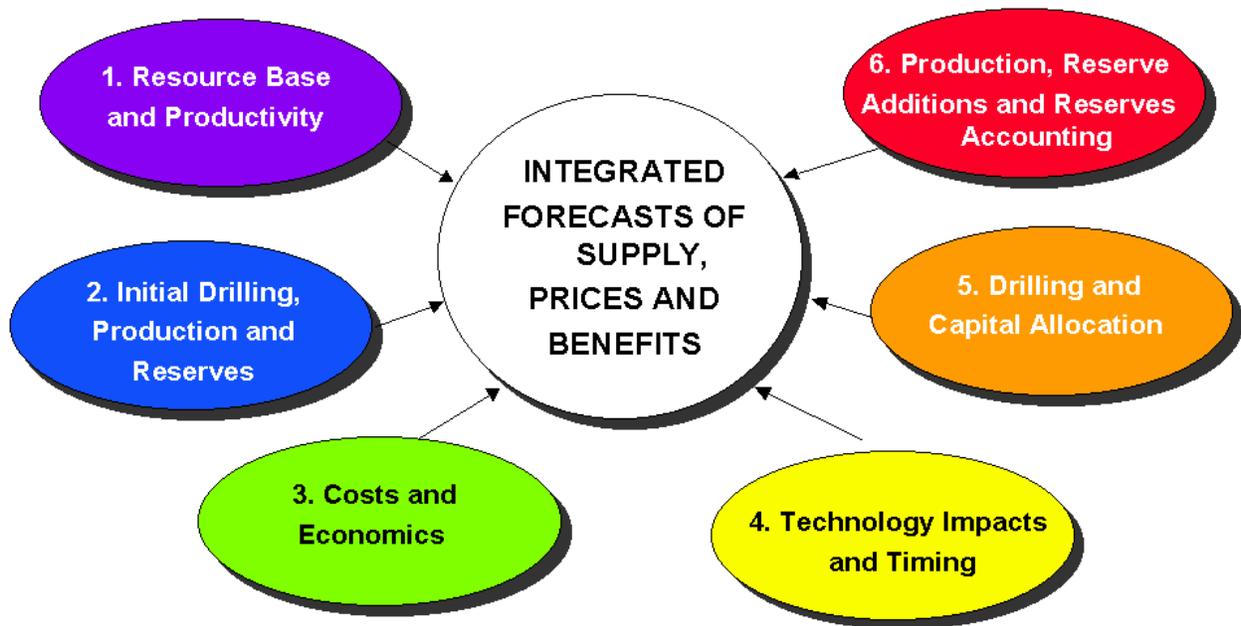
- **Reference Case without DOE R&D** (either direct or indirect) This case evaluates the future of technology progress without the contributions of DOE R&D, keeping all other contributions to the Reference Case fixed. This case can be used to measure the "added value" stemming from DOE's R&D programs in unconventional gas.

The 11 high impact technology packages addressed by the UGRSS are listed below:

1. Increasing the Resource Base with Basin Assessments.

2. Accelerating the Development of Emerging Plays and Expanding the Resource Base with Play Specific, Extended Reservoir Characterization.

3. Improving Reserve Growth in Existing Fields with Advanced Well Performance Diagnostics and Remediation.

4. Improving Exploration Efficiency with Advanced Exploration and Natural Fracture Detection R&D.

5. Increasing Reserves Per Well with Geology/Technology Modeling and Matching.

6. Improving Well Performance with More Effective, Lower Damage Well Completions and Stimulations.

7. Lowering Well Drilling and Completion Costs with Targeted Drilling and Hydraulic Fracturing R&D.

8. Lowering Water Disposal and Gas Treating Costs by using New Practices and Technology.

9. Improving Recovery Efficiencies with Advanced Well Completion Technologies such as Cavitation, Horizontal Drilling and Multi-Lateral Wells.

10. Improving and Accelerating Gas Production with Other Unconventional Gas Technologies, such as Enhanced CBM and Gas Shales Recovery.

11. Mitigating Environmental and Other Constraints that Severely Restrict Development.

The impact each of these 11 R&D packages has on unconventional gas development and the specific "technology lever" used to model these impacts in the Supply and Technology Model is shown on **Table 4D-1**.

Table 4D-1

Summary of Technological Progress

R&D Program	General Impact	Specific Technology Lever
1. Basin Assessments	Increases available resource base	Accelerates time hypothetical plays become available for development
		Increases play probability for hypothetical plays
2. Extended Resource Characterization	Increases pace of new development	Accelerates pace of development for emerging plays
3. Well Performance Diagnostics and	Expands resource base	Extends reserve growth for already proved reserves
4. Exploration and Natural Fracture Detection R&D	Increases success of development	Improves exploration/development success rate for all plays
	Improves exploration efficiency	Improves ability to find best prospects and areas
5. Geology/Technology Modeling & Matching	Matches "Best Available Technology" to play	Improves EURs/Well
6. Improved Drilling and Completion Technology	Improves fracture length and conductivity	Improves EURs/Well
	Reduces drilling and stimulation damage	Improves R/P ratios
7. Lower Cost Drilling and Stimulation	More efficient drilling and stimulation	Lowers well drilling and stimulation capital costs
8. Lower Cost Water and Gas Treating	More efficient gas separation and water	Lowers water and gas treatment O&M costs

Table 4D-1

Summary of Technological Progress

R&D Program	General Impact	Specific Technology Lever
9. Advance Well Completion	Defines applicable plays	Accelerates date technology is available
	Introduces improved version of technology	Increases recovery efficiency
10. Other Recovery Technology	Introduces dramatically new recovery technology	Accelerates date technology is available
		Increases EURs/Well and lowers costs
11. Environmental Mitigation	Removes development constraints in environmentally sensitive basins	Increases basin areas available for for development

The detailed parameter values and expected impacts for each technology case are provided on **Table 4D-2** for Coalbed Methane (CBM), on **Table 4D-3** for Gas Shales, and **Table 4D-4** for Tight Gas Sands.

The remainder of the enclosed materials describe for each technology area: (1) the technical problem(s) currently constraining unconventional gas development; (2) the technology solutions and R&D program being proposed; and, (3) the expected impact and benefits from successful development and implementation of R&D, in terms of increased volumes of lower cost unconventional gas production.

Table 4D-2
Details of Coalbed Methane Technological Progress

R&D Program	CBM Resource Impacted			Technology Cases			
		Technology Lever	Current Situation	Reference Case with DOE	Reference Case w/o DOE	Low Technology	High Technology
1. Basin Assessment	Hypothetical Plays	a. Date Available	Not Available	Year 2016	Same as Reference Case	Not Available	Year 2011
		b. Play Probability	50% to 80% (Play Specific)	No Improvement	Same as Reference Case	No Improvement	+1%/year from 2011 (Max 100%)
2. Extended Resource Characterization	Emerging Basins	Pace of Development	30 to 60 years (+20 years over Developing Basins)	-1 yr/year (Max -20 years)	Same as Reference Case	No Improvement	-2 yrs/year (Max -20 years)
3. Well Performance Diagnostics & Remediation	Proved Reserves	Reserve Growth	All Basins with Proved Reserves @ 3%/yr., declining	All Basins @ 3%/yr., declining (30 years)	Same as Reference Case	All Basins @ 1%/yr., declining (20 years)	All Basins 4%/yr., declining (40 years)
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	25% to 95%	$+\frac{1}{4}$%/year from 2000 (max 95%)	No Improvement	No Improvement	$+\frac{1}{2}$%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify "Best" 30% by Year 2017	No Improvement	No Improvement	Identify "Best" 30% by year 2007
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	$+2\frac{1}{2}$% (in 20 years)	Same as Reference Case	No Improvement	+10% (in 20 years)

Table 4D-2
Details of Coalbed Methane Technological Progress

R&D Program	CBM Resource Impacted	Technology Lever	Current Situation	Technology Cases			
				Reference Case with DOE	Reference Case w/o DOE	Low Technology	High Technology
6. Improved Drilling and Stimulation	All Plays	EUR/Well	As Calculated	+7$\frac{1}{2}$% (in 20 years)	Reference Case	+5% (in 20 years)	+15% (in 20 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-10% (in 20 years)	-5% (in 20 years)	No Improvement	-20% (in 20 years)
8. Water and GasTreating R&D	Wet CBM Plays	Water & Gas Treating O&M Costs/Mcf	$0.30/Mcf	-20%(-$0.06) (in 20 years)	-15%(-$0.015) (in 20 years)	-5%(-$0.015) (in 20 years)	-30%(-$0.09) (in 20 years)
9. Advanced CBM Cavitation	Cavity Fairway Plays	EUR/Well	As Calculated	+20% (year 2011)	No Improvement	No Improvement	+30% (year 2006)
10. Enhanced CBM Recovery	ECBM Eligible Plays	a. Recovery/ Efficiency	As Calculated	+20% (year 2015)	Same as Reference Case	No Improvement	+30% (year 2010)
		b. O&M Costs/Mcf	As Calculated	+$1.00/Mcf, Incremental	Same as Reference Case	N/A	$0.75/Mcf, Incremental
11.Environmental Mitigation	EV Sensitive Plays	Acreage Available	50% of Play Restricted	Removed in 50 years (1%/yr from 2000)	Removed in 100 years (1%/ yr from year 2000)	No Improvement	Removed in 25 years (2%/yr from year 2000)

Table 4D-3
Details of Gas Shales Technological Progress

R&D Program	Gas Shales Resource Impacted	Technology Lever	Current Situation	Technology Cases			
				Reference Case with DOE	Reference Case w/o DOE	Low Technology	High Technology
1. Basin Assessment	Hypothetical Plays	a. Date Available	Not Available	Year 2016	Same as Reference Case	Not Available	Year 2011
		b. Play Probability	50% to 80% (Play Specific)	No Improvement	Same as Reference Case	No Improvement	+1%/year from 2011 (Max 100%)
2. Extended Resource Characterization	Emerging Basins	Pace of Development	30 to 60 years (+20 years over Developing Basins)	-1 yr/year (Max -20 years)	Same as Reference Case	No Improvement	-2 yrs/year (Max -20 years)
3. Well Performance Diagnostics and Remediation	Proved Reserves	Reserve Growth	All Basins with Proved Reserves @ 3%/yr., declining	All Basins @ 3%/yr., declining (30 years)	Same as Reference Case	All Basins @ 1%/yr., declining (20 years)	All Basins 4%/yr., declining (40 years)
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	25% to 95%	$+^1/_4$%/year from 2000 (max 95%)	No Improvement	No Improvement	$+^1/_2$%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify "Best" 30% by Year 2017	No Improvement	No Improvement	Identify "Best" 30% by year 2007
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	$+2^1/_2$% (in 20 years)	Same as Reference Case	No Improvement	+10% (in 20 years)

Table 4D-3
Details of Gas Shales Technological Progress

R&D Program	Gas Shales Resource Impacted	Technology Lever	Current Situation	Technology Cases			
				Reference Case with DOE	Reference Case w/o DOE	Low Technology	High Technology
6. Improved Drilling and Stimulation	All Plays	EUR/Well	As Calculated	+7$^{1}/_{2}$% (in 20 years)	Reference Case	+5% (in 20 years)	+15% (in 20 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-10% (in 20 years)	-5% (in 20 years)	No Improvement	-20% (in 20 years)
8. Water and Gas Treating R&D	All Plays	Water & Gas Treating O&M Costs/Mcf	$0.30/Mcf	-20% (-$0.06/Mcf) (in 20 years)	-15% (-$0.045/Mcf) (in 20 years)	-5% (-$0.015/Mcf) (in 20 years)	-30% (-$0.09/Mcf) (in 20 years)
9. Multi-Lateral Completions	Eligible Plays	Recovery Efficiency	As Calculated	No Improvement	No Improvement	No Improvement	+10% (year 2011)
10. Other Gas Shales Technology	Eligible Plays	a. EUR/Well	As Calculated	N/A	N/A	N/A	N/A
		b. O&M Costs/Mcf	As Calculated	N/A	N/A	N/A	N/A
11. Environmental Mitigation	EV Sensitive Plays	Acreage Available	50% of Play Restricted	Removed in 50 years (1%/yr from 2000)	Removed in 100 years (2%/ yr from year 2000)	No Improvement	Removed in 25 years (2%/yr from year 2000)

Table 4D-4
Details of Tight Gas Sands Technological Progress

R&D Program	Tight Sands Resource Impacted	Technology Lever	Current Situation	Technology Cases			
				Reference Case with DOE	Reference Case w/o DOE	Low Technology	High Technology
1. Basin Assessment	Hypothetical Plays	a. Date Available	Not Available	Year 2016	Same as Reference Case	Not Available	Year 2011
		b. Play Probability	50% to 80% (Play Specific)	No Improvement	Same as Reference Case	No Improvement	+1%/year from 2011 (Max 100%)
2. Extended Resource Characterization	Emerging Basins	Pace of Development	30 to 60 years (+20 years over Developing Plays)	-1.25 yr/year (Max -20 years)	-1 yr/year (Max -20 years)	No Improvement	-2 yrs/year (Max -20 years)
3. Well Performance Diagnostics and Remediation	Proved Reserves	Reserve Growth	San Juan Basin @ 3%/yr., declining	All Basins @2%/yr., declining	Same as Reference Case	All Basins @ 1%/yr., declining	All Basins @ 3%/yr., declining
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	30% to 95%	$+^1/_4$%/year from 2000 (max 95%)	No Improvement	No Improvement	$+^1/_2$%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify "Best" 30% by Year 2017	No Improvement	No Improvement	Identify "Best" 30% by year 2007
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+5% (in 20 years)	$+2^1/_2$% (in 20 years)	No Improvement	+10% (in 20 years)

Table 4D-4
Details of Tight Gas Sands Technological Progress

R&D Program	Tight Sands Resource Impacted	Technology Lever	Current Situation	Technology Cases			
				Reference Case with DOE	Reference Case w/o DOE	Low Technology	High Technology
6. Improved Drilling and Stimulation	All Plays	a. EUR/Well	As Calculated	+10% (in 20 years)	+7.5% (in 20 years)	+5% (in 20 years)	+15% (in 20 years)
		b. R/P Ratio	As Calculated	R/P = 11 to 12	R/P = 12 to 13	R/P = 13 to 14	R/P = 10 to 11
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-10% (in 20 years)	-5% (in 20 years)	No Improvement	-20% (in 20 years)
8. Water and Gas Treating R&D	All Plays	Water & Gas Treating O&M Costs/Mcf	$0.15/Mcf	-20% (-$0.03/ Mcf) (in 20 years)	-15% (-$0.02/Mcf) (in 20 years)	-5% (-$0.01/Mcf) (in 20 years)	-30% (-$0.045/Mcf) (in 20 years)
9. Horizontal Wells	Continuous Sands	Recovery Efficiency	As Calculated	+10% (year 2011) (Selected Basins)	+5% (year 2016) (Selected Basins)	No Improvement	+15% (year 2011) (Add. Basins)
10. Other Tight Gas Technology	Other Sands	EUR/Well	As Calculated	+10% (year 2021)	No Improvement	No Improvement	+10% (year 2016)
11. Environmental Mitigation	EV Sensitive Plays	Acreage Available	50% of Play Restricted	Removed in 50 years (1%/yr)	Removed in 100 years ($1/2$%/ yr)	No Improvement	Removed in 25 years (2%/yr)

II.   Technology Packages

1. Increasing the Resource Base with Basin Assessments

Background and Problem

A large portion of the unconventional gas resource, about 120 Tcf, and many high potential gas plays are currently categorized by the USGS as hypothetical resources. Because basic information is lacking on these plays, industry is constrained in exploring or developing them in a timely fashion.

Technology Lever

A new round of fundamental "Basin Assessments", as were initially sponsored by the DOE and GRI on many of the gas basins and plays that are currently being developed, would provide a comprehensive foundation of geologic and reservoir data and a regional perspective for the currently designated hypothetical plays.

Impacts and Benefits

The CBM basins and plays listed on **Table 4D-6** are categorized as hypothetical and thus are currently not available for CBM development. **Tables 4D-7** and **4D-8** provide similar information on the hypothetical Gas Shale and Tight Gas Plays. (The data and information in the latest USGS National Assessment provide the foundation for the CBM, Gas Shales, and Tight Sands resource estimates on these tables). Selected high potential basin and plays not evaluates by the USGS, such as the Wind River Basin Tight Sands and the Deep Green River Basin CBM, were added from special studies by Advanced Resources International, Inc.

Reference Case Technology enables these plays to become available for industry consideration in the year 2016. Low Technology keeps the situation as is, leaving the hypothetical plays unavailable for development. High Technology makes these gas plays available for industry consideration five years earlier, in year 2011, and increases the play probabilities of hypothetical plays by 1 percent per year, from this earlier date of availability.

Reference Case Technology w/o DOE remains the same as the Reference Case because currently DOE has no direct (or indirect) R&D in basin assessments for hypothetical unconventional gas plays. At present, emerging resource and future gas studies supported by the Gas Research Institute and occasional national-level resource assessments are the main contributor to Reference Case Technology.

The specific parameter values for the technology cases, for all three of the unconventional gas resources (CBM, Gas Shales and Tight Sands), are set forth in **Table 4D-5** below:

Table 4D-5

Parameter Values for Basin Assessment Technologies

Technology Case	Year Hypothetical Plays Become Available	Changes in Play Probabilities
Current Situation	Not Available	50%-80% (Play Specific)
Reference Case	Year 2016	No Improvement
Reference Case w/o DOE	Same as Reference Case	Same as Reference Case
Low Technology	Not Available	No Improvement
High Technology	Year 2011	Improves by 1%/year from Year Available/Economic

Table 4D-6

Hypothetical CBM Plays and Resources

Basins	Gas Plays	Play Probability	Undeveloped Resource (Bcf)
Appalachia	N. Basin -- Syncline	55%	2,878
Mid-Continent	Forest City/Arkoma Syncline	80%	1,152
San Juan	Southern (Menefee)	50%	420
Uinta	Sego	80%	722
Piceance	Deep Basin	80%	2,496*
Powder River	Central Basin	50%	438
Green River	Deep Basin	50%	3,900*
Black Warrior	Central Basin	50%	228

New Deep CBM plays added by Advanced Resources International, Inc.

Table 4D-7

<u>**Hypothetical Gas Shale Plays and Resources**</u>

Basin	Gas Play	Play Probability	Undeveloped Resources (Bcf)
Appalachia	Devonian Shale - Low Thermal Maturity	80%	3,528
Michigan	Antrim Shale - Undeveloped Area	80%	13,935
Illinois	New Albany Shale - Developing Area	80%	1,985
Cincinnati Arch	Devonian Shale	50%	1,426
Williston	Shallow Niobrara, Biogenic Gas	75%	1,575

Table 4D-8

<u>Hypothetical Tight Sands Plays and Resources</u>

Basin	Gas Plays	Play Probability	Undeveloped Resources (Bcf)
Appalachia	Clinton/Medina Moderate	75%	4,106
	Clinton/Medina Low	75%	2,400
	Upper Devonian Moderate	75%	557
	Upper Devonian Low	75%	1,260
Columbia	Basin Center	50%	6,300
Uinta	Tertiary West	80%	769
	Basin Flank MV	75%	2,649
	Deep Synclinal MV	50%	958
Piceance	N. Basin WF/MV	80%	1,764
Green River	Fort Union	80%	894
	Lewis	75%	14,074
	Deep MV	75%	21,600
	Deep Frontier	75%	22,500
Wind River	Fort Union/ Lance Deep	80%	7,200*
	MV/Frontier Deep	50%	625*
N. Great Plains	Moderate Potential	80%	12,784
	Low Potential	75%	6,749

New Tight Gas Plays added by Advanced Resources International, Inc.

2. Accelerating the Development of Emerging Unconventional Gas Plays With Reservoir Characterization

Background and Problem

Much of the unconventional gas resource is in new, emerging plays and basins, such as the Raton, Powder River, Piceance and Wind River basins. Reliable, rigorous information on the key reservoir parameters controlling the gas production in these new, poorly defined gas plays is lacking. Also lacking is information on how best to match technology to the geology and reservoir properties of these gas plays. Because of this lack of information, industry assigns a higher risk when evaluating these basins and plays and proceeds slowly during their initial development.

Technology Lever

Performing extended, three-dimensional reservoir characterization studies of emerging plays, partnering with industry in "wells of opportunity", sponsoring rigorously evaluated technology and geology/reservoir tests, and providing proactive technology transfer would help define and disseminate essential information of high value to the E&P industry on the "emerging" gas plays.

Impacts and Benefits

The gas plays listed on **Tables 4D-10, 4D-11 and 4D-12** are categorized as "emerging" for CBM, Gas Shales and Tight Sands. These plays currently entail higher risks and a slower pace of development, estimated as a 20 year "stretch-out" in field development time.

Reference Case Technology removes the initial 20 year "stretch-out" in development time for the emerging plays in 20 years, at a rate of 1 year of reduced time delay per year for CBM and Gas Shales. The Reference Case removes this stretch out time in 16 years, at a rate of 1.25 years of reduced time delay per year, for Tight Sands. Low Technology keeps the current time delay situation as is. High Technology overcomes the 20 year development "stretch-out" time faster, in 10 years, at a rate of 2 years of reduced time delay per year.

Reference Case Technology w/o DOE remains the same as the Reference Case for CBM and Gas Shales because DOE currently has no direct (or indirect) R&D in extended reservoir characterization for these two resources. USGS, GRI and state survey studies on emerging resources are the main contributors to Reference Case Technology in CBM and Gas Shales.

DOE does, however, have extended reservoir characterization projects underway for selected Tight Sands plays in the Piceance and Green River Basins and may extend this program to other emerging Tight Sand basins. As such, in the Reference Case Technology w/o DOE for Tight Sand this constraint is removed considerably slower, in 20 years, at a rate of 1 year of reduced time delay per year.

The specific parameter values for the technology cases for all three of the unconventional gas resources (CBM, Gas Shales, and Tight Sands) are set forth in **Table 4D-9** below:

Table 4D-9

Parameter Values for Reservoir Characterization Technologies

Technology Case	Development Constraints on Emerging Plays	Rate of Constraint Removal
Current Situation	+20 years to development time	Not removed
Reference Case	a. Removed in 20 years, starting in 1997 for CBM and Gas Shales	a. 1 year reduction/year
	b. Removed in 16 years, starting in 1997 for Tight Sands	b. 1.25 years reduction/year
Reference Case w/o DOE	a. Same as Reference Case for CBM and Gas Shales	a. Same as Reference Case for CBM and Gas shales
	b. Removed in 20 years, starting in 1997 for Tight Sands	b. 1 year reduction/year
Low Technology	Not removed	Not removed
High Technology	Removed in 10 years, starting in 1997	2 years reduction/year

Table 4D-10

Emerging CBM Plays and Resources

Basin	Gas Play	Undeveloped Resources (Bcf)
Appalachia	N. Basin Anticline	1,034
Illinois	Central Basin	582
Mid-Continent	Cherokee/Arkoma Basin	1,718
Uinta	Blackhawk Formation	1,176
	Ferron	5,580
Piceance	Divide Creek Area	1,222
	White River Dome	629
	Shallow Basin Margins	3,390
Raton	North Area	1,781
	Purgatory River Area	950
	South Area	844
Powder River	Shallow Basin Margins	1,655
Green River	Shallow Areas	3,899

Table 4D-11

Emerging Gas Shale Plays and Resources

Basin	Gas Plays	Undeveloped Resources (Bcf)
Appalachia	Devonian Shale - Big Sandy Extension Area	9,000
	Devonian Shale - Greater Siltstone Area	2,832
Fort Worth	Barnett Shale - Main Area	3,315*

New Gas Shale play added by Advanced Resources International, Inc.

Table 4D-12

Emerging Tight Sand Plays and Resources

Basins	Gas Plays	Undeveloped Resources (Bcf)
Texas Gulf Coast	Vicksburg	660*
	Olmos	1,800*
Permian	Abo	1,875*
Wind River	Ft. Union/Lance Shallow	11,205*
	MV/Frontier Shallow	1,500*
Green River	Fox Hills/Lance	10,733
	Shallow MV	19,102
Piceance	S. BasinWF/MV	9,870*
	Iles/MV	4,716
Arkoma	Atoka	818*
N. Great Plains	Biogenic Gas, High Potential	5,299

New Tight Gas plays added by Advanced Resources International, Inc.

3. Extending Reserve Growth in Existing Unconventional Gas Fields with Advanced Well Performance Diagnostics and Remediation

Background and Problem

A review of the historical data shows that proved reserves in existing unconventional gas fields grow by 2 to 4 percent per year due to adjustments and revisions stemming from uphole well recompletions, restimulation and more effective production practices. However, the pace of this non-drilling based reserve growth has been declining steadily as operators face increasing difficulties in identifying and diagnosing the problems of low recovery efficiencies and underperforming unconventional gas wells.

Technology Lever

A rigorous unconventional gas well diagnostics and remediation R&D program would provide the appropriate set of tools for evaluating and targeting problem gas wells. It would also provide a basis for designing and selecting the appropriate cost-effective well remediation technologies, helping support continued reserve growth.

Impact and Benefits

Currently, the plays listed on **Tables 4D-14, 4D-15 and 4D-16** have proved resources of CBM, Gas Shales, and Tight Sands. Based on the available data, improved well remediation and production practices provide approximately 2 to 3 percent annual growth in proved reserves, with a noticeable decline in growth since the early 1990's.

Reference Case Technology starts with a 3 percent annual reserve growth for CBM and Gas Shales plays with existing proved reserves and declines the level of reserve growth over 30 years. Reference Case Technology for Tight Sands a considerably more mature gas resource, starts with a 2 percent annual reserve growth (for plays with existing proved reserves) and declines the level of reserve growth over 20 years. Low Technology provides much lower and declining reserve growth, starting at 1 percent per year for all three gas resources. High Technology starts with a higher 4 percent, annual growth in proved reserves for each of the unconventional gas plays with current proved reserves, and declines the growth over 40 years.

Reference Case Technology w/o DOE remains the same as the Reference Case because DOE currently has no direct (or indirect) R&D on well diagnostics or remediation technology. GRI's R&D program in well remediation for a variety of gas plays is expected to provide an important contribution to Reference Case Technology.

The specific parameter values for the technology cases are set forth **Table 4D-13** below.

Table 4D-13

**Parameter Values for Advanced Well Performance
Diagnostics and Remediation Technologies**

Technology Case	Applicable Basins	Reserve Growth Factor
Current Situation	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	2% - 4% with Recent Declines
Reference Case	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	a. 3%, Declining for CBM and Gas Shales b. 2%, Declining for Tight Gas
Reference Case w/o DOE	Same as Reference Case	Same as Reference Case
Low Technology	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	1%, Declining for All Resources
High Technology	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	4%, Declining for All Resources

Table 4D-14

CBM Plays With Proved Reserves

Basin	Gas Play	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
San Juan	North Basin (CO)	696	700
	Cavity Fairway (NM/CO)	6,170	6,157
	West Basin (NM)	586	550
	East Basin (NM)	152	150
Warrior	Shallow Basin Area	972	823
Unita	Ferron Formation	400	400
Raton	North Basin Area	0	31
	Purgatory River Area	100	249
Powder River	Shallow Basin Margin	100	150
Piceance	Divide Creek	56	52
Appalachia	Central App. Basin	1,137	1,172
Mid Continent	Cherokee & Arkoma	130	130
TOTALS		**10,499**	**10,564**

Table 4D-15

Gas Shale Plays With Proved Reserves

Basins	Gas Plays	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
Appalachia	Devonian Shale - Big Sandy Central Area	1,360	1,470
	Devonian Shale - Big Sandy Extension Area	340	330
Michigan	Antrim Shale - Developing Area	1,500	1,680
Fort Worth*	Barnett Shale - Main Area	208	270
TOTALS		**3,408**	**3,750**

New Gas Shale plays added by Advanced Resources International, Inc.

Table 4D-16

Tight Sand Plays With Proved Reserves

Basin	Gas Plays	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
Appalachia	Clinton/Medina High	900	1,020
	Upper Devonian High	3,600	3,700
San Juan	Picture Cliffs	900	960
	Central Basin/MV	5,200	5,300
	Central Basin/Dakota	2,700	2,600
Uinta	Tertiary East	500	527
	Basin Flask MV	10	9
Piceance	S. Basin WF/MV	600	700
	N. Basin WF/MV	150	140
	Iles/MV	150	140
Green River	Fox Hills/Lance	100	200
	Lewis	100	95
	Shallow MV	1,800	1,805
	Frontier (Moxa Arch)	3,400	3,406
Wind River	Ft. Union/Lance Shallow	150	210
	MV/Frontier Shallow	300	300
Denver	Deep J Sandstone	1,000	1,050
Louisiana/Mississippi Salt	Cotton Valley	4,200	4,500
Texas Gulf Coast	Vicksburg	200	170
	Wilcox/Lobo	2,400	2,580
	Olmos	650	700
Permian	Canyon	2,000	2,160
	Abo	600	640
Anadarko	Cleveland	400	496
	Cherokee/Redfork	1,500	1,420
	Granite Wash/ Atoka	380	364
N. Great Plains	Biogenic Gas, High Potential	300	300
Arkoma	Atoka	500	600
TOTALS		**34,690**	**36,221**

4. Improving Exploration Efficiency with Advanced Exploration and Natural Fracture Detection Technology

Background and Problem

In settings where the unconventional gas resource has sufficiently high gas concentration and is intensely naturally fractured, this resource can be produced at commercial rates. Finding these settings of high natural fracture intensity and diversity of orientation is a major technical challenge and greatly influences the economics of unconventional gas development. Currently, the USGS assumes that the development of unconventional gas or continuous-type basins and plays will be based on a uniform, basin wide development plan rather than selective exploration for higher permeability areas. The R&D goal is to develop and introduce improved exploration technology to enable producers to find the best, "sweet-spot" portions of these gas basins.

Technology Lever

A significant portion of DOE/FETC's current R&D on low permeability gas reservoirs is directed at technologies and field projects on natural fracture detection and improved exploration technology. These methods will help operators to identify, before drilling, the "sweet spots" in otherwise tight reservoirs, resulting in a larger initial portion of high productivity wells.

Impacts and Benefits

Currently, unconventional gas plays are generally assessed based on the performance and economics of the "average well" in the play. This assumes that large numbers of low productivity wells need to be drilled to develop the higher productivity areas, increasing the threshold costs for the gas play.

Reference Case Technology addresses the question of exploration efficiency, the "c" factor in the exploration efficiency equation, and enables the industry to find the "best 30 percent" of the basin in 20 years, by the year 2017. Reference Case Technology also improves the success rate of the play by $^1/_4$ percent per year, starting in the year 2000. Low Technology maintains the current, relatively random approach to basin and play development and provides no change in the drilling success rate. High Technology enables industry to reliably find the "best 30 percent" of a basin ten years earlier, by the year 2007, and improves the drilling success rate by $^1/_2$ percent/year, starting in the year 2000.

Reference Case Technology w/o DOE shows no improvement and becomes equal to the Low Technology Case as currently the bulk of the R&D on natural fracture detection is sponsored by the DOE.

The specific parameter values for the technology cases, for all three of the unconventional gas resources (CBM, Gas Shales, and Tight Sands), are set forth in **Table 4D-17** below:

Table 4D-17

**<u>Parameter Values for Advanced Exploration
and Natural Fracture Detection Technologies</u>**

Technology Case	Level of Exploration Efficiency	Change in Drilling Success Rate
Current Status	Random	50% to 90% Success Rates
Reference Case	Identify "Best" 30% of Play by Year 2017	Improves by $\frac{1}{4}$%/year from Year 2000
Reference Case w/o DOE	No Improvement	No Improvement
Low Technology	No Improvement	No Improvement
High Technology	Identify "Best" 30% of Play by Year 2007	Improves by $\frac{1}{2}$%/year from Year 2000

5. Increasing Recovery Efficiency With Geology/Technology Modeling and Matching

Background and Problem

Field development plans and operations are challenging to design for unconventional gas plays, given the complex, difficult to measure and widely varying reservoir properties. As a result, the selection and application of "best available" technology and production practices to optimize gas recovery has proven to be difficult.

Technology Lever

The key task is improved understanding of unconventional gas reservoir conditions and appraisals of "best available" technology. For this, new research data on multi-phase relative permeability, stress sensitive formations, and natural fracture patterns are essential. Also needed are advanced reservoir simulators that can properly model these complex settings and behaviors, and thus provide more reliable projections of gas recovery. These data and tools would allow more optimum selection of appropriate technology for efficient field development.

Impacts and Benefits

Currently, fields are designed with a variety of assumptions and "rules of thumb" about reservoir properties and technology performance, without consideration of the complex interaction of the reservoir and the chosen technology. This leads to much lower than optimum gas recoveries per well.

Reference Case Technology increases recovery from new wells by 2½ percent in 20 years, at a rate of +⅛ percent per year, for CBM and Gas Shales and increased recovery from new wells by 5 percent in 20 years, at a rate of ¼ percent per year for Tight Sands. Low Technology provides no improvement for CBM, Gas Shales or Tight Sands. High Technology increases CBM, Gas Shales and Tight Sands recovery per well by 10 percent, at a rate of ½ percent per year.

Reference Case Technology w/o DOE remains the same as the Reference Case for CBM and Gas Shales because DOE currently has no direct (or indirect) R&D on geology/technology matching for these two resources. However, for Tight Sands the Reference Case w/o DOE leads to lower progress in improved EUR's per well of 2½ percent (over 20 years), at ⅛ percent per year as DOE does have a R&D program in this area. GRI's basic science and university R&D on low permeability reservoir properties, plus the service industry's current interests in these topics, are the main contributors to the Reference Case.

The specific parameter values for technology cases are summarized in **Table 4D-18** below:

Table 4D-18

**Parameter Values for Geology/Technology
Modeling and Matching Technologies**

Technology Case	Improved Recovery After 20 Years	Rate of Change
Current Status	As Calculated	-
Reference Case	a. +2½% for CBM and Gas Shales b. +5% for Tight Sands	a. ⅛%/year for CBM and Gas Shales b. $+^1/_4$%/year for Tight Sands
Reference Case w/o DOE	a. Same as Reference Case for CBM and Gas Shales b. 2½% for Tight Sands	a. Same as Reference Case for CBM and Gas Shales b. ⅛% for Tight Sands
Low Technology	No Improvement	n/a
High Technology	+10%	½%/year

6. Improving Well Performance With Lower Damage, More Effective Well Completions and Stimulations

Background and Problem

The permeability in CBM, Gas Shale and Tight Sand formations is easily damaged by use of chemicals, gels, drilling muds and heavy cement, leading to underperforming wells. Improving well drilling, completion and stimulation fluids and procedures would help improve recoveries from such wells, particularly in multi-zone, vertically heterogeneous formations.

Technology Lever

R&D on formation and fluid compatibility, low damage fluids such as CO_2 or N_2, improved rock mechanics and stimulation models, underbalanced drilling, and improved proppant carrying fluids, particularly for multi-zone reservoirs, could reduce formation damage, increase frac length and placement, and increase fracture conductivity, thus improving reserves per well.

Impacts and Benefits

Currently, hydraulic stimulations are short, poorly propped and often ineffective. Also, overbalanced drilling through the reservoir causes formation damage, leading to lower than optimum recoveries per well and much less effective reserves to production (R/P) ratios, particularly in the economically crucial first five years.

Reference Case Technology increases recovery per well by 10 percent in 20 years (at a rate of ½ percent per year) for Tight Sands and by $7^1/_2$ percent in 20 years(at a rate of ⅜ percent per year) for CBM and Gas Shales. Low Technology increases recovery by 5 percent in 20 years, in all three resouce areas, at a rate of $^1/_4$ percent per year. High Technology increases recovery per well by 15 percent in 20 years, in all three resource areas, at a rate of $^3/_4$ percent per year.

Reference Case Technology w/o DOE for CBM and Gas Shales remains as the Reference Case because DOE has no direct (and little indirect) R&D on CBM or Gas Shale compatible drilling and stimulation. However, DOE does have a program to introduce low damage stimulation fluids, particularly CO_2, to tight sand formations. The Reference Case Technology w/o DOE for Tight Sands slows the pace of technology progress, dropping the level of improvement to $7^1/_2$ percent,in 20 years. GRI's and industry's increasing interests in lower damage drilling and stimulation are the main contributors to the Reference Case for CBM and Gas Shales.

The specific parameter values for the technology cases are summarized in **Table 4D-19** below.

Table 4D-19

**Parameter Values for Lower Damage, More Effective
Well Completions and Stimulations Technologies**

Technology Case	Improved Well Recovery After 20 Years	Rate of Change
Current Status	As Calculated	-
Reference Case	a. +7½ for CBM and Gas Shale (20 years)	a. +⅜%/year for CBM and Gas Shales
	b. +10% for Tight Sands (20 years)	b. +½%/year for Tight Sands
Reference Case w/o DOE	a. Same as Reference Case for CBM and Gas Shale	a. Same as Reference Case for CBM and Gas Shale
	b. +7½% for Tight Sands (20 years)	b. +⅜%/year for Tight Sands
Low Technology	+5% (in 20 years)	$^{+1}/_4$%/year
High Technology	+15% (in 20 years)	+¾%/year

Reference Case Technology also lowers the R/P ratio to range of 11 to 12 for CBM, Gas Shales and Tight Sands for new and still emerging plays. Low Technology maintains the R/P ratio at a relatively high 13 to 14 for all three resources. High Technology further reduces the R/P ratio to a range of 10 to 11. The well damage problems from drilling and stimulation that constrain initial production rates are minimized.

Reference Case w/o DOE provides an R/P ratio in the range of 12 to 13, as the benefits of DOE's R&D program on low damage drilling and stimulation funds are reduced.

7. Lowering Well Drilling and Completion Costs with Unconventional Gas Specific Drilling and Hydraulic Fracturing R&D

Background and Problem

Well drilling and completion represent the primary capital cost items in unconventional gas development and place a high economic hurdle on these resources, particularly when these costs are assessed using discounted cash flow analysis. Lowering well drilling and stimulation costs would significantly improve the overall economics, particularly for the deeper, low permeability gas plays.

Technology Lever

R&D on advanced drilling and completion methods, particularly the use of downhole motors and modified stimulation practices, will lead to faster formation penetration rates, simpler frac fluids, and thus lower costs.

Impacts and Benefits

Currently, drilling costs for unconventional gas range from $30 to $100 per foot, down from five years ago. However, the continuing tightness in the rig market is putting pressure on drilling day-rates and pushing up costs. Stimulation costs add $30,000 to $300,000 per well. These costs have declined over past years, but are now stabilizing. The decline in D&C costs has slowed appreciably in the past two years as many of the easier cost cutting efforts have been accomplished and the industry is back to full capacity.

Reference Case Technology reduces drilling and stimulation costs by 10 percent, at a rate of $^1/_2$ percent per year for 20 years. Low Technology maintains drilling costs at current levels which represent a considerable achievement given the tightening rig and stimulation market. High Technology reduces drilling costs by 20 percent, at a rate of 1 percent per year for 20 years.

Reference Case Technology w/o DOE is between the Reference Case and Low Technology Case because DOE R&D on drilling and stimulation provides valuable R&D of direct value to Tight Sands and indirect value to CBM and Gas Shales. Separate analysis provided to this study indicated that DOE's R&D may lead to a 5 percent reduction in D&C costs over 20 years, consistent with the technology assumptions used in this study.

The specific parameter values for the technology cases are summarized in **Table 4D-20** below.

Table 4D-20

**Parameter Values for Unconventional Gas Specific
Drilling and Hydraulic Fracturing R&D**

Technology Case	Reduction in Well D&C Costs After 20 Years	Rate of Change
Current Status	As Calculated	-
Reference Case	-10%	$^{-1}/_{2}$%/year
Reference Case w/o DOE	-5%	$^{-1}/_{4}$%/year
Low Technology	No Improvement	none
High Technology	-20%	-1%/year

8. Lowering Water Disposal and Gas Treating Costs Through New Practices and Technologies

Background and Problem

Disposing the produced water and treating the produced methane for CO_2 and N_2 contaminants add significant costs to unconventional gas operations. Lowering these costs would improve the overall economics of the gas plays, particularly those with high water production and CO_2 content.

Technology Lever

R&D on water treatment, such as the use of electrodialysis and reverse osmosis, and improved water disposal practices, may lead to lower produced water disposal costs. R&D on gas treating, such as the use of advanced membranes, may help lower the costs of CO_2 and N_2 removal.

Impacts and Benefits

Currently, the O&M costs for water disposal in a high water producing gas play are about $0.05/Mcf. The O&M costs for CO_2 and N_2 removal are on the order of $0.10/Mcf. Gas dehydration, lease fuel and gas compression cost $0.15/Mcf. The combined costs are $0.30/Mcf for wet CBM and Gas Shale plays, $0.25/Mcf for dry CBM and Gas Shale plays, and $0.15/Mcf for Tight Sand plays.

Reference Case Technology lowers the O&M costs for water disposal and gas treating by 20 percent, equal to $0.06/Mcf for CBM and wet Gas Shales and $0.03 for Tight Sand, at a rate of 1 percent per year for 20 years. Low Technology lowers these cost by 5 percent or $0.015/Mcf for CBM and Gas Shale and about $0.01/Mcf for Tight Sands, at a rate of $^1/_4$ percent per year for 20 years. High Technology lowers these cost by 30 percent, or $0.09/Mcf, at a rate of $1^1/_2$ percent per year for 20 years, for CBM and Wet Gas Shales and $0.045/Mcf for Tight Sands, at the same rate.

Reference Case Technology w/o DOE is between the Reference Case and Low Technology Case because both GRI and DOE sponsor work on gas treating. Separate analysis provided to this study states that both DOE and GRI R&D addresses improvements in N_2 and CO_2 removal technologies and GRI R&D addresses improved water disposal technologies. Thus, the Reference Case w/o DOE would show a 15 percent reduction in produced water and gas treatment costs in 20 years. Produced water and gas treatment R&D by GRI would account for the remaining difference between the Reference and Low Technology Cases.

The specific parameter values for the technology cases are summarized **Table 4D-21** below.

Table 4D-21

<u>**Parameter Values for New Practices & Technologies**</u>
<u>**for Water Disposal and Gas Treatment**</u>

Technology Case	Water Disposal/Gas Treating O&M Costs		Rate of Change
	CBM and Wet Gas Shales	**Tight Sands**	
Current Status	$0.30/Mcf	$0.15/Mcf	-
Reference Case	-20% ($0.06/Mcf) (20 years)	-20% (20 years)	-1%/year
Reference Case w/o DOE	-15% ($0.045/Mcf) (20 years)	-15% (20 years)	$-^3/_4$%/year
Low Technology	-5% ($0.015/Mcf) (20 years)	-5% (20 years)	$-^1/_4$%/year
High Technology	-30% ($0.09/Mcf) (20 years)	-30% (20 years)	$-1^1/_2$%/year

9. Improving Recovery Efficiency With Advanced Well Drilling and Completion Technology

A. Coalbed Methane

Background and Problem

Cavitation of CBM wells in geologically favorable "cavity fairways" provides gas production rates, reserves, and recovery efficiencies far in excess of traditionally drilled, cased and hydraulically stimulated wells. However, little is known as to what combination of reservoir properties is essential or favorable for cavitation, and little has been invested in cavitation science, design or operating procedures. As a result, only one "cavity fairway" has been established in the U.S. to date -- in the central San Juan Basin.

Technology Lever

A limited R&D program, sponsored by DOE's SBIR program, is working to identify other potential "CBM cavity fairways". The SBIR program has also supported the development of the first publicly available CBM cavitation model, CAVITYPC. Expansion of R&D in CBM well cavitation could help identify additional high productivity "cavity fairways" and strengthen the scientific knowledge base on the rock mechanics and flow equations that are at the heart of improving cavitation technology.

Impact and Benefits

Currently, one existing CBM play is being developed with cavitation, the central San Juan Basin. Based on preliminary data, four additional CBM plays are candidates for cavitation, as shown on **Table 4D-23**.

Reference Case Technology would improve recovery efficiency (and reserves per well) in the four potential "cavitation plays" by 20 percent over current well completion and stimulation methods and would make this technology available in the year 2010. (Once introduced, recovery efficiency and cavitation well performance would continue to improve by 1 percent per year).

Low Technology would lead to no further identification or development of cavity fairways or cavitation technology outside the San Juan Basin Fairway. High Technology would make an advanced version of cavitation technology available by the year 2006, providing an improvement of 30 percent in recovery efficiency and reserves per well in the four potential "cavitation plays" listed on Table 4D-24.

Reference Case Technology w/o DOE would become equal to the Low Technology Case as the only active and published R&D program on well cavitation is supported by DOE's SBIR program.

The specific parameter values for the technology cases for CBM are set forth in **Table 4D-22** below.

Table 4D-22

Parameter Values for Advanced Well Drilling and Completion Technology: Coalbed Methane

Technology Case	Applicable CBM Plays	Year Available	Improvement in Recovery/Efficiency
Current Status	San Juan Basin Fairway	Now	(Already Included)
Reference Case	Four New Cavity Fairways	2011	+20%
Reference Case w/o DOE	Same as Low Tech	Same as Low Tech	Same as Low Tech
Low Technology	San Juan Basin Fairway	No Change	No Change
High Technology	Four New Cavity Fairways	2006	+30%

Table 4D-23

CBM Plays That Are Candidates for Advanced Well Cavitation

Basin	Applicable CBM Plays	Status	Undeveloped Resources (Bcf)
San Juan	Cavity Fairway	Existing	6,084
Uinta	Ferron Fairway	Potential	5,580
Raton	Purgatory River	Potential	950
Piceance	Deep Basin Coals	Potential	2,496
Green River	Deep Basin Coals	Potential	3,900

* *Much of the San Juan cavity fairway has been developed accounting for 6.2 Tcf of proved reserves. Development of the remainder of the fairway and closer spaced infill development along the western portion of the fairway account for the undeveloped resources.*

B. Gas Shales

Background and Problem

       Because Gas Shales generally have a thick pay section, multiple productive horizons, and low vertical permeability, horizontal wells have not been successful and, most likely, will not be a technology of choice. However, the use of multiple laterals may enable a single vertical wellbore to contact and efficiently drain a vertically thick, heterogeneous Gas Shale formation. While multi-lateral wells are in use in oil reservoirs, no application of this technology to Gas Shales is reported.

Technology Lever

       A new program of using multi-lateral drilling in Gas Shale plays would need to be introduced to have this technology available during the forecast period.

Impact and Benefit

       Since no R&D is underway on this topic for Gas Shales, the Reference Case, Reference Case w/o DOE and the Low Technology Case would not enable multi-lateral drilling technology to be available for Gas Shales during the forecast period. The High Technology Case would introduce this technology to the Gas Shale plays listed on **Table 4D-25** in the year 2011, providing a 10 percent improvement in recovery efficiency from Gas Shale reservoirs.

       The specific parameter values for the technology cases for Gas Shales are set forth in **Table 4D-24** below.

Table 4D-24

Parameter Values for Advanced Well Drilling and Completion Technology: Shale Gas

Technology Case	Year Available	Improvement in Recovery/Efficiency
Current Status	Not Available	No Applicable
Reference Case	Not Available	No Applicable
Reference Case w/o DOE	Not Available	No Applicable
Low Technology	Not Available	No Applicable
High Technology	2011	+10%

Table 4D-25

Gas Shale Plays That Are Candidates for Multi-Lateral Drillings

Basin	Gas Play	Current Status	Undeveloped Resource (Bcf)
Michigan	Antrim, Developing Area	Not Available	4,940
	Antrim, Undeveloped Area	Not Available	13,935
Illinois	New Albany, Developing Area	Not Available	1,985
Williston	Shallow Niobrara	Not Available	1,575

C. Tight Sands

Background and Problem

Horizontal wells in geologically appropriate "blanket" type Tight Sand formations provide improved reservoir contact and, theoretically, considerably improved recovery efficiencies and reserves per well. However, the performance of horizontal wells in Tight Sand has been disappointing to date, raising questions on appropriate reservoir settings, efficient placement and drilling damage. The DOE supported horizontal well at the MWX site, drilled into the Corcoran Formation (Iles/Mesaverde) in the Southern Piceance Basin quickly turned to water after high initial gas rates and was abandoned. Meanwhile, horizontal wells in conventional oil and gas formations, such as the Austin Chalk, and the offshore Gulf of Mexico, have shown good performance.

Technology Lever

The DOE horizontal well project in the Green River Basin may help define the appropriate geologic settings for using horizontal wells in Tight Sand formations and advance the essential low damage drilling and stimulation technologies for successful application of horizontal wells in these damage sensitive, low permeability formations.

Impact and Benefits

Reference Case Technology would help define the appropriate settings for using horizontal wells by the year 2011, providing a 10 percent improvement in recovery efficiency from selected Tight Sand reservoirs and plays at costs comparable to current practices. **Table 4D-27A** list the Tight Sand Gas plays that could be applicable for horizontal wells in the Reference Case.

Low Technology would lead to no further understanding or applicability of horizontal well technology in Tight Sand plays. High Technology would provide a 15 percent improvement in recovery efficiency from a larger group of tight sand reservoirs and plays amenable to horizontal drilling, as shown on **Table 4D-27B**.

Reference Case Technology w/o DOE would introduce a somewhat less efficient (5 percent improvement in recovery efficiency) technology 5 years later (year 2016), as currently DOE is a major R&D supporter for testing and using horizontal wells in Tight Sands.

The specific parameter values for the technology cases for Tight Sands are set forth in **Table 4D-26** below.

Table 4D-26

Parameter Values for Advanced Well Drilling and Completion Technology: Tight Sands

Technology Case	Applicable Tight Sand Plays	Year Available	Improvement in Recovery/Efficiency
Current Status	None	Not Available	Not Applicable
Reference Case	See Table 4D-27A	2011	+10%
Reference Case w/o DOE	See Table 4D-27A	2016	+5%
Low Technology	None	Not Available	No Applicable
High Technology	See Table 4D-27A & 4D-27B	2011	+15%

Table 4D-27A
Tight Gas Plays Applicable for Horizontal Well Technology,
Reference Case and Reference Case w/o DOE Technology

Basin	Gas Play
Appalachia	Clinton/Medina High
Denver	Deep J Sandstone
Greater Green River	Shallow Mesaverde
	Frontier (Deep)
Piceance	Iles/Mesaverde
San Juan	Central Basin/Dakota

Table 4D-27B
Additional Tight Gas Plays Applicable for Horizontal
Well Technology, High Technology

Basin	Gas Play
Uinta	Tertiary East Basins
	Tertiary West Basins
Wind River	Mesaverde/Frontier Shallow
	Mesaverde/Frontier Deep
Appalachia	Upper Devonian High Potential
Greater Green River	Frontier (Moxa Arch)

10. Improving and Accelerating Gas Production With Other Unconventional Gas Technologies

A. Coalbed Methane

Background and Problem

Laboratory tests demonstrate that injection of adsorbing gases such as CO_2 and N_2 into coal seams can improve and accelerate the desorption of methane from the coal. However, major questions remain as to how the injected gases will flow in the reservoir, how effectively these injected gases will contact and displace the methane adsorbed on the coals, and how to cost-efficiently treat the produced methane/injected gas mixtures. As a result, only a few field pilots in the San Juan Basin have been conducted using this high potential CBM recovery process.

Technology Lever

A fundamental and comprehensive R&D program involving geologic, laboratory and field studies of enhanced CBM recovery (similar to those underway for enhanced oil recovery) would provide industry the basic information on the feasibility of and appropriate settings for conducting enhanced CBM (ECBM).

Impacts and Benefits

Based on potential access to low cost CO_2 and favorable geologic properties, the basins and gas plays listed on **Table 4D-29** are considered candidates for enhanced CBM. However, since only limited pilot testing of enhanced CBM is underway, commercial scale enhanced CBM is not currently available.

Reference Case Technology introduces new ECBM recovery technology that improves CBM recovery efficiency by 20 percent and makes this technology commercially available in the year 2015. Low Technology does not introduce this technology by year 2020. High Technology introduces a more efficient ECBM technology five years earlier, in 2010. Enhanced CBM also entails higher investment and operating costs for the injected gases of $1.00 per Mcf of incremental CBM produced in the Reference Case and $0.75 per Mcf of incremental CBM produced in the High Technology Case.

The Reference Case w/o DOE remains as the Reference Case because DOE has no active R&D on enhanced CBM recovery. The technology progress on ECBM in the Reference Case is based on an expectation that industry continues to pursue this topic of research.

The specific parameter values for the enhanced technology cases are set forth in **Table 4D-28** below.

Table 4D-28

Parameter Values for Other Unconventional Gas Technologies
Improving & Accelerating Gas Production

Technology Case	Year Available	RecoveryEfficiency	Costs
Current Status	Under R&D	As Calculated	As Calculated
Reference Case	2015	Improves Recovery Per Well by 20%	$1.00/Mcf of Incremental CBM
Reference Case w/o DOE	Same as Reference Case	Same as Reference Case	Same as Reference Case
Low Technology	Not Available	Not Available	N/A
High Technology	2010	Improves Recovery Per Well by 30%	$0.75/Mcf of Incremental CBM

B. Gas Shales

At this time no Other Gas Shales recovery technology has been defined. This technology lever is available for future use.

C. Tight Sands

At this time no Other Tight Sands recovery technology has been defined. This technology lever is available for future use.

Table 4D-29

CBM Plays That Are Candidates for Enhanced CBM

Basins	Plays	Undeveloped Resources (Bcf)
San Juan	North Basin	3,420
Raton	North Basin South Basin	1,781 844
Uinta	Blackhawk Sego	1,176 722
Piceance	Divide Creek White River Dome Basin Margin	1,222 629 3,390
Green River	Basin Margin	3,899

11. Mitigating Environmental and Other Constraints on Development

Background and Problem

Development of unconventional gas particularly in the Rocky Mountain basins, is constrained by concerns over air quality, land disturbance, water disposal and is restricted by wilderness set-asides. These environmental constraints significantly slow the pace of drilling and exclude high potential areas from access and development.

Technology Lever

The environmental constraints may be mitigated or overcome by in-depth environmental assessments of the major constraints, the introduction of environmentally enhanced E&P technology such as low NO_x compressors, improved water treatment and environmentally neutral disposal methods, and the drilling of multiple, directional wells from a single well pad.

Impacts and Benefits

Currently, the basins and gas plays listed on **Tables 4D-31, 4D-32, and 4D-33** experience development constraints that exclude a significant portion, up to 50 percent, of the productive acreage from development.

Reference Case Technology removes these environmental constraints in 50 years, starting in the year 2000. Low Technology keeps the environmental constraint situation as it exists today. High Technology removes these constraints in 25 years, starting in the year 2000.

The Reference Case w/o DOE is between the Reference Case and the Low Technology Case and removes the constraint in 100 years, starting in the year 2000. Both DOE's and GRI's environmental programs help mitigate environmental and other development constraints and help accelerate the pace at which these gas basins and plays can be developed.

The specific parameter value for the technology cases for all three of the unconventional gas resources(CBM, Gas Shales and Tight Sands) are summarized in **Table 4D-30** below.

Table 4D-30

Technology Parameters for Technologies
Mitigating Environmental & Other Constraints on Development

Technology Situation	Environmental (EV) and Other Constraints
Current Status	50% of Area Excluded in EV Sensitive Basins
Reference Case	Constraints Removed in 50 years @ 1%/year
Reference Case w/o DOE	Constraints removed in 100 years @ ½%/year
Low Technology	Constraints Remain as Is
High Technology	Constraints Removed in 25 years @ 2%/year

Table 4D-31

**CBM Plays/Basins With Environmental
Constraints on Development**

Basin	Play	Undeveloped Resource (Bcf)
Raton	North Basin South Basin	1,781 844
Uinta	Ferron* Blackhawk Sego	5,580 1,176 722
Powder River	Central Basin	438
Piceance Basin	Basin Margin Deep Basin	3,390 2,496
Green River	Basin Margin Deep Basin	3,899 3,900

Constraint removed in 1998 with approval of EIS.

Table 4D-32

**Gas Shale Play/Basins With Environmental
Constraints on Development**

Basin	Play	Undeveloped Resource (Bcf)
Appalachia	Devonian Shale - Big Sandy Central	8,568
	Devonian Shale - Big Sandy Extension	9,000
	Devonian Shale - Greater Siltstone Area	2,832
	Devonian Shale - Low Thermal Maturity Area	3,528
Michigan	Antrium Shale - Undeveloped Area	13,595
Illinois	New Albany Shale - Developing Area	1,985
Willston	Shallow Niobrara	1,575

Table 4D-33

**Tight Sands Plays/Basins With Environmental
Constraints on Development**

Basin	Play	Undeveloped Resource (Bcf)
Uinta	Tertiary West	769
	Basin Flank MV	2,469
	Deep Synclinal MV	958
Wind River	Fort Union/Lance Shallow	11,205
	MV/Frontier Shallow	1,500
	Fort Union/ Lance Deep	7,200
	MV/Frontier Deep	625
Appalachian	Upper Devonian High	7,410
	Upper Devonian Moderate	557
	Upper Devonian Low	1,260
Greater Green River	Fort Union	894
	Fox Hills/ Lance	10,733
	Lewis	14,074
	Shallow MV	19,102
	Deep MV	21,600
	Frontier (Moxa Arch)	7,406
	Frontier Deep	22,500
Piceance	North Basin - WF/MV	1,764
	South Basin - WF/MV	9,870
	Iles/MV	4,716
San Juan Basin	Picture Cliffs	3,564
	Central Basin/MV	9,596
	Central Basin/Dakota	8,550
Northern Great Plains	High Potential	3,003
	Moderate Potential	12,784
	Low Potential	6,749
Colombia	Basin Centered Gas	6,300

Appendix 4-E. Deep Water Offshore Supply Submodule

The Deepwater Offshore Supply Submodule (DWOSS) is a PC-based modeling system for projecting the reserve additions and production from undiscovered resources in deepwater offshore Gulf of Mexico Outer Continental Shelf (OCS) region.

This chapter discusses in detail the programming structure, design implementation, costing algorithms, and input databases for resource description, technology options, and other key performance parameters that were used to develop the DWOSS modeling system. In the first section, the model components are introduced. This is followed by the process flow diagrams highlighting the major steps involved in each of the components. The chapter includes a characterization of the undiscovered resource base in the deepwater Gulf of Mexico OCS classified by region and resource type (crude oil and natural gas). In the same section, the input database of resource characteristics developed for DWOSS are described. The subsequent section deals with the rationale behind the various technology options for deepwater exploration, development and production practices incorporated in DWOSS. This is followed by a discussion of the typical exploration, development and production scheduling assumed in the model. It covers the well productivity and production profile parameters assumed in DWOSS. The next section describes the unit cost equations utilized in DWOSS to estimate the various costs associated with exploration, development and production operations in the deepwater Gulf of Mexico OCS. This is followed by a discussion of the financial analysis approach and the discounted cash-flow methodology used in DWOSS to determine the profitability of deepwater crude oil and natural gas prospects, and to generate price-supply data. The final section in this chapter deals with the endogenous component of DWOSS that involves calculation of reserves and production for the total deepwater Gulf of Mexico offshore region.

INTRODUCTION

The DWOSS was developed offline from EIA's Oil and Gas Supply Module (OGSM). A methodology was developed within OGSM to enable it to readily import and manipulate the DWOSS output, which consists essentially of detailed price/supply tables disaggregated by Gulf of Mexico planning regions (Eastern, Central, and Western) and fuel type (oil, natural gas). Maps of the three Gulf of Mexico planning regions are presented in Figures 4E-1 through 4E-3.

At the most fundamental level, therefore, it is useful to identify the two structural components that make up the DWOSS, as defined by their relationship (exogenous vs. endogenous) to the OGSM:

Exogenous Component. A methodology for developing deepwater offshore undiscovered resource price/supply curves, employing a rigorous field-based discounted cash-flow (DCF) approach, was constructed exogenously from OGSM. This offline portion of the model utilizes key field properties data, algorithms to determine key technology components, and algorithms to determine the exploration, development and production costs, and computes a minimum acceptable supply price (MASP) at which the discounted net present value of an individual prospect equals zero. The MASP and the recoverable reserves for the different fields are aggregated by planning region and by resource type to generate resource-specific price-supply curves. In addition to the overall supply price and reserves, cost components for exploration, development drilling, production platform, and operating expenses, as well as exploratory and development well requirements, are also carried over to the endogenous component.

Figure 4E-1. Map of Western Gulf of Mexico Planning Area

Figure 4E- 2. Map of Central Gulf of Mexico Planning Area

Figure 4E-3. Map of Eastern Gulf of Mexico Planning Area

Endogenous Component. After the exogenous price/supply curves have been developed, they are transmitted to and manipulated by an endogenous program within OGSM. The endogenous program contains the methodology for determining the development and production schedule of the deepwater offshore Gulf of Mexico OCS oil and gas resources from the price/supply curves. The endogenous portion of the model also includes the capability to estimate the impact of penetration of advanced technology into exploration, drilling, platform, and operating costs as well as growth of reserves.

PROCESS FLOW DIAGRAMS

The general process flow diagram for the exogenous component of DWOSS model is provided in Figure 4E-4. This component of the model is used to generate price-supply curves for use in the endogenous component of the model. The general process flow diagram for the endogenous component of DWOSS model is provided in Figure 4D-5. This component utilizes price information received endogenously from NEMS to generate reserve additions and production response based on the supply potential made available by the price-supply model.

CHARACTERIZATION OF THE DEEPWATER UNDISCOVERED RESOURCE

Great bulk of undiscovered oil and gas reserves are estimated to be in deeper waters of the Gulf of Mexico OCS. Based on MMS estimates, approximately 12.94 billion of 25.39 billion barrels of oil-equivalent crude oil and natural gas resources are in deepwater areas of the Gulf of Mexico OCS, as shown below in Table 4E-1. The estimated distribution of the MMS resource between water depth ranges 200 - 400 meters and 400 - 900 meters is based on background information from MMS, and are ICF Kaiser's interpretation of this information relative to areal distributions of the Gulf of Mexico OCS area between these two water depth regions.

Figure 4E-4. Programming Structure of the Exogenous Component of DWOSS

Figure 4E-5. Programming Structure of the Endogenous Component of DWOSS

Table 4E-1
Recoverable Undiscovered Reserves in the Deepwater Gulf of Mexico
(Billions of Barrels of Oil Equivalent)

Water Depth Category	Western	Central	Eastern	Total
200 m - 400 meters	0.311	0.593	0.045	0.949
400 m - 900 meters	0.621	1.186	0.089	1.896
> 900 meters	4.449	5.148	0.500	10.097

A distribution of the fraction of resource that is leased vis-a-vis the amount that remains to be leased was also obtained from MMS. The fraction of the resource that is leased is given below:

Estimated Fraction of Discovered Resource Leased
in the Gulf of Mexico

Western	Central	Eastern	Total
0.13	0.18	0.01	0.14

Database of Undiscovered Oil and Gas Prospects

For the purposes of creating resource inputs for the DWOSS, the undiscovered oil and gas prospects in the deepwater Gulf were assumed to be distributed into the ten (10) "plays" listed in Table 4E-2 for each of the three Gulf of Mexico regions. These plays are closely tied to the MMS categorization of the undiscovered resource base in the Gulf, but have been enhanced to divide the MMS "water depth aggregation plays" in the water depth range 200 - 900 meters into two plays aggregated by water depth ranges 200 - 400 meters and 400 - 900 meters. This was done to maintain consistency with the classification of water depth ranges in DWOSS, and to account for different royalty relief opportunities available based on water depth.

The resource distribution information received from MMS consisted of two sets of databases. The first listed typical recoveries for crude oil and natural gas, typical gas-oil-ratio for oil fields and typical condensate yield for gas fields, and the proportion of oil and gas bearing fields. The other database listed a rank-ordered field size distribution (in acre-ft) in each play. The parameters listed in the first database are:

1. Proportion gas bearing fields, fraction,
2. Oil recovery factor, Bbl/Acre-ft,
3. Gas-oil ratio for oil bearing fields, Scf/Bbl,
4. Gas recovery factor, Mcf/Acre-ft, and
5. Condensate yield for gas bearing fields, Bbl/MMcf.

Table 4E-2
List of Deepwater Gulf of Mexico Plays in DWOSS

Region	Play Code	Description of the Play
WGOM	UGWG0301	Western Gulf of Mexico, Water Depth Aggregation Range 200-400 meters
	UGWG0302	Western Gulf of Mexico, Water Depth Aggregation Range 400-900 meters
	UGWG0401	Western Gulf of Mexico, Water Depth Aggregation Range > 900 meters
	UGTE0103	Gulf of Mexico Tertiary Basin, Perdido Fold Belt Play
CGOM	UGCG0301	Central Gulf of Mexico, Water Depth Aggregation Range 200-400 meters
	UGCG0302	Central Gulf of Mexico, Water Depth Aggregation, WD Range 400-900 meters
	UGCG0401	Central Gulf of Mexico, Water Depth Aggregation Range > 900 meters
EGOM	UBLK0110	GOM Atlantic, Lower Cretaceous, Carbonate Complex, Water Depth < 900 meters
	UBLK0120	GOM Atlantic, Lower Cretaceous, Carbonate Complex, Water Depth > 900 meters
	UGEG0401	Eastern Gulf of Mexico, Water Depth Aggregation Range > 900 meters

However no information was available from these databases on the distribution between oil and gas fields. Therefore, using spreadsheet analyses, different combinations of oil and gas fields in each play were assumed until close matches were obtained for the following with the corresponding MMS values:

■ Proportion gas bearing fields (number of gas fields / total number of fields in the given play); and

■ Total oil and gas resource for each water depth range in each region

Once the distribution of oil and gas bearing fields for each play was established, the resource database comprising of the field rank, field type (oil or gas), field size (oil and associated gas, or gas and associated condensate) was combined with other field properties and parameters necessary for generating the required inputs for the DWOSS to generate play-specific input database sets.

Additional Required Input Data

Additional information that is needed to perform the economic evaluation of offshore deepwater crude oil and natural gas fields include the following:

■ The Average API Gravity is used to compute a price penalty based on the quality of crude oil. These data have been obtained from published averages in the Gulf of Mexico, as well as MMS estimates.

■ The Average Gas-Oil Ratio is used to determine the total amount of associated/dissolved (A/D) gas in the oil field.

■ The Average Condensate Yield is used to determine the total amount of associated condensate in the gas field.

■ The Average Water Depth is used for platform and well cost calculations. Average water depth for each water depth class was determined from actual field data in different water depth categories of the Gulf of Mexico.

- The Total Exploration and Development Well Drilled Depths are critical factors in drilling costing algorithms. The depths reflect the most likely future exploration and development well depths in each play and were based on actual well completion data.

- Exploration and Development Drilling Success Rates are critical in determining the number of well required to explore for and develop a field.

DEEPWATER TECHNOLOGY OPTIONS

The technology employed in the deepwater offshore areas to find and develop hydrocarbons can be significantly different than that used in shallower waters, and represents significant challenges for the companies and individuals involved in the deepwater development projects. Some of the reasons behind this are that the deepwater prospects:

- Are in a predominantly frontier exploration area;

- Are in locations that are more remote;

- Have wells that produce at much higher rates; and

- Are explored for and developed in significantly more extreme environmental conditions.

This section sets forth the technology choices for exploration, development and production of the Gulf of Mexico deepwater offshore fields. The choices are consistent with current practices as well as projected technology choices for fields which are slated to be developed in the near future.

In many situations in the deep water OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed. For purposes of specifying technology choices in DWOSS, a standard classification system for categorizing fields by size class was required.

The table below shows the distribution of field sizes by classes defined by US Geological Survey (USGS), which are used for specifying many of the technology assumptions in DWOSS.

USGS Class	Field Size Range (MMBOE)		
7	0.190	-	0.380
8	0.380	-	0.760
9	0.760	-	1.520
10	1.520	-	3.040
11	3.040	-	6.070
12	6.070	-	12.140
13	12.140	-	24.300
14	24.300	-	48.600
15	48.600	-	97.200
16	97.200	-	194.300
17	194.300	-	388.600
18	388.600	-	777.200
19	777.200	-	1554.500
20		<	1554.500

Technology Choices for Exploration Drilling

During the exploration phase of an offshore project, the type of drilling rig used depends on both economic and technical criteria. Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. For deepwater exploratory drilling, two types of drilling rigs are most commonly employed.

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This extends the maximum operating depth greatly, and some of these rigs can be used in water depths up to and beyond 3,000 feet. The shape of a semisubmersible rig tends to dampen wave motion greatly regardless of wave direction. This allows its use in areas where wave action is severe.

Dynamically positioned drill ships are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3000 feet where the semi-submersible type of drilling rigs can not be deployed. Some of the drillships are designed with the rig equipment and anchoring system mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This helps to dampen wave motion.

Water depth is the primary criterion for selecting a drilling rig. Therefore, DWOSS assumes the selection of drilling rig type to be a function of water depth, as follows:

Drilling Rig Type	Water Depth (meters)
Semi-submersible	200 - 900
Drillship	> 900

Technology Options for Development/Production Structure

Six different options for development/production of deepwater offshore prospects are currently assumed in DWOSS, based on those currently considered and/or employed by deepwater operators in Gulf of Mexico OCS. These are the conventional fixed platforms, the compliant towers, tension leg platforms, Spar platforms, floating production systems and subsea satellite well systems. Choice of platform tends to be a function of the size of field and water depth, though in reality other operational, environmental, and/or economic decisions influence the choice.

1. **Conventional Fixed Platform (FP).** A fixed platform consists of a jacket with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The jacket is a tall vertical section made of tubular steel members supported by piles driven into the seabed. The fixed platform is economical for installation in water depths up to 1,200 feet. Although advances in engineering design and materials have been made, these structures are not economically feasible in deeper waters.

2. **Compliant Towers (CT).** The compliant tower is a narrow, flexible tower type of platform which is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the tower and terminating on pile or gravity anchors on the sea floor. The compliant tower can withstand significant forces while sustaining lateral deflections, and is suitable for use in water depths of 1,200 to 3,000 feet. A single tower can accommodate up to 60 wells, however, the compliant tower is constrained by limited deck loading capacity and no oil storage capacity.

3. **Tension Leg Platform (TLP).** The tension leg platform is a type of semi-submersible structure which is attached to the sea bed by tubular steel mooring lines. The natural buoyancy of the platform

creates an upward force which keeps the mooring lines under tension and helps maintain vertical stability. This type of platform becomes a viable alternative at water depths of 1,500 feet and is considered to be the dominant system at water depths greater than 2,000 feet. Further, the costs of the TLP are relatively insensitive to water depth. The primary advantages of the TLP are its applicability in ultra-deepwaters, an adequate deck loading capacity, and some oil storage capacity. In addition, the field production time lag for this system is only about three years.

4. **Floating Production System (FPS).** The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10%. These structures can only accommodate a maximum of approximately 25 wells. The wells are completed subsea on the ocean floor and are connected to the production deck through a riser system designed to accommodate platform motion. This system is suitable for marginally economic fields in water depths up to 4,000 feet.

5. **Spar Platform (SPAR).** Spar Platform consists of a large diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull which is moored using a taut caternary system of six to twenty lines anchored into the seafloor. Spar platforms are presently used in water depths up to 3,000 feet, although existing technology is believed to be able to extend this to about 10,000 feet.

6. **Subsea Wells System.** Subseas system ranges from single subsea well tied back to a nearby production platform (such as FPS or TLP) to a set of multiple wells producing through a common sub-sea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet.

The typical water depth and field size class ranges for selection of a given platform in the model is given below:

Production Structure	Water Depth (meters)			Field Size Class Range
Fixed Platform		<	400	> 12
Compliant Tower	400	-	600	> 15
Tension Leg Platform	600	-	1500	> 15
Floating Production System	400	-	1500	12 - 15
Spar Platform		>	1500	> 12
Subsea Wells System	All Depth Ranges			< 12

Technology Choices For Development Drilling

Pre-drilling of development wells during the platform construction phase is done using the drilling rig employed for exploration drilling. Development wells drilled after installation of the platform which also serves as the development structure is done using the platform itself. Hence, the choice of drilling rig for development drilling is tied to the choice of the production platform.

Technology Choices for Product Transportation

It is assumed in the model that existing trunk pipelines will be used, and that the prospect economics must support only the gathering system design and installation. However, in case of small fields tied back to some existing neighboring production platform, a pipeline is assumed to be required to transport the crude oil and natural gas to the neighboring platform.

EXPLORATION, DEVELOPMENT AND PRODUCTION SCHEDULING

This section sets forth the descriptions, assumptions, methodology, and sources used for determining the exploration, development, and production schedules assumed for various types of potential prospects that remain to be discovered in the deepwater offshore Gulf of Mexico.

The typical project development in deepwater offshore consists of the following phases. The pre-development activities, including early field evaluation using conventional geological and geophysical methods and the acquisition of the right to explore the field, are assumed to be completed before initiation of the development of the prospect:

- Exploration phase

    – Exploration drilling program
    – Delineation drilling program

- Development phase

    – Fabrication and installation of the development/production platform
    – Development drilling program

        • Pre-drilling during construction of platform
        • Drilling from platform

    – Construction of gathering system

- Production operations

- Field abandonment.

The timing of each activity, relative to the overall project life and to other activities, affects the potential economic viability of the undiscovered prospect. The modeling objective is to develop an exploration, development, and production plan which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

Exploration Phase

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

Exploration drilling. Drilling of all exploration wells (i.e., the wildcat and all corresponding exploratory dry holes) is assumed to begin in the first year of the field development project, and that exploration drilling takes one year to complete. The e*xploration success rate* (ratio of the number of field discovery wells to total wildcat wells) is used to establish the number of exploration wells required to be drilled to discover the field. For all deepwater Gulf of Mexico OCS prospects, DWOSS assumes that the exploration success rate is 1:4, i.e., for each successful well, a total of four wells need to be drilled.

Delineation drilling. The delineation well drilling program is assumed to begin the year after initiation of exploration drilling, i.e., year 2 of the project. The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. In the engineering costing model and for production operations, the delineation wells are treated as dry holes. The number of delineation wells required to define each field is calculated using the ***combined extension and development success rate*** (ratio of successful extension and development wells to total extension and development wells). The duration of the delineation well drilling program is determined as a function of the number of delineation drilling wells, the average total drilled depth, and the average drilling rate. The equations for drilling rates used in the model are shown below for various depth categories:

Total Drilled Depth (feet)	Average Drilling Rate (feet/day)
< 10,000	800 - 0.058 * Drilling Depth
≥ 10,000	200

These relationships were developed based on an examination of drilling rates currently occurring in the deepwater Gulf of Mexico.

Development Phase

During this phase of an offshore project, the development structures are designed, fabricated, and installed; the development wells (successful and dry) are drilled and completed; and the product transportation/gathering system is installed.

Development structures. The model assumes that the design and construction of any development structure begins in the year following completion of the exploration and delineation drilling program. However, the length of time required to complete the construction and installation of these structures depends upon the type of system used. The table below lists the required time for construction and installation of the various development structures used in the model. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

Large fields (Field Size Class > 15)

Water Depth (meters)	Construction and Installation Time (Years)			
	Fixed Platforms	Compliant Towers	Tension Leg Platforms	Spar Platforms
0 - 400	2	-	-	-
400 - 900	-	3	3	-
> 900	-	-	4	3

Mid-size fields (Field Size Class 12 - 15)

	Fixed Platforms	Floating Production Systems
0 - 400	2	-
> 400	-	2

Small fields (Field Size Class < 12)

Tied back to existing production facilities through subsea manifold and pipelines.

1 year

The importance of reducing the time lag is addressed by assuming the use of early production techniques, such as:

- Using simultaneous drilling and production operations

- Pre-drilling some of the development wells during the time in which the development structure is being constructed and installed.

Development drilling program. The timing of the development drilling program is also determined by the type of development system assumed. When conventional fixed platforms are used, the following development schedule is assumed.

- No pre-drilling program is utilized. Use of a fixed platform would delay initial production by two to four years, which is consistent with current offshore practices.

- The development drilling program begins the year after the platforms are installed. All wells are drilled from the platform.

For all other types of development structures, including compliant towers, tension leg platforms, Spar platforms, and floating production systems, the following development schedule is assumed:

- The subsea drilling templates are fabricated and installed the first year of structure construction.

- Pre-drilling of some development wells begins from a mobile rig during the first year of structure construction, and continues through the construction time.

- The remaining wells are drilled from the structure beginning the year after installation.

- The pre-drilled wells begin producing during the first year after installation of the structure.

Regardless of the type of development system used, the number of development wells required to completely develop the field is determined by the field size and estimated ultimate recovery per well. The *Development Success Rate* (ratio of successful to total developmental wells) is used to establish the number of unsuccessful wells that can be expected while drilling within the boundary of a known field. These development drilling success rates are based on historical drilling data.

The time required to drill all wells, both successful and dry, depends on the number of wells to be drilled, the average drilled depth and a corresponding average drilling rate:

Total Drilled Depth (feet)	Average Drilling Rate (feet/day)
< 10,000	1000 - 0.0725 * Drilling Depth
≥ 10,000	250

These relationships are based on examination of drilling rates currently occurring in the deepwater Gulf of Mexico. It is assumed that 15 days are required to complete each well, after drilling is complete. Further, an equal number of wells are assumed to be drilled each year.

Production transportation/ gathering system. It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within one year.

Production Operations

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. The well productivities and production profiles over the productive life are discussed below.

Typical production profiles. Typical oil and gas production profiles for offshore development wells are based upon typical recovery profiles generated by using standard reservoir performance models. The Primary Recovery Predictive Model (PRPM) for crude oil and Gas Systems Analysis Model (GSAM) for natural gas, developed for Department of Energy's Office of Fossil Energy, were used for this purpose. These models can predict the deliverability of the reservoir and year-wise production performance as a function of reservoir properties (area, thickness, porosity, permeability, lithology, depth, saturation etc.) and technology, using standard stream tube (for crude oil) and type curve (for natural gas) performance prediction techniques. The associated gas recovery in case of an oil well and the associated NGL (natural gas liquids) in case of a gas well are calculated using a regional average gas-oil ratios. The production profiles generated using the reservoir performance models were modified to reflect the platform capacity constraints, as well as wellbore productivity constraints not considered in the performance models. In order to generate the revised per well production profiles, the producing life of each well is assumed to be five years for a small field, ten years for a mid-size field, and fifteen years for a large field. The revised per well production profiles assumed in DWOSS are given below:

Year in Production	Percent of Total Ultimate Recovery FIELD SIZE CLASS RANGE		
	4 - 9	10 - 14	15 - 20
1	40.0	30.0	27.0
2	26.0	22.0	21.0
3	17.0	16.0	16.0
4	11.0	12.0	11.0
5	7.0	9.0	8.0
6		7.0	6.0
7		5.0	4.0
8			3.0
9			3.0
10			2.0

Productivity and number of wells. The number of producing oil / gas wells per field is a key input required by DWOSS. For a particular field, the number of required wells is determined by using an

average well productivity (arrived at by summation of the annual production figures generated by the reservoir performance models, PRPM and GSAM) as a function of field size class, divided into the field size to give the required number of wells for the particular size field. The data used for estimating recovery per well as a function of field size in DWOSS are shown in Table 4E-3.

Table 4E-3
Average Size of a USGS Field Size Class, and Per Well Recovery

USGS Class	Average Size (MMBOE)	Per Well Recovery (MBOE)
7	0.273	250.0
8	0.547	500.0
9	1.094	1000.0
10	2.189	1500.0
11	4.378	2000.0
12	8.741	2600.0
13	17.480	3300.0
14	34.990	4300.0
15	69.980	5500.0
16	139.960	6800.0
17	279.790	8500.0
18	559.580	10500.0
19	1119.160	13500.0

Notes:
1. Geometric means of USGS Field Size Classes (= 1.44 * minimum of the range).
2. 1 BOE = 5.7 Mcf

Abandonment Phase

The year when the project production reaches economic limit (operating costs exceed the revenues), defines the last year of production. The development structures and production facilities are abandoned in the year following the cessation of production.

ENGINEERING COSTING ALGORITHMS

This section sets forth descriptions, assumptions, methodology, and reference sources used for determining the engineering cost algorithms for key cost factors for developing and producing crude oil from the deepwater Gulf of Mexico. The assumptions underlying the selection of technologies for field exploration, development, and production represent the best industry practices subject to the ultimate project economics, and are based on review of a number of sources including a database of existing/proposed deepwater projects, past analytical works and reports of ICF, MMS costing assumptions, and various other sources. The cost equations represent the functional relationships between the cost components of the financial analysis model and the parameters affecting them.

Capital Costs

Geological and Geophysical Activities. The cost to conduct the geological and geophysical (G&G) assessment of the field is based on surveys of oil and gas industry expenditures. The cost of these

activities tends to be roughly 15 percent of the cost to drill and complete all exploration wells, including the field delineation wells. In financial analyses, the portion of these costs associated with drilling the unsuccessful wells (dry holes) is expensed in the year incurred (the first year of analysis), while the portion of the costs associated with drilling successful wells is depleted using unit-of-production depreciation. However, since most offshore exploration and delineation wells are plugged after drilling, all costs of all such wells are assume to be expensed in DWOSS.

Exploration and Delineation Well Drilling. The costs to drill an offshore exploration well can be divided into the following three categories:

1. Fixed cost items - including wellhead and downhole equipment, and rig setup

2. Time dependent items - including rigs, barges, labor, service equipment rentals, and other support services

3. Well depth dependent items - including casing, tubing, cementing, and other equipment associated with drilling the well.

Exploration drilling costs estimated in the model for the two classes of drilling rigs are presented below:

Semi-Submersible Rigs ($/well)

Exploration Drilling Cost = 2,000,000 + 1,825*WD + (0.01*WD + 0.045*ED - 415)*ED

Dynamically-Positioned Drill Ships ($/well)

Exploration Drilling Cost = 8,000,000 + 175*WD + (0.0525*ED - 600)*ED

where,
$$WD = \text{Water Depth (feet)}$$
$$ED = \text{Exploration Drilling Depth (feet)}$$

The engineering costing equations used for estimating exploration well drilling costs are also used to estimate the cost to drill field delineation wells (i.e., the wells drilled to define the extent of the field). The delineation wells are treated as dry exploration wells.

Delineation Drilling Cost = 0.85*Exploration Drilling Cost

All costs associated with drilling the exploration wells are treated as intangible capital investments and are expensed in the year in which they occur.

Production and Development Structure. The type of development structure depends primarily upon the conditions of water depth, environmental hostility, and reservoir size. In some cases, the development structures used for drilling production and injection wells also serve as the production facility.

The total cost of the development structures is distributed evenly over the time period between the initiation of construction and the installation of the structures. In each year during this development period, 90% of these costs are treated as capitalized tangible investments and are depreciated beginning the following year. The remaining 10% of these costs are expensed in the year incurred. The costs

associated with each type of development and production structure considered in DWOSS are described in the paragraphs below. In all the equations for the various platforms shown in the paragraphs below:

NSLT = Number of Slots per Structure
WD = Water depth (feet)
NTMP = Number of Templates

1. **Conventional Fixed Platform (FP).** The following engineering costing equations are used to estimate conventional fixed platform costs, which include design, fabrication, and installation of the jacket, pilings, and the deck sections, as shown below:

   Cost ($) = 2,000,000 + 9,000*NSLT + 1,500*WD*NSLT + 40*WD*WD

2. **Compliant Tower (CT).** The costing equation developed for compliant towers is expressed as a function of water depth and is valid for water depths greater than 1,000 feet. Costs include those for the design, fabrication, and installation of the jacket, pilings, deck sections, and mooring system (including guy lines), as shown below:

   Cost ($) = (NSLT + 30)*(1,500,000 + 2,000*(WD-1,000))

3. **Tension Leg Platform (TLP).** Tension leg platforms are designed primarily for use in deeper waters; however, the costs are relatively insensitive to water depths greater than 1,000 feet. The following costing equation includes the design, fabrication, and installation of the deck sections, mooring system, and related foundations, as shown below:

   Cost ($) = (NSLT + 30)*(3,000,000 + 750*(WD-1,000))

4. **Spar Platform (SPAR).** Spar platforms are a recent development. It is estimated that these types of platforms would be dominant in the deepwater, and that they would be applicable in water depths upto 10,000 feet. The costs are shown below:

   Cost ($) = (NSLT + 20)*(5,000,000 + 500*(WD-1,000))

5. **Floating Production System (FPS).** The costs to construct a FPS include not only the rig purchase, fabrication, and installation costs, but also the cost to fabricate and install a flexible production riser system, and are expressed by the following equation. Since flexible production risers are generally easier to install and maintain than rigid risers, DWOSS assumes that production to a converted semi-submersible or tanker is accomplished with flexible risers. The costs are shown below:

   Cost ($) = (NSLT + 20)*(1,500,000 + 250*(WD-1,000))

6. **Subsea Wells System.** Since the cost to complete a well are included in the development well drilling and completion costs, DWOSS assumes no cost for a subsea wells system. Typically subsea wells are tied back to neighboring structures, and the only cost is the cost of the pipeline to connect the wells from the subsea system to the platform.

Subsea Template Installation. The engineering costing model also assumes that a subsea template is required for all development wells producing to any structure other than a fixed platform.

   Cost of Subsea Template ($/well) = 2,500,000 * NTMP

These costs are also applicable to the subsea well systems tied back to neighboring platforms.

Development Well Drilling. During the field development phase of an offshore project, the type of structure used to drill the development wells also depends on both economic and technical criteria. The most important factors affecting the selection of a drilling structure are the timing of the field development and the type of production facility employed.

In all cases except a field where a fixed platform is assumed to be installed, DWOSS assumes that pre-drilling of development wells will be carried out using the exploration drilling rig. It is assumed that wells will be drilled from either a semi-submersible rig or a dynamically-positioned drill-ship. DWOSS assumes that the cost to pre-drill a dry development well would be equal to the cost of drilling a delineation well using one of the rigs listed above. For a successful development well, the costs for completing and equipping the well are added to the cost of drilling a dry development well.

DWOSS further assumes that once the production structure is ready, the remaining development wells will be drilled from the platform. The components of the engineering costing equations for development drilling are similar to those presented earlier for exploration drilling, except for the following differences:

■ The average time required to drill and complete a development well is much less than for an exploration well.

■ The drilling rig rates are much less for wells drilled from a platform or tower.

The dry development well drilling costs do not include costs to complete and equip the well (production casing or production facility costs, i.e., flowlines, valves, etc.). DWOSS is set up to compute the dry development drilling well costs and well completion and equipment costs. The cost of successful development drilling is calculated by summing the dry development well drilling costs and the well completion and equipment costs.

<u>Dry Development Drilling Cost</u>

For water depths less than or equal to 900 meters,

Cost ($/well) = 1,500,000 + (1,500 +0.04*DD)*WD + (0.035*DD - 300)*DD

For water depths greater than 900 meters,

Cost ($/well) = 5,500,000 + (150 + 0.004*DD)*WD + (0.035*DD - 250)*DD

where,

WD	=	Water Depth, feet
DD	=	Development Drilling Depth, feet

Well Completion and Equipment Cost ($/well)

Water Depth (feet)	Development Drilling Depth (feet)		
	< 10,000	10,001-20,000	> 20,000
0 - 3000	800,000	2,100,000	3,300,000
> 3000	1,900,000	2,700,000	3,300,000

In the engineering costing model, 70% of the costs associated with drilling development wells are treated as intangible capital investments, while the remaining 30% of the costs are considered to be tangible investments, which are capitalized and depreciated over a 10 year life. In addition, 30% of the intangible costs are capitalized beginning the year after they are incurred. Remaining 70% of the intangible costs are expensed in the year in which they occur.

Production Facility System. The cost to install production equipment on the development structure is a function of the anticipated peak oil / gas production capacity for the structure. The following equations for estimating facility costs include primary separation facilities, treating equipment, pumps, compressors, storage systems, and associated piping and control systems:

For Oil Production

Oil Production Capacity: 0 - 10,000 bbl/day

Production Equipment Cost ($/well) = (540,000 +52.5*QMXOIL) / NSTRUC

Oil Production capacity: > 10,000 bbl/day

Production Equipment Cost ($/well) = (900,000 + 7.8*QMXOIL) / NSTRUC

For Gas Production

Gas Production Capacity, 0 - 20 MMcf/day

PRCEQP = (0.675 * QMXGAS) * 1,000,000 / NSTRUC
TOPEQP = (0.950 * QMXGAS) * 1,000,000 / NSTRUC

Gas Production Capacity, 20 - 40 MMcf/day

PRCEQP = (13.5 + (0.275 * (QMXGAS-20)) * 1,000,000 / NSTRUC
TOPEQP = (19.0 + (0.225 * (QMXGAS-20)) * 1,000,000 / NSTRUC

Gas Production Capacity, 40 - 120 MMcf/day

PRCEQP = (19.0 + (0.181 * (QMXGAS-40)) * 1,000,000 / NSTRUC
TOPEQP = (23.5 + (0.100 * (QMXGAS-40)) * 1,000,000 / NSTRUC

Gas Production Capacity, > 120 MMcf/day

PRCEQP = (33.5 + (0.156 * (QMXGAS-20)) * 1,000,000 / NSTRUC
TOPEQP = (31.5) * 1,000,000 / NSTRUC

where,

NSTRUC	=	Number of Structures
PRCEQP	=	Processing Equipment Cost
TOPEQP	=	Topside Equipment Cost
QMXOIL	=	Peak Oil Production Capacity, bbl/day
QMXGAS	=	Peak Gas Production Capacity, Mmcf/day

For platforms producing primarily gas, the top total costs of the topside facility is represented by the sum of the processing equipment costs (PRC EQP) and the topisde equipment cost (TOPEQP).

The production facility costs are assumed to occur in the same year in which the development structure is constructed. All of the production and injection equipment costs are treated as tangible investments and are depreciated beginning the following year after costs are incurred.

Production Gathering System. All fields are assumed to utilize existing trunk lines in the vicinity of the field. Each development structure requires a gathering system. The average length of each gathering system in the different fields are assumed to be a function of the size of the field. The following approximations for pipeline costs were developed.

For all small fields (Field Size Class < 10),   GATDIS = 1 mile

For all large fields (Field Size Class > 15),   GATDIS = Data from Input Database

For all mid-size fields (Field Size Class Range 10-15), GATDIS is determined by interpolating between the values for the small and large fields.

DWOSS estimates the cost of constructing gathering system as follows:

Gathering Line Costs ($)   = 250,000 * GATDIS * NSTRUC

where,

        GATDIS = Average length of gathering system
        NSTRUC = Number of structures in the field

These costs are considered to be tangible capital investments and are capitalized the year following the installation costs are incurred.

Structure and Facility Abandonment. The costs to abandon the development structure and production facilities depend upon the type of production technology used. The abandonment costs for fixed platforms and compliant towers assume the structure is abandoned. The costs for tension leg platforms, converted semi-submersibles, and converted tankers assume that the structures are removed for transport to another location for reinstallation. These costs are treated as intangible capital investments and are expensed in the year following cessation of production. Based upon historical data, these costs are estimated as a fraction of the initial structure costs, as follow:

	Fraction of Initial Platform Cost
Fixed Platform	0.45
Compliant Tower	0.45
Tension Leg Platform	0.45
Floating Production Systems	0.15
Spar Platform	0.15

There is a provision in the model to not include the abandonment costs in the economic evaluation of the deepowater Gulf of Mexico OCS prospects. It is a user-defined analysis option.

Annual Operating Costs

Platform Operating Costs. In general, platform operating costs for all types of structures are a function of water depth and the number of slots on the structure. These costs include the following items:

- primary oil and gas production costs

- labor

- communications and safety equipment

- supplies and catering services

- routine process and structural maintenance

- well service and workovers

- insurance on facilities

- transportation of personnel and supplies.

The equation used for estimating annual structure operating costs is as follows:

Cost ($/structure/year) = 1,265,000 +135,000*NSLT + 0.0588*NSLT*WD*WD

If water depth is less than or equal to 1500 feet, WD = WDEP
If water depth is greater than 1500 feet, WD = 1500

where,

WDEP	=	Water depth, feet
NSLT	=	Number of Slots per Structure
QGAS	=	Gas Production Capacity
NSTRUC	=	Number of Structures

Operating Costs of Pipeline Operating System. Pipeline operating costs are estimated to be a function of the amount of oil and gas produced. The input database file for each of the water depth aggregated plays contains the typical transportation tariffs (in $/bbl of crude oil or $/Mcf of gas produced) for these regions and is used in the calculation of pipeline operating costs. These costs represent a share of the operation of the existing trunk line that is proportional to the volume of oil and gas transported through the trunk line by the prospect under consideration.

FINANCIAL ANALYSIS AND PRICE-SUPPLY MODELING

The financial analysis and price-supply model is the off-line exogenous component of DWOSS. It consists of a set of algorithms that have been designed to systematically evaluate the relative economic potential of the undiscovered crude oil and natural gas prospects in the deepwater Gulf of Mexico OCS. Key reasons for the necessity of a systematic financial analysis approach are:

- ■ To represent all standard industry accounting practices in determining the after-tax cash flow for each year of a potential project, including depreciation and expensing;

- ■ To systematically represent all issues associated with prospect-specific resource characteristics, technology choices, project scheduling, and costing ;

- ■ To represent all components that are dependent on price, such as transportation tariff deductions and API gravity adjustments;

- ■ To represent all transfer payments, such as taxes and royalties, including government incentives

- ■ To represent the time value of money; and

- ■ To solve for the replacement cost, or that value which yields a zero net present value of the combined yearly after-cash flow streams.

The financial analysis algorithms in DWOSS is a minimum supply price calculation routine that uses the method of bisection to solve for the minimum required crude oil or natural gas price for a crude oil or natural gas prospect, respectively, to be economic at a specified rate of return. A discounted cash flow (DCF) calculation is used to estimate the present net worth of the net inflow or outflow of money that occurs during a specified period, as represented below:

	Gross Revenue or Savings
less	**Operating Expenses**
less	**Tax Costs**
less	**Capital Costs**
	_____
=	**Cash Flow**

Figure 4E-6 represents the process-flow diagram of the financial analysis routines in DWOSS. In the following sections, the key components and their methodologies are described in more detail.

Gravity Adjusted Revenues

The 1984 National Petroleum Council (NPC) assessment of the potential of enhanced oil recovery (EOR) devoted considerable attention to the value of crude oils of various composition. In general, low API gravity oils (10-26° API) have less value because of a preponderance of heavy hydrocarbons (and perhaps sulfur) which reduces the volume of higher value refined products. In addition, special facilities (and higher costs) are required to transport and refine heavier crudes. Although the pricing of crude oil is

Figure 4E- 6. Process Flow Diagram of the Discounted Cash Flow Financial Analysis

```
┌──────────────────────────────────────────────────────────────────┐
│       Calculate Production Revenues for Crude Oil and Natural Gas  │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│          Calculate Gravity Penalties and Transportation Tariffs    │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│                 Calculate Royalties and Royalty Relief             │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│   Calculate Adjusted Revenues = Gross Revenues - Penalties -       │
│              Tariffs - Royalties + Relief                          │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│          Calculate Tangible and Intangible Investment Costs        │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│            Calculate Operating and Administrative Costs            │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│   Calculate Net Revenues = Adjusted Revenues - Operating and       │
│                 Administrative Costs                              │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│             Calculate Depreciation and Capital Recovery           │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│   Calculate Before-Tax Cash Flow = Net Revenues - Intangible       │
│             Investments - Depreciation                            │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│                     Calculate Federal Taxes                        │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│                      Calculate Tax Credits                         │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│  Calculate After-Tax Cash Flow = Before-Tax Cash Flow - Federal    │
│  Taxes + Tax Credits - Tangible Investments + Depreciation        │
└──────────────────────────────────────────────────────────────────┘
                                │
                                ▼
┌──────────────────────────────────────────────────────────────────┐
│                 Calculate Discounted Cash Flow                    │
└──────────────────────────────────────────────────────────────────┘
```

a complex and intricate process, the NPC EOR study was able to make the following simplifications, which have been adapted for use in DWOSS as shown below:

- The reference standard for crude oil is 40° API.

- If the typical crude gravity for a field is at or above 32° API, the price penalty is \$0.10 per degree below 40° API.

- If the typical crude gravity for a field is between 20° and 31° API, the price penalty is \$0.20 per degree below 40° API.

- If the typical crude gravity for a field is below 20° API, the price penalty is \$0.40 per degree below 40° API.

These penalties are calculated from a nominal price of \$26.50 and are escalated for prices above or below this price.

Co-product Valuation

In order to determine the value of associated/dissolved gas produced from oil-bearing fields, and the value of condensate yield from gas-bearing fields in the deepwater Gulf of Mexico OCS, a co-product valuation methodology was incorporated into DWOSS. This assumes that the value of natural gas would be 68% of the energy-equivalent value of crude oil at the nominal oil price established from recent trends in valuations of crude oil and natural gas in the market. This value is used for all calculations of revenues from associated/dissolved gas in oil-bearing fields and condensate yield in gas-bearing fields.

Capitalized and Expensed Costs

Capital investments in DWOSS include expenditures for geological and geophysical evaluations, exploration drilling, delineation drilling, development drilling including pre-drilling, production structure, and gathering pipeline system.

For tax purposes, the fastest method of deducting costs is to "expense" them in the year incurred, which means to deduct them in full amount in the year incurred. However, tax law does not permit "expensing" all costs, but instead permits these costs to be "capitalized" and deducted for tax purposes over a period of time greater than a year.

Pre-Development Costs which include geological and geophysical costs are depleted using "unit of production" depreciation method described in the following section.

Exploration and Delineation Drilling Costs are treated as "intangible" investments and are expensed in the year incurred.

Development Drilling Costs are split into tangible and intangible investment costs. In DWOSS, 30% of the costs are considered tangible investment costs. Intangible drilling costs are defined as the cost of drilling oil and gas wells to the point of completion. The model assumes that only 70% of the intangible drilling costs may be expensed in the year incurred with the remaining 30% of the intangible drilling costs "capitalized".

Production Structure Installation Costs, like drilling costs, are split into tangible and intangible investments. The model assumes that only 10% of the intangible structure installation costs may be expensed in the year incurred and the remaining 10% intangible costs are "capitalized".

Operating Costs covering costs for direct labor, indirect labor, materials, parts and supplies used for operations are modeled as structure operating costs in DWOSS, and are expensed in the year they are incurred.

Capitalized items are depleted by depreciation in DWOSS. This permits the recovery of these expenditures over a specified period of time, as described in the following section.

Depreciation Schedules Assumed

Annual taxable income is reduced by an annual depreciation deduction or allowance that reduces the annual amount of income tax payable to justify "a reasonable allowance for the exhaustion, wear and tear, and obsolescence of property held by a tax payer for the production of income". A property is depreciable if it meets these requirements:

■ It must be used in business or held for the production of income.

■ It must have a determinable life and that life must be longer than one year.

■ It must be something that wears out, decays, gets used up, becomes obsolete, or loses values from natural causes.

■ It is placed in service or is in a condition or state of readiness and available to be placed in service.

Depreciation of tangible property placed in service after 1986 is based on using modified accelerated cost recovery system (ACRS) depreciation for: (1) the applicable depreciation method, (2) the applicable recovery period (depreciation life), and (3) the applicable first year depreciation convention. Modified ACRS depreciation calculations relate to two of the following three depreciation methods modeled in DWOSS, 'straight line depreciation' and 'double declining balance'. The third method, 'unit of production' depreciation, is used to a lesser extent for tax deduction purposes but to a greater extent for shareholder reporting purposes.

1. ***Straight Line Depreciation***. Straight line depreciation is the simplest method of computing depreciation. With the straight line method, depreciation per year is determined by multiplying the cost basis of a property times a straight line depreciation rate which is one divided by the allowable depreciation life, "n" years. In equation form:

    Straight Line Depreciation Per Year   =   (Cost) * (1/n)

2. ***Double Declining Balance.*** Double declining balance depreciation applies a depreciation rate to a declining balance each year. Using a standard approach, factors for each year in the depreciation life have been developed, as shown in equation below:

    Double Declining Balance Depreciation Per Year   =   (Cost) * (Adjusted Factor)

The adjusted factors for two depreciation lives in DWOSS, 5 years and 7 years, are given below:

Year	1	2	3	4	5	6	7
Life = 7 years	0.14	0.25	0.20	0.16	0.13	0.08	0.04
Life = 5 years	0.15	0.22	0.21	0.21	0.21		

3. ***Units of Production.*** Units of production depreciation deducts the asset cost over the estimated producing life of the asset by taking annual depreciation deductions equal to the product of the "asset cost" times the ratio of the "units produced" in a depreciation year, divided by "expected asset lifetime unit of production".

Units of Production Depreciation Per Year = (Cost) * (Production in the Year)/ Total Recoverable Reserves in the Year

Federal Tax, Royalties, and Incentives

A rigorous methodology for computing federal taxes and producer royalties has been included in DWOSS. No provision has been kept for state taxes as these are not applicable in deepwater Gulf of Mexico OCS, which are exclusively federal properties. Provision has, however, been kept for calculation of severance taxes and tax incentives/credits, and have been set equal to zero for this analysis.

A federal tax rate of 34% on taxable income is assumed in the model. Royalty rates are set at 12.5% of the adjusted gross revenues. Royalty relief, as applicable under the new rules set forth by Minerals Management Service (MMS) for newly discovered fields, have been incorporated as follows:

Water Depth Range	Relief Volume Applicable (MMBOE)
200 - 400 meters	17.5
400 - 900 meters	52.5
> 900 meters	87.5

These figures set the limit on cumulative production of crude oil or natural gas that is not subject to royalty from a given field in each of the water depth classes. All production volumes in excess of these amounts are subject to royalty deductions.

Discounted Net Present Value

The term discount refers to the "present worth" in economic evaluation work. Compound interest is the generally accepted approach for calculating return on investment in time value of money calculations. The future value that is projected to be accrued from the investment of dollars today at a specified compound interest rate is equal to the sum of the accrued interest and the initial principal invested. The concept of "present worth" is just the opposite of compounding. The terms "discounting" implies reducing the value of something and is equivalent to determining the present worth of a future value. A discount rate of 10% is the default value assumed for all investment decisions in DWOSS, though this is a parameter that can be specified by the user.

Net Present Value of After-Tax Cash Flow in year "IYR"
$$= \text{(After-Tax Cash Flow)} / (1 + \text{Discount Rate})^{(IYR - 1/2)}$$

The previous sections covered the structure, methodology and key components of the exogenous portion of DWOSS which is used to generate the price-supply curves for the deepwater offshore Gulf of Mexico OCS, i.e. the potential supply from undiscovered resources in deepwater Gulf at different nominal prices for crude oil and natural gas. These price-supply data can be generated under a variety of economic scenarios and analysis options due to the modular construction of the DWOSS. Having a separate exogenous component that can be used to study the impacts of various policy, regulatory and economic scenarios outside of the Oil and Gas Supply Module (OGSM) and National Energy Modeling System (NEMS) helps to speed the computational process. Besides supply price and reserves data, the exogenous component of DWOSS also transfers key cost data (exploration, drilling, structure installation, and operations) and well counts required to develop the reserves in a field.

DEVELOPMENT OF RESERVES AND PRODUCTION TIMING

This is the endogenous component of DWOSS that is an integral part of OGSM. The primary purpose of this endogenous component is to make a realistic forecast of deepwater offshore Gulf of Mexico OCS reserves development and production performance over a study period of 15-20 years based on the information supplied to it, i.e., the price-supply and other supply-side information generated in the exogenous module, and price information for crude oil and natural gas generated from the other demand-side components of NEMS, the Petroleum Market Module (PMM) and Natural Gas Transmission and Distribution Module (NGTDM), respectively. The model has been designed to make investment and field development decisions from the perspective of a field operator, and to incorporate real-life exploration and development constraints faced by the operator.

The basic process-flow diagram of the endogenous component has already been shown in Figure 4E-5. The following sections are devoted to a more detailed discussion of the modeling approach.

Inferred Reserves

The first task of the endogenous component of DWOSS is to calculate the inferred reserves for a given year in the study. Based on the regional wellhead prices supplied by PMM and NGTDM, the crude oil and natural gas supply information generated in the exogenous component is skimmed to determine the total crude oil and natural gas reserves that are economic at those prices. It is basically the amount of crude oil and natural gas reserves that are economic to explore, develop and produce from the remaining undiscovered prospects in the deepwater Gulf of Mexico.

$$\text{INFERRED RESERVES}_{iyr, fuel} = \text{INFERRED RESERVES}_{iyr-1, fuel} + \text{FIELD RESERVES}_{fuel, nfield}$$

where,

iyr	=	Year under consideration
fuel	=	Fuel type, crude oil or natural gas
nfield	=	Fields remaining to be discovered

Inferred reserves that do not get developed in the year they become economic get carried over to the next year and are added to the inferred reserves that come onstream at the crude oil and natural gas wellhead supply prices in the next year.

The routine also determines an average supply price for crude oil and natural gas for the total inferred reserves based on a weighted average of the individual prospect supply price. The weighting basis is the amount of technically recoverable reserves in those prospects. The total number of exploration, development and dry development wells, and the total number of production structures needed to

develop the different prospects that sum up to the inferred reserves are also accounted for and carried along with the inferred reserves.

Proved Reserves

Due to physical and monetary constraints, only a portion of the inferred reserves are assumed to be developed in any given year. These are based on capital investment constraints, infrastructure and rig availability constraints. DWOSS has been designed to develop the inferred reserves and generate proved reserves in a given year based on the number of development wells that can be drilled in that particular year. Historic drilling activity levels in the deepwater offshore Gulf of Mexico were used to characterize the current drilling level constraints. Since the deepwater offshore Gulf of Mexico is a frontier area, the choice of growth rate in drilling activity has been left open as a user input parameter. This gives the flexibility of looking at drilling constraint as a variable and study its sensitivity over the forecast period in generating proved reserves data. The ratio of development drilling wells available to be drilled based on the drilling constraints to the total number of development wells needed to develop the total inferred reserves in a given year is multiplied by the total reserves for both crude oil and natural gas to project the proved reserves.

However, the model still has to decide between how much of the crude oil and how much of the natural gas reserves will be developed. Historically, the development of a particular fuel type has been driven by the "relative price-economics" of the development prospect for each of the two fuel types, crude oil and natural gas. Relative price economics is defined as the ratio of the price spread (difference between the average minimum acceptable supply price of the resource remaining to be discovered and the wellhead fuel price) and the fuel price (oil or gas wellhead prices). The higher the spread, the more economic it is to develop that category of resource that remains to be discovered. The proportion of development wells to be drilled for crude oil and natural gas prospects is determined by these ratios.

DWOSS is also designed to carry the reserves data for associated/dissolved gas in case of oil-bearing fields, and condensate yield in case of gas-bearing fields. The various equations describing this process are represented in Appendix B.

Production

Proved reserves are converted to production based on reserves-to-production (R/P) ratios. Based on the extrapolation of the reserves-to-production data for deepwater Gulf of Mexico during the last five years, a default value of 16 for the R/P ratio in DWOSS was generated, and used to convert the proved reserves data for both crude oil and natural gas into crude oil and natural gas production. The associated/dissolved gas and condensate yield reserves data are used to generate the production from these two sources for their corresponding crude oil and natural gas production counterparts.

$$\text{PRODUCTION}_{\text{fuel, iyr}} = \text{PROVED RESERVES}_{\text{fuel, iyr}} / \text{RESERVES-TO-PRODUCTION RATIO}$$

where,

$$\begin{aligned}\text{fuel} &= \text{Fuel type (crude oil or natural gas)}\\ \text{iyr} &= \text{Year under consideration}\end{aligned}$$

Reserves Growth

Reserves growth includes those resources that are expected to be added to proved reserves in a field as a consequence of extension of proved fields, through revisions of reserve estimates, and/or by addition of

new payzones in these fields. Also included in this category are resources expected to be added to reserves through application of improved recovery technologies. DWOSS has been designed to allow the remaining proved reserves at the end of the year to be adjusted by a certain multiplier to estimate additional reserves growth attributable to these activities.

$$\text{RESERVES GROWTH}_{\text{fuel, iyr}} = (\text{PROVED RESERVES}_{\text{fuel, iyr}} - \text{PRODUCTION}_{\text{fuel, iyr}}) * \text{GROWTH RATE MULTIPLIER}$$

where,

fuel	=	Fuel type (crude oil or natural gas)
iyr	=	Year under consideration

The reserves growth multiplier has currently been set to a value of 1.0 in the model, which means no reserves growth additions. However, the multiplier is an input parameter for that can be specified by the user.

Advanced Technology Impacts

Advances in technology for the various activities associated with crude oil and natural gas exploration, development and production can have a profound impact on the costs associated with these activities and hence on the profitability of the undiscovered crude oil and natural gas prospects. DWOSS has been designed to give due consideration to the effect of future advances in technology that may occur in the future. Since the exogenous component of the DWOSS that generates price-supply information evaluates the various deepwater offshore Gulf of Mexico prospects on the basis of existing technology choices, some way of translating the impact of future advances in technology needs to be incorporated into the analytical approach.

The endogenous component of DWOSS has been designed to modify the exploration, drilling, structure installation, and operational costs associated with undiscovered prospects that have not been added to the inferred reserves category. At the end of each year, exploration, drilling, structure installation, and operations costs for all the crude oil and natural gas prospects that remain uneconomic investments can individually reduced using unique factors for each of the cost components. The factors are currently set to 1.0 in the model, indicating no impact of advanced technology. However, the factors are input parameters and can be specified by the user.

$$\text{MASP}_{\text{nfield, iyr, fuel, component}} = \text{DRILLING MASP}_{\text{nfield, iyr, fuel, component}} * \text{ADV TECH FACTOR}$$

where,

nfield	=	A crude oil or natural gas field
iyr	=	Year under consideration
fuel	=	Crude oil or natural gas
component	=	Key cost components: Exploration, Drilling, Structure, Operations

The minimum acceptable supply price (MASP) for each of the undiscovered remaining uneconomic prospect is also adjusted accordingly.

Appendix A. Data Inventory

An inventory of OGSM variables is presented in the following tables. These variables are divided into four categories:

Variables: Variables calculated in OGSM
Data: Input data
Parameters: Estimated parameters
Output: OGSM outputs to other modules in NEMS.

The data inventory for the Deep Water Offshore Supply Submodule is presented in a separate table.

All regions specified under classification are OGSM regions unless otherwise noted.

Variables						
Appendix B Equation	**Subroutine**	**Variable Name**		**Description**	**Unit**	**Classification**
		Code	**Text**			
1	OGCST_L48	ESTWELLSL48	ESTWELLS	Estimated lower 48 onshore drilling (successful and dry)	Wells	Lower 48 onshore
2	OGCST_L48	ESTSUCWELL48	ESTSUCWELLS	Estimated lower 48 onshore successful wells drilled	Wells	Lower 48 onshore
3	OGFOR_OFF	CURWELLSOFF	GOMWELLS	Estimated lower 48 offshore drilling (successful and dry)	Wells	Lower 48 offshore
4	OGCST_L48	RIGSL48	RIGSL48	Available rigs	Rigs	Lower 48 onshore
5	OGFOR_OFF	RIGSOFF	RIGSOFF	Available rigs	Rigs	Lower 48 offshore
6	OGCST_L48	DRILLL48	DRILLCOST	Successful well drilling costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
7	OGCST_L48	DRYL48	DRYCOST	Dry well drilling costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
8	OGFOR_OFF	DRILLOFF	DRILLCOST	Successful well drilling costs	1987$ per well	Class(Exploratory,Developmental);8 Lower 48 offshore regions,Fuel(oil,gas)
9	OGFOR_OFF	DRYOFF	DRYCOST	Dry well drilling costs	1987$ per well	Class(Exploratory,Developmental);8 Lower 48 offshore regions,Fuel(oil,gas
10	OGCST_L48 OGFOR_OFF	LEASL48 LEASOFF	LEQC	Lease equipment costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
11	OGCST_L48 OGFOR_OFF	OPERL48 OPEROFF	OPC	Operating costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
12	OG_DCF	DCFTOT	PROJDCF	Discounted cash flow for a representative project	1987$ per project	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);8 Lower 48 offshore regions,Fuel(oil,gas); 3 Alaska regions, Fuel (oil,gas)
13	OG_DCF	PVSUM(1)	PVREV	Present value of expected revenue	1987$ per project	(Above)

		Variables				
Appendix B Equation	**Subroutine**	**Variable Name**		**Description**	**Unit**	**Classification**
		Code	**Text**			
14	OG_DCF	PVSUM(2)	PVROY	Present value of expected royalty payments	1987$ per project	(Above)
15	OG_DCF	PVSUM(3)	PVPRODTAX	Present value of expected production taxes	1987$ per project	(Above)
16	OG_DCF	PVSUM(4)	PVDRILLCOST	Present value of expected drilling costs	1987$ per project	(Above)
17	OG_DCF	PVSUM(5)	PVEQUIP	Present value of expected lease equipment costs	1987$ per project	(Above)
18	OG_DCF	PVSUM(8)	PVKAP	Present value of expected capital costs	1987$ per project	(Above)
19	OG_DCF	PVSUM(6)	PVOPERCOST	Present value of expected operating costs	1987$ per project	(Above)
20	OG_DCF	PVSUM(7)	PVABANDON	Present value of expected abandonment costs	1987$ per project	(Above)
21	OG_DCF	PVSUM(13)	PVTAXBASE	Present value of expected tax base	1987$ per project	(Above)
22	OG_DCF	XIDC	XIDC	Expensed Costs	1987$ per project	(Above)
23	OG_DCF	DHC	DHC	Dry hole costs	1987$ per project	(Above)
24	OG_DCF	DEPREC	DEPREC	Depreciable costs	1987$ per project	(Above)
25	OG_DCF	PVSUM(15)	PVSIT	Expected value of state income taxes	1987$ per project	(Above)
26	OG_DCF	PVSUM(16)	PVFIT	Expected value of federal income taxes	1987$ per project	(Above)
27-28	OG_DCF	OG_DCF	DCF	Discounted cash flow for a representative well	1987$ per well	(Above)
29	OGEXP_CALC	W1UNC	wunc	Share of total lower 48 onshore wells at class,region, fuel(unconventional gas) level	Fraction	***Not Used*** Class(Exploratory,Developmental) ;6 Lower 48 onshore regions;Fuel(3 unconventional gas)
30	OGEXP_CALC	DCFUNC	UGDCFON	Discounted cash flow for unconventional gas	1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions

Appendix B Equation	Subroutine	Variables				
		Variable Name		Description	Unit	Classification
		Code	Text			
31	OGEXP_CALC	C_SGDDCF	SGDCFON	Discounted cash flow for shallow gas	1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions
32	OGEXP_CALC	OXDCF	ODCFON	Discounted cash flow for oil	1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions
33	OGEXP_CALC	W1	w	Share of total Lower 48 wells at class,region,fuel level	Fraction	Class(Exploratory,Developmental);6 Lower 48 onshore regions;Fuel(2 oil, 5 gas)
34	OGEXP_CALC	WDCFIR	RDCFON	Lower 48 onshore discounted cash flow	1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions
35	OGEXP_CALC	WDCFOFFIR	RDCFOFF	Lower 48 offshore discounted cash flow	1987$	Class(Exploratory,Developmental) ;4 Lower 48 offshore regions
36	OGEXP_CALC	O_SGXDCFLAG	OSGDCFON	Discounted cash flow for conventional shallow oil and gas	1987$	Class(Exploratory,Developmental); 6 Lower 48 onshore regions
37-77	OGEXP_CALC	WELLSL48	WELLSON	Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
78-82	OGALL_OFF	WELLSOFF	WELLSOFF	Lower 48 offshore wells drilled	Wells	Class(Exploratory,Developmental) ;4 Lower 48 offshore regions,Fuel(oil,gas)
83	OGEXP_CALC	SUCWELLL48	SUCWELSON	Successful Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
84	OGEXP_CALC	DRYWELLL48	DRYWELON	Dry Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
85	OGALL_OFF	SUCWELLOFF	SUCWELSOFF	Successful Lower 48 offshore wells drilled	Wells	Class(Exploratory,Developmental) ;4 Lower 48 offshore regions,Fuel(oil,gas)
86	OGALL_OFF	DRYWELLOFF	DRYWELOFF	Dry Lower 48 offshore wells drilled	Wells	Class(Exploratory,Developmental) ;4 Lower 48 offshore regions,Fuel(oil,gas)
87	OGOUT_L48 OGOUT_OFF	NRDL48 NRDOFF	NRD	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions,Fuel(oil,gas)

		Variables				
Appendix B Equation	**Subroutine**	**Variable Name**		**Description**	**Unit**	**Classification**
		Code	**Text**			
88	OGOUT_L48 OGOUT_OFF	FRTECH1	FRTECH1	Past technological impact	Rate	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions,Fuel(oil,gas)
89	OGOUT_L48 OGOUT_OFF	FRTECH2	FRTECH2	Past technological impact	Rate	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions,Fuel(oil,gas)
90	OGOUT_L48 OGOUT_OFF	FRTECH3	FRTECH3	Current technological impact	Rate	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions,Fuel(oil,gas)
91	OGOUT_L48 OGOUT_OFF	FRTECH4	FRTECH4	Future techological impact	Rate	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions,Fuel(oil,gas)
92	OGOUT_L48 OGOUT_OFF	ECON	ECON2	Economic impact	Rate	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions,Fuel(oil,gas)
93	OGOUT_L48 OGOUT_OFF	FR1O	FR1O	Initial new field finding rate adjusted for technology and economics	Rate	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions,Fuel(oil,gas)
94	OGOUT_L48 OGOUT_OFF	FR1L48 FR1OFF	FR1	Finding rates for new field wildcat drilling	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
95	OGOUT_L48 OGOUT_OFF	NDIRL48 NDIROFF	I	Inferred reserves added by new field discoveries	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
96 104	OGOUT_L48 OGOUT_OFF	EXTL48 EXTOFF	EXT	Reserve extensions	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 2 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
97-100 101	OGOUT_L48 OGOUT_OFF	FR2L48 FR2OFF	FR2	Finding rates for other exploratory wells	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
102	OGOUT_OFF	DELTA2OFF	$\delta2$	Finding rate decline parameters for other exploratory wells	Fraction	4 Lower 48 offshore regions, Fuel(oil,gas)

		Variables				
Appendix B Equation	**Subroutine**	**Variable Name**		**Description**	**Unit**	**Classification**
		Code	**Text**			
103	OGOUT_OFF	CUMR2OFF	CUMRES2	Cumulative reserve extensions	Oil-MMB Gas-BCF	4 Lower 48 offshore regions, Fuel(oil,gas)
105 113	OGOUT_L48 OGOUT_OFF	REVL48 REVOFF	REV	Reserve revisions	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
106-109 110	OGOUT_L48 OGOUT_OFF	FR3L48 FR3OFF	FR3	Finding rates for developmental drilling	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions,Fuel(2 oil, 2 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
111	OGOUT_OFF	DELTA3OFF	δ3	Finding rate decline parameters for developmental wells	Fraction	4 Lower 48 offshore regions, Fuel(oil,gas)
112	OGOUT_OFF	CUMR3OFF	CUMRES3	Cumulative reserve revisions	Oil-MMB Gas-BCF	4 Lower 48 offshore regions, Fuel(oil,gas)
114	OGOUT_L48 OGOUT_OFF	RESADL48 RESADOFF	RA	Total additions to proved reserves	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
115	OGOUT_L48 OGOUT_OFF OGFOR_AK	RESBOYL48 RESBOYOFF BOYRESCOAK BOYRESNGAK	R	End of year reserves for current year	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas); 3 Alaska regions,Fuel(oil,gas)
116	OGOUT_L48 OGOUT_OFF	PRRATL48 PRRATOFF	PR	Production to reserves ratios	Fraction	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
117	OGOUT_L48 OGOUT_OFF	EXPRDL48 EXPRDOFF	Q	Production	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
118	OGOUT_L48 OGOUT_OFF	PRRATL48 PRRATOFF	PR	Production to reserves ratios	Fraction	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
119	OGOUT_L48 OGOUT_OFF	EXPRDL48 EXPRDOFF	X	Production	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)

		Variables				
Appendix B Equation	**Subroutine**	**Variable Name**		**Description**	**Unit**	**Classification**
		Code	**Text**			
120	OGOUT_L48 OGOUT_OFF	EXPRDL48 EXPRDOFF	X	Production	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
121	OGOUT_L48 OGOUT_OFF	EXPRDL48 EXPRDOFF	X°	Production	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
122	OGOUT_L48 OGOUT_OFF	EXPRDL48 EXPRDOFF	X°	Production	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas);4 Lower 48 offshore regions, Fuel(oil,gas)
123	OGCOMP_AD	OGPRDAD	ADGAS	Associated-dissolved gas production	BCF	6 Lower 48 onshore regions, 3 Lower 48 offshore regions
124	OGCOST_AK	DRILLAK	DRILLCOST	Drilling costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
125	OGCOST_AK	LEASAK	EQUIP	Lease equipment costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
126	OGCOST_AK	OPERAK	OPCOST	Operating costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
127	OGFOR_AK	TOTGRR	TRR	Alaska total gross revenue requirements	Million 1987$	NA
128	OGFOR_AK	TOTDEP	TOTDEP	Alaska total depreciation	Million 1987$	NA
129	OGFOR_AK	MARTOT	MARGIN	Alaska total after tax margin	Million 1987$	NA
130	OGFOR_AK	RECTOT	DEFRETREC	Alaska total recovery of differed returns	Million 1987$	NA
131	OGFOR_AK	TXALLW	TXALLW	Alaska income tax allowance	Million 1987$	NA
132	XOGOUT_IMP	WELLSCAN	WELLS	Canadian wells drilled	Wells	Fuel(gas)
133	XOGOUT_IMP	FRCAN	FR	Canadian finding rate	Gas:BCF per well	Fuel(gas)
134	XOGOUT_IMP	DELTACAN	δ	Canadian finding rate decline parameter	Fraction	Fuel(gas)
135	XOGOUT_IMP	RESADCAN	RA	Canadian reserve additions	Gas:BCF	Fuel(gas)

		Variables				
Appendix B Equation	**Subroutine**	**Variable Name**		**Description**	**Unit**	**Classification**
		Code	**Text**			
136	XOGOUT_IMP	CUMRCAN	CUMRES	Cumulative Canadian reserve additions	Gas:BCF	Fuel(gas)
137	XOGOUT_IMP	RESBOYCAN	R	Canadian reserves	Gas:BCF	Fuel(gas)
138	XOGOUT_IMP	PRRATCAN	PR	Canadian production to reserves ratio	Fraction	Fuel(gas)

	Data					
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGFOR_L48 OGINIT_L48	ADVLTXL48	PRODTAX	Lower 48 onshore ad valorem tax rates	Fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Colorado School of Mines. Oil Propert Evaluation, 1983, p. 9-7
OGFOR_OFF OGINIT_OFF	ADVLTXOFF	PRODTAX	Offshore ad valorem tax rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Colorado School of Mines. Oil Propert Evaluation, 1983, p. 9-7
OGINIT_AK OGPIP_AK	ANGTSMAX	--	ANGTS maximum flow	BCF/D	Alaska	National Petroleum Council
OGINIT_AK OGPIP_AK	ANGTSPRC	--	Minimum economic price for ANGTS start up	1987$/MCF	Alaska	National Petroleum Council
OGINIT_AK OGPIP_AK	ANGTSRES	--	ANGTS reserves	BCF	Alaska	National Petroleum Council
OGINIT_AK OGPIP_AK	ANGTSYR	--	Earliest start year for ANGTS flow	Year	NA	National Petroleum Council
OGEXPAND_LNG OGINIT_LNG	BUILDLAG	--	Buildup period for expansion of LNG facilities	Year	NA	Office of Integrated Analysis and Forecasting
OGINIT_EOR	COGFAC	--	factor to calculate cogeneration electric capacity as funciton of steam injection	MW/MMBS-yr	NA	Advanced Resources International, Inc.
OGINIT_IMP	CPRDCAN	--	Canadian coproduct rate	Fraction	Canada; Fuel (oil, gas)	Not Used Derived using data from the Canadian Petroleum Association
OGFOR_L48 OGINIT_L48	CPRDL48	COPRD	Lower 48 onshore coproduct rate	Fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	CPRDOFF	COPRD	Offshore coproduct rate	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP OGINIT_RES OGOUT_IMP	CURPRRCAN	PR	Canadian 1989 P/R ratio	Fraction	Canada; Fuel (gas)	Derived using data from the Canadian Petroleum Association
OGINIT_L48 OGINIT_RES OGOUT_L48	CURPRRL48	omega	Lower 48 initial P/R ratios	Fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting

	Data					
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGINIT_OFF OGINIT_RES OGOUT_OFF	CURPRROFF	omega	Offshore initial P/R ratios	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGOUT_L48	CURPRRTDM	--	Lower 48 initial P/R ratios at NGTDM level	Fraction	17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGINIT_RES OGOUT_L48	CURRESL48	R	Lower 48 onshore initial reserves	MMB BCF	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Derived from Annual Reserves Report Data
OGINIT_OFF OGINIT_RES OGOUT_OFF	CURRESOFF	R	Offshore initial reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)	Derived from Annual Reserves Report Data
OGINIT_L48 OGINIT_RES OGOUT_L48	CURRESTDM	--	Lower 48 natural gas reserves at NGTDM level	MMB BCF	17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGOUT_L48	DECFAC	DECFAC	Inferred resource simultaneous draw down decline rate adjustment factor	Fraction	NA	Office of Integrated Analysis and Forecasting
OGINIT_IMP	DECLCAN	--	Canadian decline rates	Fraction	Canada; Fuel (oil, gas)	Not Used Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48 WELL	DECLL48	--	Lower 48 onshore decline rates	Fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF WELL	DECLOFF	--	Offshore decline rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_AK OGPRO_AK	DECLPRO	--	Alaska decline rates for currently producing fields	Fraction	Field	Office of Integrated Analysis and Forecasting
OGINIT_IMP	DEPLETERT	--	Depletion rate	Fraction	NA	Not Used Office of Integrated Analysis and Forecasting

	Data					
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGDEV_AK OGINIT_AK OGSUP_AK	DEV_AK	--	Alaska drilling schedule for developmental wells	Wells per year	3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_EOR CALC_DEV_SCHED	DEV_YRS	--	development schedule for new drilling	years	profit category; EOR type	Advanced Resources International, Inc.
OGDCF_AK OGFOR_L48 OGFOR_OFF OGINIT_BFW	DISC	disc	Discount rate	Fraction	National	Office of Integrated Analysis and Forecasting
OGINIT_IMP	DISRT	--	Discount rate	Fraction	Canada	Not Used Office of Integrated Analysis and Forecasting
OGCOST_AK OGINIT_AK	DRILLAK	DRILL	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP	DRILLCAN	--	Canadian initial drilling costs	1987$	Canada; Fuel (oil, gas)	Not Used Office of Integrated Analysis and Forecasting
OGALL_OFF OGFOR_OFF OGINIT_OFF	DRILLOFF	DRILL	Offshore drilling cost	1987$	4 Lower 48 offshore subregions	Mineral Management Service
OGCOST_AK OGINIT_AK	DRLNFWAK	--	Alaska drilling cost of a new field wildcat	1990$/well	3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGDCF_AK OGDEV_AK OGINIT_AK OGNEW_AK	DRYAK	DRY	Alaska dry hole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP	DRYCAN	--	Canadian dry hole cost	1987$	Class (exploratory, developmental)	Not Used Office of Integrated Analysis and Forecasting

Data						
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGALL_OFF OGEXP_CALC OGFOR_OFF OGINIT_OFF	DRYOFF	DRY	Offshore dry hole cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Minerals Management Service
OGFOR_OFF OGINIT_OFF	DVWELLOFF	--	Offshore development project drilling schedules	wells per year	4 Lower 48 offshore subregions; Fuel (oil, gas)	Minerals Management Service
OGFOR_L48 OGINIT_L48	DVWLCBML48	--	Lower 48 development project drilling schedules for coalbed methane	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	DVWLDGSL48	--	Lower 48 development project drilling schedules for deep gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	DVWLDVSL48	--	Lower 48 development project drilling schedules for devonian shale	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGINIT_IMP	DVWLGASCAN	--	Canadian development gas drilling schedule	wells per project per year	Canada	Not Used
OGINIT_IMP	DVWLOILCAN	--	Canadian development oil drilling schedule	wells per project per year	Canada	Not Used
OGFOR_L48 OGINIT_L48	DVWLOILL48	--	Lower 48 development project drilling schedules for oil	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	DVWLSGSL48	--	Lower 48 development project drilling schedules for shallow gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	DVWLTSGL48	--	Development project drilling schedules for tight gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGINIT_IMP XOGOUT_IMP	ELASTCAN	--	Elasticity for Canadian reserves	Fraction	Canada	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGINIT_RES OGOUT_L48	ELASTL48	--	Lower 48 onshore production elasticity values	Fraction	6 OGSm Lower 48 onshore regions	Office of Integrated Analysis and Forecasting

	Variable Name					
Subroutine	Code	Text	Description	Unit	Classification	Source

Data

Subroutine	Code	Text	Description	Unit	Classification	Source
OGINIT_OFF OGINIT_RES OGOUT_OFF	ELASTOFF	--	Offshore production elasticity values	Fraction	4 Lower 48 offshore subregions	Office of Integrated Analysis and Forecasting
OGCOMP_EMIS OGINIT_EMIS	EMCO	--	Emission factors for crude oil production	Fraction	Census regions	EPA - Energy Technology Characterizations Handbook
OGCOMP_EMIS OGINIT_EMIS	EMFACT	--	Emission factors	MMB MMCF	Census regions	EPA - Energy Technology Characterizations Handbook
OGCOMP_EMIS OGINIT_EMIS	EMNG	--	Emission factors for natural gas production	Fraction	Census regions	EPA - Energy Technology Characterizations Handbook
OGINIT_EOR CALC_ECF_DATA	EORFAC	--	emissions factors for EOR production	tons/MMcf or lb/MMcf	emission categories	Advanced Resources International, Inc.
OGCOST_AK OGINIT_AK	EQUIPAK	EQUIP	Alaska lease equipment cost	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	U.S. Geological Survey
OGEXP_CALC OGINIT_BFW	EXOFFRGNLAG	--	Offshore exploration & development regional expenditure (1989)	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Office of Integrated Analysis and Forecasting
OGDEV_AK OGINIT_AK OGSUP_AK	EXP_AK	--	Alaska drilling schedule for other exploratory wells	wells per year	3 Alaska regions	Office of Integrated Analysis and Forecasting
OGINIT_IMP	EXPENSE	--	Fraction of drill costs that are expensed	fraction	Class (exploratory, developmental)	Not Used Canadian Tax Code
OGFOR_OFF OGINIT_OFF	EXWELLOFF	--	Offshore exploratory project drilling schedules	wells per year	4 Lower 48 offshore subregions	Minerals Management Service
OGFOR_L48 OGINIT_L48	EXWLCBML48	--	Lower 48 exploratory project drilling schedules for coalbed methane	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	EXWLDGSL48	--	Lower 48 exploratory and developmental project drilling schedules for deep gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	EXWLDVSL48	--	Lower 48 exploratory project drilling schedules for devonian shale	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting

	Data					
	Variable Name					
Subroutine	**Code**	**Text**	**Description**	**Unit**	**Classification**	**Source**
OGINIT_IMP	EXWLGASCAN	--	Canadian exploratory gas drilling schedule	wells per year	Canada	Not Used
OGINIT_IMP	EXWLOILCAN	--	Canadian exploratory oil drilling schedule	wells per year	Canada	Not Used
OGFOR_L48 OGINIT_L48	EXWLOILL48	--	Lower 48 exploratory project drilling schedules for oil	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	EXWLSGSL48	--	Lower 48 exploratory project drilling schedules for shallow gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	EXWLTSGL48	--	Lower 48 exploratory project drilling schedules for tight gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGDEV_AK OGFAC_AK OGINIT_AK OGSUP_AK	FACILAK	--	Alaska facility cost (oil field)	1990$/bls	Field size class	U.S. Geological Survey
OGINIT_IMP	FEDTXCAN	--	Canadian corporate tax rate	fraction	Canada	Not used. Petroleum Fiscal Systems in Canada - Energy, Mines & Resources
OGDCF_AK OGEXP_CALC OGFOR_L48 OGFOR_OFF OGINIT_BFW	FEDTXR	FDRT	U.S. federal tax rate	fraction	Canada	U.S. Tax Code
OGINIT_IMP	FLOWCAN	--	Canadian flow rates	bls, MCF per year	Canada; Fuel (oil, gas)	Not used. Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	FLOWL48	--	Lower 48 onshore flow rates	bls, MCF per year	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	EIA, Office of Oil and Gas
OGFOR_OFF OGINIT_OFF	FLOWOFF	--	Offshore flow rates	bls, MCF per year	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_LNG OGPROF_LNG	FPRDCST	--	Foreign production costs	1991$/MCF per year	LNG Source Country	National Petroleum Council

	Variable Name					
Subroutine	**Code**	**Text**	**Description**	**Unit**	**Classification**	**Source**
			Data			

Subroutine	**Code**	**Text**	**Description**	**Unit**	**Classification**	**Source**
OGINIT_IMP XOGOUT_IMP	FRMINCAN	FRMIN	Canadian minimum economic finding rate	BCF per well	Canada	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGOUT_L48	FRMINL48	FRMIN	Lower 48 onshore minimum exploratory well finding rate	MMB BCF per well	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	FRMINOFF	FRMIN	Offshore minimum exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
XOGOUT_IMP	FRTECHCAN	FRTECH	Canada technology factor applied to finding rate	fraction	Canada	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGOUT_L48	FR1L48	FR1	Lower 48 onshore new field wildcat well finding rate	MMB BCF per well	6 Lower 48 onshore regions; Fuel (2 oil, 2 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	FR1OFF	FR1	Offshore new field wildcat well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGOUT_L48	FR2L48	FR3	Lower 48 onshore developmental well finding rate	MMB BCF per well	6 Lower 48 onshore regions; Fuel (2 oil, 2 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	FR2OFF	FR3	Offshore developmental well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGOUT_L48	FR3L48	FR2	Lower 48 other exploratory well finding rate	MMB BCF per well	6 Lower 48 onshore regions; Fuel (2 oil, 2 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	FR3OFF	FR2	Offshore other exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_AK OGINIT_AK OGNEW_AK	FSZCOAK	—	Alaska oil field size distributions	MMB	3 Alaska regions	U.S. Geological Survey

Data						
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGFOR_AK OGINIT_AK OGNEW_AK	FSZNGAK	--	Alaska gas field size distributions	BCF	3 Alaska regions	U.S. Geological Survey
OGINIT_L48	HISTADL48	--	Lower 48 historical associated-dissolved natural gas reserves	BCF	NA	Annual Reserves report
OGINIT_OFF	HISTADOFF	--	Offshore historical associated-dissolved natural gas reserves	BCF	NA	Annual Reserves Report
OGINIT_IMP XOGOUT_IMP	HISTFRCAN	--	Historical Canadian finding rate for gas	BCF per well	Canada	Office of Integrated Analysis and Forecasting
OGINIT_AK OGPRO_AK	HISTPRDCO	--	Alaska historical crude oil production	MB/D	Field	Alaska Oil and Gas Conservation Commission
OGINIT_IMP XOGOUT_IMP	HISTPRRCAN	--	Canadian gas production to reserves ratio for historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
OGINIT_L48	HISTPRRL48	--	Lower 48 historical P/R ratios	fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Derived from Annual Reserves Report
OGINIT_OFF	HISTPRROFF	--	Offshore historical P/R ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Derived from Annual Reserves Report
OGINIT_L48	HISTPRRTDM	--	Lower 48 onshore historical P/R ratios at the NGTDM level	fraction	17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP XOGOUT_IMP	HISTRESAD	--	Canadian gas reserves additions for historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP XOGOUT_IMP	HISTRESCAN	--	Canadian beginning of year gas reserves for historical years	BCF	Canada; Fuel (gas)	Canadian Petroleum Association
OGINIT_IMP XOGOUT_IMP	HISTWELCAN	--	Canadian gas wells drilled in historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
OGINIT_L48	HISTRESL48	--	Lower 48 onshore historical beginning-of-year reserves	MMB BCF	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Annual Reserves Report

	Variable Name					
Subroutine	**Code**	**Text**	**Description**	**Unit**	**Classification**	**Source**
OGINIT_OFF	HISTRESOFF	--	Offshore historical beginning-of-year reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)	Annual Reserves Report
OGINIT_L48	HISTRESTDM	--	Lower 48 onshore historical beginning-of-year reserves at the NGTDM level	MMB BCF	17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas)	Annual Reserves Report
WELL OGEXPAND_LNG OGINIT_IMP XOGOUT_IMP	IMPBYR	--	Base start-year for Foreign Natural Gas Supply Submodule	--	--	Office of Integrated Analysis and Forecasting
OGINIT_EOR NEW_PROJECT_ RESERVES	INF_PR	--	production to reserves ratio for new drilling	fraction	6 Lower 48 supply regions; EOR type	Advanced Resources International, Inc.
OGINIT_EOR NEW_PROJECT_ RESERVES	INF_PS_TBL	--	thermal and gas EOR inferred reserves price supply table for unproven stock	MMBO	6 Lower 48 supply regions; EOR type; oil price categories	Advanced Resources International, Inc.
OGINIT_EOR CALC_ECF_DATA OGREPORT_EOR	INF_UTIL	--	steam cogeneration utilization for new drillling	fraction	6 Lower 48 supply regions; EOR type	Advanced Resources International, Inc.
OGDCF_AK OGFOR_L48 OGFOR_OFF OGINIT_BFW	INFL	infl	U.S. inflation rate	fraction	National	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGOUT_L48	INFRSVL48	l	Lower 48 onshore inferred reserves	MMB BCF	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	INFRSVOFF	l	Offshore inferred reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP	INFRT	--	Canadian inflation rate	fraction	Canada	Not used. Office of Integrated Analysis and Forecasting

Data						
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGINIT_EOR NEW_PROJECT_ RESERVES CALC_INVEST_T BL	INVEST_TBL	--	investment pool for new drilling	MM$	6 Lower 48 supply regions; EOR type; oil price categories	Advanced Resources International, Inc.
OGINIT_IMP	INVESTRT	--	Canadian investment tax credit	fraction	Canada	Not Used
OGDCF_AK OGINIT_AK	KAPFRCAK	EXKAP	Alaska drill costs that are tangible & must be depreciated	fraction	Alaska	U.S. Tax Code
OGFOR_L48 OGINIT_L48	KAPFRCL48	EXKAP	Lower 48 onshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)	U.S. Tax Code
OGFOR_OFF OGINIT_OFF	KAPFRCOFF	EXKAP	Offshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)	U.S. Tax Code
OGFOR_L48 OGINIT_L48	KAPSPNDL48	KAP	Lower 48 onshore other capital expenditures	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Not used
OGFOR_OFF OGINIT_OFF	KAPSPNDOFF	KAP	Offshore other capital expenditures	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Minerals Mangement Service
OGFOR_L48 OGINIT_L48	LAGDRILL48	--	1989 Lower 48 drill cost	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	LAGDRYL48	--	1989 Lower 48 dry hole cost	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	LAGLEASL48	--	1989 Lower 48 lease equipment cost	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting

	Data					
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGFOR_L48 OGINIT_L48	LAGOPERL48	--	1989 Lower 48 operating cost	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP	LEASCAN	--	Canadian lease equipment cost	1987$	Canada; Fuel (oil, gas)	Not used. Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	LEASOFF	EQUIP	Offshore lease equipment cost	1987$ per project	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Minerals Mangement Service
OGEXPAND_LNG OGINIT_LNG	LIQCAP	--	Liquefaction capacity	BCF	LNG Source Country	National Petroleum Council
OGINIT_LNG OGPROF_LNG	LIQCST	--	Liquefaction costs	1991$/MCF	LNG Source Country	National Petroleun Council
OGEXPAND_LNG OGPROF_LNG	LIQSTAGE	--	Liquefaction stage	NA	NA	National Petroleum Council
OGINIT_EOR	LPROFIT	--	lower limit on profit category for new drilling development schedule	$/BO	Profit category; EOR type	Not used. Advanced Resources International, Inc.
OGFOR_AK OGINIT_AK OGPRO_AK	MAXPRO	--	Alaska maximum crude oil production	MB/D	Field	Announced Plans
OGINIT_IMP OGOUT_MEX	MEXEXP	--	Exports from Mexico	BCF	3 US/Mexican border crossing	Office of Integrated Analysis and Forecasting
OGINIT_IMP OGOUT_MEX	MEXIMP	--	Imports from Mexico	BCF	3 US/Mexican border crossing	Office of Integrated Analysis and Forecasting
OGINIT_AK OGNEW_AK	NFW_AK	--	Alaska drilling schedule for new field wildcats	wells	NA	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	NFWCOSTOFF	COSTEXP	Offshore new field wildcat cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Minerals Management Service

	Data					
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGFOR_OFF OGINIT_OFF	NFWELLOFF	--	Offshore exploratory and developmental project drilling schedules	wells per project per year	Class (exploratory, developmental); r=1	Minerals Management Service
OGINIT_EOR CALC_ECF_DATA	NGFFAC	--	natural gas fuel consumption factor as function of steam injection	BS/mcf	NA	Advanced Resources International, Inc.
OGINIT_L48 OGINIT_RES OGOUT_L48	NGTDMMAP	--	Mapping of NGTDM regions to OGSM regions	NA	17 OGSM/NGTDM regions	Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNBLOSS	--	Gas lost in transit to border	BCF	6 US/Canadian border crossings	Not Used
OGINIT_IMP	OGCNCAPB	--	Canadian capacities at borders - base case	BCF	6 US/Canadian border crossing	Not used. Derived from Natural Gas Annual
OGINIT_IMP	OGCNCAPH	--	Canadian capacities at borders - high WOP case	BCF	6 US/Canadian border crossing	Not used. Derived from Natural Gas Annual
OGINIT_IMP	OGCNCAPL	--	Canadian capacities at borders - low WOP case	BCF	6 US/Canadian border crossing	Not used. Derived from Natural Gas Annual
OGINIT_IMP XOGOUT_IMP	OGCNCON	--	Canadian gas consumption	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNDEM	--	Canadian demand calculation parameters	NA	NA	Not Used
OGINIT_IMP	OGCNDMLOSS	--	Gas lost from wellhead to Canadian demand	BCF	Canada	Not used. Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNEXLOSS	--	Gas lost from US export to Canadian demand	BCF	Canada	Not used. Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNFLW	--	1989 flow volumes by border crossing	BCF	6 US/Canadian border crossings	Not used. Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNPARM1	--	Actual gas allocation factor	fraction	Canada	Not used. Office of Integrated Analysis and Forecasting

	Data					
	Variable Name					
Subroutine	**Code**	**Text**	**Description**	**Unit**	**Classification**	**Source**
OGINIT_IMP	OGCNPARM2	--	Responsiveness of flow to different border prices	fraction	Canada	Not used. Office of Integrated Analysis and Forecasting
OGINIT_PRICE	OGCNPPRD	--	Canadian price of oil and gas	oil: 87$s/B gas: 87$s/mcf	Canada	NGTDM
OGPIP_AK OGPROF_LNG	OGPNGIMP	--	Natural gas import price	87$s/mcf	US/Canadian & US/Mexican border crossings and LNG destination points	NGTDM
OGINIT_IMP	OPERCAN	--	Canadian operating cost	$ 1987	Canada; Fuel (gas)	Not used. Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	OPEROFF	OPCOST	Offshore operating cost	1987$ per well per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Mineral Management Service
OGDCF_AK OGINIT_AK	PRJAK	n	Alaska oil project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	PRJL48	n	Lower 48 project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	PRJOFF	n	Offshore project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_EOR SET_TEMP_VALUES	PR_MATRIX	--	mapping of PMM oil type to EOR supply regions	NA	6 Lower 48 supply regions	Advanced Resources International, Inc.
OGINIT_IMP	PROVTXCAN	PROVRT	Canadian provincial corporate tax rates	fraction	Canada	Not used. Petroleum Fiscal Systems in Canada - Energy, Mines & Resources
OGFOR_AK OGINIT_AK OGPRO_AK	PROYR	--	Start year for known fields in Alaska	Year	Field	Announced Plans

Data						
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGINIT_EOR PROVED_RESERVES	PRV_PR	--	production to reserves ratio for existing stock	fraction	6 Lower 48 supply regions; EOR type	Advanced Resources International, Inc.
OGINIT_EOR PROVED_RESERVES	PRV_PS_TBL	--	thermal and gas EOR proved reserves price supply table for existing stock	MB	6 Lower 48 supply regions; EOR type	Advanced Resources International, Inc.
OGINIT_EOR CALC_ECF_DATA OGREPORT_EOR	PRV_UTIL	--	steam cogeneration utilization for existing stock	fraction	6 Lower 48 supply regions; EOR type	Advanced Resources International, Inc.
OGEXPAND_LNG OGINIT_LNG OGLNG_OUT	QLNG	--	LNG operating flow capacity	BCF	LNG destination points	National Petroleum Council
OGEXPAND_LNG OGINIT_LNG OGLNG_OUT	QLNGMAX	--	LNG maximum capacity	BCF	LNG destination Points	National Petroleum Council
OGDCF_AK OGINIT_AK	RCPRDAK	m	Alaska recovery period of intangible & tangible drill cost	Years	Alaska	U.S. Tax Code
OGINIT_IMP	RCPRDCAN	--	Canada recovery period of intangible & tangible drill cost	Years	Canada	Not used. Petroleum Fiscal Systems in Canada - Energy, Mines & Resources
OGFOR_L48 OGINIT_L48	RCPRDL48	m	Lower 48 recovery period for intangible & tangible drill cost	Years	Lower 48 Onshore	U.S. Tax Code
OGFOR_OFF OGINIT_OFF	RCPRDOFF	m	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore	U.S. Tax Code
OGFOR_AK OGINIT_AK OGPRO_AK	RECRES	--	Alaska crude oil resources for known fields	MMB	Field	OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity*
OGINIT_LNG OGPROF_LNG	REGASCST	--	Regasification costs	1991$/MCF per year	Operational Stage; LNG destination points	National Petroleum Council
OGEXPAND_LNG OGINIT_LNG	REGASEXPAN	--	Regasification capacity	BCF	LNG destination points	National Petroleum Council

	Data					
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGEXPAND_LNG OGINIT_LNG OGPROF_LNG	REGASSTAGE	--	Regasification stage	NA	NA	National Petroleum Council
OGINIT_IMP XOGOUT_IMP	RESBASE	Q	Canadian recoverable resource estimate	BCF	Canada	Canadian Geological Survey
OGINIT_EOR SET_TEMP_VALU ES OGREPORT_EOR	RGPRICE	--	regional natural gas prices	dollars/MMbtu	6 lower 48 supply regions	Office of Integrate Analysis and Forecasting
OGINIT_IMP	ROYRATE	--	Canadian royalty rate	fraction	Canada	Not used. Petroleum Fiscal Systems in Canada - Energy, Mines & Resources
OGDCF_AK OGFOR_L48 OGINIT_BFW	ROYRT	ROYRT	Alaska royalty rate	fraction	Alaska	U.S. Geological Survey
OGINIT_AK OGSEVR_AK	SEVTXAK	PRODTAX	Alaska severance tax rates	fraction	Alaska	U.S. Geological Survey
OGFOR_L48 OGINIT_L48	SEVTXL48	PRODTAX	Lower 48 onshore severance tax rates	fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Commerce Clearing House
OGFOR_OFF OGINIT_OFF	SEVTXOFF	PRODTAX	Offshore severance tax rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Commerce Clearing House
OGINIT_EOR CALC_ECF_DATA	SIFAC	--	factor to calculate steam injection as function of production	BS/BO	NA	Advanced Resources International, Inc.
	SPENDIRKLAG	--	1989 Lower 48 exploration & development expenditures	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
OGDCF_AK OGDEV_AK OGINIT_AK OGNEW_AK	SRAK	SR	Alaska drilling success rates	fraction	Alaska	Office of Oil and Gas

	Data					
	Variable Name					
Subroutine	**Code**	**Text**	**Description**	**Unit**	**Classification**	**Source**
OGINIT_IMP	SRCAN	SR	Canada drilling success rates	fraction	Canada	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGEXP_FIX OGFOR_L48 OGINIT_L48 OGOUT_L48	SRL48	SR	Lower 48 drilling success rates	fraction	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGALL_OFF OGFOR_OFF OGINIT_OFF OGOUT_OFF	SROFF	SR	Offshore drilling success rates	fraction	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)	Minerals Management Service
OGEXPAND_LNG OGINIT_LNG	STARTLAG	--	Number of year between stages (regasification and liquefaction)	years	NA	Office of Integrated Analysis and Forecasting
OGDCF_AK OGINIT_AK	STTXAK	STRT	Alaska state tax rate	fraction	Alaska	U.S. Geological Survey
OGEXP_CALC OGFOR_L48 OGINIT_L48	STTXL48	STRT	State tax rates	fraction	6 Lower 48 onshore regions	Commerce Clearing House
OGEXP_CALC OGFOR_OFF OGINIT_L48	STTXOFF	STRT	State tax rates	fraction	4 Lower 48 offshore subregions	Commerce Clearing House
OGINIT_EOR SET_TEMP_VALUES	T_ROPRICE	--	regional wellhead prices for existing stock and new drilling (oil)	$/BO	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGINIT_EOR SET_TEMP_VALUES	T_WOPRICE	--	world oil price for existing stock and new drilling	$/BO	World	Office of Integrated Analysis and Forecasting
OGCOST_AK OGINIT_AK	TECHAK	TECH	Alaska technology factors	fraction	Alaska	Office of Integrated Analysis and Forecasting
OGINIT_IMP	TECHCAN	--	Canada technology factors applied to costs	fraction	Canada	Not used. Office of Integrated Analysis and Forecasting

	Data					
	Variable Name					
Subroutine	**Code**	**Text**	**Description**	**Unit**	**Classification**	**Source**
OGFOR_L48 OGINIT_L48	TECHL48	TECH	Lower 48 onshore technology factors applied to costs	fraction	Lower 48 Onshore	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	TECHOFF	TECH	Offshore technology factors applied to costs	fraction	Lower 48 Offshore	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	TOT_PROD	--	historical crude oil production by supply region and EOR type	MB	Lower 48 Onshore	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	TOT_RES	--	historical BOY reserves by supply region and EOR type	MB	Lower 48 Onshore	Office of Integrated Analysis and Forecasting
OGINIT_LNG OGPROF_LNG	TRANCST	--	LNG transporation costs	1990/MCF	NA	National Petroleum Council
OGDCF_AK OGINIT_AK	TRANSAK	TRANS	Alaska transportation cost	1990$	3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	TRANSL48	TRANS	Lower 48 onshore expected transportation costs	NA	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Not Used
OGFOR_OFF OGINIT_OFF	TRANSOFF	TRANS	Offshore expected transportation costs	NA	4 Lower 48 offshore subregions; Fuel (oil, gas)	Not Used
OGINIT_OFF OGOUT_OFF	UNRESOFF	Q	Offshore undiscovered resources	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_EOR CAALC_DEV_SCHED	UPROFIT	--	upper limit on profit category for new drilling development schedule	$/BO	profit category; EOR type	Advanced Resources International, Inc.
OGINIT_L48 OGOUT_L48	URRCRDL48	Q	Lower 48 onshore undiscovered recoverable crude oil resources	MMB	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGINIT_L48 OGOUT_L48	URRTDM	--	Lower 48 onshore undiscovered recoverable natural gas resources	TCF	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting

Data						
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGEXP_CALC OGINIT_BFW	WDCFIRKLAG	--	1989 Lower 48 exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	WDCFIRLAG	--	1989 Lower 48 regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions;	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	WDCFL48LAG	--	1989 Lower 48 onshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	WDCFOFFIRKLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	WDCFOFFIRLAG	--	1989 offshore regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions;	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	WDCFOFFLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
OGINIT_IMP XOGOUT_IMP	WELLAGCAN	WELLAG	1989 wells drilled in Canada	Wells per year	Fuel (gas)	Canadian Petroleum Association
OGEXP_CALC OGEXP_FIX OGINIT_L48	WELLAGL48	WELLSON	1989 Lower 48 wells drilled	Wells per year	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Oil & Gas
OGALL_OFF OGEXP_CALC OGINIT_OFF	WELLAGOFF	WELLSOFF	1989 offshore wells drilled	Wells per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Oil & Gas

	Data					
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
OGINIT_IMP	WELLLIFE	--	Canadian project life	Years	Canada	Not used. Office of Integrated Analysis and Forecasting
OGDCF_AK OGINIT_AK	XDCKAPAK	XDCKAP	Alaska intangible drill costs that must be depreciated	fraction	Alaska	U.S. Tax Code
OGFOR_L48 OGINIT_L48	XDCKAPL48	XDCKAP	Lower 48 intangible drill costs that must be depreciated	fraction	NA	U.S. Tax Code
OGFOR_OFF OGINIT_OFF	XDCKAPOFF	XDCKAP	Offshore intangible drill costs that must be depreciated	fraction	NA	U.S. Tax Code

Parameters					
Appendix B Equation Number	**Subroutine**	**Parameter Name**		**Associated Variable**	**Classification**
		Code	**Text**		
4	OGCST_l48	ALPHA_RIG	ln(b0)	Constant coefficient	Lower 48 onshore
4	OGCST_l48	B0_RIG	b1	Lower 48 onshore rigs	Lower 48 onshore
4	OGCST_l48	B1_RIG	b2	Revenue per lower 48 onshore rig	Lower 48 onshore
6	OGCST_L48	ALPHA_DRL	ln(δ0)	Constant coefficient	6 Lower 48 onshore regions; Fuel (shallow oil, deep oil, shallow gas, deep gas)
6	OGCST_L48	B0_DRL	ln(δ2)	Depth per well	Fuel (shallow oil, deep oil, shallow gas, deep gas)
6	OGCST_L48	B1_DRL	ln(δ1)	Total onshore lower 48 wells drilled	Fuel (shallow oil, deep oil, shallow gas, deep gas)
6	OGCST_L48	B2_DRL	ln(δ3)	Time trend - proxy for technology	Fuel (shallow oil, deep oil, shallow gas, deep gas)
7	OGCST_L48	ALPHA_DRY	ln(δ0)	Constant coefficient	6 Lower 48 onshore regions; Fuel (shallow oil, deep oil, shallow gas, deep gas)
7	OGCST_L48	B0_DRY	ln(δ2)	Depth per well	Fuel (shallow oil, deep oil, shallow gas, deep gas)
7	OGCST_L48	B1_DRY	ln(δ1)	Total onshore lower 48 wells drilled	Fuel (shallow oil, deep oil, shallow gas, deep gas)
7	OGCST_L48	B2_DRY	ln(δ3)	Time trend - proxy for technology	Fuel (shallow oil, deep oil, shallow gas, deep gas)
8	OGFOR_OFF	ALPHA_DRL_OFF	ln(δ0)	Constant coefficient	Fuel (oil, gas)
8	OGFOR_OFF	B0_DRL_OFF	ln(δ2)	Depth per well	Fuel (oil, gas)
8	OGFOR_OFF	B1_DRL_OFF	ln(δ1)	Offshore wells drilled in the Gulf of Mexico	NA
8	OGFOR_OFF	B2_DRL_OFF	ln(δ3)	Time trend - proxy for technology	Fuel (oil,gas)
9	OGFOR_OFF	ALPHA_DRL_OFF	ln(δ0)	Constant coefficient	Dry
9	OGFOR_OFF	B0_DRL_OFF	ln(δ2)	Depth per well	Dry

		Parameters			
Appendix B Equation Number	**Subroutine**	**Parameter Name**		**Associated Variable**	**Classification**
		Code	**Text**		
9	OGFOR_OFF	B1_DRL_OFF	$\ln(\delta 1)$	Offshore wells drilled in the Gulf of Mexico	NA
9	OGFOR_OFF	B2_DRL_OFF	$\ln(\delta 3)$	Time trend - proxy for technology	Dry
10	OGCST_L48	ALPHA_LEQ	$\ln(\epsilon 0)$	Constant coefficient	6 Lower 48 onshore regions; Fuel (shallow oil, deep oil, shallow gas, deep gas)
10	OGCST_L48	b1_LEQ	$\ln(\epsilon 1)$	Lower 48 successful wells by fuel (oil, gas)	Fuel (shallow oil, deep oil, shallow gas, deep gas)
10	OGCST_L48	B2_LEQ	$\ln(\epsilon 2)$	Time trend - proxy for technology	Fuel (shallow oil, deep oil, shallow gas, deep gas)
11	OGCST_L48	ALPHA_OPR	$\ln(\phi 0)$	Constant coefficient	6 Lower 48 onshore regions; Fuel (shallow oil, deep oil, shallow gas, deep gas)
11	OGCST_L48	B0_OPR	$\ln(\phi 2)$	Depth per well	Fuel (shallow oil, deep oil, shallow gas, deep gas)
11	OGCST_L48	B1_OPR	$\ln(\phi 1)$	Lower 48 successful wells by fuel (oil, gas)	Fuel (shallow oil, deep oil, shallow gas, deep gas)
11	OGCST_L48	B2_OPR	$\ln(\phi 3)$	Time trend - proxy for technology	Fuel (shallow oil, deep oil, shallow gas, deep gas)
126	OGCOMP_AD	ALPHA_AD	$\ln(\alpha 0)+\ln(\alpha 1)$	Constant coefficient plus regional dummy	Lower 48 regions (6 onshore, 3 offshore
126	OGCOMP_AD	BETA_AD	$\ln(\beta 0)+\ln(\beta 1)$	Crude oil production plus regional dummy	Lower 48 regions (6 onshore, 3 offshore)
135	XOGOUT_IMP	B0WELLS	B0WELLS	Constant coefficient	Canada national, Fuel(gas)
135	XOGOUT_IMP	B1WELLS	B1WELLS	Gas price	Canada national, Fuel(gas)
135	XOGOUT_IMP	B2WELLS	B2WELLS	Years 1970-1980 dummy constant	Canada national, Fuel(gas)
135	XOGOUT_IMP	B3WELLS	B2WELLS	Years 1981-1992 dummy constant	Canada national, Fuel(gas)
135	XOGOUT_IMP	BRHO	BRHO	Canadian wells auto correlation parameter	Canada national, Fuel(gas)

		Outputs			
OGSM Subroutine	**Variable Name**	**Description**	**Unit**	**Classification**	**Passed To Module**
OGFOR_AK OGPIP_AK	OGANGTSMX	Maximum natural gas flow through ANGTS	BCF	NA	NGTDM
OGINIT_IMP	OGCNBLOSS	Gas lost in transit to border	BCF	6 US/Canadian border crossings	NGTDM (Not used)
OGINIT_IMP	OGCNCAP	Canadian capacities by border crossing	BCF	6 US/Canadian border crossings	NGTDM (Not used)
OGINIT_IMP XOGOUT_IMP	OGCNCON	Canada gas consumption	Oil: MMB Gas: BCF	Fuel(oil,gas)	--
OGINIT_IMP	OGCNDMLOSS	Gas lost from wellhead to Canadian demand	BCF	NA	NGTDM (Not used)
OGINIT_IMP	OGCNEXLOSS	Gas lost from US export to Canadian demand	BCF	NA	NGTDM (Not used)
OGINIT_IMP	OGCNFLW	1989 flow volumes by border crossing	BCF	6 US/Canadian border crossings	NGTDM (Not used)
OGINIT_IMP	OGCNPARM1	Actual gas allocation factor	fraction	NA	NGTDM (Not used)
OGINIT_IMP	OGCNPARM2	Responsiveness of flow to different border prices	fraction	NA	NGTDM (Not used)
OGINIT_IMP	OGCNPMARKUP	Transportation mark-up at border	1987$	6 US/Canadian border crossings	NGTDM (Not used)
OGINIT_RES XOGOUT_IMP	OGELSCAN	Canadian price elasticity	fraction	Fuel (oil, gas)	--
OGINIT_RES OGOUT_L48 OGOUT_OFF	OGELSCO	Oil production elasticity	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGINIT_RES OGOUT_OFF	OGELSNGOF	Offshore nonassociated dry gas production elasticity	fraction	3 Lower 48 offshore regions	NGTDM
OGINIT_RES OGOUT_L48	OGELSNGON	Onshore nonassociated dry gas production elasticity	fraction	17 OGSM/NGTDM regions	NGTDM
OGOUT_EOR	OGEORCOGC	Electric cogeneration capacity from EOR	MWH	6 Lower 48 onshore regions	Industrial (not used)
OGOUT_EOR	OGEORCOGG	Electric cogeneration volumes from EOR	MWH	6 Lower 48 onshore regions	Industrial (not used)
OGCOMP_AD	OGPRDAD	Associated-dissolved gas production	BCF	6 Lower 48 onshore regions & 3 Lower 48 offshore regions	NGTDM
OGINIT_RES XOGOUT_IMP	OGPRRCAN	Canadian P/R ratio	fraction	Fuels (oil, gas)	NGTDM

		Outputs			
OGSM Subroutine	**Variable Name**	**Description**	**Unit**	**Classification**	**Passed To Module**
OGINIT_RES OGOUT_L48	OGPRRCO	Oil P/R ratio	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGINIT_RES OGOUT_OFF	OGPRRNGOF	Offshore nonassociated dry gas P/R ratio	fraction	3 Lower 48 offshore regions	NGTDM
OGINIT_RES OGOUT_L48	OGPRRNGON	Onshore nonassociated dry gas P/R ratio	fraction	17 OGSM/NGTDM regions	NGTDM
OGFOR_AK OGPIP_AK OGPRO_AK	OGQANGTS	Gas flow at U.S. border from ANGTS	BCF	NA	NGTDM
OGOUT_EOR	OGQEORCON	EOR crude oil consumption	MB	6 Lower 48 onshore regions	PMM (not used)
OGOUT_EOR	OGQEORNGC	EOR natural gas consumption	MCF	6 Lower 48 onshore regions; 2 EOR technologies (primary,other)	NGTDM (not used)
OGOUT_EOR	OGQEORNGP	EOR natural gas production	MCF	6 Lower 48 onshore regions	NGTDM (not used)
OGOUT_EOR OGINIT_EOR OGOIL_PRD	OGQEORPR	EOR crude oil production	MB	6 Lower 48 onshore regions	PMM (not used)
OGINIT_IMP XOGOUT_IMP OGOUT_MEX	OGQNGEXP	Natural gas exports	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM
OGLNG_OUT XOGOUT_IMP OGOUT_MEX	OGQNGIMP	Natural gas imports	BCF	3 US/Mexico border crossings; 4 LNG terminals	NGTDM
OGINIT_RES XOGOUT_IMP	OGRESCAN	Canadian end-of-year reserves	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGINIT_RES OGOUT_L48 OGOUT_OFF	OGRESCO	Oil reserves	MMB	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGINIT_RES OGOUT_OFF	OGRESNGOF	Offshore nonassociated dry gas reserves	BCF	3 Lower 48 offshore regions	NGTDM
OGINIT_RES OGOUT_L48	OGRESNGON	Onshore nonassociated dry gas reserves	BCF	17 OGSM/NGTDM regions	NGTDM

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	BRIEF DESCRIPTION	UNITS	SOURCE
PARAM (1)	Operating cost overhead	Fraction	ICF Resources Incorporated Various Industry Cost Surveys
PARAM (2)	G & A expenses on tangible and intangible investments	Fraction	ICF Resources Incorporated Various Industry Cost Surveys
PARAM (3)	Useful life on capital investment	Years	Internal Revenue Service
PARAM (4)	Royalty rate on producer revenue	Fraction	Minerals Management Service
PARAM (5)	Severence tax rate	Fraction	Minerals Management Service
PARAM (6)	Income tax credit on capital investment	Fraction	Internal Revenue Service
PARAM (7)	Federal income tax rate	Fraction	Internal Revenue Service
PARAM (8)	Discount factor	Multiplier	ICF Resources Incorporated
PARAM (9)	Year after tangible investment begins depreciating	Years	Internal Revenue Service
PARAM (10)	Co-product value adjustment factor	Fraction	Minerals Management Service
PARAM (11)	Year in which costs are evaluated		ICF Resources Incorporated
PARAM (12)	Current year in analysis		ICF, EIA
PARAM (13)	Convergence criterion for method of bisection	Value	ICF Resources Incorporated
PARAM (14)	Fraction of investment costs that are tangible	Fraction	Definition
PARAM (15)	Fraction of exploratory well costs that are GNG costs	Fraction	Various Industry Cost Surveys
NPYR	Total number of years in production for wells in a given field size class	year	DOE Fossil Energy Models ICF Resources Incorporated
ULT_PCT	Percent of ultimate recovery of a well that is produced each year	fraction	DOE Fossil Energy Models ICF Resources Incorporated
NUSGS	US Geological Survey defined field size class number		US Geological Survey
MIN_USGS	Minimum field size in a field size class defined by USGS	MMBOE	US Geological Survey
MAX_USGS	Maximum field size in a field size class defined by USGS	MMBOE	US Geological Survey

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
WEL_REC	Average per well ultimate recovery for fields in a USGS field size class	MMBOE	DOE Fossil Energy Models ICF Resources Incorporated
PLAY_NUM	Unit code assigned to the 'plays' defined in DWOSS		Minerals Management Service ICF Resources Incorporated
PLAY_COD	Alpha-numeric code for the 'plays' defined in DWOSS		ICF Resources Incorporated
PLAY_NAM	Description of the 'plays' defined in DWOSS		ICF Resources Incorporated Minerals Management Service
WAT_DEP	Average water depth for each of the water depth aggregated plays	feet	ICF Resources Incorporated Offshore Data Services Various Industry Sources
EXP_DEP	Average exploratory well drilling depth in each play	feet	Offshore Data Services Minerals Management Service
DEV_DEP	Average development well drilling depth in each play	feet	Offshore Data Services Minerals Management Service
EDSR	Exploration drilling success rate in each play	fraction	Offshore Data Services Various Industry Sources American Petroleum Institute
XDSR	Extension drilling success rate in each play	fraction	Offshore Data Services Various Industry Sources American Petroleum Institute
DDSR	Development drilling success rate in each play	fraction	Offshore Data Services Various Industry Sources American Petroleum Institute
GO_RATIO	Gas oil ratio for fields in each play	Scf/Bbl	Minerals Management Service
YIELD	Condensate yield for fields in each play	Bbl/MMcf	Minerals Management Service
APIGRAV	Crude oil gravity for fields in each play	Deg. API	Minerals Management Service
FLOWLINE	Length of gathering system for an average field in a play	Miles	Minerals Management Service ICF Resources Incorporated
OIL_TARF	Transportation tariff for oil for an average field in a play	$/Bbl	Minerals Management Service

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
GAS_TARF	Transportation tariff for gas for an average field in a play	$/Mcf	Minerals Management Service
NPOOL	Number of fields in a play		Minerals Management Service
OIL_GAS	The type of field - oil-bearing or gas-bearing		ICF Resources Incorporated
OIL_SIZE	Size of the field if an oil-bearing field	MMBbl	Minerals Management Service
GAS_SIZE	Size of the field if an gas-bearing fieldBcfMinerals Management Service		ICF Resources Incorporated
FSC	USGS Field Size Class to which the field belongs		US Geological Survey
WDC	Gulf of Mexico water depth category to which the field belongs		ICF Resources Incorporated Minerals Management Service
EDRATE	Exploration drilling rate	feet/day	Various Industry Sources
DDRATE	Development drilling rate	feet/day	Various Industry Sources
ITECH	Five technology choices relating to exploration drilling rig, development drilling rig, pre-drilling, production structure, and pipeline construction		Minerals Management Service ICF Resources Incorporated Various Literature Sources
EXPRIG	Exploration drilling rig		Calculated in Model
PRERIG	Pre-drilling rig		Calculated in Model
DEVRIG	Development drilling rig		Calculated in Model
EXPWEL	Number of exploratory wells		Calculated in Model
IYREXP	Year when exploratory drilling begins		Calculated in Model
EXPTIM	Time required for exploratory drilling		Calculated in Model
DELWEL	Number of delineation wells		Calculated in Model
IYRDEL	Year when delineation drilling begins		Calculated in Model
DELTIM	Time required for delineation drilling		Calculated in Model
DEVWEL	Number of development wells		Calculated in Model
DEVDRY	Number of dry development wells		Calculated in Model

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
IYRDEV	Year when development drilling begins		Calculated in Model
DEVTIM	Time required for development drilling		Calculated in Model
PREDEV	Number of pre-drilled development wells		Calculated in Model
PREDRY	Number of pre-drilled dry development wells		Calculated in Model
IYRPRE	Year when pre-drilling begins		Calculated in Model
PRETIM	Time required for pre-drilling		Calculated in Model
NSLOT	Number of slots		Calculated in Model
NSTRUC	Number of production structures		Calculated in Model
IYRSTR	Year when structure installation begins		Calculated in Model
STRTIM	Time required to complete the structure installation		Calculated in Model
NTEMP	Number of templates		Calculated in Model
IYRTEM	Year when template construction begins		Calculated in Model
TEMTIM	Time required to complete the template installation		Calculated in Model
IYRPIP	Year when the pipeline gathering system construction begins		Calculated in Model
PIPTIM	Time required to complete the pipeline gathering system installation		Calculated in Model
ULTREC	Cumulative ultimate recoverable reserves in a field	MMBOE	Calculated in Model
QAVOIL	Average oil production rate per year during the life of a field	Bbl	Calculated in Model
QOIL	Annual oil production volume for each year during the life of a field	Bbl	Calculated in Model
QCOIL	Cumulative oil production volume at the end of each year	Bbl	Calculated in Model
QAVGAS	Average gas production rate per year during the life of a field	Mcf	Calculated in Model
QGAS	Annual gas production volume for each year during the life of a field	Mcf	Calculated in Model
QCGAS	Cumulative gas production volume at the end of each year	Mcf	Calculated in Model
IYRPRD	Year when production begins in a field		Calculated in Model

	DEEP WATER OFFSHORE SUPPLY SUBMODULE		
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
PRDTIM	Time required for total production		Calculated in Model
MAXPYR	Year when the last well in a field ceases production		Calculated in Model
IYRABN	Year when the field and production structure are abandoned		Calculated in Model
GEOCST	Cost to conduct geological and geophysical evaluation	$	Calculated in Model
DNCEXP	Cost to drill an exploratory well	$/well	Calculated in Model
DNCDEL	Cost to drill a delineation well	$/well	Calculated in Model
DNCDEV	Cost to drill a development well	$/well	Calculated in Model
DNCDRY	Cost to drill a dry development well	$/well	Calculated in Model
DNCPRE	Cost to drill a pre-drilled development well	$/well	Calculated in Model
DNCPDR	Cost to drill a pre-drilled dry development well	$/well	Calculated in Model
STRCST	Cost to construct and install the production structure	$/struc	Calculated in Model
TEMCST	Cost to construct and install the template	$/temp	Calculated in Model
ABNCST	Cost to abandon the production structure	$/struc	Calculated in Model
PIPECO	Cost to install pipeline and gathering system	$/struc	Calculated in Model
PRDEQP	Cost to install topside production equipment	$/struc	Calculated in Model
STROPC	Cost to operate the production structure	$/struc/year	Calculated in Model
GEO_CST	Annual geological and geophysical costs	$/year	Calculated in Model
GNG_CAP	Annual geological and geophysical costs that are capitalized	$/year	Calculated in Model
GNG_EXP	Annual geological and geophysical costs that are expensed	$/year	Calculated in Model
EXPDCST	Annual exploratory drilling costs	$/year	Calculated in Model
DELDCST	Annual delineation drilling costs	$/year	Calculated in Model
DEVDCST	Annual development drilling costs	$/year	Calculated in Model
DDRDCST	Annual dry development drilling costs	$/year	Calculated in Model

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
PREDCST	Annual pre-drilled development drilling costs	$/year	Calculated in Model
PDRDCST	Annual dry pre-drilled development drilling costs	$/year	Calculated in Model
PDEQCST	Annual production equipment and facilities costs	$/year	Calculated in Model
STRYCST	Annual structure installation costs	$/year	Calculated in Model
TMPYCST	Annual template installation costs	$/year	Calculated in Model
PIPECST	Annual pipeline and gathering system installation costs	$/year	Calculated in Model
ABNDCST	Annual abandonment costs	$/year	Calculated in Model
OPCOST	Annual total operating costs	$/year	Calculated in Model
TANG	Annual total tangible investment costs	$/year	Calculated in Model
INTANG	Annual total intangible investment costs	$/year	Calculated in Model
INVEST	Annual total capital investment costs	$/year	Calculated in Model
REV_OIL	Annual gross oil revenues	$/year	Calculated in Model
REV_GAS	Annual gross gas revenues	$/year	Calculated in Model
REV_GROS	Annual total producer revenues	$/year	Calculated in Model
GRAV_ADJ	Annual gravity adjustment penalties	$/year	Calculated in Model
TRAN_CST	Annual transportation costs for oil and gas	$/year	Calculated in Model
REV_ADJ	Annual adjusted gross revenues	$/year	Calculated in Model
ROYALTY	Annual royalty payments	$/year	Calculated in Model
REV_PROD	Annual net producer revenues	$/year	Calculated in Model
GNA_CST	Annual GNA on investments	$/year	Calculated in Model
GNA_OPN	Annual GNA on operations	$/year	Calculated in Model
REV_NET	Annual net Revenues from operations	$/year	Calculated in Model
NET_BTCF	Annual net before-tax cash flow	$/year	Calculated in Model

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
FED_TAXS	Annual federal tax bill	$/year	Calculated in Model
FED_INTC	Annual federal income tax credits	$/year	Calculated in Model
NET_INCM	Annual net income from operations	$/year	Calculated in Model
DEPR	Annual depreciation values	$/year	Calculated in Model
GNGRC	Annual GNG cost recovery	$/year	Calculated in Model
ANN_ATCF	Annual after-tax cash flow	$/year	Calculated in Model
NPV_ATCF	Annual discounted after-tax cash flow	$/year	Calculated in Model
REPCST	Replacement cost	$/BOE	Calculated in Model
NETPV	Net present value of the after-tax cash flow	$	Calculated in Model
TYPE	Field type (oil or gas) transferred to the endogeneous component		Calculated in Exogeneous Part
MASP_TOT	Minimum acceptable supply price transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
RSRV_OIL	Recoverable oil reserves transferrd to the endogeneous component	MMBbl	Calculated in Exogeneous Part
RSRV_GAS	Recoverable gas reserves transferred to the endogeneous component	Bcf	Calculated in Exogeneous Part
MASP_EXP	Exloration part of MASP transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
MASP_DRL	Drilling part of MASP transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
MASP_STR	Structure part of MASP transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
MASP_OPR	Operations part of MASP transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
EXPL_WEL	Number of exploratory wells transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
DEVL_WEL	Number of development wells transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
DRY_HOLE	Number of dry holes transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
STRUC_NO	Number of structures transferred to the endogeneous component	$/Bbl, $/Mcf	Calculated in Exogeneous Part
NREG	Number of deepwater Gulf of Mexico regions		Minerals Management Service
NFUEL	Types of fuels in the model (oil and gas)		EIA

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
NYEAR	Number of years analyzed for forecast		EIA
RATIO_RP	Reserves to production ratio		Minerals Management Service ICF Resources Incorporated
WLDRLEVL	Drilling activity level constraint	Wells	Offshore Data Services ICF Resources Incorporated
WLDRL_RT	Growth rate in drilling activity level	fraction	EIA, ICF
CUR_YEAR	Current year in the model		EIA
RES_GROW	Growth rate for proved reserves	fraction	EIA, ICF
ADT_EXPL	Advanced technology multiplier for exploration costs	fraction	EIA, ICF
ADT_DRLG	Advanced technology multiplier for drilling costs	fraction	EIA, ICF
ADT_STRC	Advanced technology multiplier for structure costs	fraction	EIA, ICF
ADT_OPER	Advanced technology multiplier for operations costs	fraction	EIA, ICF
OILPRICE	Oil price in the analysis year	$/Bbl	PMM (NEMS)
GASPRICE	Gas price in the analysis year	$/Mcf	NGTDM (NEMS)
XPVD_OIL	Existing proved oil reserves in current year	MMBbl	Minerals Management Service ICF Resources Incorporated
XPVD_GAS	Existing proved gas reserves in current year	Bcf	Minerals Management Service ICF Resources Incorporated
XPVD_AGS	Existing proved associated gas reserves in current year	Bcf	Minerals Management Service ICF Resources Incorporated
XPVD_CND	Existing proved condensate yield reserves in current year	MMBbl	Minerals Management Service ICF Resources Incorporated
INFR_OIL	Inferred oil reserves (remaining economic) each year	MMBbl	Calculated in Model
INFR_GAS	Inferred gas reserves (remaining economic) each year	Bcf	Calculated in Model
INGR_AGS	Inferred associated gas reserves (remaining economic) each year	Bcf	Calculated in Model
INFR_CND	Inferred condensate reserves (remaining economic) each year	MMBbl	Calculated in Model

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
MSP_INFO	Average supply price for the inferred oil reserves each year	$/Bbl	Calculated in Model
MSP_INFG	Average supply price for the inferred gas reserves each year	$/Mcf	Calculated in Model
BKED_OIL	Oil reserves booked every year include reserve adds	MMBbl	Calculated in Model
BKED_GAS	Gas reserves booked every year include reserve adds	Bcf	Calculated in Model
BKED_AGS	Associated gas reserves booked every year include reserve adds	Bcf	Calculated in Model
BKED_CND	Condensate reserves booked every year include reserve adds	MMBbl	Calculated in Model
WEL_EXPO	Number of exploratory oil wells drilled each year		Calculated in Model
WEL_DRYO	Number of dry holes oil wells drilled each year		Calculated in Model
WEL_DEVO	Number of development oil wells drilled each year		Calculated in Model
NUM_STRO	Number of oil production structures installed each year		Calculated in Model
WEL_EXPG	Number of exploratory gas wells drilled each year		Calculated in Model
WEL_DRYG	Number of dry holes oil wells drilled each year		Calculated in Model
WEL_DEVG	Number of development gas wells drilled each year		Calculated in Model
NUM_STRG	Number of gas production structures installed each year		Calculated in Model
BEG_RESO	Beginning of the year proved oil reserves	MMBbl	Calculated in Model
BEG_RESG	Beginning of the year proved gas reserves	Bcf	Calculated in Model
GRO_RESO	Growth in proved oil reserves	MMBbl	Calculated in Model
GRO_RESG	Growth in proved gas reserves	Bcf	Calculated in Model
ADD_RESO	Reserve additions to proved oil reserves	MMBbl	Calculated in Model
ADD_RESG	Reserve additions to proved oil reserves	Bcf	Calculated in Model
PROD_OIL	Oil production	MMBbl	Calculated in Model
PROD_GAS	Gas production	Bcf	Calculated in Model
END_RSVO	End of the year oil reserves	MMBbl	Calculated in Model

DEEP WATER OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
END_RSVG	End of the year gas reserves	Bcf	Calculated in Model
CST_EXPL	Annual exploration costs	MM$	Calculated in Model
CST_DRLG	Annual drilling costs	MM$	Calculated in Model
CST_STRC	Annual structure installation costs	MM$	Calculated in Model
CST_OPER	Annual operating costs	MM$	Calculated in Model

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
-	BASLOC	Basin Location: The basin/play name	NA	UGR Type; Play	ARI/USGS
-	PNUM	Play Number: The play number established by ARI	-	UGR Type; Play	ARI
ATUNDRLOC	ATUL	Undrilled Locations - Advanced Technology: Number of locations available to drill under advanced technology	-	UGR Type; Play; Quality[1]	ARI
AVDEPTH	AVGDPTH	Average Depth:Average depth of the play	Feet	UGR Type; Play; Quality	ARI
BASINDIFF	BASNDIF	Basin Differential: This is a sensitivity on the gas price at a basin level. Depending on their proximity to market and infrastructure, the price varies throughout the country. The numbers are constant throughout the model.	1996$/ Mcf	UGR Type; Play; Quality	ARI
BNAREA	BASAR	Basin Area: Area in square miles	Square Miles	UGR Type; Play; Quality	ARI
CAPCSTDH	CCWDH	Capital Costs with Dry Hole Costs	1996$/ Mcf	UGR Type; Play; Quality	ARI
CTUNDRLOC	CTUL	Undrilled Locations - Current Technology: Current number of locations available to drill	-	UGR Type; Play; Quality	ARI
DCCOST	DACC	Drilling and completion costs	1996$	UGR Type; Play; Quality	ARI
DCCOSTGT	DCC_G2K	Drilling and completion cost per foot, well is greater than 2000 feet.	1996$/ Foot	UGR Type	ARI

[1]The four "Quality" Categories are Total, Best 30%, Next Best 30%, and Worst 40%.

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
DCCOSTLT	DCC_L2K	Cost per foot, well is less than 2000 feet.	1996$/ Foot	UGR Type	ARI
DEVCELLS	DEV_CEL	Developed Cells: Number of locations already drilled	-	UGR Type; Play; Quality	ARI
DISCFAC	DIS_FAC	Discount Factor: This is the discount factor that is applied to the EUR for each well. The Present Value of a production stream from a typical coalbed methane, tight sands, or gas shales well is discounted at a rate of 15%.over a twenty year period.	Fraction	UGR Type	ARI
DISCRES	DISCRES	Discounted Reserves: The mean EUR per well multiplied by the discount factor.	Bcf	UGR Type; Play; Quality	Calculated
DRILLSCHED	DRL_SCHED	Drilling Schedule	Years	UGR Type; Play; Quality	ARI
DRILLSCHED	DRL_SCHED2	Drilling Schedule adjusted to account for technological progress	Years	UGR Type; Play; Quality	ARI
DRILLSCHED	DRL_SCHED3	Drilling Schedule: This variable ensures that adjustment for technology did not result in negative value for emerging basin Drilling Schedule.	Years	UGR Type; Play; Quality	ARI
DRRESADDS	DRA	Drilled Reserve Additions	Bcf	UGR Type; Play; Quality	Calculated
DRYHOLECOST	DHC	Dry Hole Costs	1996$/ Well	UGR Type; Play; Quality	Calculated
EMBASINYRS* FINFAC	EMERG#	The number of years taken off the drilling schedule for an advancement in technology.	Years	UGR Type; Play	ARI

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
EMERGBAS	EMRG	The parameter that determines if the play is an emerging basin. This designation was made by ARI (1=yes).	-	UGR Type; Play; Quality	ARI
ENCBMYRCST	ECBM_OC	Enhanced CBM Operating Costs Variable - $1.00	1996$/ Mcf	UGR Type[CBM]; Basin; Quality	ARI
ENVIRONREG	ENV%	The percentage of the play that is not restricted from development due to environmental or pipeline regulations	Fraction	UGR Type; Play	ARI
ENVPIPREG	ENPRGS	Establishes if the play is pipeline or environmentally regulated (1=yes).	-	UGR Type; Play; Quality	ARI
EXNPVREV	ENPVR	Expected NPV Revenues: Gives the value of the entire discounted production stream for one well in real $.	1996$/ Well	UGR Type; Play; Quality	Calculated
FINFAC	TECHYRS	Number of years (from base year) over which incremental advances in indicated technology have occurred	Years	-	Calculated
FIXOMCOST	FOMC	Fixed Operating and Maintenance Costs	1996$/ Well	UGR Type; Play; Quality	Calculated
GA10	GAA10	Variable General and Administrative (G&A) Costs:	1996$/ Well	UGR Type; Play; Quality	Calculated
GABASE	RST	Variable G&A Costfactor - Currently 10% of equiprment costs, stimulation costs, and drilling costs	Fraction	UGR Type; Play; Quality	Calculated
H2OBASE	WOML_WTR	Water Producing Well Lease Equipment Costs	1996$/ Well	UGR Type; EUR Level	ARI
H2ODISP	WATR_DISP	Establishes if the play requires water disposal (1 = yes)	-	UGR Type; Play; Quality	ARI

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
HYPPLAYS	HYP%	Establishes whether or not the play is hypothetical (1=yes)	-	UGR Type; Play; Quality	ARI
LANDGG	DCC_G&G	Land / G&G Costs	1996$/ Well	UGR Type; EUR level	ARI
LANDGGH2O	WOMM_OMW	Operating & Maintenance - Medium well with H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
LANDGGH2O	WOMS_OMW	Operating & Maintenance - Small well with H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
LANDGGH2O	WOML_OMW	Operating & Maintenance - Large well with H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
LEASEQUIP	LSE_EQ	Lease Equipment Costs	$1996/ Well	UGR Type; Play; Quality	ARI
LSEQBASE	WOML_LE	Large Well Lease Equipment Costs	$1996/ Well	UGR Type; EUR Level	ARI
LSEQBASE	WOMS_LE	Small Well Lease Equipment Costs	$1996/ Well	UGR Type; EUR Level	ARI
LSEQBASE	WOMM_LE	Medium Well Lease Equipment Costs	$1996/ Well	UGR Type; EUR Level	ARI
MEANEUR	MEUR1	A weighted average of the EUR values for each (entire) basin	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR1	A weighted average of the EUR values for the best 30% of the wells in the basin	Bcf/Well	UGR Type; Play; Quality	Calculated

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	**Text**				
MEANEUR	MEUR1	A weighted average of the EUR values for the middle 30% of the wells in the basin	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR1	A weighted average of the EUR values for the worst 40% of the wells in the basin	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR2	For Coalbed Methane, "MEUR1" adjusted for technological progress in the development of new cavity fairways	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR3	For Enhanced Coalbed Methane, "MEUR2" adjusted for technological progress in the commercialization of Enhanced Coalbed Methane	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR4	Mean EUR: This variable establishes whether or not the play is profitable and if so, allows the EUR to appear for development.	Bcf/Well	UGR Type; Play; Quality	Calculated
NETPR	NET_PRC	Net Price ($/Mcf): Including Royalty and Severance Tax	1996$/Mcf	UGR Type; Play; Quality	Calculated
NETPROFIT	NET_PROF	Net Profits ($/Mcf)	1996$/Mcf	UGR Type; Play; Quality	Calculated
NETPROFIT	NET_PROF2	Net Profits (changed to 0 if < 0): Allows only the profitable plays to become developed	1996$/Mcf	UGR Type; Play; Quality	Calculated
NEWWELLS	NW_WELLS	New Wells: The amount of wells drilled for the play in that year	Wells	UGR Type; Play; Quality	Calculated
NEWWELLS	NW_WELLS2	New Wells: This variable ensures the wells drilled is a positive value.	Wells	UGR Type; Play; Quality	Calculated
NYR_UNDEVWELLS	UNDV_WELLS2	Undeveloped wells available to be drilled for the next year	Wells	UGR Type; Play; Quality	Calculated

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
1.32*OGPRCL48	WHGP	Wellhead Gas Price	1996$/ Mcf	UGR Type; OGSM Region	NGTDM (Integrated); Input(Standalone)
OPCOSTH2O	OCWW$	Operating Costs with H2O - $0.30	1996$/Mcf	UGR Type; H2O Disposal Level	ARI
OPCOSTH2O	OCNW$	Operating Costs without H2O - $0.25	$1996/ Mcf	UGR Type; H2O Disposal Level	ARI
OPCSTGASTRT	GASTR	Gas Treatment and Fuel costs - $0.25	$1996/ Mcf	UGR Type	ARI
OPCSTH2ODISP	WTR_DSPT	Water Disposal Fee: $0.05	$1996/ Mcf	UGR Type	ARI
OPCSTOMS	WOMS	H2O Costs, Small Well	$1996/ Mcf	UGR Type	ARI
PLAYPROBBASE	PLPROB	The play probability: Only hypothetical plays have a PLPROB < 100%.	Fraction	UGR Type; Play; Quality	ARI
PLAYPROB	PLPROB2	The play probability adjusted for technological progress, if initial play probability less than 1.	Fraction	UGR Type; Play; Quality	Calculated
PMPSFEQBASE	BASET	Variable cost of Pumping and Surface equipment when H2O disposal is required.	1996$/ Well	UGR Type; Play; Quality	ARI
PMPSURFEQ	PASE	Pumping and Surface Equipment Costs	1996$/ Well	UGR Type; Play; Quality	Calculated

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
PROD	PROD	Current Production	Bcf	UGR Type; Play; Quality	Calculated
PROD	PROD2	Production for the next year	Bcf	UGR Type; Play; Quality	Calculated
PROVRESV	PROV_RES	Proved Reserves	Bcf	UGR Type; Play; Quality	Calculated
PROVRESV	PROV_RES2	Proved Reserves for the next year	Bcf	UGR Type; Play; Quality	Calculated
RESADDS	R_ADD	Total Reserve Additions	Bcf	UGR Type; Play; Quality	Calculated
RESGRADDS	RGA	Reserve Growth Additions	Bcf	UGR Type; Play; Quality	Calculated
RESGRWTH	RES_GR	Establishes whether or not the play will have reserve growth (1=yes)	-	UGR Type; Play; Quality	ARI
RESWELLBCFB	RW101	Reserves per Well for the best 10% of the play (year 1): an EUR estimate	Bcf/Well	UGR Type; Play; Quality	ARI
RESWELLBCFB	RW201	Reserves per Well for the next (lesser) 20% of the play (year 1): an EUR estimate	Bcf/Well	UGR Type; Play; Quality	ARI
RESWELLBCFB	RW301	Reserves per Well for the next (lesser) 30% of the play (year 1): an EUR estimate	Bcf/Well	UGR Type; Play; Quality	ARI
RESWELLBCFB	RW401	Reserves per Well for the worst 40% of the play (year 1): an EUR estimate	Bcf/Well	UGR Type; Play; Quality	ARI

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
RESWELLBCF	RW101	Reserves per Well for the best 10% of the play (years 2,20)	Bcf/Well	UGR Type; Play; Quality	Calculated
RESWELLBCF	RW201	Reserves per Well for the next (lesser) 20% of the play (years 2,20)	Bcf/Well	UGR Type; Play; Quality	Calculated
RESWELLBCF	RW301	Reserves per Well for the next (lesser) 30% of the play (years 2,20)	Bcf/Well	UGR Type; Play; Quality	Calculated
RESWELLBCF	RW401	Reserves per Well for the worst 40% of the play (years 2,20)	Bcf/Well	UGR Type; Play; Quality	Calculated
RES_GRTH_DEC	RGR	Reserve Growth Rate	Fraction	UGR Type; Year	ARI
ROYSEVTAX	RST	Variable Royalty and Severance Tax - Set at 17%	Fraction	UGR Type	ARI
RP	R/P_RAT	Reserves-to-Production (R/P) Ratio	Fraction	UGR Type; Play; Quality	Calculated
RP	RP_RAT2	R/P Ratio for the next year	Fraction	UGR Type; Play; Quality	Calculated
RSVPRD	RESNPROD	Reserves and Production	Bcf	UGR Type; Play; Quality	Calculated
STIMCOST	STIMC	Stimulation Costs: Provides the cost of stimulating a well in the specific basin by multiplying the given average stimulation cost by the number of stimulation zones.	1996$/Well	UGR Type; Play; Quality	ARI
STIMCSTBASE	STIM_CST	Variable average cost of stimulating one zone. (Number of zones is a variable)	1996$/Zone	UGR Type	ARI

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
STIMUL	SZONE	Stimulation Zones: Number of times a single well is stimulated in the play	-	UGR Type; Play; Quality	ARI
SUCRATE	SCSSRT	Success Rate : The ratio of successful wells over total wells drilled (This can also be called the dry hole rate if you use the equation 1 - SCSSRT).	Fraction	UGR Type; Play; Quality	ARI
TECHRECWELL	TRW1	The amount of technically recoverable wells available regardless of economic feasibility.	Wells	UGR Type; Play; Quality	Calculated
TECH_PROG_ SCHED_DR	REDAM%	Total percentage increase over development period due to advances in "Reduced Damage D&S" technology	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_DR	FRCLEN%	Total percentage increase over development period due to advances in "Increased Fracture Length L&C" technology	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_DR	PAYCON%	Total percentage increase over development period due to advances in "Improved Pay Contact" technology	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_EX	EMERG%	The number of years added onto the drilling schedule because of the hindrance of the play being an emerging basin.	Years	UGR Type	ARI
TECH_PROG_ SCHED_PT	WDT%	Total percentage decrease in H2O disposal and treatment costs over the development period due to technological advances	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_PT	PUMP%	Total percentage decrease in pumping costs over the development period due to technological advances	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_PT	GTF%	Total percentage decrease in gas treatment and fuel costs over the development period due to technological advances	Fraction	UGR Type	ARI

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
TECH_PROG_ SCHED_PT	LOW%	The percentage of the play that is restricted from development due to environmental or pipeline regulations	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_PT	LOWYRS	The number of years the environmental and or pipeline regulation will last.	Years	UGR Type	ARI
TECH_PROG_ SCHED_PT	ENH_CBM%	Enhanced CBM EUR Percentage gain	Fraction	UGR Type[CBM]	ARI
TECH_PROG_ SCHED_EX	DEVPER	Development period for "Favorable Settings" technological advances	Years	UGR Type	ARI
TOTCAPCOST	TCC	Total Capital Costs: The sum of Stimulation Costs, Pumping and Surface Equipment Costs, Lease Equipment Costs, G&A Costs and Drilling and Completion Costs	1996$/Well	UGR Type; Play; Quality	Calculated
TOTCOST	TOTL_CST	Total Costs ($/Mcf)	1996$/Mcf	UGR Type; Play; Quality	Calculated
ULTRECV	URR	Ultimate Recoverable Resources	Bcf	UGR Type; Play; Quality	Calculated
UNDEVRES	UNDEV_RES	Undeveloped resources	Bcf	UGR Type; Play; Quality	Calculated
UNDEV_WELLS	UNDV_WELLS	Undeveloped wells available for development under current economic conditions	Wells	UGR Type; Play; Quality	Calculated
VAROPCOST	VOC	Variable Operating Costs	1996$/Mcf	UGR Type; Play; Quality	Calculated

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
VAROPCOST	VOC2	Variable Operating Costs: Includes an extra operating cost for plays that will incorporate the technology of Enhanced CBM in the future	1996$/Mcf	UGR Type; Play; Quality	Calculated
WELLSP	WSPAC_CT	Well Spacing - Current Technology: Current spacing in acres	Acres	UGR Type; Play; Quality; Technology Level	ARI
WELLSP	WSPAC_AT	Well Spacing - Advanced Technology: Spacing in acres under Advanced Technology	Acres	UGR Type; Play; Quality; Technology Level	ARI
.6*LANDGGH2O	WOMS_OM	Operating & Maintenance - Small well without H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
.6*LANDGGH2O	WOMM_OM	Operating & Maintenance - Medium well without H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
.6*LANDGGH2O	WOML_OM	Operating & Maintenance - Large well without H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI

Appendix B. Mathematical Description

Calculation of Costs

Estimated Wells

Onshore

$$\text{ESTWELLS}_t = \exp(\ln(b0)) \, * \, \exp(\ln(b1) * (\text{LPOIL}_t * \text{LPGAS}_t)) \, * \, \exp(\ln(b2) * (\text{LPOIL}_t * \text{LPGAS}_t) * \text{PRE91}_t)$$
where PRE1 = 1 if YEAR < 1991; 0 otherwise

(1)

$$\text{ESTSUCWELLS}_t = \exp(\ln(b0)) \, * \, \exp(\ln(b1) * (\text{LPOIL}_t * \text{LPGAS}_t)) \, * \, \exp(\ln(b2) * (\text{LPOIL}_t * \text{LPGAS}_t) * \text{PRE91}_t)$$
where PRE1 = 1 if YEAR < 1991; 0 otherwise

(2)

Offshore

$$\text{GOMWELLS}_t = \exp(\ln(\alpha 1)) \, * \, \exp(\ln(\alpha 2) * \text{PRE86}_t) \, * \, \exp(\ln(\alpha 3) * \text{PRE91}_t) \, * \, \exp(\ln(\beta 1) * (\text{LPOIL}_t * \text{LPGAS}_t)) \, *$$
$$\exp(\ln(\beta 2) * (\text{LPOIL}_t * \text{LPGAS}_t) * \text{PRE91}_t)$$
where PRE86 = 1 if YEAR < 86; 0 otherwise
        PRE91 = 1 if YEAR < 91; 0 otherwise

(3)

Lower 48 Rigs

Onshore

$$\text{RIGSL48}_t = \exp(\ln(b0)) \, * \, \text{RIGSL48}_{t-1}^{b1} \, * \, \text{REVRIG}_{t-1}^{b2}$$

(4)

Offshore

$$\text{RIGSOFF}_t = \exp(\ln(\alpha)) \, * \, \text{RIGSOFF}_{t-1}^{\beta} \, * \, \text{REVRIG}_{t-2}^{\gamma}$$

(5)

Drilling Costs
Onshore

$$\text{DRILLCOST}_{r,k,t} = \exp(\ln(\delta 0)_{r,k}) \, * \, \exp(\ln(\delta 1)_{d,k}) \, * \, \exp(\ln(\delta 2)_{r,k}) \, * \, \text{ESTWELLS}_t^{\delta 3_k} \, * \, \text{RIGSL48}_t^{\delta 4_k} \, * \, \exp(\delta 5_k * \text{TIME}_t) \, *$$
$$\text{DRILLCOST}_{r,k,t-1}^{\rho_k} \, * \, \exp(-\rho_k * \ln(\delta 0)_{r,k}) \, * \, \exp(-\rho_k * \ln(\delta 1)_{d,k}) \, * \, \exp(-\rho_k * \ln(\delta 2)_{r,k}) \, *$$
$$\text{ESTWELLS}_{t-1}^{-\rho_k * \delta 3_k} \, * \text{RIGSL48}_{t-1}^{-\rho_k * \delta 4_k} \, * \, \exp(-\rho_k \, * \, \delta 5_k \, * \, \text{TIME}_{t-1})$$

(6)

$$\text{DRYCOST}_{r,k,t} = \exp(\ln(\delta 0)_{r,k}) \, * \, \exp(\ln(\delta 1)_{d,k}) \, * \, \exp(\ln(\delta 2)_{r,k}) \, * \, \text{ESTWELLS}_t^{\delta 3_k} \, * \, \text{RIGSL48}_t^{\delta 4_k} \, * \, \exp(\delta 5_k * \text{TIME}_t) \, *$$
$$\text{DRYCOST}_{r,k,t-1}^{\rho_k} \, * \, \exp(-\rho_k * \ln(\delta 0)_{r,k}) \, * \, \exp(-\rho_k * \ln(\delta 1)_{d,k}) \, * \, \exp(-\rho_k * \ln(\delta 2)_{r,k}) \, *$$
$$\text{ESTWELLS}_{t-1}^{-\rho_k * \delta 3_k} \, * \text{RIGSL48}_{t-1}^{-\rho_k * \delta 4_k} \, * \, \exp(-\rho_k \, * \, \delta 5_k \, * \, \text{TIME}_{t-1})$$

(7)

Offshore

$$\text{DRILLCOST}_k = \exp(\delta 0_k) \, * \, \text{GOMWELLS}_t^{\delta 1_k} \, * \, \exp(\delta 2_{d,k}) \, * \, \text{RIGSOFF}_{t-2}^{\delta 3_k} \, * \, \exp(\delta 4_k * \text{TIME}_t)$$

(8)

$$\text{DRYCOST}_k = \exp(\delta 0_k) \, * \, \text{GOMWELLS}_t^{\delta 1_k} \, * \, \exp(\delta 2_{d,k}) \, * \, \text{RIGSOFF}_{t-2}^{\delta 3_k} \, * \, \exp(\delta 4_k * \text{TIME}_t)$$

(9)

Lease equipment costs

$$
\begin{aligned}
LEQC_{r,k,t} &= \exp(\ln(\epsilon 0)_{r,k}) \ * \ \exp(\ln(\epsilon 1)_k * DEPTH_{r,k,t}) \ * \ ESUCWELL_{k,t}^{\epsilon 2_k} \ * \ \exp(\epsilon 3_k * TI \\
&\quad \exp(-\rho_k * \ln(\epsilon 0)_{r,k}) \ * \ \exp(-\rho_k * \ln(\epsilon 1)_k * DEPTH_{r,k,t-1}) \ * \ ESUCWELL_{k,t-1}^{-\rho_k \ * \ \epsilon}
\end{aligned}
\tag{10}
$$

Operating Costs

$$
\begin{aligned}
OPC_{r,k,t} &= \exp(\ln(\epsilon 0)_{r,k}) \ * \ \exp(\ln(\epsilon 1)_k * DEPTH_{r,k,t}) \ * \ ESUCWELL_{k,t}^{\epsilon 2_k} \ * \ \exp(\epsilon 3_k * TIM \\
&\quad \exp(-\rho_k * \ln(\epsilon 0)_{r,k}) \ * \ \exp(-\rho_k * \ln(\epsilon 1)_k * DEPTH_{r,k,t-1}) \ * \ ESUCWELL_{k,t-1}^{-\rho_k \ * \ \epsilon 2_k}
\end{aligned}
\tag{11}
$$

Discounted Cash Flow Algorithm

Expected discounted cash flow

$$
\begin{aligned}
PROJDCF_{i,r,k,t} &= (PVREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP - \\
&\quad PVKAP - PVOPERCOST - PVABANDON - PVSIT - PVFIT)_{i,r,k,t}
\end{aligned}
\tag{12}
$$

Present value of expected revenues

$$
PVREV_{i,r,k,t} = \sum_{T=t}^{t+n} \left[Q_{r,k,T} * \lambda * (P_{r,k,T} - TRANS_{r,k}) * \left[\frac{1}{1+disc} \right]^{T-t} \right], \ \lambda = \left\{ \begin{array}{l} 1 \quad \text{if primary fuel} \\ COPRD \quad \text{if secondary fuel} \end{array} \right.
\tag{13}
$$

Present value of expected royalty payments

$$
PVROY_{i,r,k,t} = ROYRT * PVREV_{i,r,k,t}
\tag{14}
$$

Present value of expected production taxes

$$
PVPRODTAX_{i,r,k,t} = PVREV_{i,r,k,t} * (1 - ROYRT) * PRODTAX_{r,k}
\tag{15}
$$

Present value of expected costs
Drilling costs

$$
\begin{aligned}
PVDRILLCOST_{i,r,k,t} &= \sum_{T=t}^{t+n} \Big[DRILL_{1,r,k,t} * SR_{1,r,k} * WELL_{1,k,T} + DRILL_{2,r,k,t} * SR_{2,r,k} * \\
&\quad WELL_{2,k,T} + DRY_{1,r,k,t} * (1 - SR_{1,r,k}) * WELL_{1,k,T} + \\
&\quad DRY_{2,r,k,t} * (1 - SR_{2,r,k}) * WELL_{2,k,T} \Big] * \left(\frac{1}{1+disc} \right)^{T-t} \Big]
\end{aligned}
\tag{16}
$$

Lease equipment costs

$$
PVEQUIP_{i,r,k,t} = \sum_{T=t}^{t+n} \left[EQUIP_t * \left(SR_{1,r,k} * WELL_{1,k,T} + SR_{2,r,k} * WELL_{2,k,T} \right) * \left[\frac{1}{1+disc} \right]^{T-t} \right]
\tag{17}
$$

Capital costs

$$PVKAP_{i,r,k,t} = \sum_{T=t}^{t+n} \left[KAP_{i,r,k,T} * \left[\frac{1}{1 + disc} \right]^{T-t} \right] \tag{18}$$

Operating costs

$$PVOPERCOST_{i,r,k,t} = \sum_{T=t}^{t+n} \left[OPCOST_{i,r,k,t} * \sum_{k=1}^{T} \left[SR_{1,r,k}*WELL_{1,k,T} + SR_{2,r,k}*WELL_{2,k,T} \right] * \left(\frac{1}{1+disc} \right)^{T-t} \right] \tag{19}$$

Abandonment costs

$$PVABANDON_{i,r,k,t} = \sum_{T=t}^{t+n} \left[COSTABN_{i,r,k} * \left[\frac{1}{1+disc} \right]^{T-t} \right] \tag{20}$$

Present value of expected tax base

$$PVTAXBASE_{i,r,k,t} = \sum_{T=t}^{t+n} \left[(REV - ROY - PRODTAX - OPERCOST - ABANDON - XIDC - AIDC - \right.$$
$$\left. DEPREC - DHC)_{i,r,k,t} * \left(\frac{1}{1+disc} \right)^{T-t} \right] \tag{21}$$

Expected expensed costs

$$XIDC_{i,r,k,t} = DRILL_{1,r,k,t} * (1 - EXKAP) * (1 - XDCKAP) * SR_{1,r,k} * WELL_{1,k,t} +$$
$$DRILL_{2,r,k,t} * (1 - DVKAP) * (1 - XDCKAP) * SR_{2,r,k} * WELL_{2,k,t} \tag{22}$$

Expected dry hole costs

$$DHC_{i,r,k,t} = DRY_{1,r,k,t} * (1 - SR_{1,r,k}) * WELL_{1,k,t} + DRY_{2,r,k,t} * (1 - SR_{2,r,k}) * WELL_{2,k,t} \tag{23}$$

Expected depreciable costs

$$DEPREC_{i,r,k,t} = \sum_{j=\beta}^{t} \left[(DRILL_{1,r,k,T} * EXKAP + EQUIP_{1,r,k,T}) * SR_{1,r,k} * WELL_{1,k,j} + \right.$$
$$(DRILL_{2,r,k,T} * DVKAP + EQUIP_{2,r,k,T}) * SR_{2,r,k} * WELL_{2,k,j} + KAP_{r,k,j} \Big] *$$
$$\left. DEP_{t-j+1} * \left(\frac{1}{1+infl} \right)^{t-j} * \left(\frac{1}{1+disc} \right)^{t-j} \right], \tag{24}$$
$$\beta = \begin{cases} T \text{ for } t \leq T+m-1 \\ t-m+1 \text{ for } t > T+m-1 \end{cases}$$

Present value of expected state income taxes

$$PVSIT_{i,r,k,t} = PVTAXBASE_{i,r,k,t} * STRT \tag{25}$$

Present value of expected federal income taxes

$$PVFIT_{i,r,k,t} = PVTAXBASE_{i,r,k,t} * (1 - STRT) * FDRT \qquad (26)$$

Discounted cash flow for a representative developmental well

$$DCF_{2,r,k,t} = PROJDCF_{2,r,k,t} * SR_{2,r,k} \qquad (27)$$

Discounted cash flow for a representative exploratory well

$$DCF_{1,r,k,t} = PROJDCF_{1,r,k,t} * SR_{1,r,k} \qquad (28)$$

Lower 48 Onshore & Offshore Expenditures and Well Determination

Expected DCF for shallow gas recovery

$$SGDCFON_{i,r,t} = \frac{\sum_{k} (WELLS_{i,r,k,t-1} * DCFON_{i,r,k,t})}{\sum_{k} WELLS_{i,r,k,t-1}}, \text{ for } k = 3 \qquad (29)$$

Expected oil DCF

$$ODCFON_{i,r,t} = \frac{\sum_{k} (WELLS_{i,r,k,t-1} * DCFON_{i,r,k,t})}{\sum_{k} WELLS_{i,r,k,t-1}}, \text{ for } k = 1 \text{ to } 2 \qquad (30)$$

Regional share of total wells

$$w_{i,r,k,t} = \frac{WELLS_{i,r,k,t-1}}{\sum_{k} WELLS_{i,r,k,t-1}} \qquad (31)$$

Regional expected discounted cash flow

$$RDCFON_{i,r,t} = \sum_{k=1}^{7} w_{i,r,k,t} * DCFON_{i,r,k,t}, \text{ r = onshore regions, } k = 1 \text{ thru } 4 \qquad (32)$$

$$RDCFOFF_{i,r,t} = \sum_{k=1}^{2} w_{i,r,k,t} * DCFOFF_{i,r,k,t}, \text{ for } r = \text{offshore regions} \qquad (33)$$

Regional shallow oil/gas expected discounted cash flow

$$OSGDCFON_{i,r,t} = \frac{\sum_{k} (WELLS_{i,r,k,t-1} * DCFON_{i,r,k,t})}{\sum_{k} WELLS_{i,r,k,t-1}}, \text{ for } k = 1 \text{ and } 3 \qquad (34)$$

Lower 48 Onshore Well Forecasting Equations

Onshore Region 1 (r=1)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = 691.637 + 0.161251E\text{-}02 * DCFON_{i,r,k,t-2} + 1030.89 * DUM8184_t \tag{35}$$

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = 8475.18 + 0.031699 * DCFON_{i,r,k,t-1} - 5576.66 * DUM86_t \tag{36}$$

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = 108260 + 0.227959E\text{-}03 * DCFON_{i,r,k,t} + 428.155 * DUM8185_t - 54.2625 * YEAR_t \tag{37}$$

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = 187.641 + 0.207284E\text{-}02 * DCFON_{i,r,k,t-2} + 799.818 * DUM8185_t - 0.616559 * WELLSON_{i,r,k,t-1}$$
$$+ 0.616559 * \left(187.641 + 0.207284E\text{-}02 * DCFON_{i,r,k,t-3} + 799.818 * DUM8185_{t-1}\right) \tag{38}$$

Onshore Region 2 (r=2)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = -1.7465 + 0.231682E\text{-}03 * DCFON_{i,r,k,t} \tag{39}$$

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = -995.095 + 0.017907 * DCFON_{i,r,k,t} \tag{40}$$

Deep Oil Exploratory (i=1, k=2)

$$WELLSON_{i,r,k,t} = 30176.9 + 0.960199E\text{-}05 * DCFON_{i,r,k,t-1} - 15.1233 * YEAR_t \tag{41}$$

Deep Oil Development (i=2, k=2)

$$WELLSON_{i,r,k,t} = 279.14 + 0.497098E\text{-}03 * DCFON_{i,r,k,t} \tag{42}$$

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = 411.1 + 0.168511E\text{-}03 * DCFON_{i,r,k,t} + 0.883898 * WELLSON_{i,r,k,t-1} -$$
$$0.883898 * \left(411.1 + 0.168511E\text{-}03 * DCFON_{i,r,k,t-1}\right) \tag{43}$$

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = 152.967 + 0.21922E\text{-}02 * DCFON_{i,r,k,t} + 0.777603 * WELLSON_{i,r,k,t-1} -$$
$$0.777603 * \left(152.967 + 0.21922E\text{-}02 * DCFON_{i,r,k,t-1}\right) \tag{44}$$

Deep Gas Exploratory (i=1, k=4)

$$WELLSON_{i,r,k,t} = 232.047 + 0.940338E\text{-}05 * DCFON_{i,r,k,t} + 0.837494 * WELLSON_{i,r,k,t-1} -$$
$$0.837494 * \left(232.047 + 0.940338E\text{-}05 * DCFON_{i,r,k,t-1}\right) \tag{45}$$

Deep Gas Development (i=2, k=4)

$$WELLSON_{i,r,k,t} = 520.893 + 0.146519E\text{-}03 * DCFON_{i,r,k,t} + 0.441622 * WELLSON_{i,r,k,t-1} -$$
$$0.441622 * \left(520.893 + 0.146519E\text{-}03 * DCFON_{i,r,k,t-1}\right) \tag{46}$$

Onshore Region 3 (r=3)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = 291835 + 0.40577E\text{-}03 * DCFON_{i,r,k,t-1} - 146.402 * YEAR_t \tag{47}$$

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = 3201.65 + 0.018192 * DCFON_{i,r,k,t} + 0.871289 * WELLSON_{i,r,k,t-1} -$$
$$0.871289 * (3201.65 + 0.018192 * DCFON_{i,r,k,t-1}) \tag{48}$$

Deep Oil Exploratory (i=1, k=2)

$$WELLSON_{i,r,k,t} = 16.7054 + 0.342852E-05 * DCFON_{i,r,k,t-1} + 24.2414 * DUM8084_t \tag{49}$$

Deep Oil Development (i=2, k=2)

$$WELLSON_{i,r,k,t} = 75.6157 + 0.129744E-03 * DCFON_{i,r,k,t-2} + 182.826 * DUM8185_t \tag{50}$$

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = 292.033 + 0.153403E-03 * DCFON_{i,r,k,t-2} + 231.639 * DUM8084_t \tag{51}$$

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = 1115 + 0.901429E-02 * DCFON_{i,r,k,t-1} + 2202.3 * DUM8082_t \tag{52}$$

Deep Gas Exploratory (i=1, k=4)

$$WELLSON_{i,r,k,t} = 35.9188 + 0.30877E-05 * DCFON_{i,r,k,t} + 183.143 * YR82_t \tag{53}$$

Deep Gas Development (i=2, k=4)

$$WELLSON_{i,r,k,t} = 57778.8 + 0.638779E-04 * DCFON_{i,r,k,t-1} + 382.279 * YR82_t - 28.8799 * YEAR_t \tag{54}$$

Onshore Region 4 (r=4)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = 712.398 + 0.677494E-03 * DCFON_{i,r,k,t} + 0.757445 * WELLSON_{i,r,k,t-1} -$$
$$0.757445 * (712.398 + 0.677494E-03 * DCFON_{i,r,k,t-1}) \tag{55}$$

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = 2820.62 + 0.014602 * DCFON_{i,r,k,t-1} + 7231.05 * DUM8184_t \tag{56}$$

Deep Oil Exploratory (i=1, k=2)

$$WELLSON_{i,r,k,t} = 72.5471 + 0.850046E-05 * DCFON_{i,r,k,t-1} + 0.823389 * WELLSON_{i,r,k,t-1} -$$
$$0.823389 * (72.5471 + 0.850046E-05 * DCFON_{i,r,k,t-2}) \tag{57}$$

Deep Oil Development (i=2, k=2)

$$WELLSON_{i,r,k,t} = exp(184.683 + 0.720882E-06 * DCFON_{i,r,k,t} - 0.090484 * YEAR_t) \tag{58}$$

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = exp(324.918 + 0.113354E-05 * DCFON_{i,r,k,t} - 0.160516 * YEAR_t) \tag{59}$$

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = 107995 + 0.241097E-02 * DCFON_{i,r,k,t} - 54.0793 * YEAR_t + 911.089 * DUM8082_t \tag{60}$$

Deep Gas Exploratory (i=1, k=4)

$$WELLSON_{i,r,k,t} = 18.2101 + 0.11873E-05 * DCFON_{i,r,k,t} + 80.3608 * YR82_t + 0.689546 * WELLSON_{i,r,k,t-1} -$$
$$0.689546 * (18.2101 + 0.11873E-05 * DCFON_{i,r,k,t-1} + 80.3608 * YR82_{t-1}) \tag{61}$$

Deep Gas Development (i=2, k=4)

$$WELLSON_{i,r,k,t} = 33.8073 + 0.732591E-05 * DCFON_{i,r,k,t} + 134.447 * DUM8082_t \tag{62}$$

Onshore Region 5 (r=5)

Total (Shallow plus Deep) Oil Exploratory (i=1)

$$OWELLSON_{i,r,t} = 181357 + 0.145239E{-}03 * ODCFON_{i,r,t-1} - 90.9975 * YEAR_t \tag{63}$$

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = 0.75 * OWELLSON_{i,r,k,t} \tag{64}$$

Shallow Oil Development (i=2, k=1)

$$\begin{aligned} WELLSON_{i,r,k,t} = &\ 532.97 + 0.238036E{-}02 * DCFON_{i,r,k,t} + 0.811189 * WELLSON_{i,r,k,t-1} - \\ &\ 0.811189 * \left(532.97 + 0.238036E{-}02 * DCFON_{i,r,k,t-1}\right) \end{aligned} \tag{65}$$

Deep Oil Exploratory (i=1, k=2)

$$WELLSON_{i,r,k,t} = 0.25 * OWELLSON_{i,r,k,t} \tag{66}$$

Deep Oil Development (i=2, k=2)

$$WELLSON_{i,r,k,t} = 36813.4 + 0.21715E{-}03 * DCFON_{i,r,k,t} - 18.4728 * YEAR_t \tag{67}$$

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = \exp\left(5.39432 + 0.569277E{-}06 * DCFON_{i,r,k,t} + 1.27403 * DUM8081_t\right) \tag{68}$$

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = 176.32 + 0.262703E{-}03 * SGDCFON_{i,r,t-2} + 358.223 * DUM9294_t \tag{69}$$

Deep Gas Exploratory (i=1, k=4)

$$WELLSON_{i,r,k,t} = 32.2905 + 0.138592E{-}05 * DCFON_{i,r,k,t} + 106.179 * DUM8182_t \tag{70}$$

Deep Gas Development (i=2, k=4)

$$\begin{aligned} WELLSON_{i,r,k,t} = &\ -12823.9 + 0.225383E{-}04 * DCFON_{i,r,k,t} + 6.51503 * YEAR_t - 0.36423 * TREND89_t - \\ &\ 76.1673 * DUM8588_t \end{aligned} \tag{71}$$

Onshore Region 6 (r=6)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = 8.49242 + 0.300322E{-}04 * DCFON_{i,r,k,t-2} \tag{72}$$

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = 1510.83 + 0.128263E{-}02 * DCFON_{i,r,k,t} + 901.864 * DUM8485_t - 911.509 * DUM9294_t \tag{73}$$

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = 55.0794 + 0.270208E{-}04 * OSGDCFON_{i,r,t-1} \tag{74}$$

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = -70.5358 + 0.300083E{-}03 * DCFON_{i,r,k,t-2} \tag{75}$$

Lower 48 Offshore Well Forecasting Equations

Pacific (r=8)

Oil Development (i=2, k=1)

$$\text{WELLSOFF}_{i,r,k,t} = 71.1593 + 0.839564 * \text{DCFOFF}_{i,r,k,t} + 0.649205 * \text{WELLSOFF}_{i,r,k,t-1} - 0.649205 * \left(71.1593 + 0.839564 * \text{DCFOFF}_{i,r,k,t-1}\right)$$

(76)

Shallow Water Gulf of Mexico (r=9)

Oil Exploratory (i=1, k=1)

$$\text{WELLSOFF}_{i,r,k,t} = 69.0298 + 0.145046E-05 * \text{DCFOFF}_{i,r,k,t}$$

(77)

Oil Development (i=2, k=1)

$$\text{WELLSOFF}_{i,r,k,t} = 317.289 + 0.265583E-04 * \text{DCFOFF}_{i,r,k,t} - 95.2872 * \text{DUM89}_t$$

(78)

Gas Exploratory (i=1, k=3)

$$\text{WELLSOFF}_{i,r,k,t} = 290.664 + 0.529655E-05 * \text{DCFOFF}_{i,r,k,t} + 168.474 * \text{DUM8890}_t$$

(79)

Gas Development (i=2, k=3)

$$\text{WELLSOFF}_{i,r,k,t} = 324.909 + 0.305109E-04 * \text{DCFOFF}_{i,r,k,t} + 223.279 * \text{DUM7781}_t$$

(80)

Calculation of successful onshore wells

$$\text{SUCWELSON}_{i,r,k,t} = \text{WELLSON}_{i,r,k,t} * \text{SR}_{i,r,k}, \text{ for } i = 1, 2, r = \text{onshore regions}, \\ k = 1 \text{ thru } 7$$

(81)

Calculation of onshore dry holes

$$\text{DRYWELON}_{i,r,k,t} = \text{WELLSON}_{i,r,k,t} - \text{SUCWELSON}_{i,r,k,t}, \text{ for } i = 1, 2, \\ r = \text{onshore regions}, k = 1 \text{ thru } 7$$

(82)

Calculation of successful offshore wells

$$\text{SUCWELSOFF}_{i,r,k,t} = \text{WELLSOFF}_{i,r,k,t} * \text{SR}_{i,r,k}, \text{ for } i = 1, 2, r = \text{offshore regions}, k = 1, 2$$

(83)

Calculation of offshore dry holes

$$\text{DRYWELOFF}_{i,r,k,t} = \text{WELLSOFF}_{i,r,k,t} - \text{SUCWELSOFF}_{i,r,k,t}, \text{ for } i = 1, 2, \\ r = \text{offshore regions}, k = 1, 2$$

(84)

Lower 48 Onshore & Offshore Reserve Additions

New reserve discoveries

$$\text{NRD}_{r,k,t} = \text{FR1}_{r,k,t} * \text{SW1}_{r,k,t}$$

(85)

Technological Impact - Four Regimes

$$FRTECH1_{r,k,t} = 1 + \frac{PAST1A_{r,k}}{1 + e^{PAST1B1_{r,k} * (FRYEAR_t - PAST1B2_{r,k})}}$$

(86)

$$FRTECH2_{r,k,t} = 1 + \frac{PAST2A_{r,k}}{1 + e^{PAST2B1_{r,k} * (FRYEAR_t - PAST2B2_{r,k})}}$$

(87)

$$FRTECH3_{r,k,t} = 1 + \frac{ALPHA_{r,k}}{1 + e^{BETA1_{r,k} * (FRYEAR_t - BETA2_{r,k})}}$$

(88)

$$FRTECH4_{r,k,t} = 1 + \frac{FUTURA_{r,k}}{1 + e^{FUTURB1_{r,k} * (FRYEAR_t - FUTURB2_{r,k})}}$$

(89)

Economic Impact

$$ECON_{r,k,t} = \frac{OFE_{r,k} * \dfrac{CUM\_U_{r,k,t}}{CUM\_NFW_{r,k,t}} + POA_{r,k}}{OFE_{r,k} * \dfrac{CUM\_U_{r,k,t}}{CUM\_NFW_{r,k,t}} + WHP_{r,k,t}}$$

(90)

Initial Finding Rate

$$FR1O_{r,k,t} = INITFR1_{r,k} * FRTECH1_{r,k,t} * FRTECH2_{r,k,t} * FRTECH3_{r,k,t} * FRTECH4_{r,k,t} * ECON_{r,k,t}$$

(91)

Average New Field Finding Rate

$$FR1_{r,k,t} = FR1O_{r,k,t} * \left(1 - \frac{CUM\_U_{r,k,t}}{BIG\_U_{r,k}}\right)^{DELTA\_B_{r,k}}$$

(92)

Inferred reserves

$$I_{r,k,t} = NRD_{r,k,t} * (RSVGR - 1)$$

(93)

Reserve extensions

$$EXT_{r,k,t} = FR2_{r,k,t} * SW2_{r,k,t}$$

(94)

Lower 48 Onshore

Shallow Oil (k=1, r=1 thru 6)

$$
\begin{aligned}
FR2_{r,k,t} = & -182.660 * REG1_r - 180.267 * REG2_r - 181.736 * REG3_r - 179.809 * REG4_r - 180.669 * REG5_r - \\
& 181.017 * REG6_r - 0.115113E{-}02 * CUMSW2_{r,k,t-1} - 0.127988E{-}02 * SW2_{r,k,t} + 0.090704 * YEAR_t + \\
& 0.264862 * FR2_{r,k,t-1} - 0.264862 * (-182.660 * REG1_r - 180.267 * REG2_r - 181.736 * REG3_r - \\
& 179.809 * REG4_r - 180.669 * REG5_r - 181.017 * REG6_r - 0.115113E{-}02 * CUMSW2_{r,k,t} - \\
& 0.127988E{-}02 * SW2_{r,k,t} + 0.090704 * YEAR_t)
\end{aligned}
$$

(95)

Deep Oil (k=2, r= 2 thru 5)

$$FR2_{r,k,t} = -313.8517 * REG2_r - 316.1563 * REG3_r - 315.1758 * REG4_r - 313.8421 * REG5_r - \\ 0.3715817E-02 * CUMSW2_{r,k,t-1} - 0.023836 * SW2_{r,k,t} + 0.1591397 * YEAR_t$$

(96)

Shallow Gas (k=3, r=1 thru 6)

$$FR2_{r,k,t} = -117.680 * REG1_r - 123.042 * REG2_r - 123.099 * REG3_r - 124.772 * REG \\ 123.115 * REG6_r + 0.135637E-02 * CUMSW1_{r,k,t-1} - 0.208370E-02 * CUM \\ 0.010866 * SW2_{r,k,t} + 0.062119 * YEAR_t$$

(97)

Deep Gas (k=4, r=2 thru 4)

$$FR2_{r,k,t} = -84.90 * REG2_r - 86.72 * REG3_r - 88.11 * REG4_r - 0.118489E-02 * CUMSW2_{r,k,t-1} - \\ 0.011556 * SW2_{r,k,t} + 0.0459 * YEAR_t$$

(98)

Lower 48 Offshore

$$FR2_{r,k,t} = FR2_{r,k,t-1} * e^{-\delta2_{r,k,t} * SW2_{r,k,t}}$$

(99)

$$\delta2_{r,k,t} = \frac{FR2_{r,k,t-1} * DECFAC}{I_{r,k} * (1 + TECH)^{t-T} + CUMRES2_{r,k,t-1} - CUMRES3_{r,k,t-1}}$$

(100)

$$CUMRES2_{r,k,t} = \sum_{T=1}^{t} I_{r,k,T}$$

(101)

$$EXT_{r,k,t} = \frac{FR2_{r,k,t-1}}{\delta2_{r,k,t}} * \left(1 - e^{-\delta2_{r,k,t} * SW2}\right)$$

(102)

Reserve revisions

$$REV_{r,k,t} = FR3_{r,k,t} * SW3_{r,k,t}$$

(103)

Lower 48 Onshore

Shallow Oil (k=1, r=1 thru 6)

$$FR3_{r,k,t} = -1.83443 - 0.21724E-05 * CUMSW3_{r,k,t-1} + 0.10035E-03 * CUMRES2_{r,k,t-1} - \\ 0.472346E-05 * SW3_{r,k,t} + 0.9647871E-03 * YEAR_t + 0.73669 * FR3_{r,k,t-1} - \\ 0.73669 * (-1.83443 - 0.21724E-05 * CUMSW_{r,k,t-2} + 0.10035E-03 * CUMRES_{r,k,t-1} - \\ 0.472346E-05 * SW3_{r,k,t-1} + 0.9647871E-03 * YEAR_{t-1})$$

(104)

Deep Oil (k=2, r=1 thru 6)

$$FR3_{r,k,t} = -2.46997 * REG2_r - 2.573 * REG3_r - 2.5687 * REG4_r - 2.55853 * REG5_r - \\ 0.390043E-04 * CUMSW3_{r,k,t-1} + 0.35658E-03 * CUMRES2_{r,k,t-1} - 0.143752E-03 * SW3_{r,k,t} + \\ 0.13246E-02 * YEAR_t + 0.521736 * FR3_{r,k,t-1} - 0.521736 * (-2.46997 * REG2_r - \\ 2.573 * REG3_r - 2.5687 * REG4_r - 2.55853 * REG5_r - 0.390043E-04 * CUMSW3_{r,k,t-2} + \\ 0.35658E-03 * CUMRES2_{r,k,t-2} - 0.143752E-03 * SW3_{r,k,t-1} + 0.13246E-02 * YEAR_{t-1})$$

(105)

Shallow Gas (k=3, r=1 thru 6)

$$FR3_{r,k,t} = -125.857 - 0.994238E-05 * CUMSW3_{r,k,t-1} + 0.193021E-04 * CUMRES2_{r,k,t-1} - 0.566952E-05 * SW3_{r,k,t} + 0.063483 * YEAR_t + 0.39922 * FR3_{r,k,t-1} - 0.39922 * (-125.857 - 0.994238E-05 * CUMSW3_{r,k,t-2} + 0.193021E-04 * CUMRES2_{r,k,t-2} - 0.566952E-05 * SW3_{r,k,t-1} + 0.063483 * YEAR_{t-1})$$

(106)

Deep Gas (k=4, r=1 thru 6)

$$FR3_{r,k,t} = -278.372 * REG2_r - 277.781 * REG3_r - 279.884 * REG4_r - 280.133 * REG5_r - 0.209735E-03 * CUMSW3_{r,k,t-1} - 0.191325E-02 * SW3_{r,k,t} + 0.140966 * YEAR_t$$

(107)

Lower 48 Offshore

$$FR3_{r,k,t} = FR3_{r,k,t-1} * e^{-\delta3_{r,k,t} * SW3_{r,k,t}}$$

(108)

$$\delta3_{r,k,t} = \frac{FR3_{r,k,t-1} * DECFAC}{I_{r,k} * (1 + TECH)^{t-T} + CUMRES2_{r,k,t-1} - CUMRES3_{r,k,t-1}}$$

(109)

$$CUMRES3_{r,k,t} = \sum_{T=1}^{t} EXT_{r,k,T} + REV_{r,k,T}$$

(110)

$$REV_{r,k,t} = \frac{FR3_{r,k,t-1}}{\delta3_{r,k,t}} * \left(1 - e^{-\delta3_{r,k,t} * SW3}\right)$$

(111)

Total reserve additions

$$RA_{r,k,t} = NRD_{r,k,t} + EXT_{r,k,t} + REV_{r,k,t}$$

(112)

End-of-year reserves

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t}$$

(113)

Lower 48 Onshore & Offshore Production to Reserves Ratio
Option 1

$$PR_{t+1} = \frac{(R_{t-1} * PR_t * (1 - PR_t)) + (PRNEW * RA_t)}{R_t}$$

(114)

$$Q_{r,k,t+1} = [R_{r,k,t}] * [PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})]$$

(115)

Options 2 and 3

$$PR_{r,k,t} = \frac{X_{r,k,t}}{1 + X_{r,k,t}} \tag{116}$$

where,

for natural gas option 2

$$X_{r,k,t} = \exp((1-\rho gas)*cgas_r) \ * \ \exp(h*CARRIAGE_t) \ * \ \exp(-\rho gas*h*CARRIAGE_{t-1})*$$
$$\left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho gas} * \ PGAS_{r,t}^{\alpha} \ * \ PGAS_{r,t-1}^{-\rho gas*\alpha} \tag{117}$$

for crude oil option 2

$$X_{r,k,t} = \exp((1-\rho oil)*coil_r) \ * \ \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho oil} * \ \exp(\beta*POIL_{r,t}) \ * \ \exp(-\rho oil*\beta*POIL_{r,t-1}) \tag{118}$$

for natural gas option 3

$$X^{\circ}_{r,k,t} = \exp((1-\rho gas)*cgas_r) \ * \ \exp(h*CARRIAGE_t) \ * \ \exp(-\rho gas*h*CARRIAGE_{t-1})*$$
$$\left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho gas} * \ \exp(fgas_r*RA_{r,k,t-1}) \ * \ \exp(-\rho gas*fgas_r*RA_{r,k,t-2}) \tag{119}$$

for crude oil option 3

$$X^{\circ}_{r,k,t} = \exp((1-\rho oil)*coil_r) \ * \ \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho oil} * \ \exp(\beta*POIL_{r,t}) \ * \ \exp(-\rho oil*\beta*POIL_{r,t-1}) \ *$$
$$\exp(foil_r*RA_{r,k,t-1}) \ * \ \exp(-\rho oil*foil_r*RA_{r,k,t-2}) \tag{120}$$

Associated-dissolved gas production

$$ADGAS_{r,t} = e^{\ln(\alpha0)_r + \ln(\alpha1)_r*DUM86_t} \ * \ OILPROD_{r,t}^{\beta0_r + \beta1_r*DUM86_t} \tag{121}$$

Alaska Supply

Expected Costs

Drilling costs

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} \ * \ (1 \ - \ TECH1)**(t-T_b) \tag{122}$$

Lease equipment costs

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2)**(t - T_b) \tag{123}$$

Operating costs

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3)**(t - T_b) \tag{124}$$

Tariffs

$$TRR_t = OPERCOST_t + DRR_t + TOTDEP_t + MARGIN_t + DEFRETREC_t + TXALLW_t$$
$$NONTRANSREV_t + CARRYOVER_t \tag{125}$$

$$TOTDEP_t = DEP_t * \left(DEPPROP_{t-2} + ADDS_{t-1} - PROCEEDS_{t-1} - TOTDEP_{t-1}\right) \tag{126}$$

$$MARGIN_t = ALLOW_t * THRUPUT_t + 0.064 * \left(DEPPROP_{NEW,t} + DEFRET_{NEW,t} - DEFTAX_{NEW,t}\right) \tag{127}$$

$$DEFRETREC_t = DEP_t * \left(DEFRET_{t-2} + INFLADJ_{t-1} + AFUDC_{t-1} - DEFRETREC_{t-1}\right) \tag{128}$$

$$TXALLW_t = TXRATE * \left(MARGIN_t + DEFRETREC_t\right) \tag{129}$$

Canadian Gas Trade

Calculation of successful Canadian wells

$$WELLS = OGPRCIMP_{gas,1}^{B1WELLS} * OGPRCIMPL^{-BRHO*B1WELLS} * WELLAG^{BRHO} *$$

$$e^{(B0WELLS*(1-BRHO)) + (B2WELLS * DUM7080) + (B3WELLS * DUM8192)} \tag{130}$$

Reserve additions

$$FR_t = FR_{t-1} * e^{-\delta_t * WELLS_t} * (1 + FRTECH) \tag{131}$$

$$\delta_t = \frac{(FR_{t-1} - FRMIN) * RSVGR}{Q * (1.0 + TECH)^{t-T} - CUMRES_{t-1}} \tag{132}$$

$$RA_t = \frac{FR_{t-1}}{\delta_t} * (1 - e^{-\delta_t * WELLS_t}) \tag{133}$$

$$CUMRES_t = \sum_{T=1}^{t} RA_T \tag{134}$$

End-of-year reserves

$$R_t = R_{t-1} + RA_t - Q_t \tag{135}$$

Production to reserves ratio

$$PR_{t+1} = \frac{Q_t * (1 - PR_t) + PRNEW * RA_t}{R_t} \tag{136}$$

Deep Water Offshore Supply

COSTING AND CASH-FLOW ROUTINES

Geological and Geophysical Costs Per Year:

$$GNG\_CAP_t = \frac{GNGCAP}{GNG\_TIM}, \; t = IYREXP \; to \; (IYREXP + GNG\_TIM - 1) \tag{137}$$

$$GNG\_EXP_t = \frac{GNGEXP}{GNG\_TIM}, \; t = IYREXP \; to \; (IYREXP + GNG\_TIM - 1) \tag{138}$$

Exploration Drilling Costs Per Year

$$EXPDCST_t = DNCEXP * \frac{EXPWEL}{EXPTIM}, \; t = IYREXP \; to \; (IYREXP + EXPTIM - 1) \tag{139}$$

Delineation Drilling Costs Per Year

$$DELDCST_t = DNCDEL * \frac{DELWEL}{DELTIM}, \; t = IYRDEL \; to \; (IYRDEL + DELTIM - 1) \tag{140}$$

Pre-drilled Development Well Costs Per Year

$$PREDCST_t = DNCPRE * \frac{PREDEV}{PRETIM}, \; t = IYRPRE \; to \; (IYRPRE + PRETIM - 1) \tag{141}$$

Pre-drilled Dry Development Well Costs Per Year

$$PDRDCST_t = PREDRY * \frac{DELWEL}{PRETIM}, \; t = IYRPRE \; to \; (IYRPRE + PRETIM - 1) \tag{142}$$

Development Drilling Costs Per Year

$$DEVDCST_t = DNCDEV * \frac{DEVWEL}{DEVTIM}, \; t = IYRDEV \; to \; (IYRDEV + DEVTIM - 1) \tag{143}$$

Dry Development Drilling Costs Per Year

$$DDRDCST_t = DNCDRY * \frac{DEVDRY}{DEVTIM}, \; t = IYRDEV \; to \; (IYRDEV + DEVTIM - 1) \tag{144}$$

Production Structure Installation Costs Per Year

$$STRYCST_t = STRCST * \frac{NSTRUC}{STRTIM}, \; t = IYRSTR \; to \; (IYRSTR + STRTIM - 1) \tag{145}$$

Template Installation Costs Per Year

$$TMPYCST_t = TEMCST * \frac{NTEMP}{TEMTIM}, \; t = IYRTEM \tag{146}$$

Pipeline and Gathering System Installation Costs Per Year

$$PIPECST_t = PIPECO, \; t = IYRPIP \tag{147}$$

Production Structure Abandonment Costs Per Year

$$ABNDCST_t = ABNCST, \; t = IYRABN \tag{148}$$

Intangible Capital Investments Per Year

$$INTANG_t = EXPDCST_t + DELDCST_t + 0.7*PERIT*PREDCST_t + PDRDCST_t + 0.7*PERIT*DEVDCST_t + \\ DDRDCST_t + 0.9*PERIT*STRYCST_t + ABNDCST_t + GNG\_EXP_t, \; t = 1 \; to \; IYRABN \tag{149}$$

Tangible Capital Investments Per Year

$$TANG_t = PERT*PREDCST_t + 0.3*PERIT*PREDCST_t + PERT*DEVDCST_t + 0.3*PERIT*DEVDCST_t + \\ PERT*STRYCST_t + 0.1*PERIT*STRYCST_t + PIPECST_t + GNG\_\cap_t, \; t = 1 \; to \; IYRABN \tag{150}$$

Total Investments Per Year

$$INVEST_t = TANG_t + INTANG_t, \; t = 1 \; to \; IYRABN \tag{151}$$

Gross Revenues Per Year

$$REV_{OIL_t} = QOIL_t * OILPRC_t, \; t = 1 \; to \; IYRABN \tag{152}$$

$$REV\_GAS_t = QGAS_t * GASPRC_t, \; t = 1 \; to \; IYRABN \tag{153}$$

$$REV\_GROS_t = REV\_OIL_t + REV\_GAS_t, \; t = 1 \; to \; IYRABN \tag{154}$$

Gravity Penalties Per Year

$$GRAV\_ADJ_t = QOIL_t * GRADJ_t, \; t = 1 \; to \; IYRABN \tag{155}$$

Transportation Costs Per Year

$$TRAN\_CST_t = QOIL_t * TARF\_OIL_t + QGAS_t * TARF\_GAS_t, \; t = 1 \; to \; IYRABN \tag{156}$$

Adjusted Revenues Per Year

$$REV\_ADJ_t = REV\_GROS_t - GRAV\_ADJ_t - TRAN\_CST_t, \; t = 1 \; to \; IYRABN \tag{157}$$

Royalty Payments Per Year

$$ROYALTY_t = REV\_ADJ_t * ROYL\_RAT, \; t = 1 \; to \; IYRABN \tag{158}$$

$$ROYALTY_t = 0.00, \; IF \; QCBOE \leq RELIEF_{WDC} \tag{159}$$

Net Producer Revenue Per Year

$$REV\_PROD_t = REV\_ADJ_t - ROYALTY_t, \; t = 1 \; to \; IYRABN \tag{160}$$

G & A on Investments and Operation Costs

$$GNA\_CST_t = TANG_t * GNATAN + INTANG_t * GNAINT, \; t = 1 \; to \; IYRABN \tag{161}$$

$$GNA\_OPN_t = OPCOST_t * OPOVHD, \; t = 1 \; to \; IYRABN \tag{162}$$

Net Revenue from Operations Per Year

$$REV\_NET_t = REV\_PROD_t - OPCOST_t - GNA\_CST_t - GNA\_OPN_t, \; t = 1 \; to \; IYRABN \tag{163}$$

Net Income Before Taxes Per Year

$$NET\_BTCF_t = REV\_NET_t - INTANG_t - DEPR_t - GNGRC_t, \; t = 1 \; to \; IYRABN \tag{164}$$

Federal Tax Bill Per Year

$$FED\_TAXS_t = NET\_BTCF_t * FTAX\_RAT, \; t = 1 \; to \; IYRABN \tag{165}$$

Income Tax Credits Per Year

$$FED\_INTC_t = INVEST_t * XINTC, \; t = 1 \; to \; IYRABN \tag{166}$$

Net Income After Taxes Per Year

$$NET\_INCM_t = NET\_BTCF_t - FED\_TAXS_t + FED\_INTC_t, \; t = 1 \; to \; IYRABN \tag{167}$$

Annual After-Tax Cash Flow

$$ANN\_ATCF_t = NET\_INCM_t - TANG_t + DEPR_t + GNGRC_t, \; t = 1 \; to \; IYRABN \tag{168}$$

Discounted After-Tax Cash Flow Per Year

$$NPV\_ATCF_t = \frac{ANN\_ATCF_t}{DISCRT^{\, I}}, \; t = 1 \; to \; IYRABN \tag{169}$$

RESERVES DEVELOPMENT AND PRODUCTION TIMING

Inferred Oil Reserve Additions
IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr}$ $\geq$ MASP_TOT $_{ipool}$

$$INFR\_OIL_{iyr} = INFR\_OIL_{iyr} + RSRV\_OIL_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (170)$$

$$INFR\_AGS_{iyr} = INFR\_AGS_{iyr} + RSRV\_GAS_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (171)$$

Inferred Gas Reserve Additions
IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$INFR\_GAS_{iyr} = INFR\_GAS_{iyr} + RSRV\_GAS_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (172)$$

$$INFR\_CND_{iyr} = INFR\_CND_{iyr} + RSRV\_OIL_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (173)$$

Average Supply Price for Inferred Oil Reserves
IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$MSP\_INFO_{iyr} = \frac{MSP\_INFO_{iyr} * INFR\_OIL_{iyr} + MASP\_TOT_{ipool} * RSRV\_OIL_{ipool}}{INFR\_OIL_{iyr} + RSRV\_OIL_{ipool}}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (174)$$

Average Supply Price for Inferred Gas Reserves
IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$MSP\_INFG_{iyr} = \frac{MSP\_INFG_{iyr} * INFR\_GAS_{iyr} + MASP\_TOT_{ipool} * RSRV\_GAS_{ipool}}{INFR\_GAS_{iyr} + RSRV\_GAS_{ipool}}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (175)$$

Wells Required for Inferred Oil Reserves
IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$WEL\_EXPO_{iyr} = WEL\_EXPO_{iyr} + EXPL\_WEL_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (176)$$

$$WEL\_DEVO_{iyr} = WEL\_DEVO_{iyr} + DEVL\_WEL_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (177)$$

$$WEL\_DRYO_{iyr} = WEL\_DRYO_{iyr} + DRY\_HOLE_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (178)$$

Wells Required for Inferred Gas Reserves
IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$WEL\_EXPG_{iyr} = WEL\_EXPG_{iyr} + EXPL\_WEL_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (179)$$

$$WEL\_DEVG_{iyr} = WEL\_DEVG_{iyr} + DEVL\_WEL_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (180)$$

$$WEL\_DRYG_{iyr} = WEL\_DRYG_{iyr} + DRY\_HOLE_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \quad (181)$$

Number of Structures Required for Inferred Oil Reserves
IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$NUM\_STRO_{iyr} = NUM\_STRO_{iyr} + STRUC\_NO_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \tag{182}$$

Number of Structures Required for Inferred Gas Reserves
IF $POOLTYPE_{ipool} = 'GAS'$, and IF $GASPRICE_{iyr} \geq MASP\_TOT_{ipool}$

$$NUM\_STRG_{iyr} = NUM\_STRG_{iyr} + STRUC\_NO_{ipool}, \ iyr = Current \ Year, \ ipool = 1 \ to \ NFIELD \tag{183}$$

Relative Price Differential for Oil Reserves Vs. Gas Reserves Development

$$RATIO1 = \frac{OILPRICE_{iyr} - MSP\_INFO_{iyr}}{OILPRICE_{iyr}}, \ iyr = Current \ Year \tag{184}$$

$$RATIO1 = \frac{GASPRICE_{iyr} - MSP\_INFG_{iyr}}{GASPRICE_{iyr}}, \ iyr = Current \ Year \tag{185}$$

$$PRP\_OIL_{iyr} = \frac{RATIO1}{RATIO1 + RATIO2}, \ iyr = Current \ Year \tag{186}$$

Oil Well Drilling Activity

$$WEL\_LIMT_{iyr} = WELDRLEVL * WLDRL\_RT^{iyr-1}, \ iyr = Current \ Year \tag{187}$$

$$WEL\_LIMO_{iyr} = PRP\_OIL_{iyr} * WEL\_LIMIT_{iyr}, \ iyr = Current \ Year \tag{188}$$

$$WEL\_DRLO_{iyr} = \begin{cases} WEL\_LIMO_{iyr} & if \ WEL\_LIMO_{iyr} \leq WEL\_DEVO_{iyr}, \ iyr = Current \ Year \\ WEL\_DEVO_{iyr} & if \ WEL\_LIMO_{iyr} \geq WEL\_DEVO_{iyr}, \ iyr = Current \ Year \end{cases} \tag{189}$$

Gas Well Drilling Activity

$$WEL\_LIMG_{iyr} = WEL\_LIMIT_{iyr} - WEL\_LIMO_{iyr}, \ iyr = Current \ Year \tag{190}$$

$$WEL\_DRLG_{iyr} = \begin{cases} WEL\_LIMG_{iyr} & if \ WEL\_LIMG_{iyr} \leq WEL\_DEVG_{iyr}, \ iyr = Current \ Year \\ WEL\_DEVG_{iyr} & if \ WEL\_LIMG_{iyr} \geq WEL\_DEVG_{iyr}, \ iyr = Current \ Year \end{cases} \tag{191}$$

Booked Oil Reserve Additions

$$RTIO\_OIL = \frac{WEL\_DRLO_{iyr}}{WEL\_DEVO_{iyr}}, \ iyr = Current \ Year \tag{192}$$

$$BKED\_OIL_{iyr} = RTIO\_OIL * INFR\_OIL_{iyr}, \ iyr = Current \ Year \tag{193}$$

$$BKED\_AGS_{iyr} = RTIO\_OIL * INFR\_AGS_{iyr}, \ iyr = Current \ Year \tag{194}$$

Booked Gas Reserve Additions

$$\text{RTIO\_GAS} = \frac{\text{WEL\_DRLG}_{iyr}}{\text{WEL\_DEVG}_{iyr}}, \ iyr = \text{Current Year} \tag{195}$$

$$\text{BKED\_GAS}_{iyr} = \text{RTIO\_GAS} * \text{INFR\_GAS}_{iyr}, \ iyr = \text{Current Year} \tag{196}$$

$$\text{BKED\_CND}_{iyr} = \text{RTIO\_GAS} * \text{INFR\_CND}_{iyr}, \ iyr = \text{Current Year} \tag{197}$$

Oil Production Accounting

Beginning of the Year Reserves

$$\text{BEG\_RSVO}_{iyr} = \text{XPVD\_OIL} + \text{XPVD\_CND}, \ iyr = 1 \tag{199}$$

$$\text{BEG\_RSVO}_{iyr} = \text{END\_RSVO}_{iyr-1}, \ iyr = \text{Current Year} \neq 1 \tag{198}$$

Production in the Year

$$\text{PROD\_OIL}_{iyr} = \frac{\text{BEG\_RSVO}_{iyr}}{\text{RATIO\_RP}} \tag{200}$$

Reserves Growth

$$\text{GRO\_RSVO}_{iyr} = (\text{BEG\_RSVO}_{iyr} - \text{PROD\_OIL}_{iyr}) * \text{RES\_GROW}, \ iyr = \text{Current Year} \tag{201}$$

Reserve Additions

$$\text{ADD\_RSVO}_{iyr} = \text{BKED\_OIL}_{iyr} + \text{BKED\_CND}_{iyr}, \ iyr = \text{Current Year} \tag{202}$$

End of the Year Reserves

$$\text{END\_RSVO}_{iyr} = \text{BEG\_RSVO}_{iyr} + \text{GRO\_RSVO}_{iyr} + \text{ADD\_RSVO}_{iyr} - \text{PROD\_OIL}_{iyr}, \ iyr = \text{Current Year} \tag{203}$$

Gas Production Accounting

Beginning of the Year Reserves

$$\text{BEG\_RSVG}_{iyr} = \text{XPVD\_GAS} + \text{XPVD\_AGS}, \ iyr = 1 \tag{204}$$

$$\text{BEG\_RSVG}_{iyr} = \text{END\_RSVG}_{iyr}, \ iyr = \text{Current Year} \neq 1 \tag{205}$$

Production in the Year

$$\text{PROD\_GAS}_{iyr} = \frac{\text{BEG\_RSVG}_{iyr}}{\text{RATIO\_RP}}, \ iyr = \text{Current Year} \tag{206}$$

Reserves Growth

$$\mathrm{GRO\_RSVG_{iyr}} = (\mathrm{BEG\_RSVG_{iyr}} - \mathrm{PROD\_GAS_{iyr}}) * \mathrm{RES\_GROW}, \ \mathrm{iyr} = \mathrm{Current\ Year} \tag{207}$$

Reserve Additions

$$\mathrm{ADD\_RSVG_{iyr}} = \mathrm{BKED\_GAS_{iyr}} + \mathrm{BKED\_AGS_{iyr}}, \ \mathrm{iyr} = \mathrm{Current\ Year} \tag{208}$$

End of the Year Reserves

$$\mathrm{END\_RSVG_{iyr}} = \mathrm{BEG\_RSVG_{iyr}} + \mathrm{GRO\_RSVG_{iyr}} + \mathrm{ADD\_RSVG_{iyr}} - \mathrm{PROD\_GAS_{iyr}}, \ \mathrm{iyr} = \mathrm{Current\ Year} \tag{209}$$

Advanced Technology Impacts on Exploration

$$\mathrm{MASP\_EXP_{ipool,new}} = \frac{\mathrm{MASP\_EXP_{ipool,old}}}{\mathrm{ADT\_EXPL}}, \ \mathrm{ipool} = 1 \ \mathrm{to\ NFIELD} \tag{210}$$

$$\mathrm{MASP\_TOT} = \mathrm{MASP\_TOT} - \left(\mathrm{MASP\_EXP_{ipool,old}} - \mathrm{MASP\_EXP_{ipool,new}}\right), \ \mathrm{ipool} = 1 \ \mathrm{t} \tag{211}$$

Advanced Technology Impacts on Drilling

$$\mathrm{MASP\_DRL_{ipool,new}} = \frac{\mathrm{MASP\_DRL_{ipool,old}}}{\mathrm{ADT\_DRLG}}, \ \mathrm{ipool} = 1 \ \mathrm{to\ NFIELD} \tag{212}$$

$$\mathrm{MASP\_TOT} = \mathrm{MASP\_TOT} - \left(\mathrm{MASP\_DRL_{ipool,old}} - \mathrm{MASP\_DRL_{ipool,new}}\right), \ \mathrm{ipool} = 1 \ \mathrm{t} \tag{213}$$

Advanced Technology Impacts on Structure

$$\mathrm{MASP\_STR_{ipool,new}} = \frac{\mathrm{MASP\_STR_{ipool,old}}}{\mathrm{ADT\_STRC}}, \ \mathrm{ipool} = 1 \ \mathrm{to\ NFIELD} \tag{214}$$

$$\mathrm{MASP\_TOT} = \mathrm{MASP\_TOT} - \left(\mathrm{MASP\_STR_{ipool,old}} - \mathrm{MASP\_STR_{ipool,new}}\right), \ \mathrm{ipool} = 1 \ \mathrm{to} \tag{215}$$

Advanced Technology Impacts on Operations

$$\mathrm{MASP\_OPR_{ipool,new}} = \frac{\mathrm{MASP\_OPR_{ipool,old}}}{\mathrm{ADT\_OPER}}, \ \mathrm{ipool} = 1 \ \mathrm{to\ NFIELD} \tag{216}$$

$$\mathrm{MASP\_TOT} = \mathrm{MASP\_TOT} - \left(\mathrm{MASP\_OPR_{ipool,old}} - \mathrm{MASP\_OPR_{ipool,new}}\right), \ \mathrm{ipool} = 1 \ \mathrm{to\ NFIELD} \tag{217}$$

Unconventional Gas Recovery Supply

Resource Base/Well Productivity

Undrilled Locations Under Current Technology

$$CTUL = BASAR * WSPAC\_CT - DEV\_CEL \tag{218}$$

Undrilled Locations Under Advanced Technology

$$ATUL = BASAR * WSPAC\_AT - DEV\_CEL \tag{219}$$

Weighted Average of the Expected Ultimate Recovery for Each (Entire) Basin

$$MEUR1 = (.10 * RW10 + .20 * RW20 + .30 * RW30 + .40 * RW40) \tag{220}$$

Expected Ultimate Recovery for the Best 30% of the wells in the Basin

$$\begin{aligned} MEUR1_{iyr,2} = MEUR_{iyr,1} + (((((RW10_1*(1/3)) + (RW20_1*(2/3) - MEUR1_{1,1}))/DEVPER) \\ *TECHYRS)*(TECHYRS*(REDAM\%/20) + (TECHYRS*(FRCLEN\%/20)) \\ +(TECHYRS*(PAYCON\%/20)) +1)) \end{aligned} \tag{221}$$

Expected Ultimate Recovery for the middle 30% of the wells in the Basin

$$MEUR1_{iyr,3} = RW30_{iyr} \tag{222}$$

Expected Ultimate Recovery for the Worst 40% of the Wells in the Basin

$$\begin{aligned} MEUR1_{iyr,4} = (MEUR1_{iyr}) - (((RW30_1 - RW40_1)/DEVPER)*TECHYRS)*(TECHYRS*(REDAM\%/20)) \\ +(TECHYRS*(FRCLEN\%/20))+(TECHYRS)*(PAYCON\%/20))+1) \end{aligned} \tag{223}$$

Technically Recoverable Wells

$$TRW_1 = (ATUL * SCSSRT_1 * PLPROB2_1) \tag{224}$$

Undeveloped Resources

$$UNDEV\_RES_{iyr} = (MEUR3_{iyr} * TRW_{iyr}) \tag{225}$$

Reserves and Cumulative Production

$$RESNPROD_{iyr} = RESNPROD_{iyr-1} + RESADD_{iyr} \tag{226}$$

Ultimate Recoverable Resources

$$URR_{iyr} = RESNPROD_{iyr} + UNDEV\_RES_{iyr} \tag{227}$$

Economics and Pricing

Discounted Reserves

$$DISCRES_{iyr} = (DIS\_FAC * MEUR3_{iyr}) \tag{228}$$

Expected Net Present Value Revenues

$$ENPVR_{iyr} = \left(WHGP_{iyr} + BASNDIF\right) * \left(DISCRES_{iyr}) * 1{,}000{,}000\right) \tag{229}$$

Drilling and Completion Costs

$$DACC = \begin{cases} AVGDPTH*DCC\_L2K + DCC\_G\&G \Leftarrow IF(AVDPTH < 2000) \\ 2000*DCC\_L2K + (AVGDPTH - 2000)*DCC\_G2K) + DCC\_G\&G \Leftarrow IF(AVDPTH \geq 2000) \end{cases} \tag{230}$$

Stimulation Costs

$$STIMC = SZONE * STM\_CST \tag{231}$$

Pumping and Surface Equipment Costs

$$PASE = \begin{cases} BASET + 5*AVGDPTH \Leftarrow IF(WATR\_DISP = 1) \\ 10000 \Leftarrow IF(WATR\_DISP \neq 1) \end{cases} \tag{232}$$

Lease Equipment Costs

$$LSE\_EQ = \begin{cases} \begin{bmatrix} WOMS\_LE + WOML\_WTR \Leftarrow IF\{(WATR\_DISP = 1)AND(MEUR3 < .5)\} \\ WOMM\_LE + WOML\_WTR \Leftarrow IF\{(WATR\_DISP = 1)AND(MEUR3 \geq .5)AND(MEUR3 \leq 1.0)\} \\ WOML\_LE + WOML\_WTR \Leftarrow IF\{(WATR\_DISP = 1)AND(MEUR3 > 1.0)\} \\ WOMS\_LE \Leftarrow IF\{(WATR\_DISP = 0)AND(MEUR3 < .5)\} \\ WOMM\_LE \Leftarrow IF\{(WATR\_DISP = 0)AND(MEUR \geq .5)AND(MEUR3 \leq 1.0)\} \\ WOML\_LE \Leftarrow IF\{(WATR\_DISP = 0)AND(MEUR3 > 1.0)\} \end{bmatrix} \end{cases} \tag{233}$$

General and Administrative Costs

$$GAA10 = RST * (LSE\_EQ + PASE + STIMC + DACC) \tag{234}$$

Total Capital Costs

$$TCC = \left(DACC + STIMC + PASE + LSE\_EQ + GAA10\right) \tag{235}$$

Dry Hole Costs

$$DHC = (DACC + STIMC)*((1/SCSSRT) - 1)$$ (236)

Capital and Dry Hole Costs per Mcf

$$CCWDH = (TTC + DHC)/(DISCRES*1000000)$$ (237)

Variable Operating Costs

$$VOC = \begin{cases} \dfrac{\begin{array}{l} WTR\_DSPT*TECHYRS*(WDT\%/20)+WOMS*TECHYRS*(PUMP\%/20) \\ +GASTR*TECHYRS*(GTF\%/20)+OCWW\$ \end{array}}{\begin{array}{l} WTR\_DSPT*TECHYRS*(WDT\%/20)+WOMS*TECHYRS*(PUMP\%/20) \\ +GASTR*TECHYRS*(GTF\%/20)+OCNW\$ \end{array}} & \Leftarrow IF(WAT\_DISP > .4) \\[2em] & \Leftarrow IF(WAT\_DISP \leq .4) \end{cases}$$ (238)

Variable Operating Costs with Enhanced Coalbed Methane

$$VOC2 = \begin{cases} VOC+((ECBM\_OC+VOC)*(ENH\_CBM\%))/(1+ENH\_CBM\%) & \Leftarrow IF(ECBMR=1) \\ VOC & \Leftarrow IF(ECBMR \neq 1) \end{cases}$$ (239)

Fixed Operating and Maintenance Costs

$$FOMC = \begin{cases} \begin{array}{l} IF(WATR\_DISP = 1) \\ \overline{DIS\_FACT*WOMS\_OMW + VOC*DISCRES*1000000 \Leftarrow IF(MEUR3 < .5)} \\ DIS\_FACT*WOMM\_OMW + VOC*DISCRES*1000000 \Leftarrow IF(MEUR3 \geq .5)AND(MEUR3 \leq 1.0) \\ DIS\_FACT*WOMM\_OMW + VOC*DISCRES*1000000 \Leftarrow IF(MEUR3 > 1.0) \end{array} \\ \begin{array}{l} IF(WATR\_DISP = 0) \\ \overline{.6*DIS\_FACT*WOMS\_OMW + VOC*DISCRES*1000000 \Leftarrow IF(MEUR3 < .5)} \\ .6*DIS\_FACT*WOMM\_OMW + VOC*DISCRES*1000000 \Leftarrow IF(MEUR3 \geq .5)AND(MEUR3 \leq 1.0) \\ .6*DIS\_FACT*WOMM\_OMW + VOC*DISCRES*1000000 \Leftarrow IF(MEUR3 > 1.0) \end{array} \end{cases}$$ (240)

Total Costs

$$TOTL\_CST = FOMC / (DISCRES*1000000) + CCWDH$$ (241)

Net Price

$$NET\_PRC = (1 - RST)*(WHGP + BASNDIF)$$ (242)

Net Profitability

$$NET\_PROF = NET\_PRC - TOTL\_CST \tag{243}$$

$$NET\_PROFIT2 = \begin{cases} NET\_PROFIT \Leftarrow IF(NET\_PROFIT > 0) \\ 0 \Leftarrow IF(NET\_PROFIT \leq 0) \end{cases} \tag{244}$$

Model Outputs

Undeveloped Wells

$$UNDV\_WELLS = \begin{cases} TRW*(ENV\% + (LOW\% / LOWYRS)*TECHYRS) \Leftarrow IF(NET\_PROF2 > 0)AND(ENPRGS = 1) \\ TRW \Leftarrow IF(NET\_PROF2 > 0)AND(ENPRGS = 0) \\ 0 \Leftarrow IF(NET\_PROF2 = 0) \end{cases} \tag{245}$$

Expected Ultimate Recovery Adjusted for Profitability

$$MEUR4 = \begin{cases} MEUR3 \Leftarrow IF(NET\_PROF2 > 0) \\ 0 \Leftarrow IF(NET\_PROF2 = 0) \end{cases} \tag{246}$$

Drilling Schedule

$$DRL\_SCHED = \begin{cases} 0 \Leftarrow IF(HYP\% \neq 0) \\ 0 \Leftarrow IF(HYP\% = 0)AND(NET\_PROF2 = 0) \\ USLOW \Leftarrow IF(HYP\% = 0)AND(NET\_PROF2 > 0)AND(NET\_PROF < LOW\$) \\ SLOW \Leftarrow IF(HYP\% = 0)AND(NET\_PROF2 \geq LOW\$)AND(NET\_PROF < SMAL\$) \\ MED \Leftarrow IF(HYP\% = 0)AND(NET\_PROF2 \geq SMAL\$)AND(NET\_PROF < MED\$) \\ FAST \Leftarrow IF(HYP\% = 0)AND(NET\_PROF2 \geq MED\$)AND(NET\_PROF < LAR\$) \\ SLOW \Leftarrow IF(HYP\% = 0)AND(NET\_PROF2 \geq LAR\$) \end{cases} \tag{247}$$

Drilling Schedule Adjusted for Technological Advancement

$$DRL\_SCHED2 = \begin{cases} DRL\_SCHED + EMRG\% - EMERG\# \Leftarrow IF(DRL\_SCHED > 0)AND(EMRG = 1) \\ DRL\_SCHED \Leftarrow IF(DRL\_SCHED > 0)AND(EMRG \neq 1) \\ 0 \Leftarrow IF(DRL\_SCHED \leq 0) \end{cases} \tag{248}$$

$$DRL\_SCHED3 = \begin{cases} DRL\_SCHED \Leftarrow IF(DRL\_SCHED2 < DRL\_SCHED) \\ DRL\_SCHED2 \Leftarrow IF(DRL\_SCHED2 \geq DRL\_SCHED) \end{cases} \tag{249}$$

New Wells

$$NW\_WELLS = \begin{cases} (UNDV\_WELLS / DRL\_SCHED3) * (NET\_PRC / AVHISTPR)^{ELAST} \Leftarrow IF(DRL\_SCHED3 > 0) \\ 0 \Leftarrow IF(DRL\_SCHED3 \leq 0) \end{cases}$$

(250)

$$NW\_WELLS2 = \begin{cases} UNDV\_WELLS \Leftarrow IF(UNDV\_WELLS < NW\_WELLS) \\ NW\_WELLS \Leftarrow IF(UNDV\_WELLS \geq NW\_WELLS) \end{cases}$$

(251)

Reserve Additions from New Wells

$$DRA = NW\_WELLS2 * MEUR4$$

(252)

Reserve Additions from New Growth

$$RGA = \begin{cases} RGR * PROV\_RES \Leftarrow IF(RES\_GR = 1) \\ 0 \Leftarrow IF(RES\_GR \neq 1) \end{cases}$$

(253)

Total Reserve Additions

$$R\_ADD = DRA + RGA$$

(254)

Proved Reserves for the Next Year

$$PROV\_RES2 = \begin{cases} PRO\_RES + R\_ADD - PROD \Leftarrow IF((PROV\_RES + R\_ADD - PROD) > 0) \\ 0 \Leftarrow IF((PROV\_RES + R\_ADD - PROD) \leq 0) \end{cases}$$

(255)

Reserves-to-Production Ratio for the Next Year

$$RP\_RAT2 = \begin{cases} RP\_RAT - 1 \Leftarrow IF(RP\_RAT > 10) \\ RP\_RAT \Leftarrow IF(RP\_RAT \leq 10) \end{cases}$$

(256)

Production for the Next Year

$$PROD2 = \begin{cases} 0 \Leftarrow IF(RP\_RAT2 = 0) \\ PRO\_RES / RP\_RAT2 \Leftarrow IF(RP\_RAT2 \neq 0) \end{cases}$$

(257)

Undeveloped Wells for the Next Year

$$UNDV\_WELLS2 = \begin{cases} \begin{bmatrix} \dfrac{IF(ENPRGS = 1)}{TRW - NW\_WELLS2} \\ \dfrac{IF(ENPRGS \neq 1)}{0 \Leftarrow IF(UNDV\_WELLS = 0)} \\ .1 \Leftarrow IF(UNDV\_WELLS \neq 0)AND(UNDV\_WELLS - NW\_WELLS = 0) \\ NW\_WELLS2 \Leftarrow IF(UNDV\_WELLS \neq 0)AND(UNDV\_WELLS - NW\_WELLS \neq 0) \end{bmatrix} \end{cases} \qquad (258)$$

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Appendix D. Model Abstract

1. Model Name
   Oil and Gas Supply Module

2. Acronym
   OGSM

3. Description
   OGSM projects the following aspects of the crude oil and natural gas supply industry:
   - production
   - reserves
   - drilling activity
   - natural gas imports and exports

4. Purpose
   OGSM is used by the Oil and Gas Analysis Branch in the Office of Integrated Analysis and Forecasting as an analytic aid to support preparation of projections of reserves and production of crude oil and natural gas at the regional and national level. The annual projections and associated analyses appear in the Annual Energy Outlook (DOE/EIA-0383) of the Energy Information Administration. The projections also are provided as a service to other branches of the U.S. Department of Energy, the Federal Government, and non-Federal public and private institutions concerned with the crude oil and natural gas industry.

5. Date of Last Update
   1998

6. Part of Another Model
   National Energy Modeling System (NEMS)

7. Model Interface References
   Coal Module
   Electricity Module
   Industrial Module
   International Module
   Natural Gas Transportation and Distribution Model (NGTDM)
   Macroeconomic Module
   Petroleum Market Module (PMM)

8. Official Model Representative
   - Office: Integrating Analysis and Forecasting
   - Division: Energy Supply and Conversion
   - Branch: Oil and Gas Analysis
   - Model Contact: Ted McCallister
   - Telephone: (202) 586-4820

9. Documentation Reference
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10. Archive Media and Installation Manual
     NEMS99

11. Energy Systems Described
     The OGSM forecasts oil and natural gas production activities for six onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling are treated separately, with exploratory drilling further differentiated as new field wildcats or other exploratory wells. New field wildcats are those wells drilled for a new field on a structure or in an environment never before productive. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proven areas and can result in extensions or revisions. Exploration yields new additions to the stock of reserves and development determines the rate of production from the stock of known reserves.

     The OGSM also projects natural gas trade via pipeline with Canada and Mexico, as well as liquefied natural gas (LNG) trade. U.S. natural gas trade with Canada is represented by six entry/exit points and trade with Mexico by three entry/exit points. Four LNG receiving terminals are represented.

12. Coverage
     ● Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
     ● Time Units/Frequency: Annually 1990 through 2020
     ● Product(s): Crude oil and natural gas
     ● Economic Sector(s): Oil and gas field production activities and foreign natural gas trade

13. Model Features
     ● Model Structure: Modular, containing six major components
        - Lower 48 Onshore and Shallow Offshore Supply Submodule
        - Unconventional Gas Recovery Supply Submodule
        - Deep Water Offshore Supply Submodule
        - Foreign Natural Gas Supply Submodule
        - Enhanced Oil Recovery Submodule
        - Alaska Oil and Gas Supply Submodule
     ● Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are determined by the discounted cash flow that measures the expected present value profits for the proposed effort and other key economic variables. LNG imports are projected on the basis of unit supply costs for gas delivered into the Lower 48 pipeline network.
     ● Special Features: Can run stand-alone or within the NEMS. Integrated NEMS runs employ short term natural gas supply functions for efficient market equilibration.

14. Non-DOE Input Data

- Alaskan Oil and Gas Field Size Distributions - U.S. Geological Survey

- Alaska Facility Cost By Oil Field Size - U.S. Geological Survey

- Alaska Operating cost - U.S. Geological Survey

- Basin Differential Prices - Natural Gas Week, Washington, DC

- State Corporate Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*

- State Severance Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*

- Federal Corporate Tax Rate, Royalty Rate - U.S. Tax Code

- Onshore Drilling Costs - (1.) American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-1996)*, Washington, D.C.; (2.) Additional unconventional gas recovery drilling and operating cost data from operating companies

- Shallow Offshore Drilling Costs - American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-1995)*, Washington, D.C.

- Shallow Offshore Lease Equipment and Operating Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Shallow Offshore Wells Drilled per Project - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Shallow and Deep Offshore Technically Recoverable Oil and Gas Undiscovered Resources - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Deep Offshore Exploration, Drilling, Platform, and Production Costs - American Petroleum Institute,. *Joint Association Survey of Drilling Costs (1995)*, ICF Resource Incorporated (1994), Oil and Gas Journals

- Canadian Royalty Rate, Corporate Tax Rate, Provincial Corporate Tax Rate- Energy Mines and Resources Canada. *Petroleum Fiscal Systems in Canada*, (Third Edition - 1988)

- Canadian Wells drilled - Canadian Petroleum Association. *Statistical Handbook*, (1976-1993)

- Canadian Lease Equipment and Operating Costs - Sproule Associates Limited. *The Future Natural Gas Supply Capability of the Western Canadian Sedimentary Basin* (Report Prepared for Transcanada Pipelines Limited, January 1990)

- Canadian Recoverable Resource Base - National Energy Board. *Canadian Energy Supply and Demand 1990 - 2010*, June 1991

- Canadian Reserves - Canadian Petroleum Association. *Statistical Handbook*, (1976-1993)

- Unconventional Gas Resource Data - (1.) USGS *1995 National Assessment of United States Oil and Natural Gas Resources*; (2.) Additional unconventional gas data from operating companies

- Unconventional Gas Technology Parameters - (1.) Advanced Resources International Internal studies; (2.) Data gathered from operating companies

15. DOE Input Data
   - Onshore Lease Equipment Cost - Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 1995)*, DOE/EIA-0815(80-95)

   - Onshore Operating Cost - Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 1995)*, DOE/EIA-0815(80-95)

   - Emissions Factors - Energy Information Administration.

   - Oil and Gas Well Initial Flow Rates - Energy Information Administration. Office of Oil and Gas

   - Wells Drilled - Energy Information Administration. Office of Oil and Gas

   - Expected Recovery of Oil and Gas Per Well - Energy Information Administration. Office of Oil and Gas

   - Undiscovered Recoverable Resource Base - Energy Information Administration. *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy strategy*, SR/NES/92-05

   - Oil and Gas Reserves - Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-1997), DOE/EIA-0216(77-97)

16. Computing Environment
   - Hardware Used: RS/6000
   - Operating System: UNIX
   - Language/Software Used: FORTRAN
   - Memory Requirement: Unknown
   - Storage Requirement: 992 bytes for input data storage; 180,864 bytes for output storage; 1280 bytes for code storage; and 5736 bytes for compiled code storage
   - Estimated Run Time: 9.8 seconds

17. Reviews conducted
   Independent Expert Reviews, Model Quality Audit; Unconventional Gas Recovery Supply Submocule - Presentations to Mara Dean (DOE/FE - Pittsburgh) and Ray Boswell (DOE/FE - Morgantown), April 1998 and DOE/FE (Washington, DC)

18. Status of Evaluation Efforts
   Not applicable

19. Bibliography
   See Appendix C of this document.

Appendix E. Parameter Estimation

The major portion of the lower 48 oil and gas supply component of the OGSM consists of a system of equations that are used to forecast exploratory and developmental wells drilled. The equations, the estimation techniques, and the statistical results are documented below. Documentation is also provided for the estimation of the drilling, lease equipment, and operating cost equations as well as the associated-dissolved gas equations and the Canadian oil and gas wells equations. Finally, the appendix documents the estimation of oil and gas supply price elasticities that are passed to the PMM and the NGTDM for (possible) use in their short run supply functions. The econometric software packages, SAS and TSP, were used for the estimations.

Lower 48 Estimated Wells Equations

Onshore

$$LESTWELLS_t = b0 + b1*(LPOIL_t*LPGAS_t) + b2*(LPOIL_t*LPGAS_t)*PRE91$$
where PRE1 = 1 if YEAR < 1991; 0 otherwise

Equation Variable/Parameter	Output Variable/Parameter
LESTWELLS	LNWELLS
b0	C
b1	POILGAS
b2	POILGAS2

```
               Method of estimation = Ordinary Least Squares


 Dependent variable: LNWELLS
 Current sample:  16 to 26
 Number of observations:  11

        Mean of dep. var. = 10.2881         LM het. test = 1.06093 [.303]
    Std. dev. of dep. var. = .351644       Durbin-Watson = 1.99740 [<.679]
 Sum of squared residuals = .070026     Jarque-Bera test = 2.85456 [.240]
    Variance of residuals = .875319E-02  Ramsey's RESET2 = .824528E-02 [.930]
 Std. error of regression = .093558       F (zero slopes) = 66.6334 [.000]
               R-squared = .943370         Schwarz B.I.C. = -4.40282
        Adjusted R-squared = .929212        Log likelihood = 12.2040

            Estimated      Standard
 Variable  Coefficient      Error       t-statistic   P-value
 C          9.79782        .084684       115.699       [.000]
 POILGAS    .256360        .098879       2.59266       [.032]
 POILGAS2   .169122        .066885       2.52853       [.035]
```

$$\text{LESTSUCWELLS}_t = b0 + b1*(\text{LPOIL}_t*\text{LPGAS}_t) + b2*(\text{LPOIL}_t*\text{LPGAS}_t)*\text{PRE91}$$
where $\text{PRE91} = 1$ if $\text{YEAR} < 1991$; 0 otherwise

Equation Variable/Parameter	Output Variable/Parameter
LESTSUCWELLS	LSUCWELL
b0	C
b1	POILGAS
b2	POILGAS2

```
                  Method of estimation = Ordinary Least Squares


Dependent variable: LSUCWELL
 Current sample:  16 to 26
 Number of observations:  11

        Mean of dep. var. = 9.96558         LM het. test = 1.00393 [.316]
    Std. dev. of dep. var. = .325147        Durbin-Watson = 2.01427 [<.689]
 Sum of squared residuals = .066034     Jarque-Bera test = 2.44381 [.295]
     Variance of residuals = .825421E-02  Ramsey's RESET2 = .378503 [.558]
 Std. error of regression = .090853      F (zero slopes) = 60.0404 [.000]
               R-squared = .937539        Schwarz B.I.C. = -4.46151
        Adjusted R-squared = .921924      Log likelihood = 12.5268

          Estimated     Standard
Variable  Coefficient     Error      t-statistic   P-value
C          9.47805       .082235      115.256       [.000]
POILGAS    .287494       .096019      2.99412       [.017]
POILGAS2   .120828       .064951      1.86029       [.100]
```

Offshore

$$LGOMWELLS_t = \alpha1 + \alpha2 * PRE86 + \alpha3 * PRE91 + \beta1 * (LPOIL_t * LPGAS_t) + \beta2 * (LPOIL_t * LPGAS_t) * PRE91$$

where PRE86 = 1 if YEAR < 86; 0 otherwise
PRE91 = 1 if YEAR < 91; 0 otherwise

Equation Variable/Parameter	Output Variable/Parameter
LGOMWELLS	LN of offshore wells
$\alpha1$	C
$\alpha2$	PRE86
$\alpha3$	PRE91
$\beta1$	POILGAS
$\beta2$	P_OG_P91

```
                 Method of estimation = Ordinary Least Squares

 Dependent variable: LNWELLS
 Current sample:  8 to 26
 Number of observations:  19

  Mean of dependent variable = 6.80053          Adjusted R-squared = .852480
 Std. dev. of dependent var. = .319026       Durbin-Watson statistic = 2.28517
    Sum of squared residuals = .210200       F-statistic (zero slopes) = 27.0043
        Variance of residuals = .015014      Schwarz Bayes. Info. Crit. = -3.72928
    Std. error of regression = .122533       Log of likelihood function = 15.8295
                   R-squared = .885262

           Estimated     Standard
 Variable  Coefficient     Error       t-statistic
 C          6.00392       .195515       30.7082
 PRE86       .282751      .077695        3.63924
 PRE91       .668487      .210585        3.17443
 POILGAS     .352805      .175627        2.00883
 P_OG_P91   -.314139      .178516       -1.75973
```

Lower 48 RIGS Equations

Onshore

$$LRIGSL48_t = b0 + b1 * LRIGSL48_{t-1} + b2 * LREVRIG_{t-1} + \rho * LRIGSL48_{t-2} - \rho * (b0 + b1 * LRIGSL48_{t-2} + b2 * LREVRIG_{t-3})$$

Equation Variable/Parameter	Output Variable/Parameter
LRIGSL48	LNRIGS
b0	C
b1	LNRIGS(-1)
b2	LNREVRIG(-1)
ρ	RHO

```
                    FIRST-ORDER SERIAL CORRELATION OF THE ERROR

                    MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
NOTE:  Lagged dependent variable(s) present
                    ********************
                    MAXIMUM LIKELIHOOD ESTIMATION IS NOT
                    IMPLEMENTED FOR LAGGED DEPENDENT VARIABLES
                    DUE TO TREATMENT OF THE FIRST OBSERVATION.
                    METHOD OF ESTIMATION IS CHANGED TO
                    COCHRANE-ORCUTT ITERATIVE TECHNIQUE

                    CONVERGENCE ACHIEVED AFTER    6 ITERATIONS
Dependent variable: LNRIGS
Current sample:  3 to 26
Number of observations:  24

(Statistics based on transformed data)
          Mean of dep. var. = 4.38969
     Std. dev. of dep. var. = .234933
   Sum of squared residuals = .058026
      Variance of residuals = .276313E-02
   Std. error of regression = .052566
                  R-squared = .954291
         Adjusted R-squared = .949937
              Durbin-Watson = 1.62731
Rho (autocorrelation coef.) = .439691
       Standard error of rho = .232287
         t-statistic for rho = 1.89288
             Log likelihood = 38.2445
(Statistics based on original data)
          Mean of dep. var. = 7.83784
     Std. dev. of dep. var. = .389324
   Sum of squared residuals = .058026
      Variance of residuals = .276313E-02
   Std. error of regression = .052566
                  R-squared = .983357
         Adjusted R-squared = .981772
              Durbin-Watson = 1.62731
```

	Estimated	Standard		
Variable	Coefficient	Error	t-statistic	P-value
C	-3.37088	.762161	-4.42280	[.000]
LNRIGS(-1)	.803012	.053301	15.0655	[.000]
LNREVRIG(-1)	.312270	.051418	6.07313	[.000]
RHO	.439691	.232287	1.89288	[.058]

Offshore

$$LRIGSOFF_t = \alpha + \beta * LRIGSOFF_{t-1} + \gamma * LREVRIG_{t-2}$$

Equation Variable/Parameter	Output Variable/Parameter
LRIGSOFF	LNRIGS
α	C
β	LNRIGS(-1)
γ	REV_RIG(-2)

```
                  Method of estimation = Ordinary Least Squares


 Dependent variable: LNRIGS
 Current sample:  3 to 26
 Number of observations:  24

 Mean of dependent variable = 5.37463      Durbin-Watson statistic = 1.54664
Std. dev. of dependent var. = .374642              Durbin's h = 1.15820
    Sum of squared residuals = .418106     Durbin's h alternative = 1.12061
        Variance of residuals = .019910   F-statistic (zero slopes) = 70.5705
      Std. error of regression = .141102  Schwarz Bayes. Info. Crit. = -3.65282
                   R-squared = .870483    Log of likelihood function = 14.5464
          Adjusted R-squared = .858148

              Estimated     Standard
Variable      Coefficient     Error        t-statistic
C             -3.23829       2.05472        -1.57602
LNRIGS(-1)     .817466        .089122        9.17245
REV_RIG(-2)    .251762        .134253        1.87528
```

Drilling Cost Equations

Drilling costs were hypothesized to be a function of drilling, depth, and a time trend that proxies for the cumulative effect of technological advances on costs. The equations were estimated in log-linear form using Three Stage Least Squares (3SLS) technique. The forms of the equations are:

Onshore Regions

$$LDRILLCOST_{r,k,t} = \ln(\delta0)_{r,k} + \ln(\delta1)_{d,k} + \ln(\delta2)_{r,k} + \delta3_k * LESTWELLS_t + \delta4_k * LRIGSL48_t + \delta5_k * TIME_t +$$
$$\rho_k * LDRILLCOST_{r,k,t-1} - \rho_k * \left(\ln(\delta0)_{r,k} + \ln(\delta1)_{d,k} + \ln(\delta2)_{r,k} + \right.$$
$$\left. \delta3_k * LESTWELLS_{t-1} + \delta4_k * LRIGSL48_{t-1} + \delta5_k * TIME_{t-1} \right)$$

Results

Mapping of variable names from the above equation to the following SAS output.

Variable/Parameter	Successful		Dry	
	Oil	Gas	Oil	Gas
LDRILLCOST	LNOILCOST	LNGASCOST	LNDOL_C	LNDGAS_C
$\ln(\delta0)_1$	REGOIL1	REGGAS1	REGDOIL1	REGDGAS1
$\ln(\delta0)_2$	REGOIL2	REGGAS2	REGDOIL2	REGDGAS2
$\ln(\delta0)_3$	REGOIL3	REGGAS3	REGDOIL3	REGDGAS3
$\ln(\delta0)_4$	REGOIL4	REGGAS4	REGDOIL4	REGDGAS4
$\ln(\delta0)_5$	REGOIL5	REGGAS5	REGDOIL5	REGDGAS5
$\ln(\delta0)_6$	REGOIL6	REGGAS6	REGDOIL6	REGDGAS6
$\ln(\delta1)_{r,2500}$	OIL_2500	GAS_2500	DOIL_2500	DGAS_2500
$\ln(\delta1)_{r,3750}$	OIL_3750	GAS_3750	DOIL_3750	DGAS_3750
$\ln(\delta1)_{r,5000}$	OIL_5000	GAS_5000	DOIL_5000	DGAS_5000
$\ln(\delta1)_{r,7500}$	OIL_7500	GAS_7500	DOIL_7500	DGAS_7500
$\ln(\delta1)_{r,10000}$	O_10000	G_10000	DO_10000	DG_10000
$\ln(\delta1)_{r,12500}$	O_12500	G_12500	DO_12500	DG_12500
$\ln(\delta2)_{1,5000}$	OGD16_50	OGD16_50	OGD16_50	OGD16_50
$\ln(\delta2)_{6,5000}$	OGD16_50	OGD16_50	OGD16_50	OGD16_50
$\delta3$	OG_WELL	OG_WELL	DWELL	DWELL
$\delta4$	OGD_RIGS	OGD_RIGS	OGD_RIGS	OGD_RIGS

Variable/Parameter	Successful		Dry	
	Oil	Gas	Oil	Gas
δ5	TECH	TECH	TECH	TECH
ρ	RHO_O	RHO_G	RHO_DO	RHO_DG

```
Nonlinear 3SLS Summary of Residual Errors

            DF    DF                                                   Durbin
Equation  Model Error      SSE        MSE    Root MSE  R-Square  Adj R-Sq  Watson

LNOILCST  14.25 698.8   13.76439    0.01970   0.14035   0.9845   0.9843    2.061
LNGASCST  14.25 698.8   23.39868    0.03349   0.18299   0.9756   0.9751    1.943
LNDOIL_C  14.25 698.8   30.88307    0.04420   0.21023   0.9713   0.9707    1.972
LNDGAS_C  14.25 698.8   31.96803    0.04575   0.21389   0.9721   0.9716    2.010


Nonlinear 3SLS Parameter Estimates

                        Approx.    'T'    Approx.  1st Stage
Parameter   Estimate    Std Err   Ratio  Prob>|T|  R-Square  Label

REGOIL1    32.264729    4.70001    6.86   0.0001   -0.0671  DUMMY REGION 1 - OIL
REGOIL2    32.864081    4.69926    6.99   0.0001    1.0000  DUMMY REGION 2 - OIL
REGOIL3    32.733486    4.69959    6.97   0.0001    1.0000  DUMMY REGION 3 - OIL
REGOIL4    32.719970    4.69950    6.96   0.0001    1.0000  DUMMY REGION 4 - OIL
REGOIL5    33.002591    4.69927    7.02   0.0001    1.0000  DUMMY REGION 5 - OIL
REGOIL6    33.476219    4.70187    7.12   0.0001    1.0000  DUMMY REGION 6 - OIL
OGD_RIGS   -0.147827    0.05457   -2.71   0.0069    0.9998  TOTAL RIGS - SUCCESSFUL AND DRY
OG_WELL     0.462430    0.04640    9.97   0.0001    0.9998  TOTAL LOWER48 ONSHORE DRILLING - SUCCESSFUL
TECH       -0.012922   0.0022861  -5.65   0.0001    1.0000  TIME TREND - SUCCESSFUL AND DRY
OGD16_50    0.231929    0.09972    2.33   0.0203    1.0000
OIL_2500    0.975284    0.04950   19.70   0.0001    1.0000  DUMMY DEPTH RANGE 2500-3749 - OIL
OIL_3750    1.341214    0.04975   26.96   0.0001    1.0000  DUMMY DEPTH RANGE 3750-4999 - OIL
OIL_5000    1.789786    0.04951   36.15   0.0001    1.0000  DUMMY DEPTH RANGE 5000-7499 - OIL
OIL_7500    2.314636    0.04975   46.52   0.0001    1.0000  DUMMY DEPTH RANGE 7500-9999 - OIL
O_10000     2.835852    0.04975   57.00   0.0001    1.0000  DUMMY DEPTH RANGE 10000-12499 - OIL
O_12500     3.438934    0.04976   69.11   0.0001    1.0000  DUMMY DEPTH RANGE > 12500 - OIL
RHO_O       0.589180    0.01734   33.97   0.0001    0.9762  AUTOCORRELATION PARAMETER - OIL
REGGAS1    32.707044    4.70082    6.96   0.0001   -0.1383  DUMMY REGION 1 - GAS
REGGAS2    33.182871    4.70024    7.06   0.0001    1.0000  DUMMY REGION 2 - GAS
REGGAS3    33.036668    4.70001    7.03   0.0001    1.0000  DUMMY REGION 3 - GAS
REGGAS4    32.992393    4.70008    7.02   0.0001    1.0000  DUMMY REGION 4 - GAS
REGGAS5    33.237406    4.69998    7.07   0.0001    1.0000  DUMMY REGION 5 - GAS
REGGAS6    33.387365    4.70307    7.10   0.0001    1.0000  DUMMY REGION 6 - GAS
GAS_2500    0.817681    0.06518   12.55   0.0001    1.0000  DUMMY DEPTH RANGE 2500-3749 - GAS
GAS_3750    1.080166    0.06609   16.34   0.0001    1.0000  DUMMY DEPTH RANGE 3750-4999 - GAS
GAS_5000    1.480456    0.06519   22.71   0.0001    1.0000  DUMMY DEPTH RANGE 5000-7499 - GAS
GAS_7500    2.052567    0.06609   31.06   0.0001    1.0000  DUMMY DEPTH RANGE 7500-9999 - GAS
G_10000     2.739377    0.06609   41.45   0.0001    1.0000  DUMMY DEPTH RANGE 10000-12499 - GAS
G_12500     3.594551    0.06620   54.30   0.0001    1.0000  DUMMY DEPTH RANGE > 12500 - GAS
RHO_G       0.594844    0.01659   35.86   0.0001    0.9852  AUTOCORRELATION PARAMETER - GAS
REGDOIL1   31.677601    4.71230    6.72   0.0001    0.0650  DUMMY REGION 1 - DRY OIL
REGDOIL2   31.945648    4.71173    6.78   0.0001    1.0000  DUMMY REGION 2 - DRY OIL
REGDOIL3   31.810854    4.71202    6.75   0.0001    1.0000  DUMMY REGION 3 - DRY OIL
REGDOIL4   31.793981    4.71174    6.75   0.0001    1.0000  DUMMY REGION 4 - DRY OIL
REGDOIL5   32.116135    4.71163    6.82   0.0001    1.0000  DUMMY REGION 5 - DRY OIL
REGDOIL6   32.513244    4.71553    6.89   0.0001    1.0000  DUMMY REGION 6 - DRY OIL
DWELL       0.514832    0.05112   10.07   0.0001    0.9998  TOTAL LOWER48 ONSHORE DRILLING - DRY OIL AND GAS
DOIL2500    0.680240    0.07091    9.59   0.0001    1.0000  DUMMY DEPTH RANGE 2500-3749 - DRY OIL
DOIL3750    1.122066    0.07203   15.58   0.0001    1.0000  DUMMY DEPTH RANGE 3750-4999 - DRY OIL
DOIL5000    1.680679    0.07091   23.70   0.0001    1.0000  DUMMY DEPTH RANGE 5000-7499 - DRY OIL
DOIL7500    2.307321    0.07204   32.03   0.0001    1.0000  DUMMY DEPTH RANGE 7500-9999 - DRY OIL
DO_10000    2.841257    0.07203   39.44   0.0001    1.0000  DUMMY DEPTH RANGE 10000-12499 - DRY OIL
DO_12500    3.678507    0.07203   51.07   0.0001    1.0000  DUMMY DEPTH RANGE > 12500 - DRY OIL
RHO_DO      0.578512    0.01682   34.40   0.0001    0.9852  AUTOCORRELATION PARAMETER - DRY OIL
REGDGAS1   32.120454    4.71279    6.82   0.0001   -0.1403  DUMMY REGION 1 - DRY GAS
REGDGAS2   32.261712    4.71251    6.85   0.0001    1.0000  DUMMY REGION 2 - DRY GAS
REGDGAS3   32.110396    4.71227    6.81   0.0001    1.0000  DUMMY REGION 3 - DRY GAS
REGDGAS4   32.068070    4.71219    6.81   0.0001    1.0000  DUMMY REGION 4 - DRY GAS
REGDGAS5   32.346555    4.71212    6.86   0.0001    1.0000  DUMMY REGION 5 - DRY GAS
REGDGAS6   32.451122    4.71634    6.88   0.0001    1.0000  DUMMY REGION 6 - DRY GAS
DGAS2500    0.522790    0.07323    7.14   0.0001    1.0000  DUMMY DEPTH RANGE 2500-3749 - DRY GAS
DGAS3750    0.864151    0.07443   11.61   0.0001    1.0000  DUMMY DEPTH RANGE 3750-4999 - DRY GAS
DGAS5000    1.373330    0.07323   18.75   0.0001    1.0000  DUMMY DEPTH RANGE 5000-7499 - DRY GAS
DGAS7500    2.044460    0.07443   27.47   0.0001    1.0000  DUMMY DEPTH RANGE 7500-9999 - DRY GAS
DG_10000    2.753758    0.07443   37.00   0.0001    1.0000  DUMMY DEPTH RANGE 10000-12499 - DRY GAS
DG_12500    3.835372    0.07447   51.50   0.0001    1.0000  DUMMY DEPTH RANGE > 12500 - DRY GAS
RHO_DG      0.580546    0.01734   33.49   0.0001    0.9836  AUTOCORRELATION PARAMETER - DRY GAS


Number of Observations      Statistics for System
Used           713          Objective     0.3396
Missing          0          Objective*N  242.1704
```

Offshore Gulf of Mexico

$$LDRILLCOST_k = \ln(\delta 0)_k + \delta 1_k * GOMWELLS_t + \ln(\delta 2)_{d,k} + \delta 3_k * LRIGSOFF_{t-2} + \delta 4_k * TIME_t$$

Results

Mapping of variable names from the above equation to the following TSP output.

Variable/Parameter	Successful		Dry	
	Oil	Gas	Oil	Gas
LDRILLCOST	LNOILCST	LNGASCST	LNDOIL_C	LNDGAS_C
$\ln(\delta 0)$	OIL_C	GAS_C	DOIL_C	DGAS_C
$\delta 1$	OG_WELL	OG_WELL	DWELL	DWELL
$\ln(\delta 2)_{5000}$	OIL_5000	GAS_5000	DOIL5000	DGAS5000
$\ln(\delta 2)_{7500}$	OIL_7500	GAS_7500	DOIL7500	DGAS7500
$\ln(\delta 2)_{10000}$	O_10000	G_10000	DO_10000	DG_10000
$\ln(\delta 2)_{12500}$	O_12500	G_12500	DO_12500	DG_12500
$\ln(\delta 2)_{15000}$	O_15000	G_15000	DO_15000	DG_15000
$\delta 3$	OGD_RIGS	OGD_RIGS	OGD_RIGS	OGD_RIGS
$\delta 4$	TECH	TECH	TECH	TECH

```
Method of estimation =   THREE STAGE LEAST SQUARES
EQUATIONS: OIL GAS DOIL DGAS

INSTRUMENTS: YEAR REV_RIG(-2) LNRIGS(-2) LNWELLS(-1) LNPOIL
    LNPGAS LNPOIL(-1) LNPGAS(-1) D_5000 D_7500 D_10000 D_12500
    D_15000

                          Standard
Parameter  Estimate        Error         t-statistic
OIL_C       52.2481        16.1912         3.22693
OGD_RIGS   -.243117        .095599        -2.54308
OG_WELL     .515073        .139620         3.68909
TECH       -.020219        .776264E-02    -2.60466
OIL_5000    .142151        .081559         1.74292
OIL_7500    .498246        .081559         6.10900
O_10000     .800068        .081559         9.80964
O_12500     1.09105        .081559        13.3774
O_15000     1.52881        .081559        18.7447
GAS_C       52.3239        16.1912         3.23162
GAS_5000    .215660        .071866         3.00087
GAS_7500    .516246        .071866         7.18345
G_10000     .770493        .071866        10.7212
G_12500     1.13146        .071866        15.7440
G_15000     1.59037        .071866        22.1296
DOIL_C      51.0502        16.1905         3.15310
DWELL       .647036        .137727         4.69797
DOIL5000    .205968        .080407         2.56155
DOIL7500    .588379        .080407         7.31748
DO_10000    .976040        .080407        12.1387
DO_12500    1.32704        .080407        16.5039
DO_15000    1.83987        .080407        22.8818
DGAS_C      51.1420        16.1905         3.15877
DGAS5000    .272415        .065867         4.13582
DGAS7500    .585708        .065867         8.89226
DG_10000    .928666        .065867        14.0991
DG_12500    1.34880        .065867        20.4777
DG_15000    1.88683        .065867        28.6461

Standard Errors computed from   quadratic form of analytic first
derivatives (Gauss)

Dependent variable: LNOILCST
 Mean of dependent variable = 14.8956       Std. error of regression = .239445
Std. dev. of dependent var. = .608018                   R-squared = .843895
    Sum of squared residuals = 5.84805    Durbin-Watson statistic = 1.60980
        Variance of residuals = .057334

Dependent variable: LNGASCST
 Mean of dependent variable = 14.9987       Std. error of regression = .210733
Std. dev. of dependent var. = .610118                   R-squared = .879691
    Sum of squared residuals = 4.52965    Durbin-Watson statistic = 1.70109
        Variance of residuals = .044408

Dependent variable: LNDOIL_C
 Mean of dependent variable = 14.7383       Std. error of regression = .235093
Std. dev. of dependent var. = .720214                   R-squared = .892451
    Sum of squared residuals = 5.63742    Durbin-Watson statistic = 1.58237
        Variance of residuals = .055269

Dependent variable: LNDGAS_C
 Mean of dependent variable = 14.8443       Std. error of regression = .192494
Std. dev. of dependent var. = .713234                   R-squared = .926456
    Sum of squared residuals = 3.77951    Durbin-Watson statistic = 1.83208
        Variance of residuals = .037054
```

Onshore Lease Equipment Cost Equations

Lease equipment costs were hypothesized to be a function of total successful wells and a time trend that proxies for the cumulative effect of technological advances on costs. The form of the equation was assumed to be log-linear. The equations were estimated in log-linear form using Three Stage Least Squares (3SLS) technique. Where necessary, equations were estimated in generalized difference form to correct for first order serial correlation. The forms of the equations are:

Onshore Regions

$$LLEQC_{r,k,t} = \ln(\epsilon 0)_{r,k} + \ln(\epsilon 1)_k * DEPTH_{r,k,t} + \epsilon 2_k * LESUCWELL_{k,t} + \epsilon 3_k * TIN$$
$$\rho_k * (\ln(\epsilon 0)_{r,k} + \ln(\epsilon 1)_k * DEPTH_{r,k,t-1} * \epsilon 2_k * LESUCWELL_{k,t-1} +$$

Results

Mapping of variable names from the above equation to the following TSP output.

Variable/Parameter	Shallow Oil	Shallow Gas	Deep Oil	Deep Gas
LLEQC	LSO_LEQ	LSG_LEQ	LDO_LEQ	LDG_LEQ
$\ln(\epsilon 0)_1$	SOREG1	SGREG1	--	--
$\ln(\epsilon 0)_2$	SOREG2	SGREG2	DOREG2	DGREG2
$\ln(\epsilon 0)_3$	SOREG3	SGREG3	DOREG3	DGREG3
$\ln(\epsilon 0)_4$	SOREG4	SGREG4	DOREG4	DGREG4
$\ln(\epsilon 0)_5$	SOREG5	SGREG5	DOREG5	DGREG5
$\ln(\epsilon 0)_6$	SOREG6	SGREG6	--	--
$\epsilon 1$	SODEPTH	SGDEPTH	DODEPTH	DGDEPTH
$\epsilon 2$	SOWELL	SGWELL	DOWELL	DGWELL
$\epsilon 3$	TECH	TECH	TECH	TECH
ρ	SORHO	SGRHO	DORHO	DGRHO

```
                    THREE STAGE LEAST SQUARES

EQUATIONS: SOIL SGAS

INSTRUMENTS: REGION1 REGION2 REGION3 REGION4 REGION5 REGION6
    SG_DPTH SO_DPTH SG_DPTH(-1) SO_DPTH(-1) YEAR LSG_LEQ(-1)
    LSO_LEQ(-1) LSUCWELL(-1) RPGAS RPOIL RPGAS(-1) RPOIL(-1)

                  Number of Observations =    150

                          Standard
Parameter   Estimate       Error        t-statistic   P-value
SOREG1      33.7741        6.08076       5.55426       [.000]
SOREG2      33.5586        6.07805       5.52127       [.000]
SOREG3      33.5302        6.08331       5.51184       [.000]
SOREG4      33.7847        6.08023       5.55649       [.000]
SOREG5      33.7353        6.07598       5.55223       [.000]
SOREG6      34.2506        6.07892       5.63432       [.000]
SODEPTH     .181898E-03    .104214E-04   17.4544       [.000]
SOWELL      .141601        .042041       3.36814       [.001]
TECH        -.012422       .294173E-02   -4.22259      [.000]
SORHO       .658138        .062543       10.5229       [.000]
SGREG1      32.8085        6.03814       5.43355       [.000]
SGREG2      33.0401        6.03673       5.47318       [.000]
SGREG3      33.0801        6.03622       5.48027       [.000]
SGREG4      33.4552        6.03766       5.54108       [.000]
SGREG5      33.6282        6.03247       5.57453       [.000]
SGREG6      32.8046        6.03793       5.43309       [.000]
SGDEPTH     .600314E-04    .815549E-05   7.36086       [.000]
SGWELL      .141891        .043189       3.28537       [.001]
SGRHO       .665599        .055584       11.9747       [.000]


Standard Errors computed from   quadratic form of analytic first
derivatives (Gauss)


Equation: SOIL
Dependent variable: LSO_LEQ


        Mean of dep. var. = 11.2220
  Std. dev. of dep. var. = .331759
Sum of squared residuals = .899774
    Variance of residuals = .599849E-02
Std. error of regression = .077450
                R-squared = .945171
            Durbin-Watson = 1.90518 [<.859]


Equation: SGAS
Dependent variable: LSG_LEQ


        Mean of dep. var. = 10.2228
  Std. dev. of dep. var. = .379077
Sum of squared residuals = 1.32409
    Variance of residuals = .882729E-02
Std. error of regression = .093954
                R-squared = .938205
            Durbin-Watson = 2.22580 [<.999]
```

```
                          THREE STAGE LEAST SQUARES


EQUATIONS: DOIL DGAS

INSTRUMENTS: REGION2 REGION3 REGION4 REGION5 DG_DPTH DO_DPTH
     DG_DPTH(-1) DO_DPTH(-1) YEAR LDG_LEQ(-1) LDO_LEQ(-1) LSUCWELL(-1)
     RPGAS RPOIL RPGAS(-1) RPOIL(-1)

                      Number of Observations =     100

                          Standard
Parameter   Estimate       Error      t-statistic   P-value
DOREG2      19.9806       2.34600      8.51690       [.000]
DOREG3      19.9910       2.34584      8.52190       [.000]
DOREG4      20.0289       2.34601      8.53743       [.000]
DOREG5      20.0239       2.34668      8.53284       [.000]
DODEPTH     .262492E-04   .151868E-04  1.72842       [.084]
DOWELL      .332898       .019588      16.9950       [.000]
TECH        -.588957E-02  .116272E-02  -5.06534      [.000]
DGREG2      20.7534       2.38702      8.69425       [.000]
DGREG3      20.7847       2.38684      8.70805       [.000]
DGREG4      20.7550       2.38656      8.69663       [.000]
DGREG5      20.8759       2.38549      8.75119       [.000]
DGDEPTH     .163290E-04   .530570E-05  3.07763       [.002]
DGWELL      .143733       .028666      5.01403       [.000]
DGRHO       .703937       .055202      12.7519       [.000]


Standard Errors computed from   quadratic form of analytic first
derivatives (Gauss)


Equation: DOIL
Dependent variable: LDO_LEQ

        Mean of dep. var. = 12.0125
  Std. dev. of dep. var. = .179325
Sum of squared residuals = .715547
   Variance of residuals = .715547E-02
Std. error of regression = .084590
              R-squared = .776599
          Durbin-Watson = 1.89374 [<.882]

Equation: DGAS
Dependent variable: LDG_LEQ

        Mean of dep. var. = 10.7517
  Std. dev. of dep. var. = .145721
Sum of squared residuals = .228672
   Variance of residuals = .228672E-02
Std. error of regression = .047820
              R-squared = .891237
          Durbin-Watson = 1.24518 [<.020]
```

Onshore Operating Cost Equations

Operating costs were hypothesized to be a function of drilling, depth, and a time trend that proxies for the cumulative effect of technological advances on costs. The form of the equation was assumed to be log-linear. The equations were estimated in log-linear form using Three Stage Least Squares (3SLS) technique. The forms of the equations are:

Onshore Regions

$$LOPC_{r,k,t} = \ln(\varphi 0)_{r,k} + \ln(\varphi 1)_k * DEPTH_{r,k,t} + \varphi 2_k * LESUCWELL_{k,t} + \varphi 3_k * TIM$$
$$\rho_k * (\ln(\varphi 0)_{r,k} + \ln(\varphi 1)_k * DEPTH_{r,k,t-1} * \varphi 2_k * LESUCWELL_{k,t-1} + \varphi$$

Results

Mapping of variable names from the above equation to the following TSP output

Variable/Parameter	Shallow Oil	Shallow Gas	Deep Oil	Deep Gas
LOPC	LSOILC	LSGASC	LDOILC	LDGASC
$\ln(\phi 0)_1$	SOREG1	SGREG1	--	--
$\ln(\phi 0)_2$	SOREG2	SGREG2	DOREG2	DGREG2
$\ln(\phi 0)_3$	SOREG3	SGREG3	DOREG3	DGREG3
$\ln(\phi 0)_4$	SOREG4	SGREG4	DOREG4	DGREG4
$\ln(\phi 0)_5$	SOREG5	SGREG5	DOREG5	DGREG5
$\ln(\phi 0)_6$	SOREG6	SGREG6	--	--
$\phi 1$	SODEPTH	SGDEPTH	DODEPTH	DGDEPTH
$\phi 2$	SOWELL	SGWELL	DOWELL	DGWELL
$\phi 3$	TECH	TECH	TECH	TECH
ρ	SORHO	SGRHO	DORHO	DGRHO

```
                          THREE STAGE LEAST SQUARES

EQUATIONS: SOIL SGAS


INSTRUMENTS: REGION1 REGION6 REGION2 REGION3 REGION4 REGION5
    SG_DPTH SO_DPTH SG_DPTH(-1) SO_DPTH(-1) RPGAS RPOIL RPGAS(-1)
    RPOIL(-1) YEAR SUCWELL(-1) LSGASC(-1) LSOILC(-1)

                    Number of Observations =     120

                          Standard
Parameter   Estimate       Error        t-statistic   P-value
SOREG1      19.7329        4.73937       4.16362       [.000]
SOREG2      19.8498        4.73884       4.18873       [.000]
SOREG3      19.4884        4.73855       4.11274       [.000]
SOREG4      19.5184        4.73874       4.11891       [.000]
SOREG5      19.9332        4.73466       4.21007       [.000]
SOREG6      19.9044        4.74014       4.19913       [.000]
SODEPTH     .946487E-04    .953023E-05   9.93141       [.000]
SOWELL      .609541E-05    .927934E-06   6.56879       [.000]
TECH        -.541966E-02   .237814E-02   -2.27895      [.023]
SORHO       .769252        .056975       13.5015       [.000]
SGREG1      19.5708        4.73677       4.13167       [.000]
SGREG2      20.0209        4.73384       4.22933       [.000]
SGREG3      19.9579        4.73792       4.21237       [.000]
SGREG4      20.1155        4.73428       4.24891       [.000]
SGREG5      20.2424        4.73299       4.27687       [.000]
SGREG6      19.6084        4.73393       4.14210       [.000]
SGDEPTH     .478768E-04    .439728E-05   10.8878       [.000]
SGWELL      .403359E-05    .590399E-06   6.83197       [.000]
SGRHO       .600537        .069593       8.62923       [.000]

Standard Errors computed from   quadratic form of analytic first
derivatives (Gauss)


Equation: SOIL
Dependent variable: LSOILC

        Mean of dep. var. = 9.51393
  Std. dev. of dep. var. = .311544
Sum of squared residuals = .560455
    Variance of residuals = .467046E-02
Std. error of regression = .068341
              R-squared = .951571
          Durbin-Watson = 1.80935 [<.779]


Equation: SGAS
Dependent variable: LSGASC

        Mean of dep. var. = 9.51859
  Std. dev. of dep. var. = .288909
Sum of squared residuals = .179297
    Variance of residuals = .149414E-02
Std. error of regression = .038654
              R-squared = .981949
          Durbin-Watson = 2.29087 [<1.00]
```

```
                        THREE STAGE LEAST SQUARES

 EQUATIONS: DOIL DGAS

 INSTRUMENTS: REGION2 REGION3 REGION4 REGION5 DG_DPTH DO_DPTH
      DG_DPTH(-1) DO_DPTH(-1) RPGAS RPOIL YEAR LDGASC(-1) LDOILC(-1)
      SUCWELL(-1)

                  Number of Observations =     80

                         Standard
 Parameter  Estimate       Error       t-statistic   P-value
 DOREG2     16.4358       2.96641       5.54064       [.000]
 DOREG3     16.2109       2.96659       5.46448       [.000]
 DOREG4     16.2038       2.96615       5.46292       [.000]
 DOREG5     16.4152       2.96584       5.53476       [.000]
 DODEPTH    -.108916E-04  .118388E-04   -.919992      [.358]
 DOWELL     .551732E-05   .675628E-06   8.16621       [.000]
 TECH       -.321269E-02  .148901E-02   -2.15760      [.031]
 DORHO      .655473       .062263       10.5275       [.000]
 DGREG2     15.8203       2.95966       5.34532       [.000]
 DGREG3     15.7774       2.95868       5.33259       [.000]
 DGREG4     15.7656       2.95892       5.32817       [.000]
 DGREG5     15.9259       2.95919       5.38187       [.000]
 DGDEPTH    .335244E-04   .439767E-05   7.62323       [.000]
 DGWELL     .458022E-05   .500397E-06   9.15317       [.000]
 DGRHO      .379875       .096118       3.95220       [.000]


 Standard Errors computed from   quadratic form of analytic first
 derivatives (Gauss)


 Equation: DOIL
 Dependent variable: LDOILC

        Mean of dep. var. = 9.97100
   Std. dev. of dep. var. = .158303
 Sum of squared residuals = .155270
     Variance of residuals = .194088E-02
 Std. error of regression = .044055
                R-squared = .921664
            Durbin-Watson = 1.81815 [<.791]


 Equation: DGAS
 Dependent variable: LDGASC

        Mean of dep. var. = 9.99262
   Std. dev. of dep. var. = .119709
 Sum of squared residuals = .076420
     Variance of residuals = .955244E-03
 Std. error of regression = .030907
                R-squared = .932548
            Durbin-Watson = 2.08376 [<.977]
```

Onshore Well Equations

Onshore Region 1 (r=1)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}DUM8184_t$$

```
Method of estimation = Ordinary Least Squares

 Dependent variable: WELLSON_{i,r,k,t}
 Current sample: 1980-1994
 Number of observations:  15

  Mean of dependent variable = 866.200
 Std. dev. of dependent var. = 739.264
    Sum of squared residuals = .101129E+07
        Variance of residuals = 84274.3
    Std. error of regression = 290.300
                   R-squared = .867825
          Adjusted R-squared = .845796
      Durbin-Watson statistic = 1.69858
   F-statistic (zero slopes) = 39.3944
  Schwarz Bayes. Info. Crit. = 11.6603
  Log of likelihood function = -104.674
```

Parameter	Estimated Value	Standard Error	t-statistic
$m0_{i,r,k}$	691.637	108.987	6.34607
$m1_{i,r,k}$	.161251E-02	.520009E-03	3.10093
$m2_{i,r,k}$	1030.89	208.938	4.93395

Shallow Oil Development(i=2, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + m2_{i,r,k}DUM86_t$$

```
Method of estimation = Ordinary Least Squares

 Dependent variable: WELLSON_{i,r,k,t}
 Current sample:  1981-1994
 Number of observations:  14

  Mean of dependent variable = 4704.14
 Std. dev. of dependent var. = 3643.78
    Sum of squared residuals = .933225E+07
        Variance of residuals = 848387.
    Std. error of regression = 921.079
                   R-squared = .945932
          Adjusted R-squared = .936102
      Durbin-Watson statistic = 1.47134
   F-statistic (zero slopes) = 96.2239
  Schwarz Bayes. Info. Crit. = 13.9754
  Log of likelihood function = -113.735
```

Parameter	Estimated Value	Standard Error	t-statistic
$m0_{i,r,k}$	8475.18	538.450	15.7399
$m1_{i,r,k}$	.031699	.014578	2.17441
$m2_{i,r,k}$	-5576.66	846.295	-6.58951

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}DUM8185_t + m3_{i,r,k}YEAR_t$$

```
Method of estimation = Ordinary Least Squares

 Dependent variable: WELLSON_{i,r,k,t}
 Current sample:  1980-1994
 Number of observations:  15

  Mean of dependent variable = 716.907          Adjusted R-squared = .981748
 Std. dev. of dependent var. = 450.048      Durbin-Watson statistic = 2.35625
    Sum of squared residuals = 40665.3      F-statistic (zero slopes) = 252.011
        Variance of residuals = 3696.85     Schwarz Bayes. Info. Crit. = 8.62723
    Std. error of regression = 60.8017      Log of likelihood function = -80.5722
                   R-squared = .985659
```

```
               Estimated    Standard
Parameter       Value        Error      t-statistic
m0_{i,r,k}      108260.      11982.8       9.03459
m1_{i,r,k}      .227959E-03  .114961E-03   1.98293
m2_{i,r,k}      428.155      44.4400       9.63445
m3_{i,r,k}      -54.2645     6.00625      -9.03467
```

Shallow Gas Development(i=2, k=3)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-2} + m2_{i,r,k}DUM8185_t + \rho SGDWELLS_{i,r,k,t-1}$$
$$- \rho(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-3} + m2_{i,r,k}DUM8185_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    3 ITERATIONS

Dependent variable: WELLSON_{i,r,k,t}
Current sample: 1982-1994
Number of observations:  13

(Statistics based on transformed data)     (Statistics based on original data)
 Mean of dependent variable = 1206.07       Mean of dependent variable = 770.631
Std. dev. of dependent var. = 549.098      Std. dev. of dependent var. = 389.627
   Sum of squared residuals = 87948.4          Sum of squared residuals = 91908.7
       Variance of residuals = 8794.84             Variance of residuals = 9190.87
   Std. error of regression = 93.7808        Std. error of regression = 95.8690
                  R-squared = .975916                        R-squared = .950471
          Adjusted R-squared = .971099            Adjusted R-squared = .940565
     Durbin-Watson statistic = 2.00075      Durbin-Watson statistic = 1.95442
ρ (autocorrelation coef.) = -.616559
       Standard error of ρ  = .236848
          t-statistic for ρ  = -2.60318
 F-statistic (zero slopes) = 200.695
Log of likelihood function = -76.0124

               Estimated    Standard
Parameter       Value        Error      t-statistic
m0_{i,r,k}      187.641      125.279      1.49778
m1_{i,r,k}      .207284E-02  .745156E-03  2.78175
m2_{i,r,k}      799.818      38.5324     20.7570
```

Onshore Region 2 (r=2)

Shallow Oil Exploratory(i=1, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t}$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample: 1980-1994
Number of observations:  15

 Mean of dependent variable = 439.333            Adjusted R-squared = .663771
Std. dev. of dependent var. = 277.671         Durbin-Watson statistic = 1.48575
   Sum of squared residuals = 337007.      F-statistic (zero slopes) = 28.6382
       Variance of residuals = 25923.6      Schwarz Bayes. Info. Crit. = 10.3809
   Std. error of regression = 161.008      Log of likelihood function = -96.4326
                  R-squared = .687787

               Estimated    Standard
Parameter        Value        Error      t-statistic
m0_{i,r,k}      -1.74650     92.3128      -.018919
m1_{i,r,k}      .231682E-03  .432932E-04   5.35147
```

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t}$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample: 1980-1994
Number of observations:  15

 Mean of dependent variable = 4111.20
Std. dev. of dependent var. = 2930.28
   Sum of squared residuals = .123017E+08
```

```
            Variance of residuals = 946285.
       Std. error of regression = 972.772
                     R-squared = .897667
            Adjusted R-squared = .889795
        Durbin-Watson statistic = 1.69316
     F-statistic (zero slopes) = 114.036
     Schwarz Bayes. Info. Crit. = 13.9783
     Log of likelihood function = -123.413


                  Estimated     Standard
Parameter           Value        Error       t-statistic
m0_{i,r,k}         -995.095      540.126       -1.84234
m1_{i,r,k}          .017907     .167691E-02    10.6787
```

Deep Oil Exploratory (i=1, k=2)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + m2_{i,r,k}YEAR_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1981-1994
Number of observations:  14

 Mean of dependent variable = 132.786          Adjusted R-squared = .897657
Std. dev. of dependent var. = 69.7878      Durbin-Watson statistic = 2.20893
   Sum of squared residuals = 5482.92     F-statistic (zero slopes) = 58.0116
       Variance of residuals = 498.447     Schwarz Bayes. Info. Crit. = 6.53585
    Std. error of regression = 22.3259     Log of likelihood function = -61.6575
                  R-squared = .913402


                  Estimated     Standard
Parameter           Value        Error       t-statistic
m0_{i,r,k}         30176.9       2966.17       10.1737
m1_{i,r,k}         .960199E-05  .410144E-05   2.34113
m2_{i,r,k}         -15.1233      1.49204       -10.1359
```

Deep Oil Development (i=2, k=2)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t}$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

 Mean of dependent variable = 406.467          Adjusted R-squared = .453641
Std. dev. of dependent var. = 155.147      Durbin-Watson statistic = 1.73075
   Sum of squared residuals = 170965.     F-statistic (zero slopes) = 12.6242
       Variance of residuals = 13151.2     Schwarz Bayes. Info. Crit. = 9.70224
    Std. error of regression = 114.679     Log of likelihood function = -91.3428
                  R-squared = .492666


                  Estimated     Standard
Parameter           Value        Error       t-statistic
m0_{i,r,k}         279.140       46.4862       6.00478
m1_{i,r,k}         .497098E-03  .139907E-03   3.55305
```

Deep Gas Exploratory (i=1, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + \rho_{i,r,k}WELLSON_{i,r,k,t-1} - \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER   10 ITERATIONS


Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

(Statistics based on transformed data)    (Statistics based on original data)
 Mean of dependent variable = 51.0914       Mean of dependent variable = 387.667
Std. dev. of dependent var. = 131.510      Std. dev. of dependent var. = 244.867
   Sum of squared residuals = 130251.         Sum of squared residuals = 142349.
       Variance of residuals = 10019.3           Variance of residuals = 10949.9
    Std. error of regression = 100.097        Std. error of regression = 104.642
                  R-squared = .474964                     R-squared = .854826
          Adjusted R-squared = .434577            Adjusted R-squared = .843659
      Durbin-Watson statistic = 1.87826      Durbin-Watson statistic = 1.63875
 ρ (autocorrelation coef.) = .837494
```

```
         Standard error of ρ  = .134319
            t-statistic for ρ  = 6.23511
  F-statistic (zero slopes) = 11.1662
  Log of likelihood function = -89.9072


                 Estimated    Standard
Parameter          Value       Error      t-statistic
m0_{i,r,k}         232.047    150.545      1.54138
m1_{i,r,k}        .940338E-05 .469833E-05  2.00143
```

Deep Gas Development (i=2, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + \rho_{i,r,k}WELLSON_{i,r,k,t-1} - \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    9 ITERATIONS


Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15


(Statistics based on transformed data)   (Statistics based on original data)
 Mean of dependent variable = 471.176     Mean of dependent variable = 809.933
Std. dev. of dependent var. = 233.852    Std. dev. of dependent var. = 287.576
   Sum of squared residuals = 310930.       Sum of squared residuals = 316443.
      Variance of residuals = 23917.7          Variance of residuals = 24341.8
    Std. error of regression = 154.654     Std. error of regression = 156.019
                  R-squared = .598991                     R-squared = .744125
         Adjusted R-squared = .568144            Adjusted R-squared = .724443
     Durbin-Watson statistic = 1.86778    Durbin-Watson statistic = 1.86325
 ρ (autocorrelation coef.) = .441622
      Standard error of ρ  = .247156
         t-statistic for ρ  = 1.78682
  F-statistic (zero slopes) = 19.0103
  Log of likelihood function = -95.9371


                 Estimated    Standard
Parameter          Value       Error      t-statistic
m0_{i,r,k}         520.893    111.709      4.66293
m1_{i,r,k}        .146519E-03 .429086E-04  3.41467
```

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + \rho_{i,r,k}WELLSON_{i,r,k,t-1} - \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    9 ITERATIONS


Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15


(Statistics based on transformed data)   (Statistics based on original data)
 Mean of dependent variable = 81.0795     Mean of dependent variable = 836.401
Std. dev. of dependent var. = 206.812    Std. dev. of dependent var. = 384.306
   Sum of squared residuals = 254655.       Sum of squared residuals = 369431.
      Variance of residuals = 19588.9          Variance of residuals = 28417.8
    Std. error of regression = 139.960     Std. error of regression = 168.576
                  R-squared = .636141                     R-squared = .825254
         Adjusted R-squared = .608152            Adjusted R-squared = .811812
     Durbin-Watson statistic = 1.84112    Durbin-Watson statistic = 1.42462
 ρ (autocorrelation coef.) = .883898
      Standard error of ρ  = .119232
         t-statistic for ρ  = 7.41325
  F-statistic (zero slopes) = 17.5682
  Log of likelihood function = -95.0912


                 Estimated    Standard
Parameter          Value       Error      t-statistic
m0_{i,r,k}         411.100    298.424      1.37757
m1_{i,r,k}        .168511E-03 .699565E-04  2.40879
```

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + \rho_{i,r,k}WELLSON_{i,r,k,t-1} - \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER   13 ITERATIONS
```

```
Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

(Statistics based on transformed data)      (Statistics based on original data)
 Mean of dependent variable = 220.255        Mean of dependent variable = 1077.77
Std. dev. of dependent var. = 350.319       Std. dev. of dependent var. = 471.403
   Sum of squared residuals = 616543.          Sum of squared residuals = 849696.
      Variance of residuals = 47426.4             Variance of residuals = 65361.2
    Std. error of regression = 217.776        Std. error of regression = 255.658
                  R-squared = .689101                        R-squared = .734204
         Adjusted R-squared = .665185              Adjusted R-squared = .713758
     Durbin-Watson statistic = 1.54547        Durbin-Watson statistic = 1.43185
ρ (autocorrelation coef.) = .777603
      Standard error of ρ   = .216052
         t-statistic for ρ  = 3.59915
 F-statistic (zero slopes) = 23.2273
 Log of likelihood function = -101.427

                 Estimated      Standard
Parameter         Value          Error       t-statistic
m0_{i,r,k}        152.967        387.393       .394862
m1_{i,r,k}        .219220E-02    .728766E-03   3.00811
```

Onshore Region 3 (r=3)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + m2_{i,r,k}YEAR_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1981-1994
Number of observations:  14

 Mean of dependent variable = 1331.29              Adjusted R-squared = .910253
Std. dev. of dependent var. = 723.429         Durbin-Watson statistic = 2.34550
   Sum of squared residuals = 516661.         F-statistic (zero slopes) = 66.9255
      Variance of residuals = 46969.2        Schwarz Bayes. Info. Crit. = 11.0816
    Std. error of regression = 216.724       Log of likelihood function = -93.4777
                  R-squared = .924060

                 Estimated      Standard
Parameter         Value          Error       t-statistic
m0_{i,r,k}        291835.        34095.3       8.55938
m1_{i,r,k}        .405770E-03    .213490E-03   1.90065
m2_{i,r,k}        -146.402       17.0871       -8.56797
```

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + \rho_{i,r,k}\ WELLSON_{i,r,k,t-1} - \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER   12 ITERATIONS

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

(Statistics based on transformed data)
 Mean of dependent variable = 536.810
Std. dev. of dependent var. = 2457.91
   Sum of squared residuals = .526887E+08
      Variance of residuals = .405298E+07
    Std. error of regression = 2013.20
                  R-squared = .397739
         Adjusted R-squared = .351411
     Durbin-Watson statistic = 1.48479
ρ (autocorrelation coef.) = .871289
      Standard error of ρ   = .110103
         t-statistic for ρ  = 7.91340
 F-statistic (zero slopes) = 7.86827
 Log of likelihood function = -135.035
(Statistics based on original data)
 Mean of dependent variable = 6911.33
Std. dev. of dependent var. = 5395.12
   Sum of squared residuals = .601903E+08
      Variance of residuals = .463002E+07
    Std. error of regression = 2151.75
```

```
                      R-squared = .858419
            Adjusted R-squared = .847528
      Durbin-Watson statistic = 1.12145

                Estimated    Standard
Parameter         Value       Error      t-statistic
m0_{i,r,k}        3201.65     3495.77      .915863
m1_{i,r,k}        .018192     .966255E-02  1.882730
```

Deep Oil Exploratory (i=1, k=2)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + m2_{i,r,k}DUM8084_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1981-1994
Number of observations:  14

 Mean of dependent variable = 25.9286           Adjusted R-squared = .843601
Std. dev. of dependent var. = 14.7151     Durbin-Watson statistic = 1.17276
   Sum of squared residuals = 372.521     F-statistic (zero slopes) = 36.0603
       Variance of residuals = 33.8656    Schwarz Bayes. Info. Crit. = 3.84675
    Std. error of regression = 5.81941    Log of likelihood function = -42.8338
                   R-squared = .867662

                Estimated    Standard
Parameter         Value       Error       t-statistic
m0_{i,r,k}        16.7054     1.89778       8.80261
m1_{i,r,k}        .342852E-05 .106370E-05   3.22319
m2_{i,r,k}        24.2414     3.55137       6.82592
```

Deep Oil Development (i=2, k=2)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-2} + m2_{i,r,k}DUM8185_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1982-1994
Number of observations:  13

 Mean of dependent variable = 151.000           Adjusted R-squared = .819355
Std. dev. of dependent var. = 97.6499     Durbin-Watson statistic = 2.66630
   Sum of squared residuals = 17225.4     F-statistic (zero slopes) = 28.2144
       Variance of residuals = 1722.54    Schwarz Bayes. Info. Crit. = 7.78110
    Std. error of regression = 41.5035    Log of likelihood function = -65.1759
                   R-squared = .849463

                Estimated    Standard
Parameter         Value       Error       t-statistic
m0_{i,r,k}        75.6157     17.2687       4.37876
m1_{i,r,k}        .129744E-03 .683919E-04   1.89707
m2_{i,r,k}        182.826     24.9538       7.32656
```

Deep Gas Exploratory (i=1, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}YR82_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

 Mean of dependent variable = 54.3333           Adjusted R-squared = .739336
Std. dev. of dependent var. = 54.8461     Durbin-Watson statistic = 1.53255
   Sum of squared residuals = 9409.23     F-statistic (zero slopes) = 20.8545
       Variance of residuals = 784.102    Schwarz Bayes. Info. Crit. = 6.98301
    Std. error of regression = 28.0018    Log of likelihood function = -69.5945
                   R-squared = .776574

                Estimated    Standard
Parameter         Value       Error       t-statistic
m0_{i,r,k}        35.9188     7.83466       4.58459
m1_{i,r,k}        .308770E-05 .926748E-06   3.33175
m2_{i,r,k}        183.143     29.7806       6.14975
```

Deep Gas Development (i=2, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + m2_{i,r,k}YR82_t + m3_{i,r,k}YEAR_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1981-1994
Number of observations:  14

 Mean of dependent variable = 418.857         Adjusted R-squared = .930168
Std. dev. of dependent var. = 221.719      Durbin-Watson statistic = 1.30189
    Sum of squared residuals = 34329.0      F-statistic (zero slopes) = 58.7202
        Variance of residuals = 3432.90     Schwarz Bayes. Info. Crit. = 8.55870
    Std. error of regression = 58.5909      Log of likelihood function = -74.4980
                    R-squared = .946283

                Estimated     Standard
Parameter         Value        Error      t-statistic
m0_{i,r,k}           57778.8     8941.68       6.46175
m1_{i,r,k}          .638779E-04 .284653E-04   2.24406
m2_{i,r,k}           382.279      71.9866      5.31042
m3_{i,r,k}          -28.8799      4.49756     -6.42124
```

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-2} + m2_{i,r,k}DUM8084_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1982-1994
Number of observations:  13

 Mean of dependent variable = 404.936         Adjusted R-squared = .762792
Std. dev. of dependent var. = 110.813      Durbin-Watson statistic = 2.72216
    Sum of squared residuals = 29128.1      F-statistic (zero slopes) = 20.2942
        Variance of residuals = 2912.81     Schwarz Bayes. Info. Crit. = 8.30642
    Std. error of regression = 53.9704      Log of likelihood function = -68.5905
                    R-squared = .802327

                Estimated     Standard
Parameter         Value        Error      t-statistic
m0_{i,r,k}           292.033      33.6368      8.68194
m1_{i,r,k}          .153403E-03 .695886E-04   2.20442
m2_{i,r,k}           231.639      36.5880      6.33100
```

Shallow Gas Development (i=2, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + m2_{i,r,k}DUM8082_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1981-1994
Number of observations:  14

 Mean of dependent variable = 2187.30
Std. dev. of dependent var. = 864.917
    Sum of squared residuals = .131082E+07
        Variance of residuals = 119166.
    Std. error of regression = 345.204
                    R-squared = .865212
            Adjusted R-squared = .840705
      Durbin-Watson statistic = 1.21818
   F-statistic (zero slopes) = 35.3047
   Schwarz Bayes. Info. Crit. = 12.0126
   Log of likelihood function = -99.9949

                Estimated     Standard
Parameter         Value        Error      t-statistic
m0_{i,r,k}           1115.00     201.292       5.53921
m1_{i,r,k}          .901429E-02 .195134E-02   4.61953
m2_{i,r,k}           2202.30     274.423       8.02518
```

Onshore Region 4 (r=4)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + \rho_{i,r,k}\ WELLSON_{i,r,k,t-1} - \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER   32 ITERATIONS

Dependent variable: WELLSON_{i,r,k,t}
Current sample: 1980-1994
Number of observations: 15

(Statistics based on transformed data)    (Statistics based on original data)
 Mean of dependent variable = 241.799      Mean of dependent variable = 1038.33
Std. dev. of dependent var. = 339.750     Std. dev. of dependent var. = 617.707
   Sum of squared residuals = 882458.        Sum of squared residuals = 888803.
      Variance of residuals = 67881.4           Variance of residuals = 68369.5
    Std. error of regression = 260.541       Std. error of regression = 261.476
                  R-squared = .455258                       R-squared = .846607
         Adjusted R-squared = .413355              Adjusted R-squared = .834807
     Durbin-Watson statistic = 1.97106       Durbin-Watson statistic = 1.91931
 ρ (autocorrelation coef.) = .757445
        Standard error of ρ  = .157843
           t-statistic for ρ = 4.79874
  F-statistic (zero slopes) = 10.8066
 Log of likelihood function = -104.079

                   Estimated    Standard
Parameter            Value       Error      t-statistic
m0_{i,r,k}          712.398     263.756      2.70097
m1_{i,r,k}          .677494E-03 .292467E-03  2.31648
```

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + m2_{i,r,k}DUM8184_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample: 1981-1994
Number of observations: 14

 Mean of dependent variable = 6370.86
Std. dev. of dependent var. = 3672.46
   Sum of squared residuals = .375562E+08
      Variance of residuals = .341420E+07
    Std. error of regression = 1847.75
                  R-squared = .785798
         Adjusted R-squared = .746853
    Durbin-Watson statistic = 1.84047
  F-statistic (zero slopes) = 20.1767
 Schwarz Bayes. Info. Crit. = 15.3678
 Log of likelihood function = -123.481

                   Estimated    Standard
Parameter            Value       Error      t-statistic
m0_{i,r,k}          2820.62     964.782      2.92358
m1_{i,r,k}          .014602     .663741E-02  2.20002
m2_{i,r,k}          7231.05     1140.65      6.33942
```

Deep Oil Exploratory (i=1, k=2)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + \rho_{i,r,k}\ WELLSON_{i,r,k,t-1} - \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-2})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    5 ITERATIONS

Dependent variable: WELLSON_{i,r,k,t}
Current sample: 1981-1994
Number of observations: 14

(Statistics based on transformed data)    (Statistics based on original data)
 Mean of dependent variable = 17.2519      Mean of dependent variable = 99.9286
Std. dev. of dependent var. = 31.3842     Std. dev. of dependent var. = 46.6121
   Sum of squared residuals = 5833.14        Sum of squared residuals = 6863.24
      Variance of residuals = 486.095           Variance of residuals = 571.937
    Std. error of regression = 22.0476       Std. error of regression = 23.9152
                  R-squared = .573583                       R-squared = .759818
         Adjusted R-squared = .538049              Adjusted R-squared = .739802
     Durbin-Watson statistic = 1.93281       Durbin-Watson statistic = 1.71538
```

```
           ρ (autocorrelation coef.) = .823389
              Standard error of ρ   = .145243
                 t-statistic for ρ  = 5.66903
        F-statistic (zero slopes) = 14.3418
        Log of likelihood function = -62.6575


                     Estimated    Standard
Parameter             Value        Error        t-statistic
m0_{i,r,k}             72.5471      28.4839        2.54695
m1_{i,r,k}             .850046E-05 .325929E-05    2.60807
```

Deep Oil Development (i=2, k=2)

$$LNWELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}YEAR_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: LNWELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

 Mean of dependent variable = 5.14976            Adjusted R-squared = .601020
Std. dev. of dependent var. = .527130      Durbin-Watson statistic = 1.32222
    Sum of squared residuals = 1.33036    F-statistic (zero slopes) = 11.5448
       Variance of residuals = .110863    Schwarz Bayes. Info. Crit. = -1.88099
     Std. error of regression = .332961    Log of likelihood function = -3.11455
                    R-squared = .658017


                     Estimated    Standard
Parameter             Value        Error        t-statistic
m0_{i,r,k}            184.683       39.9989        4.61719
m1_{i,r,k}            .720882E-06  .303480E-06    2.37539
m2_{i,r,k}            -.090484     .020139        -4.49306
```

Deep Gas Exploratory (i=1, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}YR82_t + \rho_{i,r,k} WELLSON_{i,r,k,t-1}$$
$$- \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1} + m2_{i,r,k}YR82_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER   33 ITERATIONS

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

(Statistics based on transformed data)   (Statistics based on original data)
 Mean of dependent variable = 13.0217     Mean of dependent variable = 46.0000
Std. dev. of dependent var. = 28.6707    Std. dev. of dependent var. = 41.0331
    Sum of squared residuals = 2192.03        Sum of squared residuals = 2435.18
       Variance of residuals = 182.669           Variance of residuals = 202.932
     Std. error of regression = 13.5155        Std. error of regression = 14.2454
                    R-squared = .813279                        R-squared = .900654
            Adjusted R-squared = .782159            Adjusted R-squared = .884097
      Durbin-Watson statistic = 1.83921      Durbin-Watson statistic = 1.81918
    ρ (autocorrelation coef.) = .689546
              Standard error of ρ   = .207809
                 t-statistic for ρ  = 3.31818
        F-statistic (zero slopes) = 25.4999
        Log of likelihood function = -58.9907


                     Estimated    Standard
Parameter             Value        Error        t-statistic
m0_{i,r,k}            18.2101      12.7659        1.42647
m1_{i,r,k}            .118730E-05  .330892E-06    3.58816
m2_{i,r,k}            80.3608      12.8874        6.23559
```

Deep Gas Development (i=2, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}DUM8082_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

 Mean of dependent variable = 81.0667            Adjusted R-squared = .952218
Std. dev. of dependent var. = 59.0272      Durbin-Watson statistic = 2.07278
```

```
        Sum of squared residuals = 1997.80     F-statistic (zero slopes) = 140.498
           Variance of residuals = 166.484     Schwarz Bayes. Info. Crit. = 5.43336
       Std. error of regression = 12.9029     Log of likelihood function = -57.9722
                        R-squared = .959044

                   Estimated     Standard
Parameter            Value        Error        t-statistic
m0_{i,r,k}           33.8073      5.86379       5.76543
m1_{i,r,k}           .732591E-05  .162962E-05   4.49548
m2_{i,r,k}           134.447      8.32876       16.1425
```

Shallow Gas Exploratory (i=1, k=3)

$$LNWELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}YEAR_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: LNWELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

 Mean of dependent variable = 5.92941            Adjusted R-squared = .927499
Std. dev. of dependent var. = .776926        Durbin-Watson statistic = 1.80213
   Sum of squared residuals = .525151         F-statistic (zero slopes) = 90.5504
       Variance of residuals = .043763        Schwarz Bayes. Info. Crit. = -2.81051
      Std. error of regression = .209195      Log of likelihood function = 3.85682
                        R-squared = .937856

                   Estimated     Standard
Parameter            Value        Error        t-statistic
m0_{i,r,k}           324.918      24.9038       13.0469
m1_{i,r,k}           .113354E-05  .353256E-06   3.20884
m2_{i,r,k}           -.160516     .012534       -12.8067
```

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}YEAR_t + m3_{i,r,k}DUM8082_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

 Mean of dependent variable = 609.951            Adjusted R-squared = .933044
Std. dev. of dependent var. = 382.393        Durbin-Watson statistic = 2.34778
   Sum of squared residuals = 107696.         F-statistic (zero slopes) = 66.0313
       Variance of residuals = 9790.53        Schwarz Bayes. Info. Crit. = 9.60116
      Std. error of regression = 98.9471      Log of likelihood function = -87.8767
                        R-squared = .947392

                   Estimated     Standard
Parameter            Value        Error        t-statistic
m0_{i,r,k}           107995.      18917.3       5.70881
m1_{i,r,k}           .241097E-02  .660128E-03   3.65228
m2_{i,r,k}           -54.0793     9.51212       -5.68530
m3_{i,r,k}           313.510      102.046       3.07223
```

Onshore Region 5 (r=5)

Total Oil Exploratory (i=1, k=1 and k=2)

$$OWELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}ODCFON_{i,r,k,t-1} + m2_{i,r,k}YEAR_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: OWELLSON_{i,r,k,t}
Current sample:  1982-1994
Number of observations:  13

 Mean of dependent variable = 761.000            Adjusted R-squared = .911076
Std. dev. of dependent var. = 441.875        Durbin-Watson statistic = 2.13801
   Sum of squared residuals = 173628.         F-statistic (zero slopes) = 62.4731
       Variance of residuals = 17362.8        Schwarz Bayes. Info. Crit. = 10.0916
      Std. error of regression = 131.768      Log of likelihood function = -80.1944
                        R-squared = .925896

                   Estimated     Standard
Parameter            Value        Error        t-statistic
m0_{i,r,k}              181357.      21613.1        8.39107
```

```
m1_i,r,k                        .145239E-03 .484006E-04   3.00077
m2_i,r,k                        -90.9975    10.8493       -8.38743
```

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + \rho_{i,r,k} \; WELLSON_{i,r,k,t-1} - \rho_{i,r,k}(m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    6 ITERATIONS


Dependent variable: WELLSON_i,r,k,t
Current sample: 1980-1994
Number of observations:  15


(Statistics based on transformed data)
 Mean of dependent variable = 198.714
Std. dev. of dependent var. = 487.786
   Sum of squared residuals = .217916E+07
      Variance of residuals = 167627.
  Std. error of regression = 409.423
                 R-squared = .357759
         Adjusted R-squared = .308355
  Durbin-Watson statistic = 2.04554
 ρ (autocorrelation coef.) = .811189
       Standard error of ρ  = .140535
          t-statistic for ρ  = 5.77216
 F-statistic (zero slopes) = 6.87203
Log of likelihood function = -110.969
(Statistics based on original data)
 Mean of dependent variable = 1192.73
Std. dev. of dependent var. = 838.284
   Sum of squared residuals = .231530E+07
      Variance of residuals = 178100.
   Std. error of regression = 422.019
                 R-squared = .772354
         Adjusted R-squared = .754843
   Durbin-Watson statistic = 1.86703


               Estimated    Standard
Parameter        Value       Error      t-statistic
m0_i,r,k         532.970     530.425     1.00480
m1_i,r,k         .238036E-02 .116839E-02 2.03729
```

Deep Oil Development (i=2, k=2)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}YEAR_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_i,r,k,t
Current sample: 1980-1994
Number of observations:  15

 Mean of dependent variable = 164.667        Adjusted R-squared = .816386
Std. dev. of dependent var. = 103.712        Durbin-Watson statistic = 2.32745
   Sum of squared residuals = 23699.6        F-statistic (zero slopes) = 32.1235
      Variance of residuals = 1974.97        Schwarz Bayes. Info. Crit. = 7.90677
   Std. error of regression = 44.4406        Log of likelihood function = -76.5228
                 R-squared = .842617


               Estimated    Standard
Parameter        Value       Error      t-statistic
m0_i,r,k         36813.4     5346.90     6.88499
m1_i,r,k         .217157E-03 .724417E-04 2.99768
m2_i,r,k         -18.4728    2.68942     -6.86872
```

Deep Gas Exploratory (i=1, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}DUM8182_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_i,r,k,t
Current sample: 1980-1994
Number of observations:  15

 Mean of dependent variable = 49.6000        Adjusted R-squared = .853328
Std. dev. of dependent var. = 43.1191        Durbin-Watson statistic = 1.31012
   Sum of squared residuals = 3272.40        F-statistic (zero slopes) = 41.7256
      Variance of residuals = 272.700        Schwarz Bayes. Info. Crit. = 5.92684
```

```
      Std. error of regression = 16.5136      Log of likelihood function = -61.6733
                    R-squared = .874281

                 Estimated    Standard
Parameter          Value       Error        t-statistic
m0_{i,r,k}         33.2905     4.63347       7.18478
m1_{i,r,k}         .138592E-05 .693578E-06   1.99822
m2_{i,r,k}         106.179     12.8555       8.25941
```

Deep Gas Development i=2, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}YEAR_t + m3_{i,r,k}TREND89_t + m4_{i,r,k}DUM8588_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

  Mean of dependent variable = 104.533           Adjusted R-squared = .676028
Std. dev. of dependent var. = 62.9533        Durbin-Watson statistic = 1.23263
   Sum of squared residuals = 12839.4        F-statistic (zero slopes) = 8.30340
       Variance of residuals = 1283.94       Schwarz Bayes. Info. Crit. = 7.65491
     Std. error of regression = 35.8321      Log of likelihood function = -71.9258
                    R-squared = .768591

                 Estimated    Standard
Parameter          Value       Error        t-statistic
m0_{i,r,k}         -12823.9    4464.86       -2.87218
m1_{i,r,k}         .225383E-04 .129048E-04   1.74650
m2_{i,r,k}         6.51503     2.24587       2.90090
m3_{i,r,k}         -.036423    .019420       -1.87553
m4_{i,r,k}         -68.9619    26.6921       -2.58361
```

Shallow Gas Exploratory (i=1, k=3)

$$LNWELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}DUM8081_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: LNWELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

  Mean of dependent variable = 5.72082           Adjusted R-squared = .734225
Std. dev. of dependent var. = .527038        Durbin-Watson statistic = 1.26455
   Sum of squared residuals = .885888        F-statistic (zero slopes) = 20.3381
       Variance of residuals = .073824       Schwarz Bayes. Info. Crit. = -2.28761
     Std. error of regression = .271706      Log of likelihood function = -.064963
                    R-squared = .772193

                 Estimated    Standard
Parameter          Value       Error        t-statistic
m0_{i,r,k}         5.39432     .099335       54.3044
m1_{i,r,k}         .569277E-06 .222253E-06   2.56139
m2_{i,r,k}         1.27403     .208107       6.12200
```

Shallow Gas Development (i=2, k=4)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}GDCFON_{i,r,k,t-2} + m2_{i,r,k}DUM9294_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1983-1994
Number of observations:  12

  Mean of dependent variable = 530.980           Adjusted R-squared = .867207
Std. dev. of dependent var. = 429.140        Durbin-Watson statistic = 2.15657
   Sum of squared residuals = 220098.        F-statistic (zero slopes) = 36.9177
       Variance of residuals = 24455.3       Schwarz Bayes. Info. Crit. = 10.4381
     Std. error of regression = 156.382      Log of likelihood function = -75.9288
                    R-squared = .891351

                 Estimated    Standard
Parameter          Value       Error        t-statistic
m0_{i,r,k}         176.320     65.8773       2.67649
m1_{i,r,k}         .262703E-03 .540270E-04   4.86244
m2_{i,r,k}         358.223     158.888       2.25456
```

Onshore Region 6 (r=6)

Shallow Oil Exploratory (i=1, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-2}$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1983-1994
Number of observations:  12

 Mean of dependent variable = 43.9167          Adjusted R-squared = .670476
Std. dev. of dependent var. = 33.5951      Durbin-Watson statistic = 1.46277
   Sum of squared residuals = 3719.10       F-statistic (zero slopes) = 23.3815
       Variance of residuals = 371.910      Schwarz Bayes. Info. Crit. = 6.15048
    Std. error of regression = 19.2850      Log of likelihood function = -51.4452
                   R-squared = .700433

                 Estimated    Standard
Parameter          Value       Error      t-statistic
m0_{i,r,k}          8.49242     9.20120      .922969
m1_{i,r,k}          .300322E-04 .621086E-05  4.83544
```

Shallow Oil Development (i=2, k=1)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t} + m2_{i,r,k}DUM8485_t + m3_{i,r,k}DUM9294_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1980-1994
Number of observations:  15

 Mean of dependent variable = 1776.67          Adjusted R-squared = .903631
Std. dev. of dependent var. = 671.564      Durbin-Watson statistic = 2.58759
   Sum of squared residuals = 478084.      F-statistic (zero slopes) = 44.7584
       Variance of residuals = 43462.1     Schwarz Bayes. Info. Crit. = 11.0916
    Std. error of regression = 208.476      Log of likelihood function = -99.0553
                   R-squared = .924282

                 Estimated    Standard
Parameter          Value       Error      t-statistic
m0_{i,r,k}         1510.83     153.999      9.81067
m1_{i,r,k}          .128263E-02 .517766E-03  2.47724
m2_{i,r,k}          901.864    170.053      5.30342
m3_{i,r,k}         -911.509    153.877     -5.92361
```

Shallow Gas Exploratory (i=1, k=3)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}RDCFON_{i,r,t-1}$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1981-1994
Number of observations:  14

 Mean of dependent variable = 101.714          Adjusted R-squared = .225785
Std. dev. of dependent var. = 40.0085      Durbin-Watson statistic = 1.26695
   Sum of squared residuals = 14871.3      F-statistic (zero slopes) = 4.79120
       Variance of residuals = 1239.27     Schwarz Bayes. Info. Crit. = 7.34514
    Std. error of regression = 35.2033      Log of likelihood function = -68.6420
                   R-squared = .285340

                 Estimated    Standard
Parameter          Value       Error      t-statistic
m0_{i,r,k}         55.0794      23.2903      2.36491
m1_{i,r,k}          .270208E-04 .123446E-04  2.18888
```

Shallow Gas Development (i=2, k=3)

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}DCFON_{i,r,k,t-2}$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSON_{i,r,k,t}
Current sample:  1983-1994
Number of observations:  12
```

```
 Mean of dependent variable = 77.9167          Adjusted R-squared = .622272
Std. dev. of dependent var. = 34.7313     Durbin-Watson statistic = 1.28137
   Sum of squared residuals = 4556.40     F-statistic (zero slopes) = 19.1215
       Variance of residuals = 455.640     Schwarz Bayes. Info. Crit. = 6.35353
    Std. error of regression = 21.3457     Log of likelihood function = -52.6635
                   R-squared = .656611
```

```
              Estimated     Standard
Parameter       Value        Error       t-statistic
m0_{i,r,k}      -70.5358     34.5036      -2.04430
m1_{i,r,k}      .300083E-03  .686247E-04  4.37281
```

Offshore Well Equations

Shallow Gulf of Mexico Offshore (r=9)

Oil Exploratory (i=1, k=1)

$$\text{WELLSOFF}_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k}\text{DCFOFF}_{i,r,k,t}$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSOFF_{i,r,k,t}
Current sample: 1976-1995
Number of observations:  20
```

```
 Mean of dependent variable = 45.9500          Adjusted R-squared = .293567
Std. dev. of dependent var. = 23.8581     Durbin-Watson statistic = 2.31070
   Sum of squared residuals = 7237.93     F-statistic (zero slopes) = 8.89570
       Variance of residuals = 402.107     Schwarz Bayes. Info. Crit. = 6.19093
    Std. error of regression = 20.0526     Log of likelihood function = -87.2923
                   R-squared = .330748
```

```
              Estimated     Standard
Parameter       Value        Error       t-statistic
α0_{i,r,k}      69.0298      8.94347      7.71846
α1_{i,r,k}      .145046E-05  .486313E-06  2.98257
```

Gas Exploratory (i=1, k=3)

$$\text{WELLSOFF}_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k}\text{DCFOFF}_{i,r,k,t} + \alpha 2_{i,r,k}\text{DUM8890}_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSOFF_{i,r,k,t}
Current sample: 1976-1995
Number of observations:  20
```

```
 Mean of dependent variable = 242.200          Adjusted R-squared = .823507
Std. dev. of dependent var. = 69.3318     Durbin-Watson statistic = 1.67735
   Sum of squared residuals = 14422.5     F-statistic (zero slopes) = 45.3265
       Variance of residuals = 848.385     Schwarz Bayes. Info. Crit. = 7.03018
    Std. error of regression = 29.1270     Log of likelihood function = -94.1869
                   R-squared = .842085
```

```
              Estimated     Standard
Parameter       Value        Error       t-statistic
α0_{i,r,k}      290.664      12.5901      23.0866
α1_{i,r,k}      .529655E-05  .817187E-06  6.48144
α2_{i,r,k}      168.474      19.3189      8.72066
```

Oil Development (i=2, k=1)

$$\text{WELLSOFF}_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k}\text{DCFOFF}_{i,r,k,t} + \alpha 2_{i,r,k}\text{DUM89}_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSOFF_{i,r,k,t}
Current sample: 1976-1995
Number of observations:  20
```

```
 Mean of dependent variable = 214.400          Adjusted R-squared = .728374
Std. dev. of dependent var. = 92.5245     Durbin-Watson statistic = 1.66187
   Sum of squared residuals = 39530.6     F-statistic (zero slopes) = 26.4745
       Variance of residuals = 2325.33     Schwarz Bayes. Info. Crit. = 8.03846
    Std. error of regression = 48.2217     Log of likelihood function = -104.270
                   R-squared = .756966
```

```
              Estimated    Standard
Parameter       Value       Error      t-statistic
α0_{i,r,k}      317.289     20.3162      15.6175
α1_{i,r,k}      .265583E-04 .781357E-05  3.39900
α2_{i,r,k}      -95.2872    26.9976      -3.52947
```

Gas Development (i=2, k=3)

$$\text{WELLSOFF}_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k}\text{DCFOFF}_{i,r,k,t} + \alpha 2_{i,r,k}\text{DUM7781}_t$$

```
Method of estimation = Ordinary Least Squares

Dependent variable: WELLSOFF_{i,r,k,t}
Current sample: 1976-1995
Number of observations:  20

 Mean of dependent variable = 304.600        Adjusted R-squared = .756496
Std. dev. of dependent var. = 123.480    Durbin-Watson statistic = 1.59134
   Sum of squared residuals = 63117.3    F-statistic (zero slopes) = 30.5137
       Variance of residuals = 3712.78   Schwarz Bayes. Info. Crit. = 8.50638
    Std. error of regression = 60.9326   Log of likelihood function = -108.949
                  R-squared = .782128

              Estimated    Standard
Parameter       Value       Error      t-statistic
α0_{i,r,k}      324.909     26.1568      12.4216
α1_{i,r,k}      .305109E-04 .851119E-05  3.58479
α2_{i,r,k}      223.279     31.4949      7.08937
```

Pacific Offshore (r=8)

Oil Development (i=2, k=1)

$$\text{WELLSOFF}_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k}\text{DCFOFF}_{i,r,k,t} + \rho_{i,r,k}\text{WELLSOFF}_{i,r,k,t-1} - \rho_{i,r,k}(\alpha 0_{i,r,k} + \alpha 1_{i,r,k}\text{DCFOFF}_{i,r,k,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER   13 ITERATIONS

Dependent variable: WELLSOFF_{i,r,k,t}
Current sample: 1976-1995
Number of observations:  20

(Statistics based on transformed data)    (Statistics based on original data)
 Mean of dependent variable = 18.3187       Mean of dependent variable = 50.9500
Std. dev. of dependent var. = 22.9640      Std. dev. of dependent var. = 37.7631
   Sum of squared residuals = 8201.92         Sum of squared residuals = 8575.41
       Variance of residuals = 455.662            Variance of residuals = 476.412
    Std. error of regression = 21.3462        Std. error of regression = 21.8269
                  R-squared = .192233                      R-squared = .684233
          Adjusted R-squared = .147357              Adjusted R-squared = .666691
   Durbin-Watson statistic = 2.11893         Durbin-Watson statistic = 2.08930
 ρ (autocorrelation coef.) = .649205
        Standard error of ρ   = .171663
          t-statistic for ρ   = 3.78186
 F-statistic (zero slopes) = 3.98903
 Log of likelihood function = -88.8163


              Estimated    Standard
Parameter       Value       Error      t-statistic
α0_{i,r,k}      71.1593     16.6760      4.26718
α1_{i,r,k}      .839564E-05 .366655E-05  2.28980
```

Finding Rate Equations

Extensions

Onshore Shallow Oil (k=1, r=1 thru 6)

$$\begin{aligned}
\text{FR2}_{r,k,t} = {} & \delta 01_k\text{REG1}_r + \delta 02_k\text{REG2}_r + \delta 03_k\text{REG3}_r + \delta 04_k\text{REG4}_r + \delta 05_k\text{REG5}_r + \delta 06_k\text{REG6}_r \\
& + \delta 1_k\text{CUMSW2}_{r,k,t-1} + \delta 2_k\text{SW2}_{r,k,t} + \delta 3_k\text{YEAR}_t + \rho_k\text{FR2}_{r,k,t-1} \\
& - \rho_k(\delta 01_k\text{REG1}_r + \delta 02_k\text{REG2}_r + \delta 03_k\text{REG3}_r + \delta 04_k\text{REG4}_r + \delta 05_k\text{REG5}_r \\
& + \delta 06_k\text{REG6}_r + \delta 1_k\text{CUMSW2}_{r,k,t-2} + \delta 2_k\text{SW2}_{r,k,t-1} + \delta 3_k\text{YEAR}_{t-1})
\end{aligned}$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER 4 ITERATIONS

Dependent variable: FR2
Number of observations:  78

(Statistics based on transformed data)   (Statistics based on original data)
 Mean of dependent variable = -4.43906    Mean of dependent variable = -5.92048
Std. dev. of dependent var. = 2.83643    Std. dev. of dependent var. = 3.58544
   Sum of squared residuals = 71.1872       Sum of squared residuals = 71.6048
        Variance of residuals = 1.03170         Variance of residuals = 1.03775
      Std. error of regression = 1.01573     Std. error of regression = 1.01870
                   R-squared = .885211                     R-squared = .927682
            Adjusted R-squared = .871902            Adjusted R-squared = .919298
       Durbin-Watson statistic = 1.85255       Durbin-Watson statistic = 1.84622
Rho (autocorrelation coef.) = .264862
        Standard error of rho = .116877
             t-statistic for rho = 2.26615
 F-statistic (zero slopes) = 66.4323
 Log of likelihood function = -107.331


            Estimated      Standard
Variable   Coefficient      Error        t-statistic
δ01        -182.660        61.2392        -2.98273
δ02        -180.267        61.2957        -2.94094
δ03        -181.736        61.2551        -2.96687
δ04        -179.809        61.0124        -2.94709
δ05        -180.669        61.1767        -2.95324
δ06        -181.017        61.5678        -2.94012
δ1         -.115113E-02    .474231E-03    -2.42737
δ2         -.127988E-02    .717999E-03    -1.78257
δ3         .090704         .030972         2.92857
```

Onshore Deep Oil (k=2, r=2 thru 5)

$$FR2_{r,k,t} = \delta02_k REG2_r + \delta03_k REG3_r + \delta04_k REG4_r + \delta05_k REG5_r + \delta1_k CUMSW2_{r,k,t-1} + \delta2_k SW2_{r,k,t} + \delta3_k YEAR_t$$

```
                    Method of estimation = Ordinary Least Squares

Dependent variable: FR2
Number of observations:  37

 Mean of dependent variable = -1.4543007757
Std. dev. of dependent var. = .95074956951
   Sum of squared residuals = 4.2497244175
        Variance of residuals = .14165748058
      Std. error of regression = .37637412316
                   R-squared = .86940516754
            Adjusted R-squared = .84328620105
       Durbin-Watson statistic = 2.1530048711
 F-statistic (zero slopes) = 33.286354107
 Schwarz Bayes. Info. Crit. = -1.4809171426
 Log of likelihood function = -12.465545896


            Estimated      Standard
Variable   Coefficient      Error        t-statistic
δ2         -293.448        92.9438        -3.15726
δ3         -295.819        93.3664        -3.16837
δ4         -294.780        93.0478        -3.16805
δ5         -293.430        92.5932        -3.16902
δ1         -.376199E-02    .1408405E-02   -2.67110
δ2         -.024597        .570730E-02    -4.30989
δ3         .148902         .04715          3.15782
```

Onshore Shallow Gas (k=3, r=1 thru 6)

$$FR2_{r,k,t} = \delta01_k REG1_r + \delta02_k REG2_r + \delta03_k REG3_r + \delta04_k REG4_r + \delta05_k REG5_r + \delta06_k REG6_r$$
$$+ \delta1_k CUMSW1_{r,k,t-1} + \delta2_k CUMSW2_{r,k,t} + \delta3_k SW2_{r,k,t} + \delta4_k YEAR_t$$

```
                    Method of estimation = Ordinary Least Squares

Dependent variable: FR2
Number of observations:  78

 Mean of dependent variable = 1.79246              Adjusted R-squared = .873510
Std. dev. of dependent var. = 2.99209        Durbin-Watson statistic = 1.65575
   Sum of squared residuals = 77.0044        F-statistic (zero slopes) = 60.0825
```

```
              Variance of residuals = 1.13242      Schwarz Bayes. Info. Crit. = .545706
          Std. error of regression = 1.06415      Log of likelihood function = -110.176
                      R-squared = .888294

                  Estimated     Standard
     Variable     Coefficient    Error       t-statistic
     δ01          -117.680      54.9294       -2.14239
     δ02          -123.042      55.6660       -2.21037
     δ03          -123.099      55.9312       -2.20089
     δ04          -124.772      56.0192       -2.22731
     δ05          -121.500      55.8478       -2.17555
     δ06          -123.115      55.9134       -2.20189
     δ1           .135637E-02   .326017E-03    4.16044
     δ2           -.208370E-02  .434272E-03   -4.79815
     δ3           -.010866      .139171E-02   -7.80771
     δ4           .062119       .028181        2.20427
```

Onshore Deep Gas (k=4, r=2 thru 4)

$$FR2_{r,k,t} = \delta02_k REG2_r + \delta03_k REG3_r + \delta04_k REG4_r + \delta1_k CUMSW2_{r,k,t-1} + \delta2_k SW2_{r,k,t} + \delta3_k YEAR_t$$

```
                          Method of estimation = Ordinary Least Squares

     Dependent variable: FR2
     Number of observations:  39

      Mean of dependent variable = 2.76471            Adjusted R-squared = .722033
     Std. dev. of dependent var. = .729370       Durbin-Watson statistic = 1.66835
         Sum of squared residuals = 4.87981       F-statistic (zero slopes) = 20.7413
              Variance of residuals = .147873     Schwarz Bayes. Info. Crit. = -1.51483
         Std. error of regression = .384543       Log of likelihood function = -14.8087
                      R-squared = .758607

                  Estimated     Standard
     Variable     Coefficient    Error       t-statistic
     δ02          -84.9000      49.1192       -1.72845
     δ03          -86.7281      48.9406       -1.77211
     δ04          -88.1140      48.9236       -1.80105
     δ1           -.118489E-02  .649976E-03   -1.82297
     δ2           -.011556      .459332E-02   -2.51586
     δ3           .045939       .024598        1.86755
```

Revisions

Onshore Shallow Oil (k=1, r=1 thru 6)

$$FR3_{r,k,t} = \delta0_k + \delta1_k CUMSW3_{r,k,t-1} + \delta2_k CUMRES2_{r,k,t-1} + \delta3_k SW3_{i,r,k,t} + \delta4_k YEAR_t + \delta5_k REG5\_89_t$$
$$+ \delta6_k REG5\_90_t + \rho_k FR3_{r,k,t-1} - \rho_k(\delta0_k + \delta1_k CUMSW3_{r,k,t-2} + \delta2_k CUMRES2_{r,k,t-2}$$
$$+ \delta3_k SW3_{r,k,t-1} + \delta4_k YEAR_{t-1} + \delta5_k REG5\_89_{t-1} + \delta6_k REG5\_90_{t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    7 ITERATIONS

CORRECTION FOR HETEROSCEDASTIC ERROR STRUCTURE

Dependent variable: FR3
Number of observations:  66 (Pooled Sample: 1984-1994 for 6 onshore regions)

(Statistics based on transformed data)      (Statistics based on original data)
 Mean of dependent variable = .536731        Mean of dependent variable = 1.71348
Std. dev. of dependent var. = 1.05644       Std. dev. of dependent var. = 1.63570
    Sum of squared residuals = 27.9541           Sum of squared residuals = 29.3000
         Variance of residuals = .473798            Variance of residuals = .496609
    Std. error of regression = .688330        Std. error of regression = .704705
                  R-squared = .615852                       R-squared = .832086
        Adjusted R-squared = .576786              Adjusted R-squared = .815010
    Durbin-Watson statistic = 1.14220         Durbin-Watson statistic = 1.11963
 ρ (autocorrelation coef.) = .736690
       Standard error of rho = .082926
        t-statistic for rho = 8.88367
 F-statistic (zero slopes) = 15.6854
 Log of likelihood function = -67.6472

           Estimated     Standard
Parameter    Value        Error       t-statistic
δ0          -1.83443      7.57319       -.242227
δ1          -.217240E-05  .953289E-06   -2.27885
δ2          .100350E-03   .375885E-04    2.66971
δ3          -.472346E-05  .363227E-05   -1.30041
```

```
δ4           .964787E-03  .381248E-02   .253060
δ5           .131625      .027710      4.75003
δ6           .259405      .027675      9.37319
```

Onshore Deep Oil (k=2, r=2 thru 5)

$$FR3_{r,k,t} = \delta 02_k REG2_r + \delta 03_k REG3_r + \delta 04_k REG4_r + \delta 05_k REG5_r + \delta 1_k CUMSW3_{r,k,t-1}$$
$$+ \delta 2_k CUMRES2_{r,k,t-1} + \delta 3_k SW3_{r,k,t} + \delta 4_k YEAR_t + \rho_k FR3_{r,k,t-1}$$
$$- \rho_k(\delta 02_k REG2_r + \delta 03_k REG3_r + \delta 04_k REG4_r + \delta 05_k REG5_r + \delta 1_k CUMSW3_{r,k,t-2}$$
$$+ \delta 2_k CUMRES2_{r,k,t-2} + \delta 3_k SW3_{r,k,t-1} + \delta 4_k YEAR_{t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    7 ITERATIONS

CORRECTION FOR HETEROSCEDASTIC ERROR STRUCTURE

Dependent variable: FR3
Number of observations:  44 (Pooled Sample: 1984-1994 for 4 onshore regions)

(Statistics based on transformed data)
 Mean of dependent variable = .018755
Std. dev. of dependent var. = .029913
   Sum of squared residuals = .023379
      Variance of residuals = .649425E-03
  Std. error of regression = .025484
                 R-squared = .392824
         Adjusted R-squared = .274762
   Durbin-Watson statistic = 1.37401
 ρ (autocorrelation coef.) = .521736
      Standard error of rho = .139310
        t-statistic for rho = 3.74515
 F-statistic (zero slopes) = 3.32093
Log of likelihood function = 102.813
(Statistics based on original data)
 Mean of dependent variable = .037592
Std. dev. of dependent var. = .044100
   Sum of squared residuals = .023514
      Variance of residuals = .653174E-03
  Std. error of regression = .025557
                 R-squared = .720156
         Adjusted R-squared = .665742
   Durbin-Watson statistic = 1.36954

                  Estimated    Standard
Parameter           Value      Error       t-statistic
δ02              -2.46997      7.79795      -.316746
δ03              -2.57300      7.81028      -.329437
δ04              -2.56870      7.80313      -.329189
δ05              -2.55853      7.81107      -.327552
δ1               -.390043E-04  .348436E-04  -1.11941
δ2                .356580E-03  .658660E-03   .541372
δ3               -.143752E-03  .554131E-04  -2.59418
δ4                .132462E-02  .393491E-02   .336633
```

Onshore Shallow Gas (k=3, r=1 thru 6)

$$FR3_{r,k,t} = \delta 0_k + \delta 1_k CUMSW3_{r,k,t-1} + \delta 2_k CUMRES2_{r,k,t-1} + \delta 3_k SW3_{r,k,t} + \delta 4_k YEAR_t + \delta 5_k REG5\_88_{r,t}$$
$$+ \delta 6_k REG5\_89_{r,t} + \rho_k FR3_{r,k,t-1} - \rho_k(\delta 0_k + \delta 1_k CUMSW3_{r,k,t-2} + \delta 2_k CUMRES2_{r,k,t-2}$$
$$+ \delta 3_k SW3_{r,k,t-1} + \delta 4_k YEAR_{t-1} + \delta 5_k REG5\_88_{r,t-1} + \delta 6_k REG5\_89_{r,t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    6 ITERATIONS

Dependent variable: FR3
Number of observations:  66 (Pooled Sample: 1984-1994 for 6 onshore regions)

(Statistics based on transformed data)      (Statistics based on original data)
 Mean of dependent variable = .914220        Mean of dependent variable = 1.37020
Std. dev. of dependent var. = 1.50739        Std. dev. of dependent var. = 1.70546
   Sum of squared residuals = 51.5586            Sum of squared residuals = 51.8830
      Variance of residuals = .873874               Variance of residuals = .879373
  Std. error of regression = .934812           Std. error of regression = .937749
                 R-squared = .651609                          R-squared = .725995
         Adjusted R-squared = .616180                  Adjusted R-squared = .698130
   Durbin-Watson statistic = 1.47886            Durbin-Watson statistic = 1.47894
 ρ (autocorrelation coef.) = .399220
      Standard error of ρ   = .117969
```

```
        t-statistic for ρ   = 3.38411
  F-statistic (zero slopes) = 18.3352
 Log of likelihood function = -86.0219


                    Estimated    Standard
Parameter             Value       Error       t-statistic
δ0                  -125.857     52.4847        -2.39798
δ1                  -.994238E-05 .541447E-05    -1.83626
δ2                   .193021E-04 .159843E-04     1.20756
δ3                  -.566952E-05 .210428E-04     -.269427
δ4                   .063483     .026455         2.39965
δ5                  3.98305      .449671         8.85769
δ6                  2.41533      .448860         5.38104
```

Onshore Deep Gas (k=4, r=2 thru 5)

$$FR3_{r,k,t} = \delta 02_k REG2_r + \delta 03_k REG3_r + \delta 04_k REG4_r + \delta 05_k REG5_r + \delta 1_k CUMSW3_{r,k,t-1}$$
$$+ \delta 2_k SW3_{r,k,t} + \delta 3_k YEAR_t + \delta 4_k REG5\_85_{r,t} + \delta 5_k REG5\_87_{r,t} + \delta 6_k REG5\_88_{r,t} + \rho_k FR3_{r,k,t-1}$$
$$- \rho_k(\delta 02_k REG2_r + \delta 03_k REG3_r + \delta 04_k REG4_r + \delta 05_k REG5_r + \delta 1_k CUMSW3_{r,k,t-2}$$
$$+ \delta 2_k SW3_{r,k,t-1} + \delta 3_k YEAR_{t-1} + \delta 4_k REG5\_85_{r,t-1} + \delta 5_k REG5\_87_{r,t-1}$$
$$+ \delta 6_k REG5\_88_{r,t-1})$$

```
Method of estimation = Ordinary Least Squares

CORRECTION FOR HETEROSCEDASTIC ERROR STRUCTURE

Dependent variable: FR3
Number of observations:  44 (Pooled Sample: 1984-1994 for 4 onshore regions)

 Mean of dependent variable = .596207          Adjusted R-squared = .893260
Std. dev. of dependent var. = 3.35357       Durbin-Watson statistic = 1.70986
   Sum of squared residuals = 40.8149      F-statistic (zero slopes) = 40.9833
       Variance of residuals = 1.20044     Schwarz Bayes. Info. Crit. = .784900
   Std. error of regression = 1.09564      Log of likelihood function = -60.7802
                 R-squared = .915601

                    Estimated    Standard
Parameter             Value       Error       t-statistic
δ02                 -278.372     192.446        -1.44649
δ03                 -277.781     192.762        -1.44106
δ04                 -279.884     193.127        -1.44922
δ05                 -280.133     193.188        -1.45006
δ1                  -.209735E-03 .236080E-03     -.888407
δ2                  -.191325E-02 .729128E-03    -2.62402
δ3                   .140966     .097135         1.45124
δ4                  -10.0467     1.09179         -9.20198
δ5                  12.6303      1.03788         12.1693
δ6                  -6.53947     1.02187         -6.39953
```

Price Elasticities of Short Run Supply

As noted in chapter 4, the PMM and NGTDM calculate production levels through the use of short-run supply functions that require estimates of the price elasticities of supply. Option 1 employs the price elasticity estimates that are passed from the OGSM to the PMM and NGTDM. Options 2 and 3 employ econometrically estimated alternative to the elasticity approach. The section below documents the estimations.

Option 1

Onshore Lower 48 Oil

Price elasticities were estimated using the AR1 technique in TSP which corrects for serial correlation using the maximum likelihood iterative technique of Beach and MacKinnon (1978). Equations for onshore regions 1 and 6 were estimated separately due to the regions' unique characteristics. The functional form is given by:

$$LCRUDE_t = a0 + a1*LOILRES_t + a2*LPOIL_t + \rho*LCRUDE_{t-1}$$
$$- \rho*(a0 + a1*LOILRES_{t-1} + a2*LPOIL_{t-1})$$

where,

LCRUDE = natural log of crude oil production
LOILRES = natural log of beginning of year oil reserves
LPOIL = natural log of the regional wellhead price of oil in 1987 dollars
ρ = autocorrelation parameter
t = year.

Region 1

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	-.977125	.680644	-1.43559
LOILRES	.814563	.114311	7.12584
LPOIL	.08385	.040682	2.06115
ρ	.334416	.297765	1.12309

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 13

Dependent variable:  LCRUDE
(Statistics based on transformed data)
  Mean of dependent variable = 3.03941
 Std. dev. of dependent var. = .365187
    Sum of squared residuals = .015765
       Variance of residuals = .157651E-02
    Std. error of regression = .039705
                   R-squared = .990477
          Adjusted R-squared = .988573
     Durbin-Watson statistic = 1.58775
  F-statistic (zero slopes) = 502.556
  Log of likelihood function = 25.1414

(Statistics based on original data)
  Mean of dependent variable = 4.43559
 Std. dev. of dependent var. = .142410
    Sum of squared residuals = .015832
       Variance of residuals = .158323E-02
    Std. error of regression = .039790
                   R-squared = .936035
          Adjusted R-squared = .923242
     Durbin-Watson statistic = 1.57879
```

Region 6

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	6.69155	2.14661	3.11727
LOILRES	-.123763	.255535	-.484329
LPOIL	.031845	.038040	.837163
ρ	.833915	.135664	6.14691

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 13

Dependent variable:  LCRUDE
(Statistics based on transformed data)
  Mean of dependent variable = 1.13005
 Std. dev. of dependent var. = .605103
    Sum of squared residuals = .013218
       Variance of residuals = .132176E-02
    Std. error of regression = .036356
                   R-squared = .997230
          Adjusted R-squared = .996676
      Durbin-Watson statistic = .896816
   F-statistic (zero slopes) = 1657.10
  Log of likelihood function = 25.7519

(Statistics based on original data)
  Mean of dependent variable = 5.78242
 Std. dev. of dependent var. = .061666
    Sum of squared residuals = .014455
       Variance of residuals = .144552E-02
    Std. error of regression = .038020
                   R-squared = .707387
          Adjusted R-squared = .648864
      Durbin-Watson statistic = .892422
```

For onshore regions 2 through 5, the data were pooled and regional dummy variables were used to allow the estimated production elasticity to vary across the regions. Region 2 is taken as the base region. The form of the equation is given by:

$$
\begin{aligned}
\text{LCRUDE}_t = {} & a0 + a1*\text{LOILRES}_t + a2*\text{LPOIL}_t + a3*\text{LPDUM3}_t + a4*\text{LPDUM} \\
& a5*\text{LPDUM5}_t + \rho*\text{LCRUDE}_{t-1} - \rho*(a0 + a1*\text{LOILRES}_{t-1} + \\
& a2*\text{LPOIL}_{t-1} + a3*\text{LPDUM3}_{t-1} + a4*\text{LPDUM4}_{t-1} + a5*\text{LPDUM}
\end{aligned}
$$

where,

LPDUMr	=	DUMr*LPOIL
DUMr	=	a dummy variable that equals 1 if region=r and 0 otherwise
r	=	onshore regions 2 through 5
ρ	=	autocorrelation parameter
t	=	year.

Regions 2 through 5

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	1.38487	.646290	2.14279
LOILRES	.549313	.077877	7.05360
LPOIL	.105051	.032631	3.21932
LPDUM3	-.077217	.034067	-2.26660
LPDUM4	-.028657	.034318	-.835047
LPDUM5	-.089397	.032700	-2.73387
ρ	.867072	.080470	10.7751

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 52

Dependent variable:  LCRUDE
(Statistics based on transformed data)
  Mean of dependent variable = .936528
 Std. dev. of dependent var. = .612526
    Sum of squared residuals = .109259
       Variance of residuals = .237519E-02
    Std. error of regression = .048736
                   R-squared = .994731
          Adjusted R-squared = .994159
     Durbin-Watson statistic = 1.42150
   F-statistic (zero slopes) = 1602.00
 Log of likelihood function = 83.7253

(Statistics based on original data)
  Mean of dependent variable = 5.93153
 Std. dev. of dependent var. = .428916
    Sum of squared residuals = .110274
       Variance of residuals = .239725E-02
    Std. error of regression = .048962
                   R-squared = .988524
          Adjusted R-squared = .987277
     Durbin-Watson statistic = 1.40740
```

The estimated coefficient on LPOIL is the price elasticity of crude oil production for region 2. The elasticity for region r (r = 3,4,5) is obtained by adding the coefficient on LPDUM$_r$ to the coefficient on LPOIL.

Lower 48 Dry Non-Associated Natural Gas

The data for onshore regions 1 through 6 were pooled and a single regression equation estimated with dummy variables used to allow the slope coefficients to vary across regions. Region 1 was taken as the base region. The equation was estimated using the non-linear two stage least squares procedure in TSP. The form of the equation is given by:

$$LPROD = A0 + (A1 + \sum_r Ar*DUMr)*LGASRES + (B1 + \sum_r Br*DUMr) *$$
$$LPGAS + C*DEDSHR$$

where,

LPROD	=	natural log of natural gas production
LGASRES	=	natural log of beginning of year natural gas reserves
LPGAS	=	natural log of the regional wellhead price of natural gas in 1987 dollars
DEDSHR	=	natural log of the share of natural gas production that is accounted for by pipeline sales(included to capture the effect of open access on production)
DUMr	=	dummy variable that equals 1 if region = r and 0 otherwise
r	=	onshore regions 2 through 6.

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
A0	-3.02039	3.46358	-.872044
A1	.962078	.206360	4.66213
A2	.067699	.016754	4.04076
A3	.049399	.017549	2.81494
A4	.062093	.018170	3.41733
A5	.450603E-02	.016987	.265262
A6	.047330	.054670	.865738
B1	.852276	.326959	2.60668
B2	-.589608	.331977	-1.77605
B3	-.645398	.306376	-2.10623
B4	-.730398	.341712	-2.13747
B5	-.733917	.265693	-2.76228
B6	-.388545	.471104	-.822833
C	-.305243	.082627	-3.69421

```
SAMPLE:  1985 to 1990
NUMBER OF OBSERVATIONS = 36

Dependent variable:  LPROD
  Mean of dependent variable = 13.7972
 Std. dev. of dependent var. = 1.08967
     Sum of squared residuals = .089311
        Variance of residuals = .405960E-02
     Std. error of regression = .063715
                    R-squared = .997851
           Adjusted R-squared = .996581
       Durbin-Watson statistic = 2.42140
```

The price elasticity of natural gas production for onshore region 1 is given by the estimated parameter B1. The price elasticity for any other onshore region r (r = 2 through 6) is derived by adding the estimate for Br to the value of B1.

Offshore Gulf of Mexico Crude Oil

Price elasticities were estimated using OLS. The functional form is given by:

$$LCRUDE = a0 + a1*LOILRES + a2*LPOIL + a3*LCRUDE(-1) + a4*DUM$$

where,

LCRUDE	=	natural log of crude oil production
LOILRES	=	natural log of beginning of year oil reserves
LPOIL	=	natural log of the regional wellhead price of oil in 1987 dollars
LCRUDE(-1)	=	natural log of crude oil production in the previous year
DUM	=	a dummy variable that equals 1 for years after 1986 and 0 otherwise.

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	-6.48638	2.65947	-2.43897
LOILRES	.821851	.313405	2.62233
LPOIL	.115556	.051365	2.24969
LCRUDE(-1)	.974244	.137890	7.06538
DUM	.079112	.045683	1.73175

```
SAMPLE:  1978 to 1991
NUMBER OF OBSERVATIONS = 14

Dependent variable:  LCRUDE
 Mean of dependent variable = 5.65758
Std. dev. of dependent var. = .106897
   Sum of squared residuals = .021640
      Variance of residuals = .240446E-02
   Std. error of regression = .049035
                  R-squared = .854325
         Adjusted R-squared = .789581
    Durbin-Watson statistic = 1.47269
               Durbin's h = 1.04017
     Durbin's h alternative = .725714
 F-statistic (zero slopes) = 13.1954
 Schwarz Bayes. Info. Crit. = -5.52974
 Log of likelihood function = 25.4407
```

Pacific Offshore Crude Oil

Price elasticities were estimated using the AR1 procedure in TSP which corrects for first order serial correlation using a maximum likelihood iterative technique. The regression equation is given by:

$$LCRUDE_t = a0 + a1*LOILRES_t + a2*LPOIL_t + \rho*LCRUDE_{t-1} - $$
$$\rho*(a0 + a1*LOILRES_{t-1} + a2*LPOIL_{t-1})$$

where,

LCRUDE	=	natural log of crude oil production
LOILRES	=	natural log of beginning of year crude oil reserves
LPOIL	=	natural log of the regional wellhead price of crude oil in 1987 dollars
ρ	=	autocorrelation parameter
t	=	year.

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	1.34325	.443323	3.02995
LOILRES	.310216	.067090	4.62390
LPOIL	.181190	.067391	2.68865
ρ	-.355962	.320266	-1.11146

```
SAMPLE:  1977 to 1991
NUMBER OF OBSERVATIONS = 15

Dependent variable:  LCRUDE
(Statistics based on transformed data)
        Mean of dependent variable = 5.31728
      Std. dev. of dependent var. = .646106
         Sum of squared residuals = .209786
             Variance of residuals = .017482
          Std. error of regression = .132220
                        R-squared = .971382
               Adjusted R-squared = .966613
            Durbin-Watson statistic = 1.61085
         F-statistic (zero slopes) = 161.152
         Log of likelihood function = 10.6711

(Statistics based on original data)
        Mean of dependent variable = 4.001171
      Std. dev. of dependent var. = .231415
         Sum of squared residuals = .220359
             Variance of residuals = .018363
          Std. error of regression = .135511
                        R-squared = .711359
               Adjusted R-squared = .663252
            Durbin-Watson statistic = 1.61258
```

Option 2

Natural Gas

The following variables are the instrumental variables not included in the estimation of the supply curve (Option 1):

TRAN_M: the differential between the average citygate price and the average wellhead price
L_PR(-1):   the lag of the dependent variable
KERN_R: a dummy variable for the Kern river pipeline project which increased the demand for gas (at the wellhead) in the Rocky Mountain region. Equal to one after 1992 in OGSM region 5.
KERN_R(-1):   the lag of the Kern river dummy variable.
LNPGAS(-1):   lag of the natural log of the wellhead price.
NEWTREND: time trend reflecting the growth in demand after 1990 due to the 1990 Clean Air Act.
CARRIAGE(-1):   Lag of Carriage
REAL_GDP: real GDP
HDD_TOT: total HDD in the year.
WINTER: HDD in the heating season relative to the total
NUM_CUST: number of residences that use gas
WOP: world oil price

Dependent variable: L_PR
Number of observations: 153
Sample period: 1987-1995

(Statistics based on transformed data)   (Statistics based on original data)
 Mean of dependent variable = -1.55656   Mean of dependent variable = -2.38198
Std. dev. of dependent var. = .339730   Std. dev. of dependent var. = .478945
   Sum of squared residuals = 4.94292   Sum of squared residuals = 4.94292
        Variance of residuals = .036887   Variance of residuals = .036887
    Std. error of regression = .192061   Std. error of regression = .192061
                   R-squared = .718249   R-squared = .858237
          Adjusted R-squared = .680402   Adjusted R-squared = .839194
       Durbin-Watson statistic = 1.76858   Durbin-Watson statistic = 1.76858
Rho (autocorrelation coef.) = .344682
        Standard error of rho = .075891
            t-statistic for rho = 4.54180
 Log of likelihood function = 45.4873

	Estimated	Standard	
Variable	Coefficient	Error	t-statistic
NGTDM2	-3.20969	.267598	-11.9944
NGTDM3	-2.93531	.270587	-10.8479
NGTDM4	-3.35590	.227408	-14.7571
NGTDM5	-3.69366	.233568	-15.8141
NGTDM6	-3.43275	.283371	-12.1140
NGTDM7	-3.34650	.254599	-13.1442
NGTDM8	-2.86265	.254779	-11.2358
NGTDM9	-2.42438	.236553	-10.2488
NGTDM10	-2.66263	.236034	-11.2807
NGTDM11	-2.73809	.234900	-11.6564
NGTDM12	-3.41090	.225810	-15.1052
NGTDM13	-3.09228	.223031	-13.8648
NGTDM15	-2.41018	.230816	-10.4420
NGTDM16	-3.63902	.229486	-15.8572
NGTDM17	-2.63371	.253934	-10.3716
NGTDM19	-2.28560	.244244	-9.35786
NGTDM20	-3.30895	.271987	-12.1658
CARRIAGE	.619146	.222396	2.78398
LNPGAS	.281044	.128351	2.18965

Crude Oil

Dependent variable: L_PR
Number of observations: 96

(Statistics based on transformed data)
 Mean of dependent variable = -.584480
Std. dev. of dependent var. = .261828

```
       Sum of squared residuals = .437095
         Variance of residuals = .508250E-02
     Std. error of regression = .071292
                   R-squared = .936387
          Adjusted R-squared = .929730
      Durbin-Watson statistic = 1.44267
Rho (autocorrelation coef.) = .761773
        Standard error of rho = .069740
            t-statistic for rho = 10.9230
 F-statistic (zero slopes) = 132.820
Log of likelihood function = 119.123
(Statistics based on original data)
 Mean of dependent variable = -2.14110
Std. dev. of dependent var. = .431497
     Sum of squared residuals = .474641
         Variance of residuals = .551908E-02
     Std. error of regression = .074290
                   R-squared = .973561
          Adjusted R-squared = .970794
      Durbin-Watson statistic = 1.40316


                Estimated     Standard
Variable    Coefficient      Error        t-statistic
REG1        -2.04097        .077337        -26.3907
REG2        -1.85617        .077354        -23.9959
REG3        -1.87340        .077245        -24.2528
REG4        -2.43427        .077277        -31.5004
REG5        -2.11561        .076618        -27.6126
REG6        -2.53210        .074498        -33.9888
PACIFIC     -2.49487        .084604        -29.4887
GULF_MEX    -1.80544        .077760        -23.2180
POIL      .405730E-02    .172851E-02        2.34728
PAC_DUM     -.593325        .071096         -8.34536
```

Option 3

Natural Gas

Option 3 version of the model employs the same list of excluded instrumental variable as does Option 1. In the case of the Gulf of Mexico, a preliminary analysis indicated that reserve additions had no statistically significant impact on the production to reserves ratio. Accordingly, this variable was dropped from the equation. The results are presented below.

```
Dependent variable: L_PR                       Number of observations:  153
 (Statistics based on transformed data)  (Statistics based on original data)
 Mean of dependent variable = -1.42246   Mean of dependent variable = -2.38198
Std. dev. of dependent var. = .319648   Std. dev. of dependent var. = .478945
     Sum of squared residuals = 4.46210     Sum of squared residuals = 4.46210
         Variance of residuals = .033804         Variance of residuals = .033804
     Std. error of regression = .183858     Std. error of regression = .183858
                   R-squared = .712709                   R-squared = .872026
          Adjusted R-squared = .669180          Adjusted R-squared = .852636
      Durbin-Watson statistic = 1.62494      Durbin-Watson statistic = 1.62494
Rho (autocorrelation coef.) = .400681
        Standard error of rho = .074072
            t-statistic for rho = 5.40936
 Log of likelihood function = 53.3160


                Estimated     Standard
Variable    Coefficient      Error        t-statistic
NGTDM2      -3.11539        .278833        -11.1730
NGTDM3      -2.79435        .282534         -9.89030
NGTDM4      -3.26363        .241656        -13.5052
NGTDM5      -3.59802        .246935        -14.5708
NGTDM6      -3.31451        .293341        -11.2992
NGTDM7      -3.25806        .266375        -12.2311
NGTDM8      -2.75296        .266779        -10.3193
NGTDM9      -2.30780        .250683         -9.20604
NGTDM10     -2.55775        .249785        -10.2398
NGTDM11     -2.64004        .248712        -10.6148
NGTDM12     -3.30683        .239582        -13.8025
```

```
NGTDM13     -2.98086     .237457      -12.5533
NGTDM15     -2.29135     .245011      -9.35203
NGTDM16     -3.51849     .243483      -14.4506
NGTDM17     -2.54880     .265098      -9.61458
NGTDM19     -2.21204     .256088      -8.63780
NGTDM20     -3.23998     .281333      -11.5165
CARRIAGE    .536012      .237033      2.26134
LNPGAS      .282299      .123910      2.27826
RA_ON(-1)   -.346953     .100072      -3.46705
RA_PAC(-1)  -1.32524     .529135      -2.50454
```

Crude Oil

```
Dependent variable: L_PR
Number of observations:  96

(Statistics based on transformed data)
 Mean of dependent variable = -.632077
Std. dev. of dependent var. = .266610
    Sum of squared residuals = .324944
       Variance of residuals = .391498E-02
    Std. error of regression = .062570
                   R-squared = .956140
          Adjusted R-squared = .949799
     Durbin-Watson statistic = 1.74406
Rho (autocorrelation coef.) = .739711
        Standard error of rho = .074223
           t-statistic for rho = 9.96602
  F-statistic (zero slopes) = 136.820
 Log of likelihood function = 133.659
(Statistics based on original data)
 Mean of dependent variable = -2.14110
Std. dev. of dependent var. = .431497
    Sum of squared residuals = .366427
        Variance of residuals = .441479E-02
    Std. error of regression = .066444
                   R-squared = .979550
          Adjusted R-squared = .976594
     Durbin-Watson statistic = 1.65740

             Estimated    Standard
Variable     Coefficient    Error        t-statistic
REG1         -2.01983     .065639      -30.7717
REG2         -1.83432     .065673      -27.9311
REG3         -1.85302     .065588      -28.2523
REG4         -2.42216     .064756      -37.4044
REG5         -2.09453     .065178      -32.1357
REG6         -2.52458     .061903      -40.7830
PACIFIC      -2.42401     .073212      -33.1095
GULF_MEX     -1.64851     .080708      -20.4256
POIL         .415848E-02  .151184E-02  2.75061
RA_ON(-1)    -.200143     .121602      -1.64589
RA_PAC(-1)   1.12904      .280958      4.01853
RA_GOM(-1)   -.974495     .299639      -3.25223
PAC_DUM      -.784702     .076707      -10.2298
```

Associated Dissolved Gas Equations

Associated dissolved gas production was hypothesized to be a function of crude oil production. The form of the equation was assumed to be log-linear. The equations were estimated in log-linear form using ordinary least squares (OLS) technique available in TSP. The forms of the equations are :

$$\text{LADGAS}_{r,t} = \ln(\alpha 0)_r + \ln(\alpha 1)_r * \text{DUM86}_t + \left(\beta 0_r + \beta 1_r * \text{DUM86}_t\right) * \text{LOILPROD}_{r,t}$$

Results

```
                           Onshore Region   1
                           *****************

                    Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  11 to 24
Number of observations:  14
```

```
 Mean of dependent variable = 5.12499
Std. dev. of dependent var. = .164729
   Sum of squared residuals = .038353
      Variance of residuals = .319609E-02
   Std. error of regression = .056534
                 R-squared = .891278
         Adjusted R-squared = .882218
    Durbin-Watson statistic = 1.75215
  F-statistic (zero slopes) = 98.3730
 Schwarz Bayes. Info. Crit. = -5.52297
 Log of likelihood function = 21.4347


          Estimated    Standard
Variable  Coefficient    Error       t-statistic
ln(α0)    2.07491      .307892       6.73908
β0        .701885      .070766       9.91832

                              Onshore Region   2
                              ******************

                    Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  35 to 48
Number of observations:  14

 Mean of dependent variable = 6.49697
Std. dev. of dependent var. = .266043
   Sum of squared residuals = .048056
      Variance of residuals = .400467E-02
   Std. error of regression = .063282
                 R-squared = .947773
         Adjusted R-squared = .943420
    Durbin-Watson statistic = 1.22587
  F-statistic (zero slopes) = 217.764
 Schwarz Bayes. Info. Crit. = -5.29744
 Log of likelihood function = 19.8560


          Estimated    Standard
Variable  Coefficient    Error       t-statistic
ln(α0)    -3.07832     .649092       -4.74250
β0        1.56944      .106353       14.7568

                              Onshore Region   3
                              ******************

                    Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  65 to 72
Number of observations:  8

 Mean of dependent variable = 5.92117
Std. dev. of dependent var. = .188982
   Sum of squared residuals = .013619
      Variance of residuals = .226982E-02
   Std. error of regression = .047643
                 R-squared = .945524
         Adjusted R-squared = .936445
    Durbin-Watson statistic = 2.19391
  F-statistic (zero slopes) = 104.141
 Schwarz Bayes. Info. Crit. = -5.85588
 Log of likelihood function = 14.1514

          Estimated    Standard
Variable  Coefficient    Error       t-statistic
ln(α0)    -1.65468     .742561       -2.22834
β0        1.42210      .139354       10.2050

                              Onshore Region   4
                              ******************

                    Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  82 to 96
Number of observations:  15

 Mean of dependent variable = 6.51049
Std. dev. of dependent var. = .080768
   Sum of squared residuals = .065307
      Variance of residuals = .502359E-02
   Std. error of regression = .070877
                 R-squared = .284921
```

```
        Adjusted R-squared = .229915
   Durbin-Watson statistic = 1.28517
 F-statistic (zero slopes) = 5.17980
 Schwarz Bayes. Info. Crit. = -5.07564
 Log of likelihood function = 19.4913

            Estimated    Standard
Variable  Coefficient     Error      t-statistic
ln(α0)     4.49271       .886765      5.06640
β0         .315372       .138569      2.27592
```

                          Onshore Region   5
                          ****

                  Method of estimation = Ordinary Least Squares

```
Dependent variable: LADGAS
Current sample:  107 to 120
Number of observations:  14

 Mean of dependent variable = 5.49207
Std. dev. of dependent var. = .176267
    Sum of squared residuals = .169883
        Variance of residuals = .014157
    Std. error of regression = .118983
                   R-squared = .579402
         Adjusted R-squared = .544352
    Durbin-Watson statistic = 1.15658
 F-statistic (zero slopes) = 16.5308
 Schwarz Bayes. Info. Crit. = -4.03469
 Log of likelihood function = 11.0168

            Estimated    Standard
Variable  Coefficient     Error      t-statistic
ln(α0)     5.34284       .048562      110.021
β1         .047917       .011785      4.06581
```

                          Onshore Region   6
                          ****

                  Method of estimation = Ordinary Least Squares

```
Dependent variable: LADGAS
Current sample:  131 to 144
Number of observations:  14

 Mean of dependent variable = 5.20320
Std. dev. of dependent var. = .126146
    Sum of squared residuals = .030218
        Variance of residuals = .302183E-02
    Std. error of regression = .054971
                   R-squared = .853924
         Adjusted R-squared = .810102
    Durbin-Watson statistic = 1.16621
 F-statistic (zero slopes) = 19.4859
 Schwarz Bayes. Info. Crit. = -5.38435
 Log of likelihood function = 23.1034

            Estimated    Standard
Variable  Coefficient     Error      t-statistic
ln(α0)    -12.1971       2.95896     -4.12210
ln(α1)     10.7230       3.27845      3.27075
β0          2.99621       .508887      5.88778
β1         -1.83291       .565439     -3.24157
```

                          Offshore California
                          ****

                  Method of estimation = Ordinary Least Squares

```
Dependent variable: LADGAS
Current sample:  146 to 157
Number of observations:  12

 Mean of dependent variable = 3.46459
Std. dev. of dependent var. = .235388
    Sum of squared residuals = .130029
        Variance of residuals = .016254
    Std. error of regression = .127490
                   R-squared = .786657
         Adjusted R-squared = .706654
    Durbin-Watson statistic = 1.46033
 F-statistic (zero slopes) = 9.83279
 Schwarz Bayes. Info. Crit. = -3.69661
```

```
 Log of likelihood function = 10.1222

         Estimated    Standard
Variable Coefficient    Error      t-statistic
ln(α0)    -42.1148      14.1531      -2.97566
ln(α1)     43.1508      14.3122       3.01497
β0         10.7112       3.34207      3.20497
β1        -10.0929       3.38203     -2.98428
```

```
                              Offshore Gulf of Mexico
                              ***********************

                     Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  159 to 170
Number of observations:  12

 Mean of dependent variable = 6.38670
Std. dev. of dependent var. = .092892
   Sum of squared residuals = .026872
      Variance of residuals = .298574E-02
   Std. error of regression = .054642
                  R-squared = .721601
         Adjusted R-squared = .659735
     Durbin-Watson statistic = 2.45155
 F-statistic (zero slopes) = 11.3951
 Schwarz Bayes. Info. Crit. = -5.48036
 Log of likelihood function = 19.5823

         Estimated    Standard
Variable Coefficient    Error      t-statistic
ln(α1)     4.21386      1.49771       2.81354
β0         1.07834      .466028E-02   231.391
β1        -.697473      .258646      -2.69663
```

Canadian Successful Oil and Gas Wells Equations

A successful oil wells equation and a successful gas wells equation were estimated in generalized difference form using SURE. Successful oil (gas) wells were estimated as a function of the expected DCF for an oil (gas) well and a dummy variable to control for Canadian oil and gas policy changes in the early to mid 1980's.

Total Gas Wells

$$\text{LNGWELLS}_t = \beta0 + \beta1*\text{LNGPRICE}_t + \beta2*\text{DUM7080}_t + \beta3*\text{DUM8192}_t + \rho*\text{LNGWELLS}_{t-1}$$
$$- \rho(\beta0 + \beta1*\text{LNGPRICE}_{t-1} + \beta2*\text{DUM7080}_{t-1} + \beta3*\text{DUM8192}_{t-1})$$

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE
CONVERGENCE ACHIEVED AFTER    6 ITERATIONS

Dependent variable: LNGWELLS
Current sample:  1970-1996
Number of observations:  27

(Statistics based on transformed data)    (Statistics based on original data)
 Mean of dependent variable = 4.56416      Mean of dependent variable = 7.67551
Std. dev. of dependent var. = .463825     Std. dev. of dependent var. = .512194
   Sum of squared residuals = 1.70436        Sum of squared residuals = 1.73759
      Variance of residuals = .074102           Variance of residuals = .075547
   Std. error of regression = .272218        Std. error of regression = .274859
                  R-squared = .726625                    R-squared = .745766
         Adjusted R-squared = .690967           Adjusted R-squared = .712606
    Durbin-Watson statistic = 1.67029       Durbin-Watson statistic = 1.65317
 ρ (autocorrelation coef.) = .419025
       Standard error of rho = .192734
           t-statistic for rho = 2.17410
 F-statistic (zero slopes) = 17.4943
 Log of likelihood function = -1.11211

         Estimated    Standard
Parameter    Value      Error      t-statistic
β0          8.00847     .207970       38.5079
```

```
β1          .642265     .140558      4.56940
β2         -.667461     .233659     -2.85656
β3        -1.03720      .218583     -4.74511
```