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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, simulating 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 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 1-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 NEMS2001. The version is that used to produce the *Annual Energy Outlook 2001 (AEO2001)*. 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 and 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, PMM, 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.

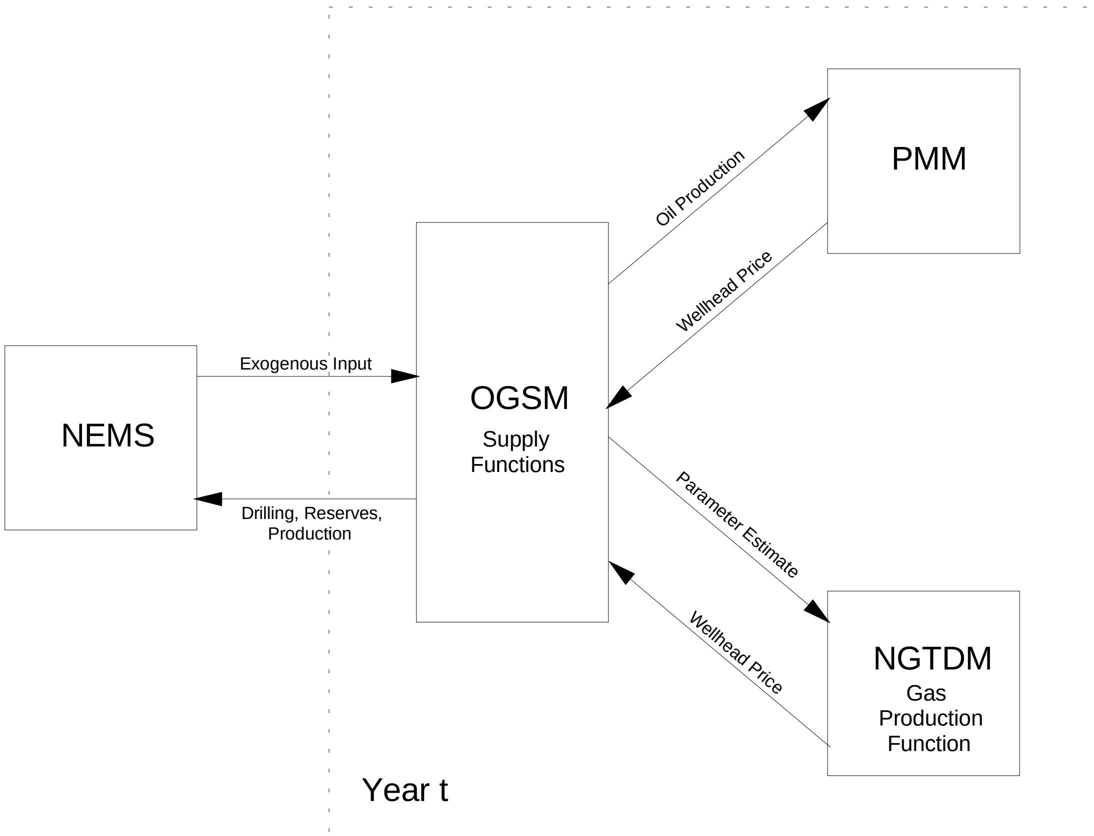
OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 2). The primary fuel types are crude oil and natural gas, 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 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 coalbed methane formations.

OGSM provides mid-term (through year 2020) 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,

[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.

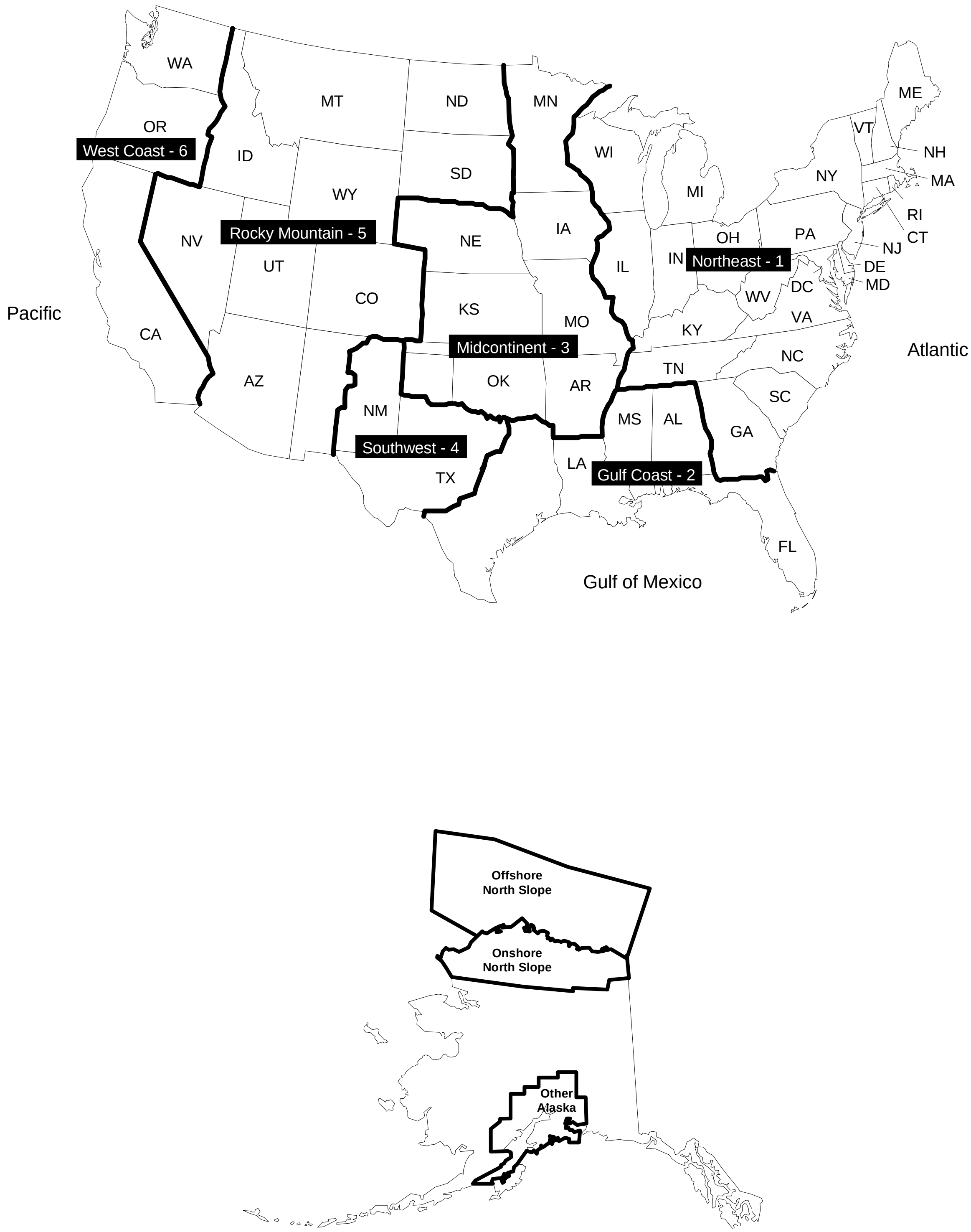
OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). With some modification this feature could allow 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 1970's and early 1980's. 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 30 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.

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. 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' (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

[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

[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 8-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 1980's, 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 1960's discovery of the Prudhoe Bay field, which is the largest in North America. During the years since the mid-1970's, 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 until later in this decade at the earliest, because of the lack of facilities to move the gas to Lower 48 markets.

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.

[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.

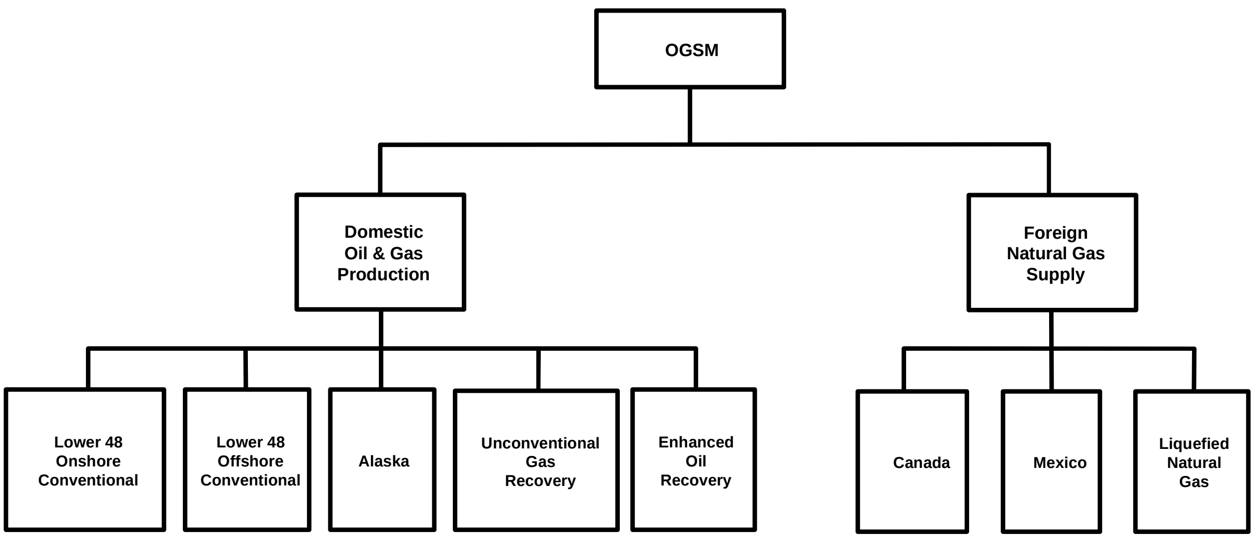
Oil and gas prices are the principal driving variables and are received from the Petroleum Market Module and the Natural Gas Transmission and Distribution Module respectively.

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 low permeability sandstone and shale formations, 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 1-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 literature regarding resource recovery.[5]

The breadth of supply processes that are encompassed within OGSM results in methodological differences between the oil and gas production from lower 48 onshore conventional resources, lower 48 onshore unconventional resources, lower 48 offshore, Alaska, and foreign gas trade. The present OGSM consequently comprises a set of four distinct approaches and corresponding

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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.

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 low permeability sandstone and shale formations, and coalbeds. The Offshore Supply Submodule (OSS) models oil and gas production in the 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 AEO2001. New finding rate functions from conventional oil and natural gas resources were incorporated. Lower 48 onshore and offshore rigs, drilling, and cost equations were re-estimated for conventional sources. Parameters for the Unconventional Gas Recovery Submodule were updated. The drilling equations and finding rate functions for the Canadian Supply Submodule were revised to improve performance.

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. This is followed by the methodology of the 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 offshore Gulf of Mexico supply.

Lower 48 Onshore Supply Submodule

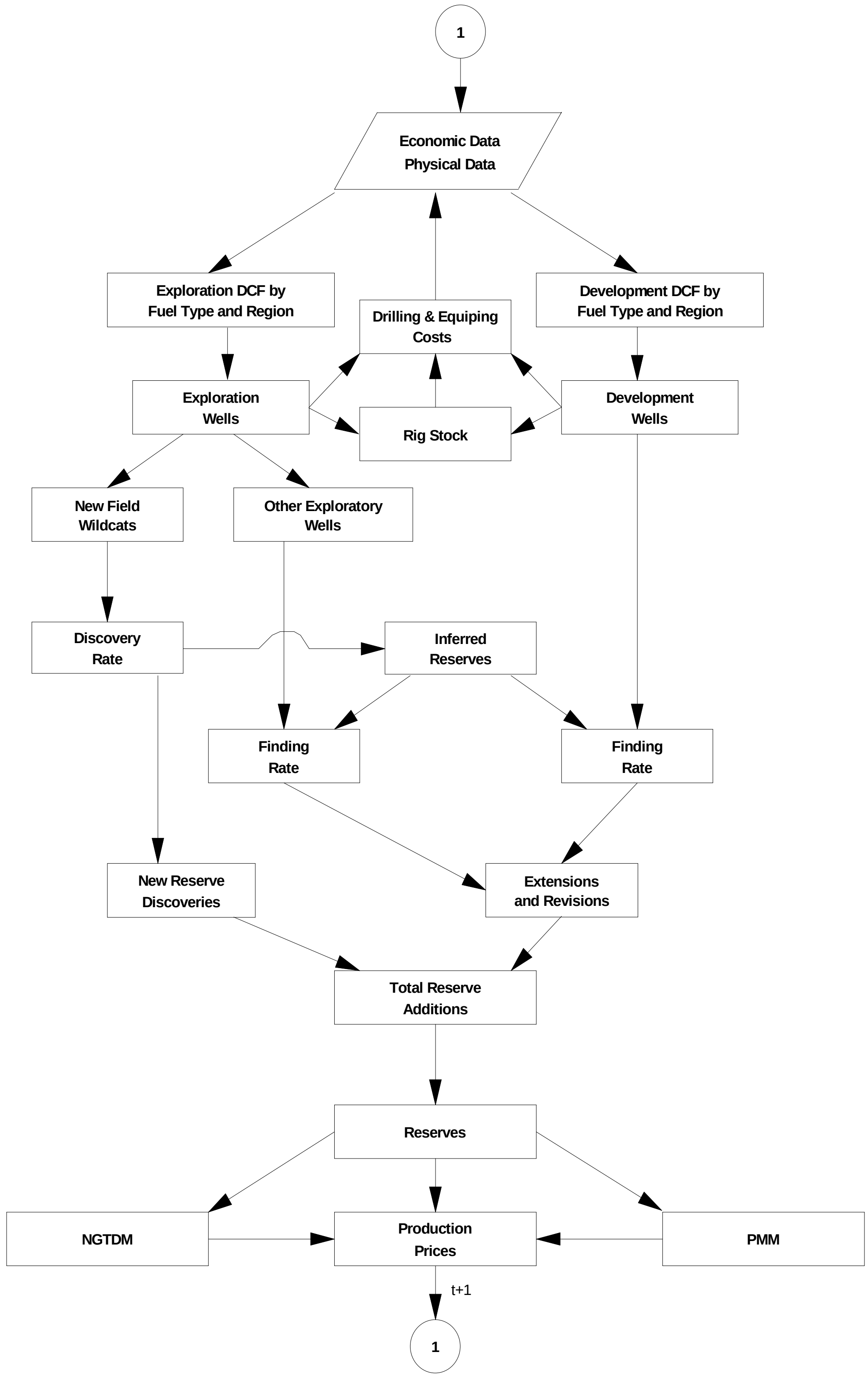
Introduction

This section describes the structure of the models that comprise the lower 48 onshore (excluding EOR and UGR) 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 (crude 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 Lower 48 States Onshore Oil and Gas Submodule



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 is subtracted to yield the end of year reserves for the current period. Natural gas reserves along with an estimate of the expected production-to-reserves ratio for the next period are passed to the NGTDM 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:

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

where,

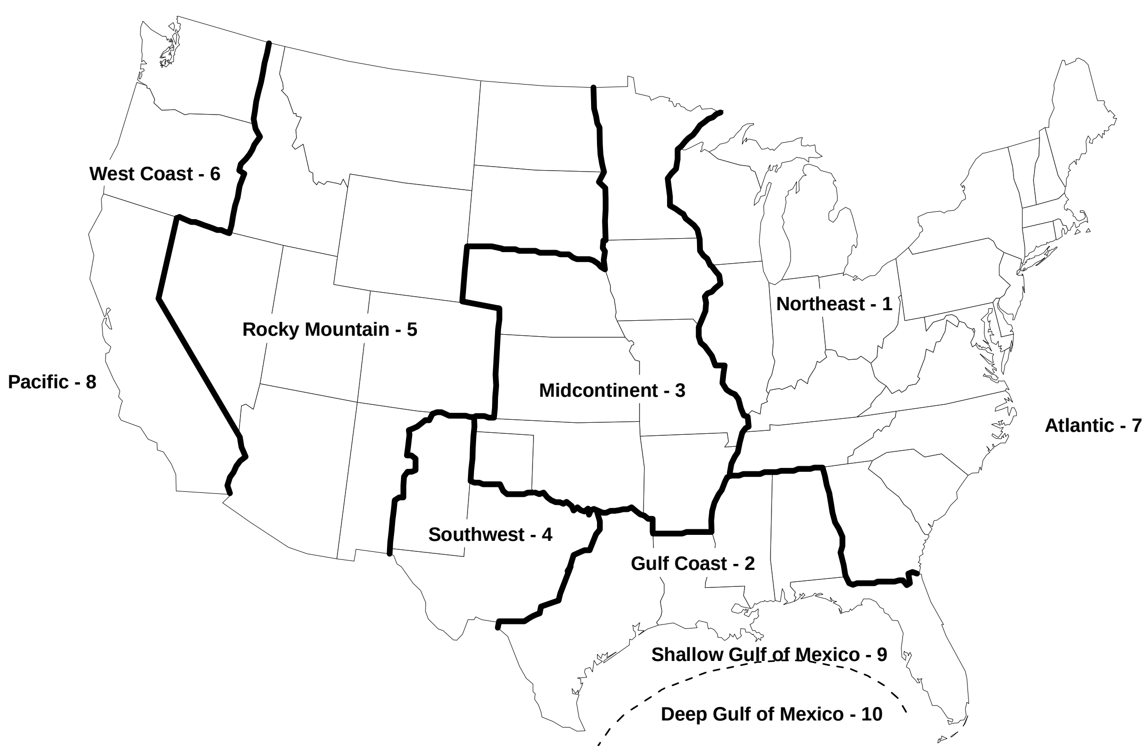
NCFON	=	annual undiscounted net cash flow for a representative onshore development project
REV	=	revenue from the sale of the primary and co-product fuel

[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.

ROY	=	royalty taxes
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

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



[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.

to the historical average for production over the first 12 months. Production subsequently declines at a rate equal to the historical 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:

$$PROJDCFON_{i,r,k,t} = SUCDCFON_{i,r,k,t} + [(\frac{1}{SR_{i,r,k}}) - 1] * DRYDCFON_{i,r,k,t}, \quad \text{for } i = 2 \qquad (2)$$

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:

$$DCFON_{i,r,k,t} = SR_{i,r,k} * SUCDCFON_{i,r,k,t} + (1 - SR_{i,r,k}) * DRYDCFON_{i,r,k,t}, \text{ for } i = 2 \qquad (3)$$

it is easily calculated as:

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

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:

$$PROJDCFON_{1,r,k,t} = SUCDCFON_{1,r,k,t} + m_k * \left[SUCDCFON_{2,r,k,t} + \left(\left(\frac{1}{SR_{2,r,k}} \right) - 1 \right) * DRYDCFON_{2,r,k,t} \right] + \left(\left(\frac{1}{SR_{1,r,k}} \right) - 1 \right) * DRYDCFON_{1,r,k,t} \qquad (5)$$

where,

m_k = 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:

$$DCFON_{1,r,k,t} = PROJDCFON_{1,r,k,t} * SR_{1,r,k} \qquad (6)$$

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, an aggregate expected fuel level DCF is calculated for each region . This aggregate expected DCF is calculated as a weighted average of the expected exploratory DCF and the expected developmental DCF for each fuel. Specifically,

$$w1_{i,r,k,t} = \frac{WELLS_{i,r,k,t-1}}{\sum_{i=1}^{2} WELLS_{i,r,k,t-1}} \qquad (7)$$

and

$$ODCFON_{r,t} = \sum_{i=1}^{2} w1_{i,r,k,t} * DCFON_{i,r,k,t} \text{ for } k = 1 \qquad (8)$$

$$SGDCFON_{r,t} = \sum_{i=1}^{2} w1_{i,r,k,t} * DCFON_{i,r,k,t} \text{ for } k = 3 \qquad (9)$$

where,

WELLS = wells drilled
ODCFON = expected DCF for oil

SGDCFON = expected DCF for shallow gas
DCFON = expected discounted cash flow for a representative onshore well.

Calculation of Cash Flow for Wells Determination

Expected industry cash flow is calculated as,

$$CASHFLOW_t = c0 + c1 * OILRATIO_t + c2 * GASRATIO_t \tag{10}$$

where OILRATIO (GASRATIO) is the ratio of the price of oil (natural gas) in 1997 dollars to the national oil (natural gas) well operating cost index in 1997 dollars. The national operating cost indices were constructed as follows.

For each year, a weighted average of regional well operating costs (in 1997 dollars) was calculated for oil, shallow gas, and deep gas using successful wells from the previous year as weights. The national gas operating cost was calculated as a weighted average of the national shallow and deep operating costs using successful wells from the previous year as weights. The indices were then calculated by dividing the operating costs for each year by the operating cost for 1997.

Lower 48 Onshore Wells Forecasting Equations

For each onshore Lower 48 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 and expected industry cash flow. 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.

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.

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & \exp(m0_{i,k} + m00_{i,r,k}) * DCFON_{i,r,k,t}^{m1_{i,r,k}} * CASHFLOW_t^{m2_{i,k}} * WELLSON_{i,r,k,t-1}^{\rho_{i,k}} \\ & * \exp(-\rho_{i,k} * (m0_{i,k} + m00_{i,r,k})) * DCFON_{i,r,k,t-1}^{-\rho_{i,k} * m1_{i,r,k}} * CASHFLOW_{t-1}^{-\rho_{i,k} * m2_{i,k}} \end{aligned} \tag{11}$$

where,

WELLSON = lower 48 onshore 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
CASHFLOW = cash flow in year t
m's, α's = estimated parameters
ρ = estimated serial correlation parameter
i = well type
r = lower 48 regions
k = fuel type
t = year.

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,

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, r = \text{onshore regions}, \quad k = 1 \text{ thru } 4 \tag{12}$$

where,

SUCWELSON	=	successful onshore lower 48 wells drilled
WELLSON	=	onshore lower 48 wells drilled
SR	=	drilling success rate
i	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 onshore regions
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:

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t}, \text{ for } i = 1, 2, \\ r = \text{onshore regions}, \ k = 1 \text{ thru } 4 \tag{13}$$

where,

DRYWELON	=	number of dry wells drilled onshore
SUCWELSON	=	successful lower 48 onshore wells drilled by fuel type, region, and well type
WELLSON	=	onshore lower 48 wells drilled by fuel type, region, and well type
i	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 onshore regions
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:

$$ESTWELLS_t = \exp(b0) * POIL_t^{b1} * PGAS_t^{b2} * ESTWELLS_{t-1}^{\rho} * \exp(-\rho * b0) * POIL_{t-1}^{-\rho * b1} * PGAS_{t-1}^{-\rho * b2} \tag{14}$$

$$ESTSUCWELLS_t = \exp(c0) * POIL_t^{c1} * PGAS_t^{c2} * ESTSUCWELLS_{t-1}^{\rho} * \exp(-\rho * c0) * POIL_{t-1}^{-\rho * c1} * PGAS_{t-1}^{-\rho * c2} \tag{15}$$

where,

ESTWELLS	=	estimated total onshore lower 48 wells drilled
ESTSUCWELLS	=	estimated successful onshore lower48 wells drilled

POIL	=	average wellhead price of crude oil
PGAS	=	average wellhead price of natural gas
b0,b1,b2,c0,c1,c2	=	estimated parameters
ρ	=	estimated serial correlation parameter
t	=	year.

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

$$RIGSL48_t = \exp(b0) * RIGSL48_{t-1}^{b1} * REVRIG_{t-1}^{b2} \quad (16)$$

where,

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

Drilling Costs

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

$$DRILLCOST_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_{d,k}) * \exp(b2_{r,k}) * ESTWELLS_t^{b3_k} * RIGSL48_t^{b4_k} * \exp(b5 * TIME_t) \quad (17)$$

$$DRYCOST_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_{d,k}) * \exp(b2_{r,k}) * ESTWELLS_t^{b3_k} * RIGSL48_t^{b4_k} * \exp(b5 * TIME_t) \quad (18)$$

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.

Lease Equipment Costs

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

$$LEQC_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_k * DEPTH_{r,k,t}) * ESTSUCWELLS_t^{b2_k} * \exp(b3_k * TIME_t) \quad (19)$$

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
ε0, ε1, ε2	=	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:

$$OPC_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_k * DEPTH_{r,k,t}) * ESTSUCWELLS_{t-1}^{b2_k} * \exp(b3_k * TIME_t) \qquad (20)$$

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.[8]

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[8]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*.

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.

This approach relies on the finding rate equation:

$$\begin{aligned} FR1_{r,k,t} = {} & \exp(\alpha_{r,k}) * SW1_{r,k,t}^{\beta 1_k} * \exp(\beta 2_k * year_t) * \exp(\beta 3_{r,k} * CUMSW1_{r,k,t}) * FR1_{r,k,t-1}^{\rho_k} \\ & * \exp(-\rho_k * \alpha_{r,k}) * SW1_{r,k,t-1}^{-\rho_k * \beta 1_k} * \exp(-\rho_k * \beta 2_k * year_{t-1}) * \exp(-\rho_k * \beta 3_{r,k} * CUMSW1_{r,k,t-1}) \end{aligned} \tag{21}$$

where,

FR1	=	new field wildcats finding rate
SW1	=	number of successful new field wildcats
CUMSW1	=	cumulative successful new field wildcats
α, β1, β2, β3	=	estimated parameters
ρ	=	estimated serial correlation parameter
r	=	region
k	=	fuel type (oil or gas)
t	=	year.

The above equation provides a rate at which undiscovered resources convert into proved and inferred reserves as a function of cumulative new field wildcats. 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

$$NRD_{r,k,t} = \frac{1}{X_{r,k}} * FR1_{r,k,t} * SW1_{r,k,t} \tag{22}$$

where,

X	=	reserves growth factor
NRD	=	additions to proved reserves from new field discoveries.

X is derived from historical data and it is assumed to be constant during the forecast period.

Reserves are converted from inferred to proved with the drilling of other exploratory wells and developmental wells in a similar way as proved and inferred reserves are modeled as moving from the resource base as described above. The volumetric return to other exploratory wells and developmental wells is shown in the following equations.

$$FR2_{r,k,t} = \exp(\alpha_{r,k}) * \exp(\beta1_k * SW2_{r,k,t}) * \exp(\beta2_{r,k} * CUMSW1_{r,k,t}) * \exp(\beta3_{r,k} * CUMSW2_{r,k,t}) * \exp(\beta4_k * year_t)$$
$$* FR2^{\rho_k}_{r,k,t-1} * \exp(\alpha_{r,k}) * \exp(\beta1_k * SW2_{r,k,t-1}) * \exp(\beta2_{r,k} * CUMSW1_{r,k,t-1}) \tag{23}$$
$$* \exp(\beta3_{r,k} * CUMSW2_{r,k,t-1}) * \exp(\beta4_k * year_{t-1})$$

where,

FR2	=	other exploratory wells finding rate
SW2	=	successful other exploratory wells
CUMSW2	=	cumulative successful other exploratory wells
α, $\beta1$, $\beta2$, $\beta3$, $\beta4$	=	estimated parameters
ρ	=	estimated serial correlation parameter
r	=	region
k	=	fuel type (oil or gas)
t	=	year

and

$$FR3_{r,k,t} = AVGFR3_{r,k,t} \tag{24}$$

where,

FR3	=	developmental wells finding rate
AVGFR3	=	average developmental finding rate over the historical period.

The conversion of inferred reserves into proved reserves occurs as both other exploratory wells and developmental wells exploit a single stock of inferred reserves. The entire stock of inferred reserves can be exhausted through either the other exploratory wells or developmental wells alone. This extreme result is unlikely given reasonable drilling levels in any one year. Nonetheless, the simultaneous extraction from inferred reserves by both drilling types could be expected to affect the productivity of each other. Specifically, the more one drilling type draws down the inferred reserve stock, there could be a corresponding acceleration in the productivity decline of the other type.

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

$$RA_{r,k,t} = \frac{1}{X_{r,k}} * FR1_{r,k,t} * SW1_{r,k,t} + FR2_{r,k,t} * SW2_{r,k,t} + FR3_{r,k,t} * SW3_{r,k,t} \tag{25}$$

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

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \tag{26}$$

where,

R	=	reserves measured as of the end-of-year
Q	=	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.

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

$$PR_t = \frac{Q_t}{R_{t-1}} \tag{27}$$

where,

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

$$PR_{t+1} = \frac{(R_{t-1} * PR_t * (1 - PR_t)) + (PRNEW * RA_t)}{R_t} \tag{28}$$

where,

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

PR_t is constrained not to vary from PR_{t-1} by more than 10 percent. It is also constrained not to exceed 30 percent.

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

$$Q_{r,k,t+1} = [R_{r,k,t}] * [PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})] \quad (29)$$

where,

R_t	=	end of year reserves in period t
PR_t	=	extraction rate in period t
β	=	estimated short run price elasticity of supply
ΔP_{t+1}	=	$(P_{t+1}-P_t)/P_t$, proportional change in price from t to t+1.

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. Documentation of the equations used to estimate β is provided in Appendix E.

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:

$$ADGAS_{r,t} = e^{\ln(\alpha)_r} * OILPROD_{r,t}^{\beta} \quad (30)$$

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,

$$ADGAS_{r,t} = e^{\ln(\alpha 0)_r + \ln(\alpha 1)_r * DUM86_t} * OILPROD_{r,t}^{\beta 0_r + \beta 1_r * DUM86_t} \quad (31)$$

where,

DUM86	=	dummy variable (1 if t>1985, otherwise 0)
α0,α1,β0,β1	=	estimated parameters.

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.

Offshore Supply Submodule

This section describes the basic structure of the Offshore Supply Submodule (OSS). The OSS is designed to project oil and gas production from the shallow and 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 OSS.

The OSS was developed offline from the OGSM. A methodology was developed within OGSM to enable it to readily import and manipulate the OSS 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 OSS, as defined by their relationship (exogenous vs. endogenous) to the OGSM:

Exogenous Component. A methodology for developing 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 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

For every year (and model iteration) of the forecast horizon,[9] the remaining EOR proved reserves that continue to be economic are determined for each region. Production from a given stock of proved reserves is determined by the application of an assumed production-to-reserves ratio. The methodology used for determining end-of-year (EOY) proved reserves for thermal production in OGSM region 6 is more detailed than that used for the thermal and gas EOR in the other OGSM regions. This is because OGSM region 6 is a much larger EOR producing region, with more extensive field-specific data available. The two methodologies used to determine proved reserves, and the algorithm used to set EOR production from proved reserves, are presented separately below.

Thermal (not region 6) and Gas EOR Proved Reserves

For the specified regions and EOR methods, EOY proved reserves in year t are defined as the difference between the EOY proved reserves in the previous year, and the EOR production in the current year. This is represented by the following equation (using the production to reserves ratio (PRV_PR) to determine EOR production in year t).

$$PRV\_RES_{r,e} = T\_PRV\_RES_{r,e,t-1} * (1. - PRV\_PR_{tc,r,e,t}) \qquad (32)$$

where,

$PRV\_RES_{r,e}$ = EOR end-of-year proved reserves for year t (MMBO)
$T\_PRV\_RES_{r,e,t-1}$ = EOR end-of-year proved reserves for year t-1 (MMBO)
$PRV\_PR_{tc,r,e,t}$ = Production to reserves ratio for year t
r = OGSM supply region (not region 6, thermal)
e = EOR type (1=thermal, 2=gas)
t = year
tc = tech case

Thermal EOR Proved Reserves in OGSM Region 6

The methodology used to determine thermal EOR proved reserves in region 6 focuses on assessing the economic viability of continued production or shutting in of wells represented for each field in the region. The EOY proved reserves in region 6 are defined as the sum (across fields) of the economic production of each field, divided by a field-specific reserves decline rate (production to reserves ratio), times a benchmark adjustment factor.

$$PRV\_RES_{r,e} = \sum_{f} \left(\frac{TF\_ECONPRD_f}{DCL\_RATE_f} * \frac{365.25}{1000000.} \right) * PRV\_RESADJ_e \qquad (33)$$

where,

[9] The EOR base year of operation is 1995; however, historical production and reserves data through 1999 (by EOR method) are included in the EORSS input. In order to keep proved and inferred reserves accounting sepearte beginning in the EOR base year, proved reserves ($PRV\_RES_{r,e}$) for EOR historical years are set equal to total historical EOY reserves ($TOT\_RES_{r,e,t}$/ 1000) minus the model calculated inferred reserves additions ($TRP\_RES_{r,e}$).

$PRV\_RES_{r,e}$ = EOR end-of-year proved reserves for year t, region 6 (MMBO)
$TF\_ECONPRD_{f}$ = Economic production of existing wells in each field in region 6 (BOPD)
DCL_RATE_{f} = Reserves decline ratio; i.e., production to reserves ratio (decimal, data)
PRV_RESADJ_{e} = Proved reserves adjustment factor to scale model reserves in last historical year to equal history (ratio)
r = OGSM supply region 6
e = EOR method (1=thermal, 2=gas)
f = EOR field

The reserves adjustment factor for region 6 is the ratio of historical EOY reserves (net model generated reserve additions) in the last EOR historical year (1997) and the remaining EOY proved reserves determined by the model, as follows:

$$PRV\_RESADJ_{e} = \frac{\left(\dfrac{TOT\_RES_{r,e,t}}{1000.} - TRP\_RES_{r,e}\right)}{PRV\_RES_{r,e}} \tag{34}$$

where,
PRV_RESADJ_{e} = Proved reserves adjustment factor to scale model reserves in last historical year to equal history (ratio)
$TOT\_RES_{r,e,t}$ = Total historical EOY proved reserves in region 6 for last EOR historical year t (MBO, data)
$TRP\_RES_{r,e}$ = Model generated EOR inferred reserve additions in region 6 for last EOR historical year [accounted separate from proved reserves] (MMBO)
$PRV\_RES_{r,e}$ = EOR end-of-year proved reserves in region 6 for last EOR historical year MMBO)
r = OGSM supply region 6
e = EOR method (1=thermal, 2=gas)
t = Last EOR historical year (1997)

As described in a separate EOR design appendix[10] (page 36) and implemented in the EORSS code (subroutine TEOR_PRV_RES), total economic production ($TF\_ECONPRD_{f}$) of existing wells in each field is defined as the sum of the economic production levels for each of *eight* productivity categories established for each field. If any productivity category is determined to be subeconomic, then the associated wells are assumed to be shut-in and the economic production for this productivity category is set to zero. Thus, proved wells that have unit operating costs ($SHUTIN\_PRC_{f,cat}$) that exceed the current net price (ADJ_RWOP_{f}) by a discount factor (OPRDELAY), do not contribute to current production. Unit operating costs consist of both fixed and variable costs ($EORFXOC_{f,cat}$ and $EORVOC_{f}$). The current net price represents the current regional wellhead price (adjusted for field-specific API gravity), 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. The following equation defines the net price.

[10]A complete description of the EORSS design was published in the spring of 1997 as a special appendix to this document, entitled "Enhanced Oil Recovery Supply Submodule (EORSS): Documentation for *1998 Annual Energy Outlook*." Note that the calculations described in the special appendix are now being performed directly in the EORSS (and not exogenously preprocessed in EXCEL spreadsheets as was done in the *AEO*s prior to *AEO2000*).

$$ADJ\_RWOP_f = (ROPRICE_{r,e,t} + ((API\_GRV_f - 13.) * 0.15)) * (1. - ROYALTY - ADVALRM) \quad (35)$$

where,

ADJ_RWOP$_f$ = Gross well revenues by field (MM$1987)
ROPRICE$_{r,e,t}$ = Regional oil price in year t ($1987/BO)
API_GRV$_f$ = Field-specific API gravity (^{o}API)
ROYALTY = Royalty (MM$1987)
ADVALRM = Ad valorum tax (MM$1987)
r = OGSM supply region 6
f = EOR field
e = EOR method (1=thermal, 2=gas)
t = Last EOR historical year (1997)

Variable operating costs for each field in region 6 are first determined in the EOR base year (1995) using base year field-specific production and cost data. For the successive forecast years, variable operating costs are defined as a function of the base year operating costs (INITVOC$_f$) and a percentage change in natural gas price (over the base year gas price). *Fixed* operating costs are defined using base year operating cost data per well and the average per well productivity level. The following equations describe how the initial and forecast *variable* operating costs are determined, and how the *fixed* operating costs are set.

$$INITVOC_f = \frac{(FUELVOC_f + OTHOMC_f) * EORWELLS_f}{(1,000,000. * TF\_EORPROD_f)} \quad (36)$$

$$EORVOC_f = INITVOC_f * \frac{RGPRICE_{r,t,2}}{INITPNG} \quad (37)$$

$$EORFXOC_{f,cat} = \frac{WELLFXOC_f}{MIDPRD_{f,cat} * 365.} \quad (38)$$

where,

INITVOC$_f$ = Variable operating costs in EOR base year (1995) by field in region 6 (87$/BO)
EORVOC$_f$ = Variable operating costs in EOR forecast year by field in region 6 (87$/BO)
EORFXOC$_{f,cat}$ = Fixed well operating costs by field and productivity category (87$/BO)
FUELVOC$_f$ = Fuel[11] operating costs per well by field in region 6 (87$/well)
OTHOMC$_f$ = O&M and other operating costs per well by field in region 6 (87$/well)
EORWELLS$_f$ = Number of wells by EOR field in region 6
TF_EORPROD$_f$ = Average EOR per well by field in region 6 (MMBO)
RGPRICE$_{r,t,2}$ = Natural gas price in region 6 in year t (87$/mcf)
INITPNG = Natural gas price in region 6 in base year (87$/mcf)
WELLFXOC$_f$ = Fixed operating costs per well by field (87$-year)
MIDPRD$_{f,cat}$ = Midpoint EOR production level per well by field and productivity category (BOPD)

[11]Refer to page 31 in special EOR design appendix, "Enhanced Oil Recovery Supply Submodule (EORSS): Documentation for 1998 Annual Energy Outlook."

f = EOR field
r = region 6
t = year
cat = productivity category

EOR Production from Proved Reserves

The EORSS uses the production to reserves (P/R) ratio, in combination with the EOY proved reserves to define EOR production from proved reserves. In the following equation, EOY reserves for the previous year are determined from EOY reserves for the current year, multiplied by the P/R ratio for the current year.

$$PRV\_PROD_{r,e} = PRV\_PR_{tc,r,e,t} * \frac{PRV\_RES_{r,e}}{(1. - PRV\_PR_{tc,r,e,t})} \quad (39)$$

where,

$PRV\_PROD_{r,e}$ = EOR production from proved reserves for year t (MMBO)
$PRV\_RES_{r,e}$ = EOR end-of-year proved reserves for year t (MMBO)
$PRV\_PR_{tc,r,e,t}$ = Production to reserves ratio for year t
r = OGSM supply region (1-6)
e = EOR type (1=thermal, 2=gas)
t = year
tc = tech case

New EOR Reserves and Production

New EOR reserves (also referred to as "proved" inferred reserves) are defined as potential resources that, "while not currently producing, have a strong likelihood of future development and recovery under favorable economic conditions."[12] In the EORSS, inferred reserves and corresponding production levels are tracked beginning in the EOR base year (1995) and throughout the forecast horizon. (This accounting is done separate from the proved reserves described in the previous section.) In each year, specially formulated price-supply relationships and economic development schedules are the basis for determining new EOR reserves (i.e., reserve additions). The methodology for defining the economic development schedule used to determine reserve additions is the same for both thermal and gas EOR methods, but the methods for determining the price-supply relationships differ between thermal and gas. These various methods are presented in the subsections below.

Determining EOR Inferred Reserve Additions

The price/supply relationships represent an incremental breakout of undeveloped EOR reserves, with the potential for development based on the regional oil wellhead price and corresponding development schedule. Thus, at each incremental ($0.50) wellhead price level, an incremental amount of undeveloped EOR reserves is established (similar to defining a resource base). A development schedule then defines what portion of the undeveloped reserves can potentially be developed at each price level in the current year. This is established using the current year regional oil wellhead price. Thus, the economic portion of undeveloped inferred reserves becomes "proved" inferred reserves based on the net difference between wellhead price and unit cost (profit) on each

[12]EIA/USDOE, "Enhanced Oil Recovery Supply Submodule (EORSS): Documentation for 1998 Annual Energy Outlook," p.37.

step of price/supply table. The rate of conversion is a fraction determined as the inverse of the expected number of years for development (see table below).

Table 1. 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

Thus, using the current year regional oil wellhead price as the delineation point in the price-supply table, only those "developed" reserves ($NEW\_PRV\_RES_{r,e,i}$) included at and below this delineation price are totaled to become reserve additions ($TNP\_RES_{r,e}$) for that year. The following equations apply:

$$NEW\_PRV\_RES_{r,e,i} = \frac{INF\_PS\_TBL_{tc,r,e,t,i}}{DEV\_SCHED_i} \tag{40}$$

$$TNP\_RES_{r,e} = \sum_i NEW\_PRV\_RES_{r,e,i} \tag{41}$$

where,

$NEW\_PRV\_RES_{r,e,i}$ = Inferred reserve additions at each incremental price step in year t (MMBO)
$TNP\_RES_{r,e}$ = Inferred reserve additions in year t
$INF\_PS\_TBL_{tc,r,e,t,i}$ = Price-supply table containing incremental oil wellhead prices and corresponding available undeveloped reserves for year t (MMBO)
DEV_SCHED_i = Development schedule at each oil wellhead price increment for year t (number of development years)
r = OGSM supply region (1-6)
e = EOR type (1=thermal, 2=gas)
i = Oil wellhead price step in price-supply table
t = year
tc = tech case

EOR Production from Inferred Reserve Additions

The inferred reserve additions are then added to last year's remaining end-of-year (EOY) "proved" inferred reserves. A P/R ratio is applied to determine production from these total inferred reserves. Thus,

$$CUR\_PRV\_RES_{r,e,i} = P\_CUR\_PRV\_RES_{r,e,i} + NEW\_PRV\_RES_{r,e,i} \tag{42}$$

$$NEW\_PROD_{r,e,t,i} = INF\_PR_{tc,r,e,t} * CUR\_PRV\_RES_{r,e,i} \tag{43}$$

and,

$$TN\_PROD_{r,e} = \sum_{i} NEW\_PROD_{r,e,t,i} \tag{44}$$

$$TRP\_RES_{r,e} = \sum_{i} (CUR\_PRV\_RES_{r,e,i} - NEW\_PROD_{r,e,t,i}) \tag{45}$$

where,

$CUR\_PRV\_RES_{r,e,i}$ = Inferred reserves available for production at each incremental price step, in year t (MMBO)
$NEW\_PROD_{r,e,t,i}$ = Production from inferred reserves at each incremental price step, in year t (MMBO)
$TN\_PROD_{r,e}$ = Total production from inferred reserves in region r, EOR type e, in t (MMBO)
$TRP\_RES_{r,e}$ = EOY "proved" inferred reserves in region r, EOR type e, in t (MMBO)
$P\_CUR\_PRV\_RES_{r,e,i}$ = EOY "proved" inferred reserves at each incremental price step, in year t-1 (MMBO)
$NEW\_PRV\_RES_{r,e,i}$ = Inferred reserve additions at each incremental price step, for year t (MMBO)
$INF\_PR_{tc,r,e,t}$ = Production to reserves ratio for year t
r = OGSM supply region (1-6)
e = EOR type (1=thermal, 2=gas)
i = Oil wellhead price step in price-supply table
t = year
tc = tech case

Thermal EOR Inferred Price/Supply Relationships

The price/supply relationships ($INF\_PS\_TBL_{tc,r,e,t,i}$) established to determine thermal inferred reserve additions each year (in all OGSM supply regions except region 6) are not developed within the EORSS, but rather contained in the input file in the form of a price/supply table.[13] In contrast, the price/supply table ($INF\_PS\_TBL_{tc,r,e,t,i}$) defined for thermal inferred reserves in OGSM region 6 is endogenously determined using 1992 field-specific characteristics and economic relationships associated with thermal extraction. The procedure is described in detail in the special EOR design appendix,[14] and is summarized below.

In each model year (beginning with the EOR base year, 1995), three sets of price/supply pairs are defined for each of 14 thermal EOR production fields in region 6. The prices at each field consist of an average threshold price, and related high and low threshold prices. The corresponding reserves are an allocation of the total potential reserves estimated for the field from field-specific

[13]This was necessary because the algorithm used to establish the data in the original data table could not be reconstructed.

[14]EIA/USDOE, "Enhanced Oil Recovery Supply Submodule (EORSS): Documentation for 1998 Annual Energy Outlook," Section 4.3, p.37.

horizontal and vertical drilling data. The average threshold price is determined from tangible, intangible, fixed, and variable costs. The algorithms describing both the average threshold price and the total reserves calculations are as follows:

$$AVGPR\_THRSHLD_{f,t} = TANGCC_{f,t} + ITANGCC_{f,t} + EORVOC_{f,t} + EORFXOC_{f,t} \tag{46}$$

$$TOT\_RESV_{f,t} = VINF\_RESV_{f} * (1. + HIMPRV\_REC * PCTPEN_{t}) \tag{47}$$

where,

$AVGPR\_THRSHLD_{f,t}$ = Average threshold price for reserves development (87$/BO)
$TOT\_RESV_{f,t}$ = Total potential reserves development (MMBO)
$TANGCC_{f,t}$ = Tangible capital costs (87$/BO)
$ITANGCC_{f,t}$ = Intangible capital costs (87$/BO)
$EORVOC_{f,t}$ = Variable operating costs (87$/BO)
$EORFXOC_{f,t}$ = Fixed operating costs (87$/BO)
$VINF\_RESV_{f}$ = Inferred reserves from vertical drilling (MMBO)
HIMPRV_REC = Inferred reserves factor for horizontal drilling (MMBO/well)
$PCTPEN_{t}$ = Percent penetration factor for horizontal drilling
t = year
f = EOR field

The high and low prices are defined as a specified percentage ($LAHPCT\_COST_{p}$) above and below the average threshold price ($AVGPR\_THRSHLD_{f,t}$). The inferred reserves corresponding to all three prices are a percent ($LAHPCT\_RESV_{p}$) of the total potential reserves development ($TOT\_RESV_{f,t}$) for a field. Each of the price/supply pairs established for all fields in region 6 are brought together to establish the regional price/supply table.

Gas Misible EOR Inferred Price/Supply Relationships

The algorithm used to endogenously develop the price/supply tables for gas misible inferred reserves is documented in detail in the special EOR design appendix,[15] and summarized below. The general approach was to establish a "total" potential resource base ($CO2RES\_INF_{r,t}$) for each region and year, based on an expansion rate formula. This resource base is then divided into price-specific levels of development using a previously established relationship. Although the parameters used in the relationship are different across supply regions, the relationship is the same: a specified percent of the resource base is allocated for development over 5 price ranges, with quantities divided equally across the 10 prices within each price range. Thus, the "total" potential resource base and corresponding price/supply tables are calculated as follows:

$$CO2RES\_INF_{r,t} = (CO2RES\_INF_{r,t-1} * MULT\_INF_{r}) + CONST\_INF_{r} \tag{48}$$

$$INF\_PS\_TBL_{tc,r,e,t,i} = CO2RES\_INF_{r,t} * \frac{SPLIT\_INF_{m,r}}{10.} \tag{49}$$

where,

[15]EIA/USDOE, "Enhanced Oil Recovery Supply Submodule (EORSS): Documentation for 1998 Annual Energy Outlook," p.57.

$CO2RES\_INF_{r,t}$ = Gas misible inferred reserves (MMBO)
$INF\_PS\_TBL_{tc,r,e,t,i}$ = Inferred reserves price-supply table (MMBO)
$MULT\_INF_r$ = Inferred reserves expansion parameter
$CONST\_INF_r$ = Inferred reserves expansion parameter
$SPLIT\_INF_{m,r}$ = Inferred reserves allocation factor over price ranges (fraction)
r = OGSM supply region (1-6)
e = EOR type (1=thermal, 2=gas)
i = Oil wellhead price step in price-supply table
t = year
tc = tech case
m = number of price ranges (=5)

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. Thus, cogeneration electric capacity is determined by multiplying total EOR steam requirements, times a cogeneration penetration factor, times a generating capacity conversion factor, as follows:

$$PRV\_COGEN_{r,1} = PRV\_STEAM_r * PRV\_COGENPEN * COGFAC \tag{50}$$

$$INF\_COGEN_{r,1} = INF\_STEAM_r * INF\_COGENPEN * COGFAC \tag{51}$$

where,

$PRV\_COGEN_{r,1}$ = Cogeneration electric capacity from production of proved reserves (MW)
$INF\_COGEN_{r,1}$ = Cogeneration electric capacity from production of inferred reserves (MW)
PRV_STEAM_r = Total steam required for production from proved reserves (MMBS)
INF_STEAM_r = Total steam required for production from inferred reserves (MMBS)
PRV_COGENPEN = Cogeneration penetration factor, percent of total steam for production from proved reserves going to cogen (fraction)
INF_COGENPEN = Cogeneration penetration factor, percent of total steam for production from inferred reserves going to cogen (fraction)
COGFAC = Conversion from steam to electric capacity (=7.8 MW/MMBS-yr)
r = OGSM supply region (1-6)
1 = Capacity array position

Electricity from existing capacity occurs according to assumed utilization factors as follows:

$$PRV\_COGEN_{r,4} = PRV\_COGEN_{r,1} * PRV\_UTIL_{r,1,t,2} * \frac{24 * 365}{1000} \tag{52}$$

$$INF\_COGEN_{r,4} = INF\_COGEN_{r,1} * INF\_UTIL_{r,1,t,2} * \frac{24 * 365}{1000} \tag{53}$$

where,

$PRV\_COGEN_{r,4}$ = Cogeneration electric generation from production of proved reserves (GWH)
$INF\_COGEN_{r,4}$ = Cogeneration electric generation from production of inferred reserves (GWH)

$PRV\_COGEN_{r,1}$ = Cogeneration electric capacity from production of proved reserves (MW)
$INF\_COGEN_{r,1}$ = Cogeneration electric capacity from production of inferred reserves (MW)
$PRV\_UTIL_{r,1,t,2}$ = Cogen capacity utilization factors associated with production of prv reserves (fraction)
$INF\_UTIL_{r,1,t,2}$ = Cogen capacity utilization factors associated with production of inf reserves (fraction)
r = OGSM supply region (1-6)
t = year
4 = Generation array position

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 6).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.

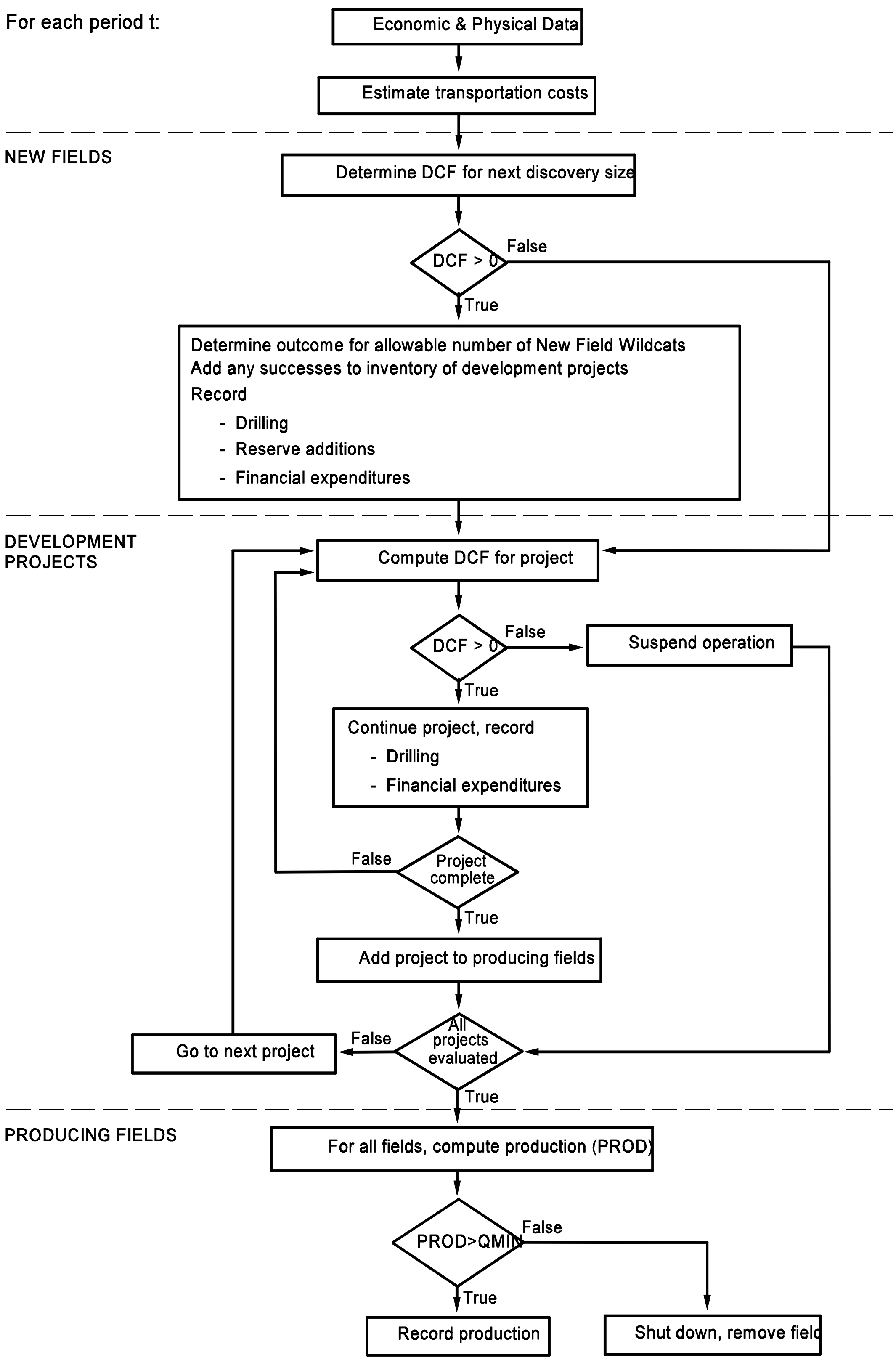
Calculation of Costs

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

- Drilling costs,
- Lease equipment costs, and
- 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 6. Flowchart for the Alaska Oil and Gas Supply Module



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:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1)**(t-T_b) \tag{54}$$

where,

I	=	well class(exploratory=1, developmental=2)
r	=	region
k	=	fuel type (oil=1, gas=2)
t	=	forecast year
DRILLCOST	=	drilling costs
T_b	=	base year of the forecast
TECH1	=	annual decline in drilling costs due to improved technology.

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:

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2)**(t - T_b) \tag{55}$$

where,

r	=	region
k	=	fuel type (oil=1, gas=2)
t	=	forecast year
EQUIP	=	lease equipment costs
T_b	=	base year of the forecast
TECH2	=	annual decline in lease equipment costs due to improved technology.

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:

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3)**(t - T_b) \tag{56}$$

where,

r	=	region
k	=	fuel type (oil=1, gas=2)
t	=	forecast year
OPCOST	=	operating cost
T_b	=	base year of the forecast
TECH3	=	annual decline in operating costs due to improved technology.

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.

$$\begin{aligned} TRR_t = {} & OPERCOST_t + DRR_t + TOTDEP_t + MARGIN_t + DEFRETREC_t + TXALLW_t \\ & NONTRANSREV_t + CARRYOVER_t \end{aligned} \tag{57}$$

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.[16] These assumed costs exclude any incurred or expected DR&R expenses, any depreciation or amortization of capitalized

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

cost, and any settlements with shippers for lost or undelivered oil due to normal operations during transportation.

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

$$TOTDEP_t = DEP_t * \left(DEPPROP_{t-2} + ADDS_{t-1} - PROCEEDS_{t-1} - TOTDEP_{t-1}\right) \quad (58)$$

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.

$$MARGIN_t = ALLOW_t * THRUPUT_t + 0.064 * \left(DEPPROP_{NEW,t} + DEFRET_{NEW,t} - DEFTAX_{NEW,t}\right) \quad (59)$$

where,

MARGIN	=	total after-tax margin
ALLOW	=	allowance per barrel
THRUPUT	=	projected net deliveries
$DEPPROP_{NEW}$	=	new depreciable property in service
$DEFRET_{NEW}$	=	new deferred return
$DEFTAX_{NEW}$	=	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

$$DEFRETREC_t = DEP_t * \left(DEFRET_{t-2} + INFLADJ_{t-1} + AFUDC_{t-1} - DEFRETREC_{t-1}\right) \quad (60)$$

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.

$$TXALLW_t = TXRATE * \left(MARGIN_t + DEFRETREC_t\right) \tag{61}$$

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.[17] 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:[18]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_{f,t}) \tag{62}$$

where,

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

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

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

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

$$DCF_{f,t} = (PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP - PVOPCOST - PVPRODTAX - PVSIT - PVFIT - PVWPT)_{f,t} \quad (63)$$

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[19]

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

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \quad (64)$$

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:

$$PROF_{f,t} = DCF_{f,t} \;/\; COST_{f,t} \quad (65)$$

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.

[19]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.

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,
- distribution of technically recoverable field sizes[20] within each region,
- the maximum number of new field wildcat wells drilled in any year,
- new field wildcat success rate, and
- 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, and
- 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.[21] 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 eight 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

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

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

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.

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.[22] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to peak rate,
- peak rate sustained for 3 to 8 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 depends on the construction of a major transportation facility to move natural gas to lower 48 markets.[23] In addition, the reinjection of North Slope gas for increased oil recovery poses an operational/economic barrier

[22] *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).

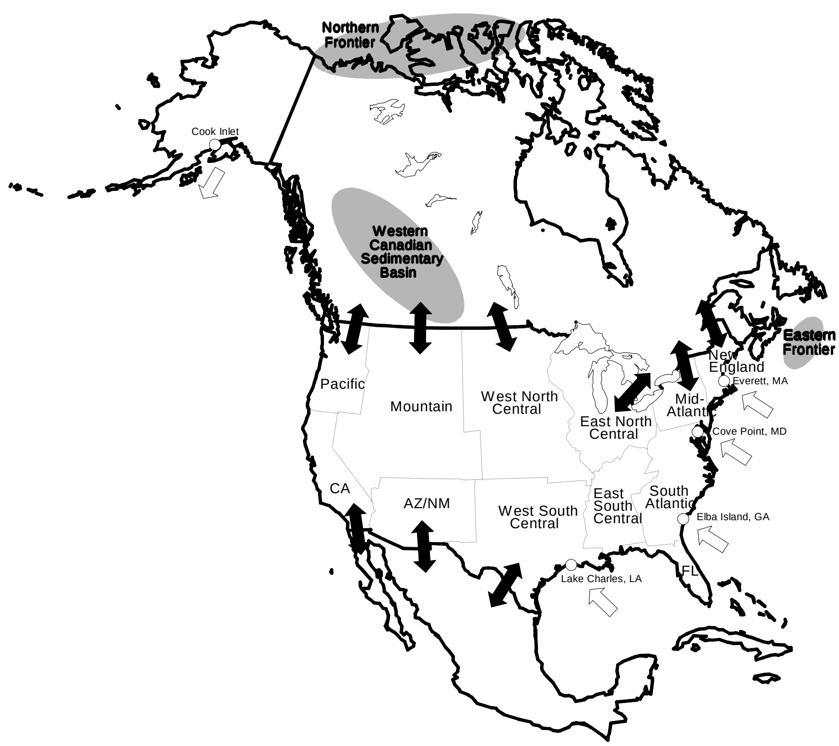
[23] Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction.

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.[24]

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.[25] Gas is traded with Canada and Mexico via pipelines. The border crossing locations are identified in Figure 7. 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 from Algeria, Trinidad and Tobago, Australia,Qatar, Malaysia, and the United Arab Emirates.

Figure 7. Foreign Natural Gas Trade via Pipeline



[24]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.

[25]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.

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 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 and production in the preveious year, rather than as a function of expected profitability proxied by the expected DCF. No distinction is made between exploration and development. For modeling purposes, conventional and unconventional resources are combined. 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. The number of successful wells drilled for the WCSB is determined using an econometric model. Next, an estimated finding rate is applied to the successful wells 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 8.

The determination of the import volumes into the United States 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.

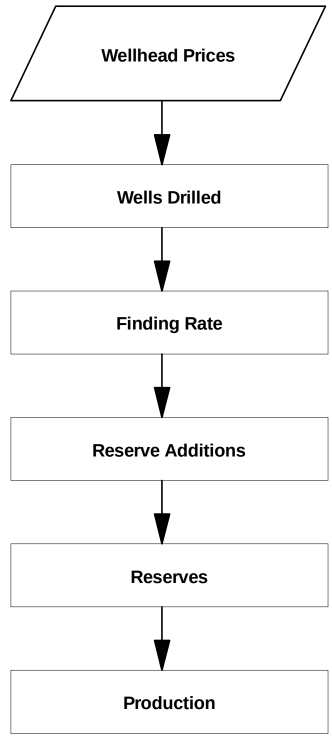
Western Canadian Sedimentary Basin

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 production in the previous year. Thus,

$$SUCWELL_t = e^{(\beta0+\beta3)} * GPRICE_t^{\beta2} * SUCWELL_{t-1}^{\rho} * e^{[-\rho*(\beta0+\beta3)]} * GPRICE_{t-1}^{-\rho*\beta2} \qquad (66)$$

Figure 8. A General Outline of the Canadian Algorithm of the FNGSS



where,

GPRICE	=	price per mcf of natural gas in 1987 US dollars
SUCWELL	=	total successful gas wells completed in Western Canada
$\beta0$	=	econometrically estimated parameter (7.66066, Appendix B)
$\beta2$	=	econometrically estimated parameter (0.58936, Appendix B)
$\beta3$	=	econometrically estimated parameter (0.656529, Appendix B)
ρ	=	econometrically estimated parameter (0.402134, Appendix B).

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 applied to the number of successful wells. If remaining economically recoverable resources are positive, total reserve additions are defined as:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \tag{67}$$

where,

$RESADCAN_t$	=	Reserve additions in year t, in BCF
$FRCAN_t$	=	Finding rate, in BCF/well
$SUCWELL_t$	=	Successful gas wells drilled in year t

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. Thus, the finding rate (FRCAN) equation for gas is estimated as follows:

$$FRCAN_t = e^{-115.706} * CUMGWELLS_t^{-0.763412} * e^{-0.000278607 * SUCWELL + 0.0} \qquad (68)$$

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

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \qquad (69)$$

where,

$RESBOYCAN_{t+1}$	=	Beginning of year reserves for t+1 (end of year reserves for t), in BCF
$CURRESCAN_t$	=	Beginning of year reserves for t, in BCF
$RESADCAN_t$	=	Reserve additions in year t, in BCF
$OGPRDCAN_t$	=	Production in year t, in BCF
t	=	forecast year

Finally, remaining economically recoverable resources defined in this model incorporate 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. 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. Thus, the remaining resources are defined as:

$$URRCAN_t = RESBASE_{resbasyr} * (1. + RESTECH)^T - CUMRCAN_{t-1} \qquad (70)$$

where

$URRCAN_t$	=	Remaining resources, in BCF
$RESBASE_{resbasyr}$	=	Economically recoverable resource base in reserves base year, in BCF
RESTECH	=	Technology factor
$CUMRCAN_{t-1}$	=	Cumulative reserve discoveries over the projection period (initial value = 0), in BCF
resbasyr	=	reserves base year
T	=	time delta between reserves base year and current year, T = t - (RESBASYR - BASEYR + 1)

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.

Gas production in the Western Canadian Sedimentary Basin (WCSB) in year t is processed in the NGTDM and is represented by the following equation:

$$Q_t = R_{t-1} * PR_t * (1 + \beta * \frac{\Delta P_t}{P_{t-1}}) \tag{71}$$

where,

Q_t	=	Canadian gas production in period t, BCF
R_{t-1}	=	end-of-year gas reserves in period t-1, BCF
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, 1987$/mcf
β	=	estimated short run price elasticity of extraction
ΔP_t	=	(P_t-P_{t-1}), the change in price from t-1 to t, 1987$/mcf

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}) for year t+1 is defined in the FNGSS as:

$$PR_{t+1} = \frac{Q_t * (1 - PR_t) + PRNEW * RA_t}{R_t} \tag{72}$$

where,

PR_{t+1}	=	gas extraction rate in period t+1 (measured as the production to reserves ratio at the end of period t)
PR_t	=	gas extraction rate in period t (measured as the production to reserves ratio at the end of period t-1: $PR_t = Q_t / R_{t-1}$)
R_t	=	end-of-year gas reserves in period t, BCF
Q_t	=	Canadian gas production in period t, BCF
RA_t	=	reserve additions in period t, BCF
PRNEW	=	new production to reserves ratio for new reserve additions

Supplies from the Northern Canadian Frontier and Eastern Canada

Frontier production and eastern Canada production in FNGSS were 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 and the National Petroleum Council (NPC). The NEB study[26] published in June 1999 indicates that the economics of frontier gas recovery and transportation prevent the occurrence of frontier flows until after 2015. The present implementation is handled by the NGTDM, and is based on an average of two NEB forecast cases reported in the 1999 study, with frontier production beginning in 2016. 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. Similarly, estimates for eastern Canada gas are handled by the NGTDM (also obtained from the 1999 NEB Supply and Demand study), with details included in the associated methodology documentation.

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.[27]

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.

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[26]National Energy Board, *Canadian Energy Supply and Demand to 2025*, 1999.

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

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.

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 scheduled to open by 2003 (Figure 7).

Given the rather low variable costs (generally under $1 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 1 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,[28] and
- Price increments that would bring forth additional LNG import capacity.

[28]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 effects 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)).

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

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] 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,

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

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,

$PVREV_{T,1}$	=	present value of expected revenues generated from the primary fuel
$PVREV_{T,2}$	=	present value of expected revenues generated from the secondary fuel.

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	=	royalty rate, expressed as a fraction of gross revenues.

[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.

[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:

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

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

where,

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

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

where,

EQUIP	=	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:

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

where,

KAP	=	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:

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[OPCOST_T * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left(\frac{1}{1 + disc} \right)^{t-T} \right] \tag{9}$$

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

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[COSTABN_T * \left[\frac{1}{1+disc} \right]^{t-T} \right] \tag{10}$$

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

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

Table 4A-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** G&G[a] Lease Acquisition	**Cost Depletion**[b] G&G Lease Acquisition	**Maximum of Percentage or Cost Depletion** G&G Lease Acquisition
Depreciable Costs	**MACRS**[c] Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC's **5-year SLM**[d] 20 percent of IDC's	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC's	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC's
Expensed Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs

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, and
- 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:

$$\text{PVTAXBASE}_T = \sum_{t=T}^{T+n} \Big[(\text{TREV}_t - \text{ROY}_t - \text{PRODTAX}_t - \text{OPCOST}_t - \text{ABANDON}_t - \text{XIDC}_t - \text{AIDC}_t - \text{DEPREC}_t - \text{DHC}_t) * \left(\frac{1}{1+\text{disc}}\right)^{t-T} \Big] \tag{11}$$

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. 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:

$$\text{XIDC}_t = \text{COSTEXP}_T * (1 - \text{EXKAP}) * (1 - \text{XDCKAP}) * \text{SR}_1 * \text{NUMEXP}_t + \text{COSTDEV}_T * (1 - \text{DVKAP}) * (1 - \text{XDCKAP}) * \text{SR}_2 * \text{NUMDEV}_t \tag{12}$$

where,

COSTEXP	=	drilling cost for a successful exploratory well

[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:

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

where,

j	=	year of recovery
β	=	index for write-off schedule
DEPIDC	=	for t $\le$ 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.

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

Table 4A-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.

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

$$\text{DEPREC}_t = \sum_{j=\beta}^{t} \Bigg[\Big[(\text{COSTEXP}_T * \text{EXKAP} + \text{EQUIP}_T) * \text{SR}_1 * \text{NUMEXP}_j + (\text{COSTDEV}_T * \text{DVKAP} + \text{EQUIP}_T) * \text{SR}_2 * \text{NUMDEV}_j + \text{KAP}_j \Big] * \text{DEP}_{t-j+1} * \left(\frac{1}{1+\text{infl}}\right)^{t-j} * \left(\frac{1}{1+\text{disc}}\right)^{t-j} \Bigg], \qquad (15)$$

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

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

$$\text{PVSIT}_T = \text{PVTAXBASE}_T * \text{STRT} \qquad (16)$$

where,

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

[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.

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

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \qquad (17)$$

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 a National Petroleum Council study (1992).

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

where,

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

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:

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

where,

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

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:

$$SHPCST_t = \frac{CAPCSTS_{s,t} + OMCSTS_{s,t} + MSCSTS_{s,t}}{VOLYR_{s,t}} \tag{4}$$

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:

$$CAPCSTS_{s,t} = DEP_{s,t} + INTR_{s,t} + ROE_{s,t} + TAX_{s,t} \tag{5}$$

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,

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

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,

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

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,

$RSCAP_{r,t}$ = restart capital costs
$EXCAP_{r,t}$ = 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 as 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 ($\sum_{y=1}^{t} EXDEP_{r,y}$)
d_r = debt financing amount (fraction)
kd_r = cost of debt (percent)
y = year of expansion

[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.

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

$EXTAX_{r,t}$ = tax on capital ($EXINVST_r$ * $EXTRATE_r$)
$EXTRATE_r$ = 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:

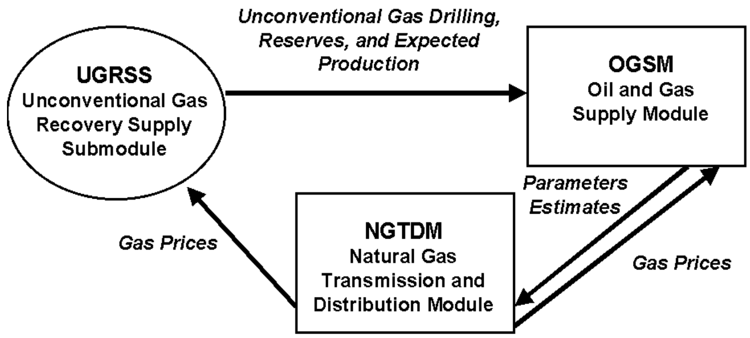
- Model purpose;
- Model overview and rationale;
- Model structure
- Inventory of input data, technological variables, model output;

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).

Figure 4C-1. UGRSS Interfaces with EIA/NEMS Modules



The UGRSS uses pricing data from EIA's NGTDM, resource data from the USGS's 1995 National Assessment[1], 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.

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 30 percent 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.

[1]"1995 National Assessment of United States Oil and Gas Resources," U.S. Geological Survey, National Oil and Gas Resource Assessment Team, U.S. Geological Survey Circular 1118, (1995)

Table 4C-1. USGS 1995 National Assessment

Background

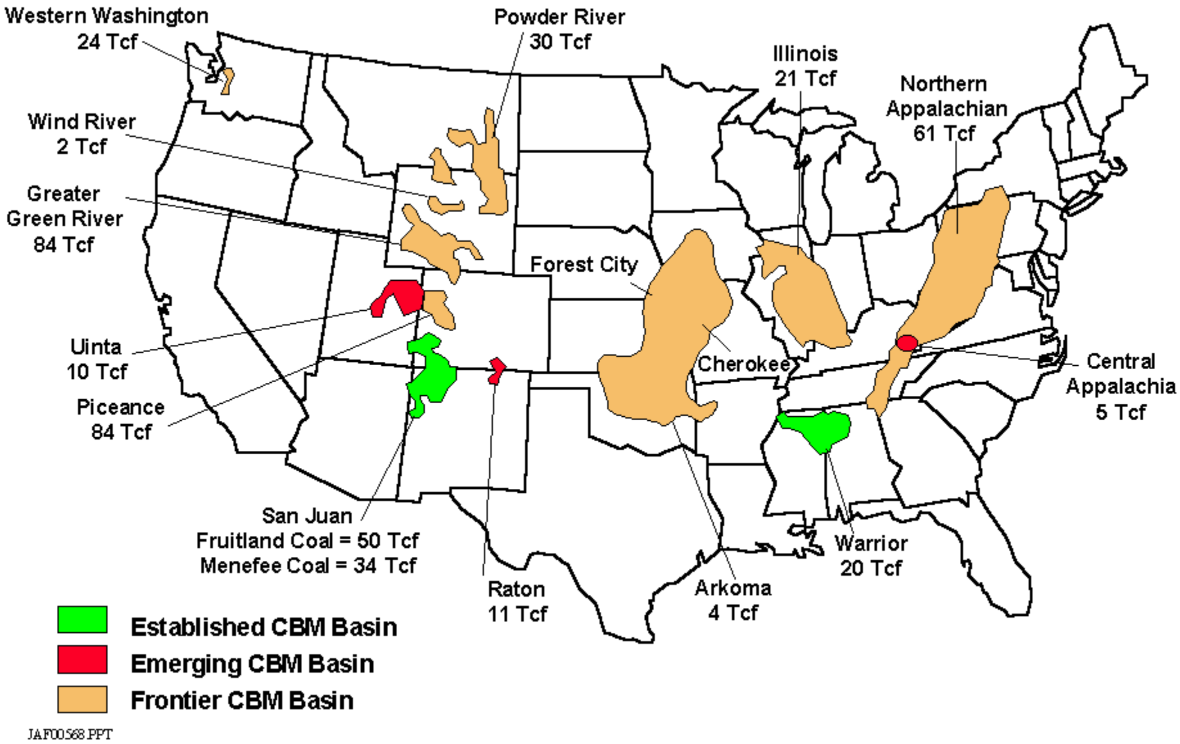
- **The 1995 National Assessment of U.S. Oil and Gas Resources by the USGS established unconventional gas (continuous-type deposits) as the largest undiscovered onshore technically recoverable natural gas resource:**

-- Continuous-Type Deposits		358 Tcf
- CBM	(50 Tcf)	
- Gas Shales	(49 Tcf)	
- Tight Sands*	(260 Tcf)	
-- Reserve Growth		322 Tcf
-- Undiscovered Conventional Resources		259 Tcf

*Includes low permeability chalks

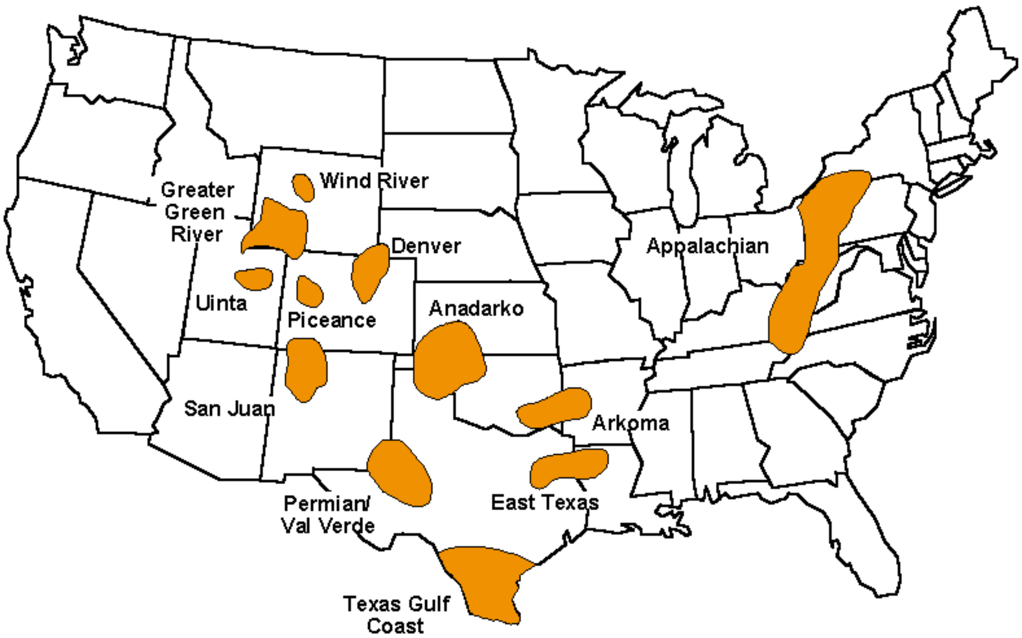
- **Significantly, the 1995 Assessment did not quantitatively assess many large, already producing unconventional gas deposits, such as:**
  - -- Wind River Basin, Tertiary and Upper Cretaceous Tight Sands
  - -- Fort Worth Basin, Barnett Shale
  - -- Green River Basin, Deep Coalbed Methane

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



Source: Advanced Resources, International

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



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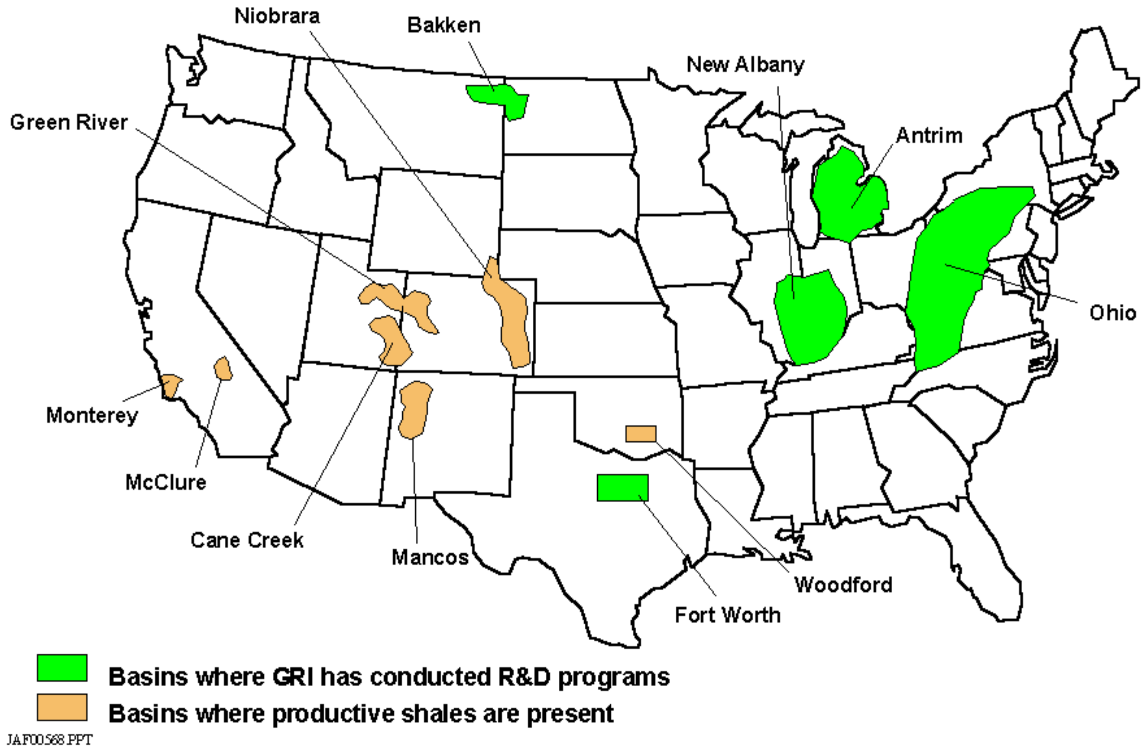
Source: Advanced Resources, International

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



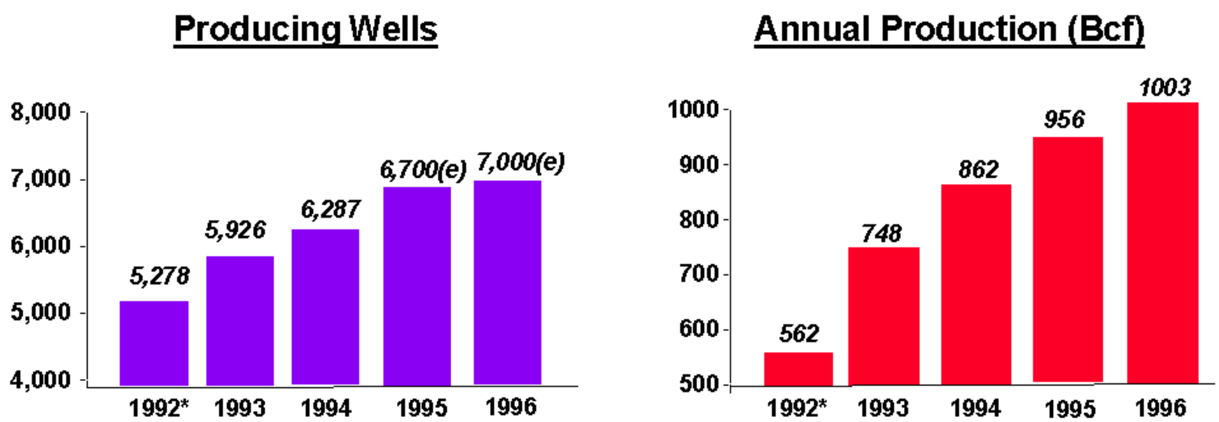
Source: Advanced Resources, International

MODEL OVERVIEW & RATIONALE

The growth of unconventional gas activities in the recent past 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



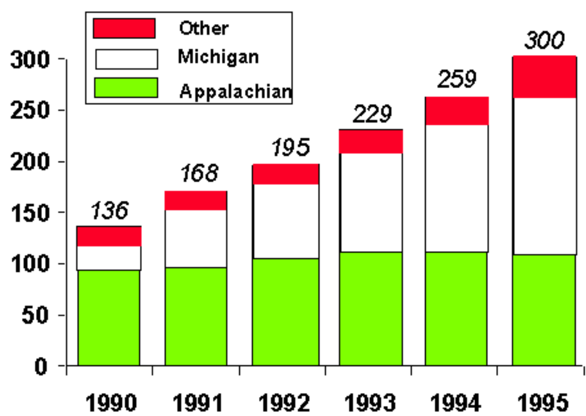
*1992 was the end of the Sec. 29 tax credit.

Source: Advanced Resources, International

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).

Source: Advanced Resources, International

Table 4C-2

Tight Gas Production -- 1992-1996

	Annual Production (Bcf)				
Basins/Regions	**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**

Source: Advanced Resources, International

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 affect 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
(as of 1/1/96)

Tight Sand Basins	Undeveloped Recoverable Resources (Tcf) No. Plays	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	19.4	Improved Performance
Mid-Continent (Anadarko)	3	N/A	14.0	New Assessment
Northern Great Plains	3	39.9	22.5	Reduced Performance
Rocky Mountain Basins				
- *Denver*	*1*	*0.8*	*0.8*	*Comparable Assessment*
- *San Juan*	*3*	*21.7*	*22.2*	*Comparable Assessment*
- *Uinta*	*4*	*7.9*	*6.2*	*Comparable Assessment*
- *Green River*	*7*	*86.7*	*100.6*	*Added Deep Gas Resource*
- *Piceance*	*3*	*12.8*	*16.2*	*Improved S. Basin Assessment*
- *Wind River*	*4*	*N/A*	*19.6*	*New Assessment*
Permian	2	N/A	14.5	New Assessment
Texas Gulf	3	N/A	8.1	New Assessment
TOTAL		**232.5**	**273.8**	

Source: Advanced Resources, International

Table 4C-4

Gas Shales Resource Base
(as of 1/1/96)

Gas Shales Basins	Undeveloped Recoverable Resources (Tcf)			Comments
	No. Plays	USGS	ARI	
Appalachian Basin	4	24.4	23.9	Comparable Assessment
- *Big Sandy Central*	*1*	*9.1*	*8.6*	
- *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	18.9	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	-	6.9	USGS Did Not Assess
TOTAL	**10**	**48.5**	**54.7**	

Source: Advanced Resources, International

Table 4C-5

Coalbed Methane Resource Base
(as of 1/1/96)

CBM Basins	Undeveloped Recoverable Resources (Tcf) No. Plays	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*	*10.3*	*Improved Well EURs, Success Rates, Play Probabilities; Expanded Area*
- *Green River*	*2*	*3.9*	*7.4*	*Added Deep Coals (3.6 Tcf)*
- *Piceance*	*4*	*7.5*	*7.5*	*Comparable Assessment*
Others (Wind River, etc.)	2	1.1	-	Small Resources, Little Data
TOTAL	**28**	**49.9**	**62.8**	

Source: Advanced Resources, International

UGRSS MODEL STRUCTURE

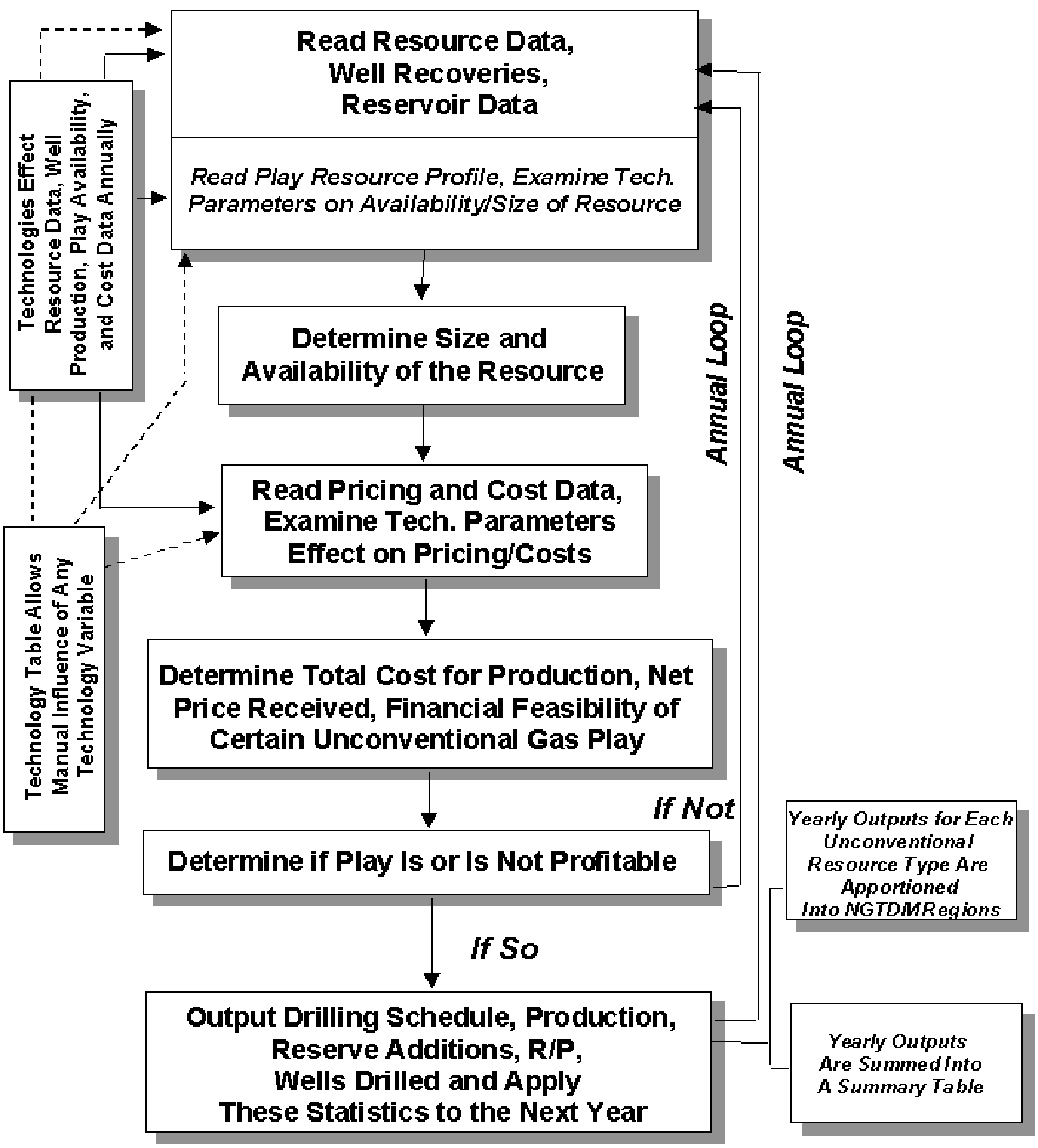
The UGRSS is a FORTRAN-based modeling system developed in a spreadsheet format. The UGRSS projects future unconventional natural gas production for the U. S. onshore lower 48 States. This section discusses in detail the programming structure, design, model inputs and technology variables that allow the 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



The USGS estimates 352 trillion cubic feet (TCF) of continuous-type resources for the onshore United States, 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 United States 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 10 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 number 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 (with some modifications) from 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 from which to forecast. Each is noted in this documentation and the actual number and forecast equation are described.

The EUR's of the potential wells to be drilled in areas that are thought in a given year to be the best 30 percent (in terms of productivity), middle 30 percent, and worst 40 percent, respectively, of a basin are based on weighted averages of the true EUR's for the best 10 percent, next best 20 percent, middle 30 percent, and worst 40 percent of the basin. The weights reflect the degree to which the driller is able to ascertain a complete understanding of the basin's structure.

The actual EUR's for the basin are represented as follows.

$RW10_1$ = 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

Variables representing the EUR's of the potential wells to be drilled in a given year are shown below. Note that the EUR's of all three qualitative categories of wells (best 30 percent, middle 30 percent, and worst 40 percent) are equal in the first year. This reflects the relatively random nature of drilling decisions early in the basin's developmental history. As will be shown, these respective EUR's evolve as information accumulates and technology advances, enabling drillers to more effectively locate the best prospective areas of the basin.

For Year 1:

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

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

$MEUR1_{1,2}$ = A weighted average for the best 30 percent of the potential 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 potential 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 potential 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, experience and technology enable the basin to be better understood geologically and from a potential productive aspect. Accordingly, the model gradually high grades each basin into a best, average, and worst area. As the understanding of the basin develops over time and technology advances, the area thought to be the best 30 percent from a drilling prospective moves toward an EUR representative of the best 10 percent and 20 percent of the basin, the average area stays consistent with the middle 30 percent basin EUR value and the area figured to constitute the worst

40 percent of the potential drilling prospects slowly downgrades to the bottom 40 percent basin EUR value. This process uses the following equations:

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

$$MEUR1_{iyr,2} = MEUR1_{1,1}+(((((RW10_1*(1/3))+(RW20_1*(2/3)-MEUR1_{1,1}))/DEVPER)*TECHYRS)*(TECHYRS*(REDAM\%/20)+TECHYRS*(FRCLEN\%/20)+TECHYRS*(PAYCON\%/20)+1)) \quad (4)$$

Where,

DEVPER	=	Development period for "Favorable Settings" technological advances
REDAM%	=	Total percentage increase over development period due to advances in "Reduced Damage D&S" technology
FRCLEN%	=	Total percentage increase over development period due to advances in "Increased Fracture Length L&C" technology
PAYCON%	=	Total percentage increase over development period due to advances in "Improved Pay Contact" technology
TECHYRS	=	Number of years (from base year) over which incremental advances in indicated technology have occurred

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

$$MEUR1_{iyr,3} = RW30_{iyr} \quad (5)$$

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

$$MEUR1_{iyr,4} = MEUR1_{1,1}-((RW30_1-RW40_1)/DEVPER)*TECHYRS)*(TECHYRS*(REDAM\%/20)+TECHYRS*(FRCLEN\%/20)+TECHYRS*(PAYCON\%/20)+1) \quad (6)$$

NEWCAVFRWY	=	For Coalbed Methane, establishes whether or not cavitation technology is advanced to the point that "New Cavity Fairways" are developed for the basins geologically favorable for use of this technology.

CAVFRWY% = For Coalbed Methane, total percentage increase in EUR due to development of New Cavity Fairways.

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)

MEUR2 =	IF NEWCAVFRWY equal to 1: MEUR2 = MEUR1 * (1 + CAVFRWY%) IF NEWCAVFRWY equal to 0: MEUR2 = MEUR1	(7)

ENCBM = For Coalbed Methane, establishes whether or not enhanced coalbed methane technologies are available to be used in basins in which such technologies are applicable.

ENCBM% = For Enhanced Coalbed Methane, total percentage increase in EUR due to implementation of enhanced coalbed methane technologies.

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)

MEUR3 =	IF ENCBM equal to 1: MEUR3 = MEUR2 * (1 + ENCBM%) IF ENCBM not equal to 1: MEUR3 = MEUR2	(8)

S C

$SSRT_1$ = 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.

PLPROB = The play probability: Only hypothetical plays have a PLPROB < 100 percent.

PLPROB2 = The play probability adjusted for technological progress, if initial play probability less than 1

TRW = 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.

$$\boxed{TRW = (ATUL*SCSSRT*PLPROB2)} \quad (9)$$

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

$$\boxed{UNDEV\_RES = (MEUR3*TRW)} \quad (10)$$

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

$$\boxed{RESNPROD_{iyr} = RESNPROD_{iyr-1}+RESADD_{iyr-1}} \quad (11)$$

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

$$\boxed{URR = (RESNPROD+UNDEV\_RES)} \quad (12)$$

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.

DIS_FAC = Discount Factor: This is the discount factor[2] 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)	(13)

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 dollars.

ENPVR = (WHGP+BASNDIF)*DISCRES*1,000,000	(14)

DACC = 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
```
(15)

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

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

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	$50.00 / foot	$10,000
> 2000 feet	$80.00 / foot	$10,000

Source: Advanced Resources, International

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

Source: Advanced Resources, International

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	-

Source: Advanced Resources, International

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	=	(SZONE*STM_CST)	(16)

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.

PASE	=	IF WATR_DISP equal to 1: PASE = BASET+5*AVGDPTH IF WATR_DISP not equal to 1: PASE = 10,000	(17)

BASET = 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.

LSE_EQ = IF WATR_DISP equal to 1:
IF MEUR3 less than 0.5:
LSE_EQ = WOMS_LE +WOML_WTR
IF MEUR3 greater than or equal to 0.5:
IF MEUR3 less than or equal to 1:
LSE_EQ = WOMM_LE+ WOML_WTR
IF MEUR3 greater than 1:
LSE_EQ = WOML_LE+ WOML_WTR (18)
IF WATR_DISP equal to 0:
IF MEUR3 less than 0.5:
LSE_EQ = WOMS_LE
IF MEUR3 greater than or equal to 0.5:
IF MEUR3 less than or equal to 1:
LSE_EQ = WOMM_LE
IF MEUR3 greater than 1:
LSE_EQ = WOML_LE

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

Source: Advanced Resources, International

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

$$GAA10 = RST*(LSE\_EQ + PASE + STIMC + DACC) \quad (19)$$

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

$$TCC = DACC+STIMC+PASE+LSE\_EQ+GAA10 \quad (20)$$

DHC = Dry Hole Costs: Calculates the dry hole costs

$$DHC = (DACC+STIMC) * ((1/SCSSRT)-1) \quad (21)$$

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

$$CCWDH = (TCC+DHC)/(DISCRES*1,000,000) \quad (22)$$

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

VOC	=	IF WATR_DISP greater than 0.4: VOC = (WTR_DSPT*(TECHYRS)*(WDT%/20)) +((WOMS)*(TECHYRS)*(PUMP%/20)) +((GASTR)*(TECHYRS)*(GTF%/20)) +(OCWW$) IF WATR_DISP less than or equal to 0.4: VOC = (WTR_DSPT*(TECHYRS)*(WDT%/20)) +((WOMS)*(TECHYRS)*(PUMP%/20)) +((GASTR)*(TECHYRS)*(GTF%/20)) +(OCNW$)	(23)

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

VOC2	=	If ECBMR is equal to 1: VOC2 = (VOC+((ECBM_OC+VOC)*(ENH_CBM%))/ (1+ENH_CBM%)) If ECBMR is not equal to 1: VOC2 = VOC	(24)

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

FOMC = If WATR_DISP is greater than or equal to 0.5:
If MEUR3 is less than or equal to .5:
FOMC = DIS_FACT*WOMS_OMW+ VOC* (DISCRES*1,000,000)
If MEUR3 is greater .5 and less than or equal to 1:
FOMC = DIS_FACT*WOMM_OMW +VOC*(DISCRES*1,000,000)
If MEUR3 is greater than 1:
FOMC = DIS_FACT*WOML_OMW +VOC*(DISCRES*1,000,000)
If WATR_DISP is less than 0.5:
If MEUR3 is less than or equal to .5:
FOMC = .6*DIS_FACT*WOMS_OMW+VOC* (DISCRES*1,000,000)
If MEUR3 is greater .5 and less than or equal to 1:
FOMC = .6*DIS_FACT*WOMM_OMW+VOC* (DISCRES*1,000,000)
If MEUR3 is greater than 1:
FOMC = .6*DIS_FACT*WOML_OMW+VOC* (DISCRES*1,000,000)

(25)

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

Source: Advanced Resources, International

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)	(26)

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

NET_PRC = (1-RST)*(WHGP+BASNDIF)	(27)

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	(28)

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	(29)

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)                (30)
                     IF ENPRGS   =   0:
                     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:
                        MEUR4         =        0
```
(31)

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$:
                             DRL_SCHED  =        SLOW
                             If NET_PROF2 is greater than or equal to
                             SMAL$:
                                  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
```
(32)

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 (33)

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		(34)

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

NW_WELLS =	If DRL_SCHED3 is greater than 0:
	    If Year is greater than 1 and NW_WELLS_LAG is greater than 0:
	        If UNDV_WELLS/DRL_SCHED3 is greater than 1.3*NW_WELLS_LAG:
	        NW_WELLS = 1.3*NW_WELLS_LAG
	        Else if UNDV_WELLS/DRL_SCHED3 is less than .7*NW_WELLS_LAG:
	        NW_WELLS = .7*NW_WELLS_LAG
	        Else:
	        NW_WELLS = UNDV_WELLS/ DRL_SCHED3
	    If Year is equal to 1 or NW_WELLS_LAG is equal to 0:
	    NW_WELLS = UNDV_WELLS/DRL_SCHED3
	If DRL_SCHED3 is equal to 0:
			(35)

NW_WELLS_LAG = New Wells Lagged: The amount of wells drilled in the play in the previous year

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	(36)

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	(37)

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: If ENCBM is equal to 1: RGA = RGR*PROV_RES + .025*((MEUR3-MEUR2)*DEV_CEL) If ENCBM is not equal to 1: RGA = RGR*PROV_RES: If RES_GR is not equal to 1: RGA = 0	(38)

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	(39)

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.

PROV_RES2 =	If (PROV_RES+R_ADD-PROD) is greater than 0:
	PROV_RES2 = PROV_RES+R_ADD-PROD
	If (PROV_RES+R_ADD-PROD) is less than or equal to 0:
	PROV_RES2 = 0
		(40)

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.

RP_RAT2 =	If R/P is greater than 10: RP_RAT2 = RP_RAT-1 If R/P is less than or equal to 10: RP_RAT2 = RP_RAT	(41)

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

PROD2 =	If R/P2 is equal to 0: PROD2 = 0 If R/P2 is not equal to 0: PROD2 = PROV_RES2/(RP_RAT2)	(42)

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

UNDV_WELLS2 = If ENPRGS is equal to 1:

UNDV_WELLS2 = TRW-NW_WELLS2

If ENPRGS is not equal to 1:

If UNDV_WELLS is equal to 0:

UNDV_WELLS2 = 0

If UNDV_WELLS is not equal to 0:

If (UNDV_WELLS-NW_WELLS2) is equal to 0:

UNDV_WELLS2 = 0.1

If (UNDV_WELLS-NW_WELLS2) is not equal to 0:

UNDV_WELLS2 = UNDV_WELLS-NW_WELLS2 (43)

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 11 specific "technology packages," that encompass the full spectrum of key disciplines -- geology, engineering, operations, and the environment. The enclosed materials define these 11 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:

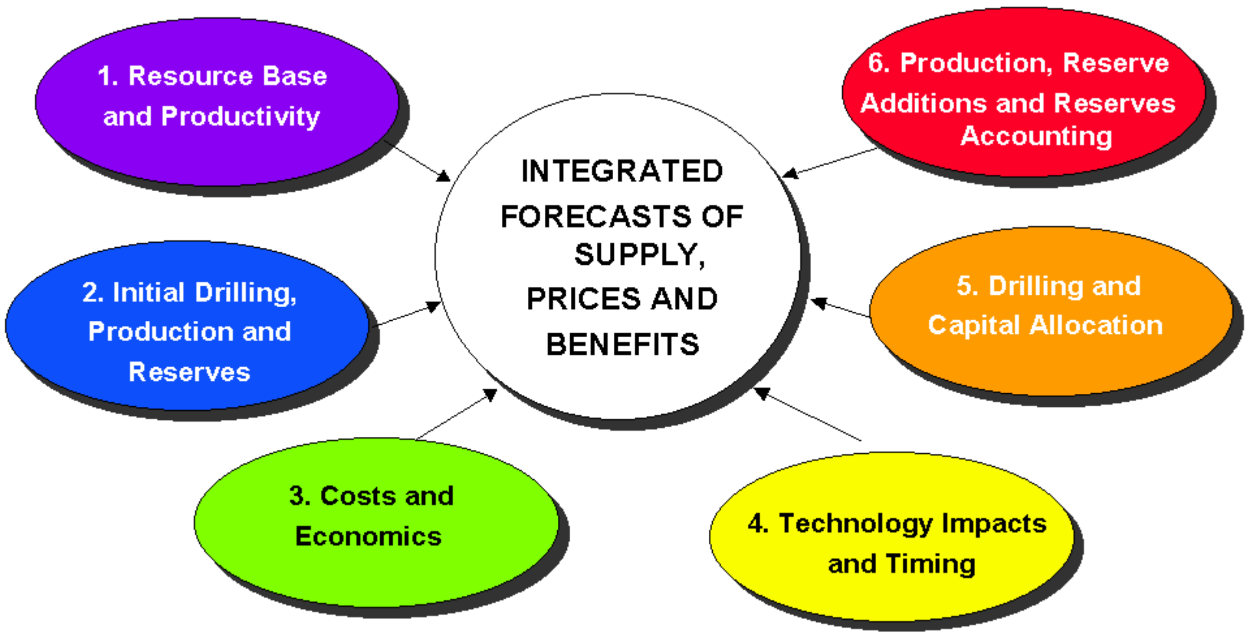
- **Reference Case** captures the current status and trends in the E&P technology for unconventional gas. A limited amount of R&D on tight sand reservoirs is directly supported by the DOE, particularly on advanced macro-exploration, seismic technologies, and matching of technology to reservoir settings. 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).

- The **Low Technology** case developed by ARI for the UGRSS captured 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 was expected to be modest. For the Annual Energy Outlook 2001 (AEO2001), the Low Technology case was modified to represent an R&D outlook which falls approximately midway between the Reference Case and the original Low Technology case.

- The **High Technology** case developed by ARI for the UGRSS defined strong, focused and integrated industry, DOE and GRI R&D programs in unconventional gas. It reflected 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. For the AEO2001, the High Technology case was modified to represent an R&D outlook which falls approximately midway between the Reference Case and the original High Technology case.

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 Severly 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 Remediation	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. Advanced 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 2012
		b. Play Probability	50% to 80% (Play Specific)	No Improvement	Same as Reference Case	No Improvement	No Improvement
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	$-^{3}/_{4}$ yrs/year (Max -20 years)	$-1^{1}/_{4}$ 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 @ $2^{1}/_{4}$%/yr., declining (20 years)	All Basins $3^{1}/_{4}$%., 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	$+^{3}/_{16}$%/year from 2000 (max 95%)	$+^{5}/_{16}$%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify "Best" 30% by Year 2017	Identify "Best" 30% by year 2017	Identify "Best" 30% by year 2024	Identify "Best" 30% by year 2013
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+5% (in 20 years)	Same as Reference Case	$+3^{3}/_{4}$% (in 20 years)	$+6^{1}/_{4}$% (in 20 years)

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
6. Improved Drilling and Stimulation	All Plays	EUR/Well	As Calculated	+10% (in 20 years)	Reference Case	+$7^{1}/_{2}$% (in 20 years)	+$12^{1}/_{2}$% (in 20 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-10% (in 20 years)	-5% (in 20 years)	-$7^{1}/_{2}$% (in 20 years)	-$12^{1}/_{2}$% (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%(-$0.05) (in 20 years)	-15%(-$0.05) (in 20 years)	-25%(-$0.08) (in 20 years)
9. Advanced CBM Cavitation	Cavity Fairway Plays	EUR/Well	As Calculated	+20% (year 2011)	No Improvement	+15% (year 2016)	+25% (year 2008)
10. Enhanced CBM Recovery	ECBM Eligible Plays	a. Recovery/ Efficiency	As Calculated	+30% (year 2015)	Same as Reference Case	+$22^{1}/_{2}$% (year 2018)	+$37^{1}/_{2}$% (year 2010)
		b. O&M Costs/Mcf	As Calculated	+$1.00/Mcf, Incremental	Same as Reference Case	+$1.25/Mcf, Incremental	+$0.75/Mcf, Incremental
11. Environmental Mitigation	EV Sensitive Plays	Acreage Available	50% of Play Restricted	Removed in 50 years (1%/yr from 2000)	Removed in 100 years ($^{1}/_{2}$%/ yr from year 2000)	Removed in 67 years ($^{3}/_{4}$%/ yr from year 2000	Removed in 40 years ($1^{1}/_{4}$%/yr from year 2000)

Table 4D-3
Details of Gas Shales Technological Progress

R&D Program	Gas Shales 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	Year 2023	Year 2018
		b. Play Probability	50% to 80% (Play Specific)	No Improvement	Same as Reference Case	No Improvement	No Improvement
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	-$^3/_4$ yrs/year (Max -20 years)	-1$^1/_4$ 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 @ 2$^1/_4$%/yr., declining (20 years)	All Basins 3$^3/_4$%/yr., declining (35 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	+$^3/_{16}$%/year from 2000 (max 95%)	+$^5/_{16}$%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify "Best" 30% by Year 2017	No Improvement	Identify "Best" 30% by year 2024	Identify "Best" 30% by year 2017
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+5% (in 20 years)	Same as Reference Case	+3$^3/_4$% (in 20 years)	+6$^1/_4$% (in 20 years)

Table 4D-3
Details of Gas Shales Technological Progress

R&D Program	Gas Shales Resource Impacted			Technology Cases			
		Technology Lever	Current Situation	Reference Case with DOE	Reference Case w/o DOE	Low Technology	High Technology
6. Improved Drilling and Stimulation	All Plays	EUR/Well	As Calculated	+10% (in 20 years)	Reference Case	$+7^{1}/_{2}$% (in 20 years)	$+12^{1}/_{2}$% (in 20 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-10% (in 20 years)	-5% (in 20 years)	$-7^{1}/_{2}$% (in 20 years)	$-12^{1}/_{2}$% (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% (-$0.05/Mcf) (in 20 years)	-15% (-$0.05/Mcf) (in 20 years)	-25% (-$0.08/Mcf) (in 20 years)
9. Multi-Lateral Completions	Eligible Plays	Recovery Efficiency	As Calculated	No Improvement	No Improvement	No Improvement	No Improvement
10. Other Gas Shales Technology	Eligible Plays	a. EUR/Well	As Calculated	N/A	N/A	N/A	N/A
		b. O&M Costs/Mcf	As Calculated	N/A	N/A	N/A	N/A
11. Environmental Mitigation	EV Sensitive Plays	Acreage Available	50% of Play Restricted	Removed in 50 years (1%/yr from 2000)	Removed in 100 years ($^{1}/_{2}$%/ yr from year 2000)	Removed in 67 years ($^{3}/_{4}$%/ yr from year 2000)	Removed in 40 years ($1^{1}/_{4}$%/yr from year 2000)

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

R&D Program	Tight Sands 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	Year 2023	Year 2013
		b. Play Probability	50% to 80% (Play Specific)	No Improvement	Same as Reference Case	No Improvement	No Improvement
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)	-0.94 yr/year (Max -20 years)	-1.56 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 @ $1^1/_2$%/yr., declining	All Basins @ $2^1/_2$%/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	$+^3/_{16}$%/year from 2000 (max 95%)	$+^5/_{16}$%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify "Best" 30% by Year 2017	No Improvement	Identify "Best" 30% by Year 2024	Identify "Best" 30% by year 2013
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+5% (in 20 years)	$+2^1/_2$% (in 20 years)	$+3^3/_4$% (in 20 years)	$+6^1/_4$% (in 20 years)

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

R&D Program	Tight Sands Resource Impacted			Technology Cases			
		Technology Lever	Current Situation	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$^{1}/_{2}$% (in 20 years)	+7$^{1}/_{2}$% (in 20 years)	+12$^{1}/_{2}$% (in 20 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-10% (in 20 years)	-5% (in 20 years)	-7$^{1}/_{2}$% (in 20 years)	-12$^{1}/_{2}$% (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)	-15% (-$0.02/Mcf) (in 20 years)	-25% (-$0.04/Mcf) (in 20 years)
9. Horizontal Wells	Continuous Sands	Recovery Efficiency	As Calculated	+10% (year 2011) (Selected Basins)	+5% (year 2016) (Selected Basins)	-7$^{1}/_{2}$% (year 2016) (Selected Basins)	+12$^{1}/_{2}$% (year 2008) (Add. Basins)
10. Other Tight Gas Technology	Other Sands	EUR/Well	As Calculated	No Improvement	No Improvement	No Improvement	+12$^{1}/_{2}$% (year 2016)
11. Environmental Mitigation	EV Sensitive Plays	Acreage Available	50% of Play Restricted	Removed in 50 years (1%/yr from 2000)	Removed in 100 years ($^{1}/_{2}$%/ yr from 2000)	Removed in 67 years ($^{3}/_{4}$%/yr from 2000)	Removed in 40 years (1$^{1}/_{4}$%/yr from 2000)

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 evaluated 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 4 years earlier, in year 2012.

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 2012	No Improvement

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

Source: Advanced Resources, International

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

Table 4D-7

Hypothetical Gas Shale Plays and Resources

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

Source: Advanced Resources, International

Table 4D-8

Hypothetical Tight Sand Plays and Resources

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

Source: Advanced Resources, International

**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 removes the "stretch-out" period in 27 years at 0.75 years per year for coalbed methane and gas shales and 21 years at 0.9 years per year for tight sands. High Technology overcomes the 20 year development "stretch-out" time faster, in 16 years, at a rate of 1.25 years of reduced time delay per year for CBM and gas shales and in 13 years, at a rate of 1.56 years of reduced time delay per year for tight sands.

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 sands basins. As such, in the Reference Case Technology w/o DOE for tight sands 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	a. Removed in 27 years, starting in 1997 for CBM and Gas Shales	a. .75 years reduction/year for CBM and Gas Shales
	b. Removed in 21 years, starting in 1997 for Tight Sands	b. .94 years reduction/year for Tight Sands
High Technology	a. Removed in 16 years, starting in 1997 for CBM and Gas Shales	a. 1.25 years reduction/year for CBM and Gas Shales
	b. Removed in 13 years, starting in 1997 for Tight Sands	b. 1.625 years reduction/year for Tight Sands

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

Source: Advanced Resources, International

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*

Source: Advanced Resources, International

**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

Source: Advanced Resources, International

**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 lower and declining reserve growth, starting at 2.25 percent per year for CBM and gas shales and 1.5 percent per year for tight sands. Growth in the low technology case declines over 20 years for CBM and gas shales and over 15 years for tight sands. High Technology starts with a higher 3.75 percent annual growth in proved reserves for CBM and gas shales and a 2.5 percent growth for tight sands. This growth declines over 35 years for CBM and gas shales and over 25 years for tight sands.

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	a. 2.25%, Declining for CBM and Gas Shales
		b. 1.5% Declining for Tight Gas
High Technology	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	a. 3.75%, Declining for CBM and Gas Shales
		b. 2.5% Declining for Tight Gas

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**

Source: Advanced Resources, International

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**

Source: Advanced Resources, International

**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**

Source: Advanced Resources, International

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/NETL'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. For all recovery types, Low Technology improves the success rate of the play by $^{3}/_{16}$ percent per year and enables industry to find the "best 30 percent" of the basin in 24 years. High Technology enables industry to reliably find the "best 30 percent" of a basin by the year 2013 for all recovery types. For this case the drilling success rate increases by $^{5}/_{16}$ percent per year, all increases starting in the year 2000.

Reference Case Technology w/o DOE shows no improvement 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

Parameter Values for Advanced Exploration and Natural Fracture Detection Technologies

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 $^{1}/_{4}$%/year from Year 2000
Reference Case w/o DOE	No Improvement	No Improvement
Low Technology	Identify "Best" 30% of Play by Year 2024	Improves by $^{3}/_{16}$%/year from Year 2000
High Technology	Identify "Best" 30% of Play by Year 2013	Improves by $^{5}/_{16}$%/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 5 percent in 20 years, at a rate of $^{1}/_{4}$ percent per years for all recovery types. Low Technology increases recovery from new wells by $3^{1}/_{4}$ percent in 20 years at a rate of $^{3}/_{16}$ percent per years. High Technology increases recovery per well by $6^{1}/_{4}$ percent, at a rate of $^{5}/_{16}$ 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	5%	$^{1}/_{4}$%/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. 2½% for Tight Sands	b. ⅛%/year for Tight Sands
Low Technology	$3^{3}/_{4}$%	$^{3}/_{16}$%/year
High Technology	$6^{1}/_{4}$%	$^{5}/_{16}$%/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 fracture 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 5 years.

Reference Case Technology increases recovery per well by 10 percent in 20 years (at a rate of ½ percent per year) for all recovery types. Low Technology increases recovery by $7^1/_2$ percent in 20 years (at a rate of $^5/_8$ percent per year). High Technology increases recovery by $12^1/_2$ percent in 20 years (at a rate of $^5/_8$ 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	10% (20 years)	½%/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 Shale
	b. 7½% for Tight Sands (20 years)	b. ⅜%/year for Tight Sands
Low Technology	$7^1/_2$% (20 years)	$^3/_8$%/year
High Technology	12½% (20 years)	$^5/_8$%/year

Reference Case Technology lowers the R/P ratio to a range of 9 to 10 for CBM, 10 to 11 for tight sands, and 11 to 12 for gas shales for new and still emerging plays. Low Technology maintains the R/P ratio at a relatively high 12 to 13 for gas shales. High Technology further reduces the R/P ratio to a range of 10.5 to 11.5 for gas shales. 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. However, 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 as many of the easier cost cutting efforts have been accomplished and the industry is returning 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 reduces drilling costs by 7.5 percent, at a rate of $^{3}/_{8}$ percent per year for 20 years. High Technology reduces drilling costs by 12.5 percent, at a rate of $^{5}/_{8}$ percent per year for 20 years.

Reference Case Technology w/o DOE is the same as the low technology case. 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	-7.5%	$^{-3}/_{8}$%/year
High Technology	-12.5%	$^{-5}/_{8}$%/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

As of 1998 (the year the UGRSS was developed), the O&M costs for water disposal in a high water producing gas play were about $0.05/Mcf. The O&M costs for CO_2 and N_2 removal were on the order of $0.10/Mcf. Gas dehydration, lease fuel and gas compression cost $0.15/Mcf. The combined costs were $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 sands, at a rate of 1 percent per year for 20 years. Low Technology lowers these cost by 15 percent or $0.05/Mcf for CBM and Gas Shale and about $0.02/Mcf for tight sands, at a rate of $^{3}/_{4}$ percent per year for 20 years. High Technology lowers these cost by 25 percent, or $0.08/Mcf, at a rate of $1^{1}/_{4}$ percent per year for 20 years, for CBM and wet gas shales and $0.04/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

Parameter Values for New Practices & Technologies for Water Disposal and Gas Treatment

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% ($0.03/Mcf) (20 years)	-1%/year
Reference Case w/o DOE	-15% ($0.05/Mcf) (20 years)	-15% ($0.02/Mcf) (20 years)	-$^{3}/_{4}$%/year
Low Technology	-15% ($0.04/Mcf) (20 years)	-15% ($0.02/Mcf) (20 years)	-$^{3}/_{4}$%/year
High Technology	-25% ($0.08/Mcf) (20 years)	-25% ($0.04/Mcf) (20 years)	-1$^{1}/_{4}$%/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 United States 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 2011. Once introduced, recovery efficiency and cavitation well performance would continue to improve by 1 percent per year.

Low Technology would improve recovery efficiency (and reserves per well) in the four potential "cavitation plays" by 15 percent over current well completion and stimulation methods but would not make this technology available until the year 2016. Recovery efficiency and cavitation well performance would then continue to improve by $^3/_4$ percent per year. High Technology would make an advanced version of cavitation technology available by the year 2008, providing a total improvement of 25 percent (at $1^1/_4$ percent per year) 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 show no improvement 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	San Juan Basin Fairway	No Change	No Change
Low Technology	Four New Cavity Fairways	2016	15%
High Technology	Four New Cavity Fairways	2008	25%

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

Source: Advanced Resources, International

* *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

Multi-lateral drilling technology would not be available in any of the four cases for gas shales during the forecast period.

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	Not Applicable
Reference Case	Not Available	Not Applicable
Reference Case w/o DOE	Not Available	Not Applicable
Low Technology	Not Available	Not Applicable
High Technology	Not Available	Not Applicable

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

Source: Advanced Resources, International

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-27** list the tight sands gas plays that could be applicable for horizontal wells.

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.

Low Technology would introduce a $7^1/_2$ percent improvement in recovery efficiency in 2016 and High Technology would provide a $12^1/_2$ percent improvement in recovery efficiency starting in 2011.

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-27	2011	10%
Reference Case w/o DOE	See Table 4D-27	2016	5%
Low Technology	See Table 4D-27	2016	$7^1/_2$%
High Technology	See Table 4D-27	2008	$12^1/_2$%

Table 4D-27
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

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 30 percent and makes this technology commercially available in the year 2015. Low Technology introduces new ECBM recovery technology that improves CBM recovery efficiency by $22^1/_2$ percent but does not introduce this technology until year 2018. High Technology introduces a more efficient ECBM technology in 2010 that improves efficiency by $37^1/_2$ percent. 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, $0.75 per Mcf of incremental CBM produced in the high technology case, and $1.25 per Mcf of incremental CBM produced in the Low 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 30%	$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	2018	Improves Recovery Per Well by $22^1/_2$%	$1.25/Mcf of Incremental CBM
High Technology	2010	Improves Recovery Per Well by $37^1/_2$%	$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

Only the high technology case has any effect from Other Tight Sands recovery technology. Recovery efficiency is increased by $12^1/_2$% in the year 2016.

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, and 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 removes these environmental constraints in 67 years. High Technology removes these constraints in 40 years, starting in the year 2000.

The Reference Case w/o DOE 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 @$^1/_2$%/year
Low Technology	Constraints removed in 67 years @ $^3/_4$%/year
High Technology	Constraints Removed in 40 years @ 1$^1/_4$%/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

Source: Advanced Resources, International

** 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

Source: Advanced Resources, International

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

Source: Advanced Resources, International

Appendix 4-E. Offshore Supply Submodule

The Offshore Supply Submodule (OSS) is a PC-based modeling system for projecting the reserve additions and production from undiscovered resources in the 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 OSS 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 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 OSS are described. The subsequent section deals with the rationale behind the various technology options for shallow and deepwater exploration, development and production practices incorporated in OSS. 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 OSS. The next section describes the unit cost equations utilized in the OSS to estimate the various costs associated with exploration, development, and production operations in the Gulf of Mexico OCS. This is followed by a discussion of the financial analysis approach and the discounted cash-flow methodology used in OSS to determine the profitability of crude oil and natural gas prospects, and to generate price-supply data. The final section in this chapter deals with the endogenous component of OSS that involves calculation of reserves and production for the total Gulf of Mexico offshore region.

INTRODUCTION

The OSS 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 OSS output, which consists essentially of detailed price/supply tables disaggregated by the Minerals Management Services (MMS) Gulf of Mexico planning regions (Eastern, Central, and Western) and fuel type (oil or 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 OSS, as defined by their relationship (exogenous vs. endogenous) to the OGSM:

Exogenous Component. A methodology for developing 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 <u>m</u>inimum <u>a</u>cceptable <u>s</u>upply <u>p</u>rice (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

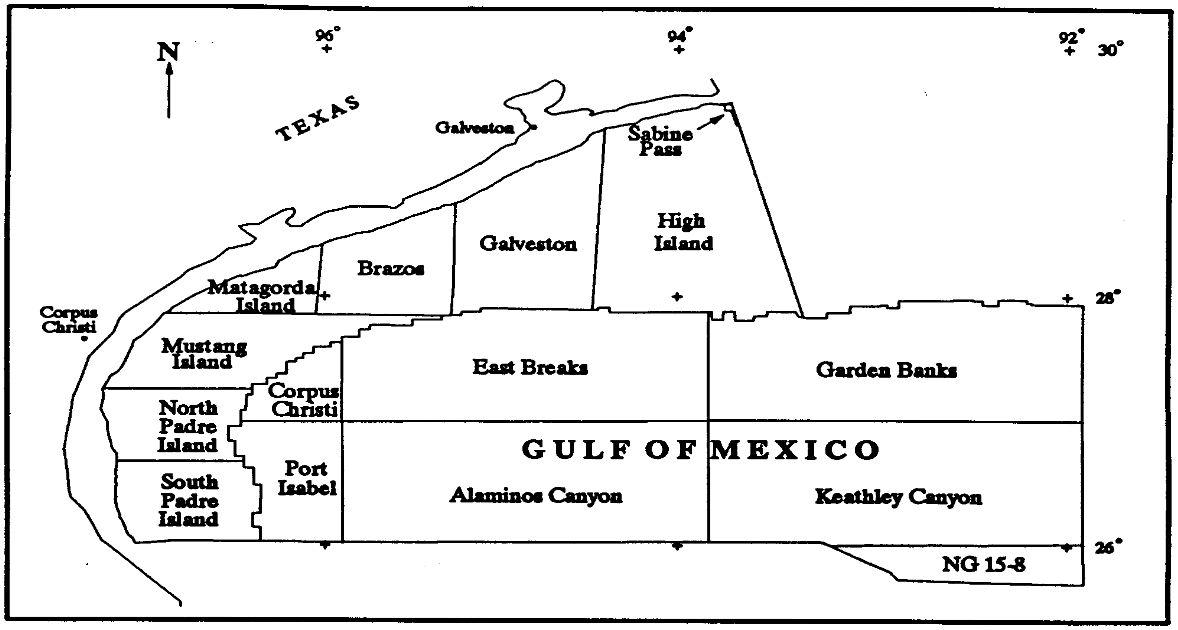


Figure 4E - 2. Map of Central Gulf of Mexico Planning Area

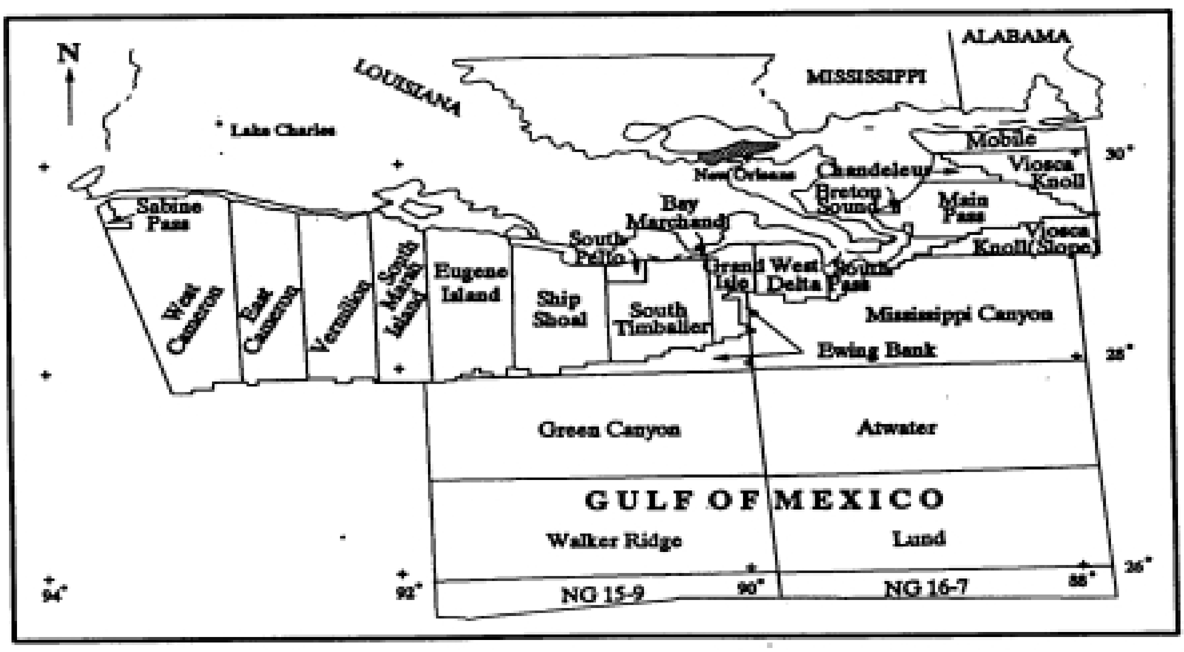
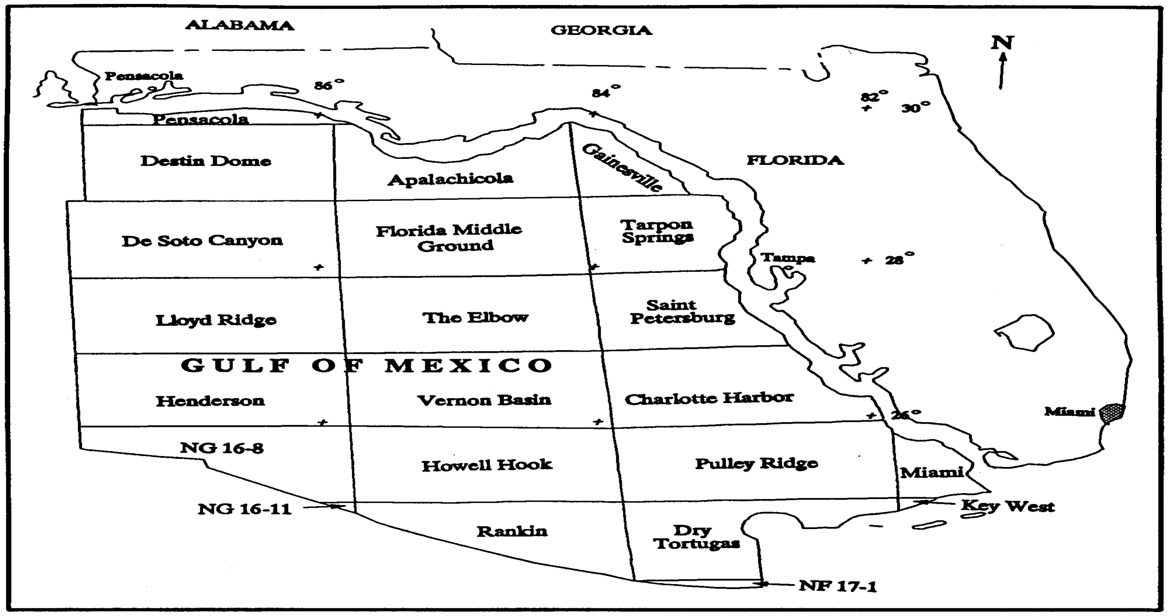


Figure 4E - 3. Map of Eastern Gulf of Mexico Planning Area



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 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 OSS 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 OSS 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 GULF OF MEXICO UNDISCOVERED RESOURCES

The reat bulk of undiscovered oil and gas resources are estimated to be in deeper waters of the Gulf of Mexico OCS. Based on the estimates developed for the National Petroleum Council's 1999 report *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand*, approximately 42 billion of 50 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.

Figure 4E - 4. Programming Structure of the Exogenous Component of the OSS

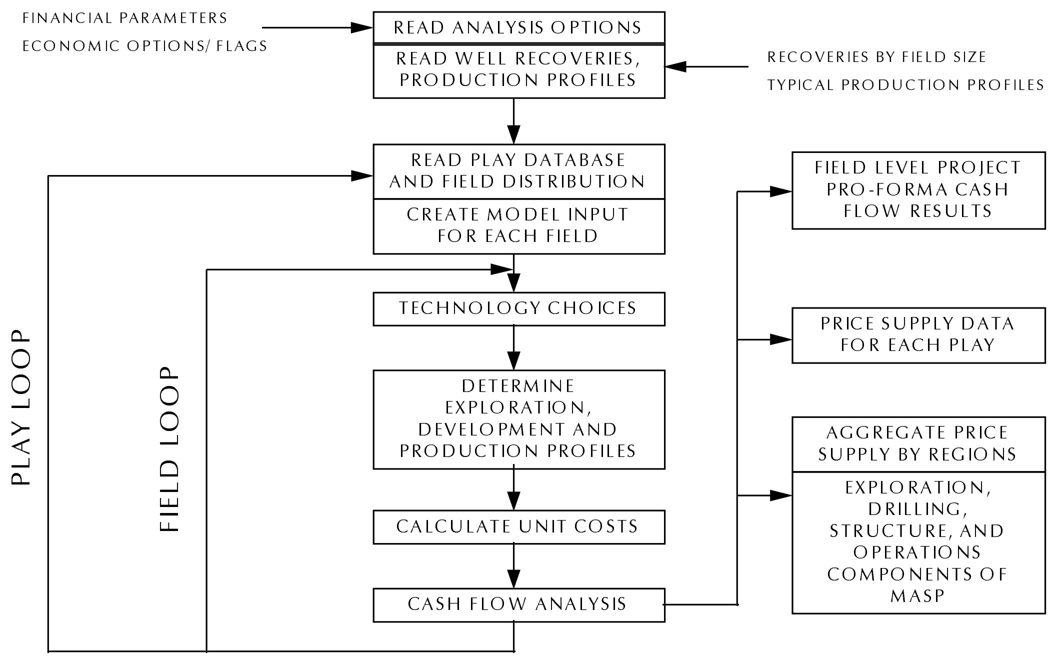


Figure 4E - 5. Programming Structure of the Endogenous Component of the OSS

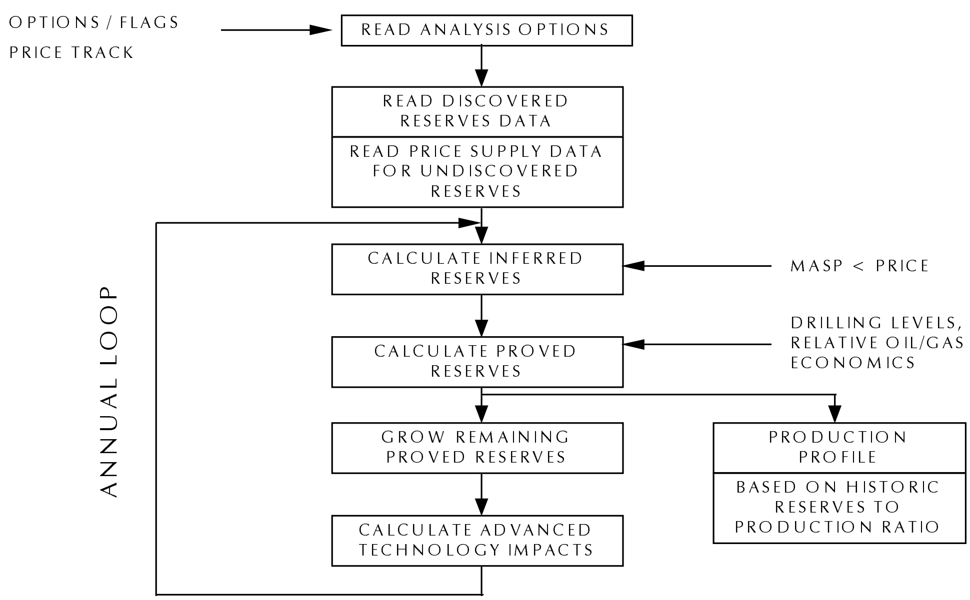


Table 4E-1. Recoverable Undiscovered Resources in the Gulf of Mexico (Billions of Barrels of Oil Equivalent)

Water Depth Category	Western	Central	Total
0 – 60 meters	2.011	2.025	4.036
60 – 200 meters	1.079	2.817	3.896
200 - 400 meters	1.176	2.427	3.603
400 - 900 meters	2.873	5.918	8.791
900 – 1500 meters	5.004	6.720	11.724
> 1500 meters	6.369	11.941	18.310
All Depths	18.512	31.848	50.360

Source: ICF

Database of Undiscovered Oil and Gas Prospects

For the purposes of creating resource inputs for the OSS, the undiscovered oil and gas prospects in the Gulf of Mexico were assumed to be distributed into the 23 Aplays@ listed in Table 4E-2. These plays are closely tied to the Minerals Management Service (MMS) categorization of the undiscovered resource base, but have been enhanced to divide the MMS Awater 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 and volumes adjusted to match the 1999 NPC study. This was done to maintain consistency with the classification of water depth ranges in OSS, 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 Gulf of Mexico Plays in the OSS

Region	Play Code	Description of the Play
WGOM	WGMSPC01	Western Gulf of Mexico, Water Depth 0-60 meters, Conventional Play
	WGMSPC02	Western Gulf of Mexico, Water 60-200 meters, Conventional Play
	WGMSPS01	Western Gulf of Mexico, Water Depth 60-200 meters, Subsalt Play
	WGMDPC01	Western Gulf of Mexico, Water Depth 200-400 meters, Conventional Play
	WGMDPC02	Western Gulf of Mexico, Water Depth 400-900 meters, Conventional Play
	WGMDPC03	Western Gulf of Mexico, Water Depth 900-1500 meters, Conventional Play
	WGMDPC04	Western Gulf of Mexico, Water Depth > 1500 meters, Conventional Play
	PERDID01	Gulf of Mexico Tertiary Basin, Perdido Fold Belt Play, Conventional Play
	WGMDPS01	Western Gulf of Mexico, Water Depth 200-400 meters, Subsalt Play
	WGMDPS02	Western Gulf of Mexico, Water Depth 400-900 meters, Subsalt Play
	WGMDPS03	Western Gulf of Mexico, Water Depth 900-1500 meters, Subsalt Play
CGOM	CGMSPC01	Central Gulf of Mexico, Water Depth 0-60 meters, Conventional Play
	CGMSPC02	Central Gulf of Mexico, Water 60-200 meters, Conventional Play
	CGMSPS01	Central Gulf of Mexico, Water Depth 60-200 meters, Subsalt Play
	CGMDPC01	Western Gulf of Mexico, Water Depth 200-400 meters, Conventional Play
	CGMDPC02	Western Gulf of Mexico, Water Depth 400-900 meters, Conventional Play
	CGMDPC03	Western Gulf of Mexico, Water Depth 900-1500 meters, Conventional Play
	CGMDPC04	Western Gulf of Mexico, Water Depth > 1500 meters, Conventional Play
	CGMDPS01	Western Gulf of Mexico, Water Depth 200-400 meters, Subsalt Play
	CGMDPS02	Western Gulf of Mexico, Water Depth 400-900 meters, Subsalt Play
	CGMDPS03	Western Gulf of Mexico, Water Depth 900-1500 meters, Subsalt Play
EGOM	EGMSPC01	Eastern Gulf of Mexico, Water Depth 0-60 meters, Conventional Play
	EGMDPC01	Eastern Gulf of Mexico, Water Depth > 900 meters, Conventional Play

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 OSS to generate play-specific input database sets.

Additional Required Input Data

Additional information that is needed to perform the economic evaluation of offshore 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.

TECHNOLOGY OPTIONS

This section sets forth the technology choices for exploration, development and production of the Gulf of Mexico offshore fields. The choices are consistent with current practices as well as projected technology choices for fields that are slated to be developed in the near future.

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.

In many situations in the deepwater 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 OSS, 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 OSS.

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, OSS assumes the selection of drilling rig type to be a function of water depth, as follows:

Drilling Rig Type	Water Depth (meters)
Jack-up	< 200
Semi-submersible	200 – 900
Drillship	> 900

Technology Options for Development/Production Structure

Six different options for development/production of offshore prospects are currently assumed in OSS, based on those currently considered and/or employed by 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 3 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 percent. 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 6 to 20 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 offshore Gulf of Mexico.

The typical project development in the 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 exploration 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 discover the field. For all Gulf of Mexico OCS prospects, OSS 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 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	Construction and Installation Time (Years)			
(meters)	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, or
- 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 2 to 4 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; and
- 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 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 1 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 5 years for a small field, 10 years for a mid-size field, and 15 years for a large field. The revised per well production profiles assumed in OSS 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 OSS. 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 OSS 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 = 5.8 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 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 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 OSS.

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; and
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:

<u>Jack-Up Rigs ($/well)</u>

$$\text{Exploration Drilling Cost} = 1{,}000{,}000 + 600*WD + (0.03*WD - 0.05*ED - 500)*ED + (15.0E\text{-}10*WD + 3.2E\text{-}06)*ED^3$$

<u>Semi-Submersible Rigs ($/well)</u>

$$\text{Exploration Drilling Cost} = 2{,}000{,}000 + 1{,}825*WD + (0.01*WD + 0.045*ED - 415)*ED$$

<u>Dynamically-Positioned Drill Ships ($/well)</u>

Exploration Drilling Cost = 8,000,000 + 175*WD + (0.0525*ED - 600)*ED

where,

WD	=	Water Depth (feet)
ED	=	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 percent of these costs are treated as capitalized tangible investments and are depreciated beginning the following year. The remaining 10 percent of these costs are expensed in the year incurred. The costs associated with each type of development and production structure considered in OSS 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, OSS 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, OSS 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, OSS 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. OSS 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.

OSS 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.). OSS 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.

Dry Development Drilling Cost

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 percent of the costs associated with drilling development wells are treated as intangible capital investments, while the remaining 30 percent of the costs are considered to be tangible investments, which are capitalized and depreciated over a 10-year life. In addition, 30 percent of the intangible costs are capitalized beginning the year after they are incurred. Remaining 70 percent 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 primarly 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.

OSS 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 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, and
- 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 OSS. 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 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 OSS 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:

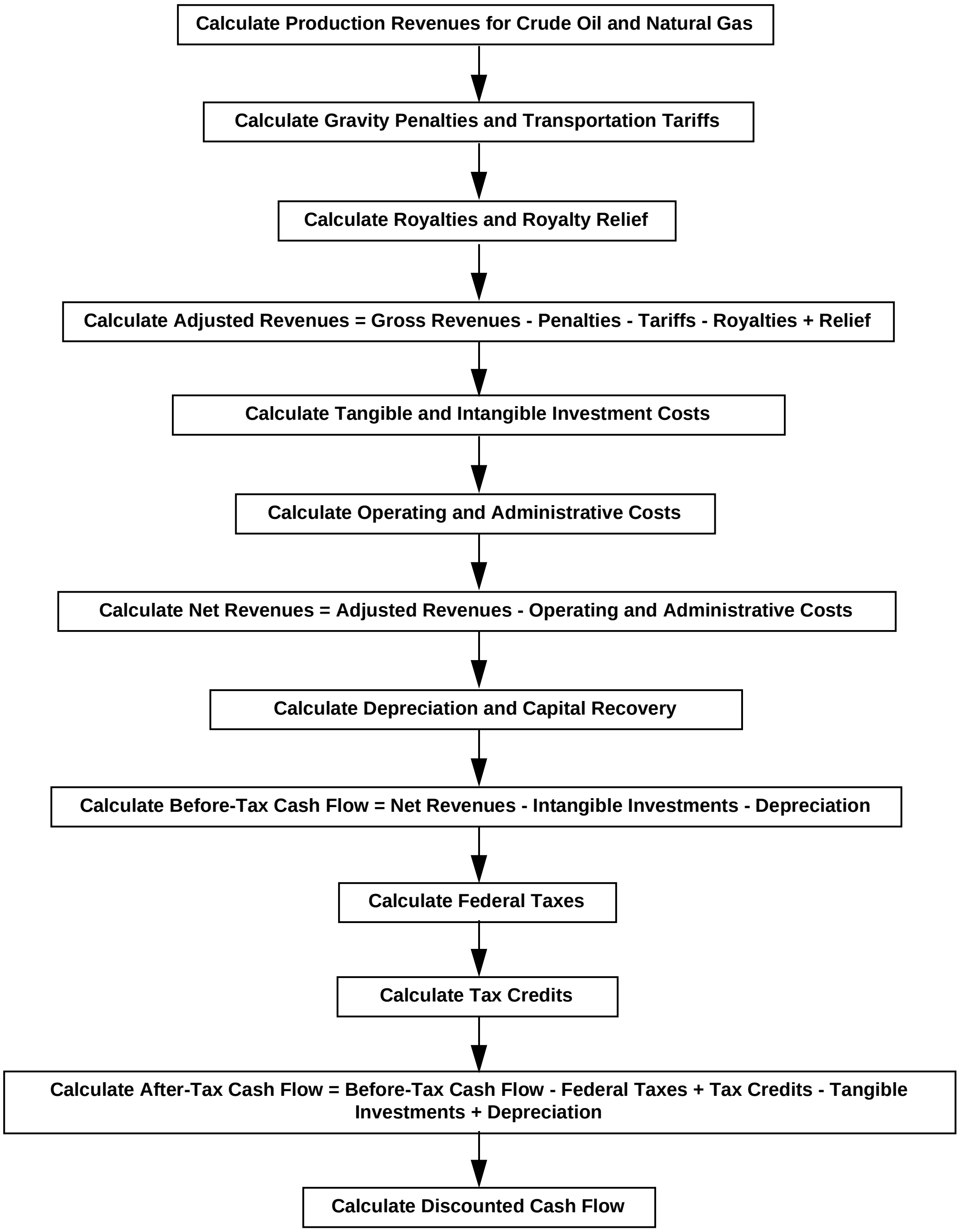
Gross Revenue or Savings
less **Operating Expenses**
less **Tax Costs**
less **Capital Costs**
____
= Cash Flow

Figure 4E-6 represents the process-flow diagram of the financial analysis routines in OSS. 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^o 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 a complex and intricate process,

Figure 4E - 6. Process Flow Diagram of the Discounted Cash Flow Financial Analysis



the NPC EOR study was able to make the following simplifications, which have been adapted for use in OSS as shown below:

- The reference standard for crude oil is 40^o API.
- If the typical crude gravity for a field is at or above 32^o API, the price penalty is \$0.10 per degree below 40^o API.
- If the typical crude gravity for a field is between 20^o and 31^o API, the price penalty is \$0.20 per degree below 40^o API.
- If the typical crude gravity for a field is below 20^o API, the price penalty is \$0.40 per degree below 40^o 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 Gulf of Mexico OCS, a co-product valuation methodology was incorporated into the OSS. This assumes that the value of natural gas would be 68 percent 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 the OSS 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 Aexpense@ them in the year incurred, which means to deduct them in full amount in the year incurred. However, tax law does not permit Aexpensing@ all costs, but instead permits these costs to be Acapitalized@ 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 Aunit of production@ depreciation method described in the following section.

Exploration and Delineation Drilling Costs are treated as Aintangible@ investments and are expensed in the year incurred.

Development Drilling Costs are split into tangible and intangible investment costs. In the OSS, 30 percent 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 percent of the intangible drilling costs may be expensed in the year incurred with the remaining 30 percent of the intangible drilling costs Acapitalized@.

Production Structure Installation Costs, like drilling costs, are split into tangible and intangible investments. The model assumes that only 10 percent of the intangible structure installation costs may be expensed in the year incurred and the remaining 10 percent intangible costs are Acapitalized@.

Operating Costs covering costs for direct labor, indirect labor, materials, parts and supplies used for operations are modeled as structure operating costs in the OSS, and are expensed in the year they are incurred.

Capitalized items are depleted by depreciation in the OSS. 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 Aa 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 1 year;
- It must be something that wears out, decays, gets used up, becomes obsolete, or loses values from natural causes; and
- 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 OSS, >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, An@ 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 the OSS, 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 Aasset cost@ times the ratio of the Aunits produced@ in a depreciation year, divided by Aexpected 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 the OSS. No provision has been kept for State taxes as these are not applicable in 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 percent on taxable income is assumed in the model. Royalty rates are set at 12.5 percent of the adjusted gross revenues. Royalty relief, as applicable under the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, 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 Apresent 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 Apresent worth@ is just the opposite of compounding. The terms Adiscounting@ implies reducing the value of something and is equivalent to determining the present worth of a future value. A discount rate of 10 percent is the default value assumed for all investment decisions in the OSS, though this is a parameter that can be specified by the user.

Net Present Value of After-Tax Cash Flow in year AIYR@

$$= \quad \text{(After-Tax Cash Flow)} / (1 + \text{Discount Rate})^{(IYR - 1/2)}$$

The previous sections covered the structure, methodology, and key components of the exogenous portion of the OSS which is used to generate the price-supply curves for the offshore Gulf of Mexico OCS, i.e. the potential supply from undiscovered resources 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 OSS. 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 OSS 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

The endogenous component of the OSS is an integral part of OGSM. The primary purpose of this endogenous component is to make a realistic forecast of 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 the OSS 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 resources that are economic at those prices. It is basically the amount of crude oil and natural gas resources that are economic to explore, develop, and produce from the remaining undiscovered prospects in the 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. OSS 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 offshore Gulf of Mexico were used to characterize the current drilling level constraints. The governing equations for calculating rig and drilling capacities are:

$$RIGS_{iyr} = rig\_B0 + rig\_B1*RIGS_{iyr-1} + rig\_B2*gasprice_{iyr} + rig\_B3*oilprice_{iyr}$$

$$ExpWell_{iyr} = exp\_B0 + exp\_B1*RIGS_{iyr}$$

$$DevWell_{iyr} = dev\_B0 + dev\_B1*ExpWell_{iyr-5} + dev\_B2*RIGS_{iyr} + dev\_B3*DevWell_{iyr-1}$$

where,

RIGS = offshore rig capacity
ExpWell = exploratory wells
DevWell = developmental wells
rig_B0, rig_B1, rig_B2, rig_B3 = estimated parameters for rigs
exp_B0, exp_B1 = estimated parameters for exploratory wells
dev_B0, dev_B1, dev_B2, dev_B3 = estimated parameters for exploratory wells
iyr = year.

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 Arelative 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.

Production

Proved reserves are converted to production based on reserves-to-production (R/P) ratios as defined in the following equations.

$$\text{RESERVES-TO-PRODUCTION}_{iyr} = rp\_B0 + rp\_B1*\ln(iyr + ModelStartYear\ B\ rp\_B2)$$

$$\text{PRODUCTION}_{k,\, iyr} = \text{PROVED-RESERVES}_{k,iyr} / \text{RESERVES-TO-PRODUCTION-RATIO}_{iyr}$$

where,

k	=	fuel type (crude oil or natural gas)
iyr	=	year under consideration.

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. OSS 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.

$$\text{RESERVES GROWTH}_{k,\, iyr} = (\text{PROVED RESERVES}_{k,\, iyr} - \text{PRODUCTION}_{k,\, iyr}) * \text{GROWTH RATE MULTIPLIER}$$

where,

k	=	Fuel type (crude oil or natural gas)
iyr	=	Year under consideration

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. The OSS 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 OSS that generates price-supply information evaluates the various 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 the OSS 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.

$$\text{MASP}_{nfield,\, iyr,\, fuel,\, component} = \text{DRILLING MASP}_{nfield,\, iyr,\, fuel,\, component} * \text{ADV TECH FACTOR}$$

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 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	OGCST_L48	RIGSL48	RIGSL48	Available rigs	Rigs	Lower 48 onshore
4	OGCST_L48	DRILLL48	DRILLCOST	Successful well drilling costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
5	OGCST_L48	DRYL48	DRYCOST	Dry well drilling costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
6	OGCST_L48	LEASL48	LEQC	Lease equipment costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
7	OGCST_L48	OPERL48	OPC	Operating costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
8	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); 3 Alaska regions, Fuel (oil,gas)
9	OG_DCF	PVSUM(1)	PVREV	Present value of expected revenue	1987$ per project	(Above)
10	OG_DCF	PVSUM(2)	PVROY	Present value of expected royalty payments	1987$ per project	(Above)

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
11	OG_DCF	PVSUM(3)	PVPRODTAX	Present value of expected production taxes	1987$ per project	(Above)
12	OG_DCF	PVSUM(4)	PVDRILLCOST	Present value of expected drilling costs	1987$ per project	(Above)
13	OG_DCF	PVSUM(5)	PVEQUIP	Present value of expected lease equipment costs	1987$ per project	(Above)
14	OG_DCF	PVSUM(8)	PVKAP	Present value of expected capital costs	1987$ per project	(Above)
15	OG_DCF	PVSUM(6)	PVOPERCOST	Present value of expected operating costs	1987$ per project	(Above)
16	OG_DCF	PVSUM(7)	PVABANDON	Present value of expected abandonment costs	1987$ per project	(Above)
17	OG_DCF	PVSUM(13)	PVTAXBASE	Present value of expected tax base	1987$ per project	(Above)
18	OG_DCF	XIDC	XIDC	Expensed Costs	1987$ per project	(Above)
19	OG_DCF	DHC	DHC	Dry hole costs	1987$ per project	(Above)
20	OG_DCF	DEPREC	DEPREC	Depreciable costs	1987$ per project	(Above)
21	OG_DCF	PVSUM(15)	PVSIT	Expected value of state income taxes	1987$ per project	(Above)

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
22	OG_DCF	PVSUM(16)	PVFIT	Expected value of federal income taxes	1987$ per project	(Above)
23-24	OG_DCF	OG_DCF	DCF	Discounted cash flow for a representative well	1987$ per well	(Above)
25	OGEXP_CALC	C_SGDDCF	SGDCFON	Discounted cash flow for shallow gas	1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions
26	OGEXP_CALC	OXDCF	ODCFON	Discounted cash flow for oil	1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions
27-32	OGEXP_CALC	WELLSL48	WELLSON	Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
33-34	OGEXP_CALC	SRL48	SR	Lower 48 onshore success rates	Fraction	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
35	OGEXP_CALC	SUCWELLL48	SUCWELSON	Successful Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
36	OGEXP_CALC	DRYWELLL48	DRYWELON	Dry Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
37	OGOUT_L48	NRDL48	NRD	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil,2 gas);

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
38	OGOUT_L48	FR1L48	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)
39	OGOUT_L48	NDIRL48	I	Inferred reserves added by new field discoveries	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil,2 gas)
40	OGOUT_L48	FR2L48	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)
41	OGOUT_L48	EXTL48	EXT	Reserve extensions	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 2 gas)
42	OGOUT_L48	FR3L48	FR3	Finding rates for developmental drilling	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions,Fuel(2 oil, 2 gas)
43	OGOUT_L48	REVL48	REV	Reserve revisions	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
44	OGOUT_L48	RESADL48	RA	Total additions to proved reserves	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas)
45	OGOUT_L48 OGFOR_AK	RESBOYL48 BOYRESCOAK BOYRESNGAK	R	End of year reserves for current year	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(2 oil, 5 gas); 3 Alaska regions,Fuel(oil,gas)

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
46	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)
47	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)
48	OGCOMP_AD	OGPRDAD	ADGAS	Associated-dissolved gas production	BCF	6 Lower 48 onshore regions, 3 Lower 48 offshore regions
49	PROVED_RESERVE S	PRV_RES	PRV_RES	TEOR and gas EOR proved reserves, all OGSM supply regions (except 6)	MMBO	6 Lower 48 supply regions; EOR type
50	TEOR_PRV_RES	PRV_RES	PRV_RES	TEOR proved reserves in OGSM supply region 6	MMBO	6 Lower 48 supply regions; EOR method
51	PROVED_RESERVE S	PRV_RESADJ	PRV_RESADJ	EOR proved reserves adjustment (benchmark) factor	--	EOR method
52	TEOR_PRV_RES	ADJ_RWOP	ADJ_RWOP	Gross EOR well revenues by field	MM$1987	EOR field
53	TEOR_PRV_RES	INITVOC	INITVOC	Variable operating costs in TEOR base year (1995)	87$ /BO	EOR field
54	TEOR_PRV_RES	EORVOC	EORVOC	Variable operating costs in TEOR forecast year	87$ /BO	EOR field
55	TEOR_PRV_RES	EORFXOC	EORFXOC	Fixed well operating costs for TEOR	87$ /BO	EOR field; productivity category

Appendix B Equation	Variables					
	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
56	PROVED_RESERVES	PRV_PROD	PRV_PROD	EOR production from proved reserves	MMBO	6 Lower 48 supply regions; EOR method
57	NEW_PROJECT_RESERVES	NEW_PRV_RES	NEW_PRV_RES	EOR inferred reserve additions at each oil price step	MMBO	6 Lower 48 onshore regions; EOR method; oil price categories
58	NEW_PROJECT_RESERVES	TNP_RES	TNP_RES	EOR inferred reserve additions	MMBO	6 Lower 48 supply regions; EOR method
59	NEW_PROJECT_RESERVES	CUR_PRV_RES	CUR_PRV_RES	EOR inferred reserves available for production at each oil price step	MMBO	6 Lower 48 onshore regions; EOR method; oil price categories
60	NEW_PROJECT_RESERVES	NEW_PROD	NEW_PROD	EOR production from inferred reserves at each oil price step	MMBO	6 Lower 48 onshore regions; EOR method; model year; oil price categories
61	NEW_PROJECT_RESERVES	TN_PROD	TN_PROD	Total EOR production from inferred reserves	MMBO	6 Lower 48 supply regions; EOR method
62	NEW_PROJECT_RESERVES	TRP_RES	TRP_RES	EOY "proved" EOR inferred reserves	MMBO	6 Lower 48 supply regions; EOR method
63	TEOR_INF_PS_TBL	AVGPR_THRSHLD	AVGPR_THRSHLD	Average threshold price for TEOR reserves development	87$ /BO	EOR field; model year
64	TEOR_INF_PS_TBL	TOT_RESV	TOT_RESV	Total potential TEOR reserves development	MMBO	EOR field; model year
65	OGINIT_EOR	CO2RES_INF	CO2RES_INF	Gas misible inferred reserves	MMBO	6 Lower 48 supply regions; model year
66	CO2_INF_[S_TBL	INF_PS_TBL	INF_PS_TBL	EOR inferred reserves price-supply table	MMBO	tech case; 6 Lower 48 onshore regions; EOR method; model year; oil price categories

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
67	CALC_ECF_DATA	PRV_COGEN	PRV_COGEN	Cogeneration electric capacity from production of EOR proved reserves	MW	6 Lower 48 supply regions; cogen characteristic (array position 1=capacity)
68	CALC_ECF_DATA	INF_COGEN	INF_COGEN	Cogeneration electric capacity from production of EOR inferred reserves	MW	6 Lower 48 supply regions; cogen characteristic (array position 1=capacity)
69	CALC_ECF_DATA	PRV_COGEN	PRV_COGEN	Cogeneration electric generation from production of EOR proved reserves	GWH	6 Lower 48 supply regions; cogen characteristic (array position 4=generation)
70	CALC_ECF_DATA	INF_COGEN	INF_COGEN	Cogeneration electric generation from production of EOR inferred reserves	GWH	6 Lower 48 supply regions; cogen characteristic (array position 4=generation)
71	OGCOST_AK	DRILLAK	DRILLCOST	Drilling costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
72	OGCOST_AK	LEASAK	EQUIP	Lease equipment costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
73	OGCOST_AK	OPERAK	OPCOST	Operating costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
74	OGFOR_AK	TOTGRR	TRR	Alaska total gross revenue requirements	Million 1987$	NA
75	OGFOR_AK	TOTDEP	TOTDEP	Alaska total depreciation	Million 1987$	NA
76	OGFOR_AK	MARTOT	MARGIN	Alaska total after tax margin	Million 1987$	NA

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
77	OGFOR_AK	RECTOT	DEFRETREC	Alaska total recovery of differed returns	Million 1987$	NA
78	OGFOR_AK	TXALLW	TXALLW	Alaska income tax allowance	Million 1987$	NA
79	XOGOUT_IMP	SUCWELL	SUCWELL	Successful Canadian wells drilled in WCSB	Wells	Fuel(gas)
80	XOGOUT_IMP	RESADCAN	RESADCAN	Canadian reserve additions in WCSB	Gas: BCF	Fuel(gas)
81	XOGOUT_IMP	FRCAN	FRCAN	Canadian finding rate for WCSB	Gas:BCF per well	Fuel(gas)
82	XOGOUT_IMP	RESBOYCAN	RESBOYCAN	WCSB Canadian reserves (BOY for t+1)	Gas: BCF	Fuel(gas)
83	XOGOUT_IMP	URRCAN	URRCAN	Remaining Canadian resources in WCSB	Gas: BCF	Fuel(gas)
84	XOGOUT_IMP	PRRATCAN	PR	Canadian production to reserves ratio in WCSB	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_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

Data						
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
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
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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
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
OGDCF_AK OGFOR_L48 OGFOR_OFF OGINIT_BFW	DISC	disc	Discount rate	Fraction	National	Office of Integrated Analysis and Forecasting

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
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

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
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
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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
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

Data							
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
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
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

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGFOR_AK OGINIT_AK OGNEW_AK	FSZCOAK	__	Alaska oil field size distributions	MMB	3 Alaska regions	U.S. Geological Survey
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

Data						
Subroutine	Variable Name: Code	Variable Name: Text	Description	Unit	Classification	Source
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
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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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	I	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	I	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
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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
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

Data							
Subroutine	**Variable Name**		**Description**	**Unit**	**Classification**	**Source**
	Code	**Text**				
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$/MCF	LNG Source Country	National Petroleun Council
OGEXPAND_LNG OGPROF_LNG	LIQSTAGE	--	Liquefaction stage	NA	NA	National Petroleum Council
OGFOR_AK OGINIT_AK OGPRO_AK	MAXPRO	--	Alaska maximum crude oil production	MB/D	Field	Announced Plans
OGINIT_IMP OGOUT_MEX	MEXEXP	--	Exports from Mexico	BCF	3 US/Mexican border crossing	Office of Integrated Analysis and Forecasting
OGINIT_IMP OGOUT_MEX	MEXIMP	--	Imports from Mexico	BCF	3 US/Mexican border crossing	Office of Integrated Analysis and Forecasting
OGINIT_AK OGNEW_AK	NFW_AK	--	Alaska drilling schedule for new field wildcats	wells	NA	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	NFWCOSTOFF	COSTEXP	Offshore new field wildcat cost	1987$	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_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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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_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
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

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
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_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

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
	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
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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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
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
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_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

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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_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
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

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGEXP_CALC OGINIT_BFW	WDCFOFFIRKLA G	--	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
OGINIT_IMP	WELLLIFE	--	Canadian project life	Years	Canada	Not used. Office of Integrated Analysis and Forecasting

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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

ENHANCED OIL RECOVERY SUPPLY SUBMODULE
-- DATA --

Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR TEOR_PRV_RES	ADVALRM	TEOR ad valorum tax as percent of WOP	fraction	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_PRV_RES	API_GRV	API gravity of oil at EOR field	Deg API	EOR field	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	AVGRDEPTH	Average TEOR reservoir depth	feet	EOR field	Advanced Resources International, Inc.
OGINIT_EOR CO2_INF_PS_TBL	CALCPR_INF	Price break points for the CO2 inferred price/supply table calculations	87$ /BO5	oil price groups	Advanced Resources International, Inc.
OGINIT_EOR CO2_INF_PS_TBL	CO2RES_INF	Historical CO2 inferred EOR reserves	MMBO	6 Lower 48 supply regions; year	ARI Excel Worksheets 98rgi*r.xls
OGINIT_EOR CALC_ECF_DATA	COGFAC	factor to calculate cogeneration electric capacity as function of steam injection	MW /MMBS-yr	NA	Advanced Resources International, Inc.
OGINIT_EOR	CONST_INF	Parameter used to calculate CO2 inferred EOR reserves	--	6 Lower 48 supply regions	ARI Excel Worksheets 98rgi*r.xls
OGINIT_EOR TEOR_PRV_RES	DCL_RATE	TEOR proved: production to reserves ratio (reserves decline rate)	fraction	EOR production field	Advanced Resources International, Inc.
OGINIT_EOR CALC_DEV_SCHED	DEV_YRS	development schedule for new drilling	years	tech case; 6 Lower 48 supply regions; EOR type; profit category	Advanced Resources International, Inc.

ENHANCED OIL RECOVERY SUPPLY SUBMODULE

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Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR TEOR_INF_PS_TBL	DISCRATE	TEOR discount rate before taxes	fraction	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL SET_TEMP_VALUES CALC_ROLAVG CALC_DEV_SCHED PROVED_RESERVES CO2_INF_PS_TBL TEOR_PRV_RES NEW_PROJECT_RESE RVES CALC_ECF_DATA OGOUT_EOR	EORBYR	EORSS first year of operation	--	NA	User input
OGINIT_EOR CALC_ECF_DATA	EORFAC	emissions factors for EOR production	tons/MMcf or lb/MMcf	emission categories	Advanced Resources International, Inc.
OGINIT_EOR PROVED_RESERVES CALC_ECF_DATA OGOUT_EOR	EORHYR	EORSS historical data defined through this year	--	NA	User input
OGINIT_EOR TEOR_PRV_RES	EORWELLS	Number of producing TEOR wells in 1995	--	EOR field	Advanced Resources International, Inc.
OGINIT_EOR TEOR_PRV_RES	FAC1	TEOR proved: total TEOR producing wells in 1993 by production field	wells	EOR production field	Advanced Resources International, Inc.

ENHANCED OIL RECOVERY SUPPLY SUBMODULE

-- DATA --

Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR TEOR_PRV_RES	FAC2	TEOR proved: total TEOR producing wells in 1993 by production field and category	wells	EOR production field; production category	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	HIMPRV_REC	TEOR inferred: horizontal reserves factor	MMBO /well	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	HLENGTH	TEOR inferred: horizontal well length	feet	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	HPRDYR	TEOR inferred: horizontal production years	--	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	HREPLWELL	Number of TEOR vertical wells replaced with horizontal wells	wells	EOR field	Advanced Resources International, Inc.
OGINIT_EOR NEW_PROJECT_RESERVES OGSUMMARY_EOR	INF_PR	production to reserves ratio for new drilling	fraction	tech case; 6 Lower 48 supply regions; EOR type; year	Advanced Resources International, Inc.
OGINIT_EOR CO2_INF_PS_TBL TEOR_INF_PS_TBL NEW_PROJECT_RESERVES OGDEBUG_EOR	INF_PS_TBL	thermal (data) and gas (calculated) EOR inferred reserves price supply table for unproven stock	MMBO	tech case; 6 Lower 48 supply regions; EOR type; year; oil price categories	Advanced Resources International, Inc.

ENHANCED OIL RECOVERY SUPPLY SUBMODULE
-- DATA --

Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR CALC_ECF_DATA OGREPORT_EOR OGDEBUG_EOR	INF_UTIL	Inferred (1) cogen penetration factor: fraction of steam for cogeneration (2) cogeneration capacity utilization (3) grid vs non-grid cogeneration usage	fraction	6 Lower 48 supply regions; EOR type; year; other grouping	Advanced Resources International, Inc.
OGINIT_EOR TEOR_PRV_RES	INITPRD	TEOR midpoint production in each of 8 production categories	BOPD	oil files per region; production categories (8)	Advanced Resources International, Inc.
OGINIT_EOR NEW_PROJECT_RESE RVES CALC_INVEST_YR OGDEBUG_EOR	INVEST_TBL	investment pool for new drilling	MM$	tech case; 6 Lower 48 supply regions; EOR type; year; oil price categories	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	LAHPCT_COST	TEOR inferred: percentage above /below average threshold price	fraction	low, avg, high	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	LAHPCT_RESV	TEOR inferred: percent of reserves with low, average, high cost	fraction	low, avg, high	Advanced Resources International, Inc.
OGINIT_EOR	LPROFIT	lower limit on profit category for new drilling development schedule	$/BO	tech case; 6 Lower 48 supply regions; EOR type; profit category	Not used. Advanced Resources International, Inc.
OGINIT_EOR	MULT_INF	Parameter used to calculate CO2 inferred EOR reserves	--	6 Lower 48 supply regions	ARI Excel Worksheets 98rgi*r.xls

ENHANCED OIL RECOVERY SUPPLY SUBMODULE

-- DATA --

Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR TEOR_INF_PS_TBL CALC_ECF_DATA	NGFFAC	natural gas fuel consumption factor as function of steam injection	BS/mcf	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_PRV_RES	OPRDELAY	TEOR operating delay factor for shut-ins	fraction	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL TEOR_PRV_RES	OTHOMC	Other TEOR O&M costs	87$ per well-yr	EOR field	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	PENMAX	TEOR inferred: maximum penetration of horizontal production	fraction	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	PENPERD	TEOR inferred: penetration period	--	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	PHASYR	TEOR inferred: phase-in year	--	NA	Advanced Resources International, Inc.
OGINIT_EOR SET_TEMP_VALUES TEOR_PRV_RES	PR_MATRIX	mapping of PMM oil type to EOR supply regions	--	6 Lower 48 supply regions; EOR type (+1)	Advanced Resources International, Inc.
OGINIT_EOR PROVED_RESERVES OGREPORT_EOR OGDEBUG_EOR OGSUMMARY_EOR	PRV_PR	production to reserves ratio for existing stock	fraction	tech case; 6 Lower 48 supply regions; EOR type; year	Advanced Resources International, Inc.

ENHANCED OIL RECOVERY SUPPLY SUBMODULE
-- DATA --

Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR CALC_ECF_DATA OGREPORT_EOR OGDEBUG_EOR	PRV_UTIL	Proved (1) cogen penetration factor: fraction of steam for cogeneration; (2) cogeneration capacity utilization (3) grid vs non-grid cogeneration usage	fraction	6 Lower 48 supply regions; EOR type; year; other grouping	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	PSPACING	TEOR pattern spacing	acres	EOR field	Advanced Resources International, Inc.
OGINIT_EOR TEOR_PRV_RES OGREPORT_EOR OGDEBUG_EOR	RGPRICE	regional natural gas prices	87$ /MMbtu	6 lower 48 supply regions; year	Office of Integrate Analysis and Forecasting
OGINIT_EOR TEOR_PRV_RES	ROYALTY	TEOR royalty as percent of WOP	fraction	NA	Advanced Resources International, Inc.
OGINIT_EOR CALC_ECF_DATA	SIFAC	factor to calculate steam injection as function of production	BS/BO	NA	Advanced Resources International, Inc.
OGINIT_EOR CO2_INF_PS_TBL	SPLIT_INF	Distribution of the estimated CO2 reserves base over the 5 price groups for the CO2 inferred price/supply table calculations	fraction	5 oil price groups; 6 Lower 48 supply regions	ARI Excel Worksheets 98rgi*r.xls
OGINIT_EOR TEOR_INF_PS_TBL TEOR_PRV_RES	STMINJ	Total steam injected for TEOR in 1995	MMBS	EOR field	Advanced Resources International, Inc.

ENHANCED OIL RECOVERY SUPPLY SUBMODULE

-- DATA --

Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR SET_TEMP_VALUES	T_ROPRICE	regional wellhead prices for existing stock and new drilling (oil)	87$ /BO	6 Lower 48 onshore regions; EOR type; year	Office of Integrated Analysis and Forecasting
OGINIT_EOR SET_TEMP_VALUES	T_WOPRICE	world oil price for existing stock and new drilling	87$ /BO	year (world)	Office of Integrated Analysis and Forecasting
OGINIT_EOR TEOR_INF_PS_TBL TEOR_PRV_RES	TF_EORPROD	Total TEOR production in 1995	MMBO	EOR field	Advanced Resources International, Inc.
OGINIT_EOR TEOR_PRV_RES	TF_FLDPROD	Total EOR production (thermal, CO2, other) in 1995	MMBO	EOR field	Advanced Resources International, Inc.
OGINIT_EOR TEOR_PRV_RES	TF_FLDRESV	Total EOR reserves (for thermal, CO2, other) production in 1995	MMBO	EOR field	Advanced Resources International, Inc.
OGINIT_EOR PROVED_RESERVES OGOUT_EOR OGSUMMARY_EOR	TOT_PROD	historical crude oil production by supply region and EOR type	MBO	Lower 48 Onshore	Office of Integrated Analysis and Forecasting
OGINIT_EOR PROVED_RESERVES OGOUT_EOR OGSUMMARY_EOR	TOT_RES	historical BOY reserves by supply region and EOR type	MBO	Lower 48 Onshore	Office of Integrated Analysis and Forecasting
OGINIT_EOR TEOR_INF_PS_TBL	UNDEVACRE	TEOR Undeveloped reserve acreage	acres	EOR field	Advanced Resources International, Inc.

ENHANCED OIL RECOVERY SUPPLY SUBMODULE

-- DATA --

Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR CALC_DEV_SCHED	UPROFIT	upper limit on profit category for new drilling development schedule	87$ /BO	tech case; 6 Lower 48 supply regions; EOR type; profit category	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	V92_DRILLEQ	TEOR inferred: cost for drill, comp, equip new producer	92$ /foot	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	V92_H2ODISP	TEOR inferred: cost for water disposal well	92$ /BW capacity	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	V92_PLTFAC	TEOR inferred: cost for central plant facilities	92$ /BOPD	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	V92_PRD2INJ	TEOR inferred: cost for converting producer to injector	92$ /well	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	V92_STMLINE	TEOR inferred: cost for steam manifold & flowlines	92$ /acre	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	V92_SURFLINE	TEOR inferred: cost for surface production lines	92$ /acre	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	V92_VAPREC	TEOR inferred: cost for vapor recovery	92$ /acre	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	VPRDYR	TEOR inferred: vertical production years	--	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	VRESWELL	TEOR vertical reserves per well	BO per well	EOR field	Advanced Resources International, Inc.

ENHANCED OIL RECOVERY SUPPLY SUBMODULE

-- DATA --

Subroutine	Variable Name	Brief Description	Units	Classification	Source
OGINIT_EOR TEOR_INF_PS_TBL	VTCH_CREDU C	TEOR inferred: technology cost reduction	fraction	NA	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL TEOR_PRV_RES	WELLFXOC	TEOR well operating costs in 1996	87$ per well-yr	EOR field	Advanced Resources International, Inc.
OGINIT_EOR TEOR_INF_PS_TBL	YRDOL	TEOR inferred: year dollars for vertical drilling cost data	--	NA	Advanced Resources International, Inc.

Parameters

Appendix B Equation Number	Subroutine	Parameter Name		Associated Variable	Classification
		Code	Text		
1-2	OGCST_L48	value from regression	b0	Constant coefficient	Lower 48 onshore
1-2	OGCST_L48	value from regression	b1	Crude oil wellhead price coefficient	Lower 48 onshore
1-2	OGCST_L48	value from regression	b2	Natural gas wellhead price coefficient	Lower 48 onshore
1-2	OGCST_L48	value from regression	ρ	Aurocorrelation parameter	Lower 48 onshore
3	OGCST_l48	ALPHA_RIG	ln(b0)	Constant coefficient	Lower 48 onshore
3	OGCST_l48	B0_RIG	b1	Lower 48 onshore rigs	Lower 48 onshore
3	OGCST_l48	B1_RIG	b2	Revenue per lower 48 onshore rig	Lower 48 onshore
4, 5	OGCST_l48	alpha_drl alpha_dry	ln(δ0)	Constant coefficient for onshore drilling and dry costs	6 lower 48 onshore regions, 3 fuels (oil, shallow gas, deep gas)
4, 5	OGCST_l48	b0_drl b0_dry	ln(δ1)	Average depth per well	depth category, 3 fuels (oil, shallow gas, deep gas)
4, 5	OGCST_l48	b4_drl b4_dry	ln(δ2)	Region 1 and region 6 adjustment	3 fuels (oil, shallow gas, deep gas)
4, 5	OGCST_l48	b1_drl b1_dry	δ3	Estimated number of Lower 48 wells drilled	3 fuels (oil, shallow gas, deep gas)
4, 5	OGCST_l48	b3_drl b3_dry	δ4	Lower 48 onshore rigs	3 fuels (oil, shallow gas, deep gas)
4, 5	OGCST_l48	b2_drl b2_dry	δ5	Time trend - proxy for technology	3 fuels (oil, shallow gas, deep gas)

Parameters					
Appendix B Equation Number	Subroutine	Parameter Name		Associated Variable	Classification
		Code	Text		
4, 5	OGCST_l48	rho_drl rho_dry	ρ	Autocorrelation parameter	3 fuels (oil, shallow gas, deep gas)
6	OGCST_L48	ALPHA_LEQ	ln(ε0)	Constant coefficient	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
6	OGCST_L48	B0_LEQ	ln(ε1)	Lower 48 successful wells by fuel (oil, gas)	Fuel (oil, shallow gas, deep gas)
6	OGCST_L48	B1_LEQ	ln(ε2)	Time trend - proxy for technology	Fuel (oil, shallow gas, deep gas)
6	OGCST_L48	B2_LEQ	ln(ε3)	Estimated successful wells	Fuel (oil, shallow gas, deep gas)
6	OGCST_L48	RHO_LEQ	ρ	Autocorrelation parameter	Fuel (oil, shallow gas, deep gas)
7	OGCST_L48	ALPHA_OPR	ln(ε0)	Constant coefficient	6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas)
7	OGCST_L48	B0_OPR	ln(ε1)	Depth per well	Fuel (oil, shallow gas, deep gas)
7	OGCST_L48	B1_OPR	ln(ε2)	Lower 48 successful wells by fuel (oil, gas)	Fuel (oil, shallow gas, deep gas)
7	OGCST_L48	B2_OPR	ln(ε3)	Time trend - proxy for technology	Fuel (oil, shallow gas, deep gas)
7	OGCST_L48	RHO_OPR	ρ	Autocorrelation parameter	Fuel (oil, shallow gas, deep gas)
27-28	OGWELLS_L48	value from regression	m0	Constant coefficient - oil wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
27-28	OGWELLS_L48	value from regression	m00	Regional coefficient - oil wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)

Parameters					
Appendix B Equation Number	Subroutine	Parameter Name		Associated Variable	Classification
		Code	Text		
27-28	OGWELLS_L48	value from regression	m1	Discounted cash flow - oil wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
27-28	OGWELLS_L48	value from regression	m2	Cashflow - oil wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
27-28	OGWELLS_L48	value from regression	ρ	Autocorrelation parameter - oil wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
29-30	OGWELLS_L48	value from regression	m0	Constant coefficient - shallow gas wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
29-30	OGWELLS_L48	value from regression	m00	Regional coefficient - shallow gas wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
29-30	OGWELLS_L48	value from regression	m1	Discounted cash flow - shallow gas wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
29-30	OGWELLS_L48	value from regression	m2	Cashflow - shallow gas wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
29-30	OGWELLS_L48	value from regression	ρ	Autocorrelation - shallow gas wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
31-32	OGWELLS_L48	value from regression	m0	Constant coefficient - deep gas wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
31-32	OGWELLS_L48	value from regression	m00	Regional coefficient - deep gas wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
31-32	OGWELLS_L48	value from regression	m1	Discounted cash flow - deep gas wells	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)

Parameters					
Appendix B Equation Number	Subroutine	Parameter Name		Associated Variable	Classification
		Code	Text		
31-32	OGWELLS_L48	value from regression	ρ	Autocorrelation parameter	6 Lower 48 onshore regions; Fuel oil, shallow gas, deep gas)
48	OGCOMP_AD	ALPHA_AD	$\ln(\alpha 0)+\ln(\alpha 1)$	Constant coefficient plus regional dummy	Lower 48 regions (6 onshore, 3 offshore
48	OGCOMP_AD	BETA_AD	$\ln(\beta 0)+\ln(\beta 1)$	Crude oil production plus regional dummy	Lower 48 regions (6 onshore, 3 offshore)
79	XOGOUT_IMP	value from regression	B0	Constant coefficient	Canada national, Fuel(gas)
79	XOGOUT_IMP	value from regression	B2	Gas price	Canada national, Fuel(gas)
79	XOGOUT_IMP	not represented	B3	Years >1992 dummy constant	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

Outputs					
OGSM Subroutine	**Variable Name**	**Description**	**Unit**	**Classification**	**Passed To Module**
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
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)

Outputs					
OGSM Subroutine	**Variable Name**	**Description**	**Unit**	**Classification**	**Passed To Module**
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

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

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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
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

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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
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

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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
IYRDEV	Year when development drilling begins		Calculated in Model
DEVTIM	Time required for development drilling		Calculated in Model

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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
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

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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
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

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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
FED_TAXS	Annual federal tax bill	$/year	Calculated in Model

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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 Gulf of Mexico regions		Minerals Management Service
NFUEL	Types of fuels in the model (oil and gas)		EIA
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)

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	**BRIEF DESCRIPTION**	**UNITS**	**SOURCE**
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
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

OFFSHORE SUPPLY SUBMODULE			
VARIABLE	BRIEF DESCRIPTION	UNITS	SOURCE
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

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

[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				
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$/ Foot	UGR Type	ARI
DCCOSTLT	DCC_L2K	Cost per foot, well is less than 2000 feet.	1996$/ 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

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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
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

Unconventional Gas Recovery Supply Submodule					
Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
H2OBASE	WOML_WTR	Water Producing Well Lease Equipment Costs	1996$/ Well	UGR Type; EUR Level	ARI
H2ODISP	WATR_DISP	Establishes if the play requires water disposal (1 = yes)	-	UGR Type; Play; Quality	ARI
HYPPLAYS	HYP%	Establishes whether or not the play is hypothetical (1=yes)	-	UGR Type; Play; Quality	ARI
LANDGG	DCC_G&G	Land / G&G Costs	1996$/ 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

Unconventional Gas Recovery Supply Submodule					
Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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
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

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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_LAG	NW_WELLS_LAG	New Wells Lagged: The amount of wells drilled for the play in the previous year	Wells	UGR Type; Play; Quality	Calculated

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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
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

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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
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

Unconventional Gas Recovery Supply Submodule					
Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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

Unconventional Gas Recovery Supply Submodule					
Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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
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

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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
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

Unconventional Gas Recovery Supply Submodule					
Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
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

Unconventional Gas Recovery Supply Submodule					
Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
VAROPCOST	VOC	Variable Operating Costs	1996$/Mcf	UGR Type; Play; Quality	Calculated
VAROPCOST	VOC2	Variable Operating Costs: Includes an extra operating cost for plays that will incorporate the technology of Enhanced CBM in the future	1996$/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

Unconventional Gas Recovery Supply Submodule					
Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
.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

$$ESTWELLS_t = \exp(b0) * POIL_t^{b1} * PGAS_t^{b2} * ESTWELLS_{t-1}^{\rho} * \exp(-\rho * b0) * POIL_{t-1}^{-\rho * b1} * PGAS_{t-1}^{-\rho * b2} \tag{1}$$

$$ESTSUCWELLS_t = \exp(c0) * POIL_t^{c1} * PGAS_t^{c2} * ESTSUCWELLS_{t-1}^{\rho} * \exp(-\rho * c0) * POIL_{t-1}^{-\rho * c1} * PGAS_{t-1}^{-\rho * c2} \tag{2}$$

Lower 48 Onshore Rigs

$$RIGSL48_t = \exp(b0) * RIGSL48_{t-1}^{b1} * REVRIG_{t-1}^{b2} \tag{3}$$

Onshore Drilling Costs

$$\begin{aligned} DRILLCOST_{r,k,t} = {} & \exp(\ln(\delta 0)_{r,k}) * \exp(\ln(\delta 1)_{d,k}) * \exp(\ln(\delta 2)_{r,k}) * ESTWELLS_t^{\delta 3_k} * RIGSL48_t^{\delta 4_k} * \exp(\delta 5_k * TIME_t) * \\ & DRILLCOST_{r,k,t-1}^{\rho_k} * \exp(-\rho_k * \ln(\delta 0)_{r,k}) * \exp(-\rho_k * \ln(\delta 1)_{d,k}) * \exp(-\rho_k * \ln(\delta 2)_{r,k}) * \\ & ESTWELLS_{t-1}^{-\rho_k * \delta 3_k} * RIGSL48_{t-1}^{-\rho_k * \delta 4_k} * \exp(-\rho_k * \delta 5_k * TIME_{t-1}) \end{aligned} \tag{4}$$

$$\begin{aligned} DRYCOST_{r,k,t} = {} & \exp(\ln(\delta 0)_{r,k}) * \exp(\ln(\delta 1)_{d,k}) * \exp(\ln(\delta 2)_{r,k}) * ESTWELLS_t^{\delta 3_k} * RIGSL48_t^{\delta 4_k} * \exp(\delta 5_k * TIME_t) * \\ & DRYCOST_{r,k,t-1}^{\rho_k} * \exp(-\rho_k * \ln(\delta 0)_{r,k}) * \exp(-\rho_k * \ln(\delta 1)_{d,k}) * \exp(-\rho_k * \ln(\delta 2)_{r,k}) * \\ & ESTWELLS_{t-1}^{-\rho_k * \delta 3_k} * RIGSL48_{t-1}^{-\rho_k * \delta 4_k} * \exp(-\rho_k * \delta 5_k * TIME_{t-1}) \end{aligned} \tag{5}$$

Lease equipment costs

$$\begin{aligned} LEQC_{r,k,t} = {} & \exp(\ln(\varepsilon 0)_{r,k}) * \exp(\ln(\varepsilon 1)_k * DEPTH_{r,k,t}) * ESUCWELL_{k,t}^{\varepsilon 2_k} * \exp(\varepsilon 3_k * TIM \\ & \exp(-\rho_k * \ln(\varepsilon 0)_{r,k}) * \exp(-\rho_k * \ln(\varepsilon 1)_k * DEPTH_{r,k,t-1}) * ESUCWELL_{k,t-1}^{-\rho_k * \varepsilon 2} \end{aligned} \tag{6}$$

Operating Costs

$$\begin{aligned} OPC_{r,k,t} = {} & \exp(\ln(\varepsilon 0)_{r,k}) * \exp(\ln(\varepsilon 1)_k * DEPTH_{r,k,t}) * ESUCWELL_{k,t}^{\varepsilon 2_k} * \exp(\varepsilon 3_k * TIME \\ & \exp(-\rho_k * \ln(\varepsilon 0)_{r,k}) * \exp(-\rho_k * \ln(\varepsilon 1)_k * DEPTH_{r,k,t-1}) * ESUCWELL_{k,t-1}^{-\rho_k * \varepsilon 2_k} \end{aligned} \tag{7}$$

Discounted Cash Flow Algorithm

Expected discounted cash flow

$$\mathrm{PROJDCF}_{i,r,k,t} = (\mathrm{PVREV} - \mathrm{PVROY} - \mathrm{PVPRODTAX} - \mathrm{PVDRILLCOST} - \mathrm{PVEQUIP} - \mathrm{PVKAP} - \mathrm{PVOPERCOST} - \mathrm{PVABANDON} - \mathrm{PVSIT} - \mathrm{PVFIT})_{i,r,k,t} \tag{8}$$

Present value of expected revenues

$$\mathrm{PVREV}_{i,r,k,t} = \sum_{T=t}^{t+n} \left[Q_{r,k,T} * \lambda * (P_{r,k,T} - \mathrm{TRANS}_{r,k}) * \left[\frac{1}{1+\mathrm{disc}}\right]^{T-t} \right], \ \lambda = \begin{cases} 1 & \text{if primary fuel} \\ \mathrm{COPRD} & \text{if secondary fuel} \end{cases} \tag{9}$$

Present value of expected royalty payments

$$\mathrm{PVROY}_{i,r,k,t} = \mathrm{ROYRT} * \mathrm{PVREV}_{i,r,k,t} \tag{10}$$

Present value of expected production taxes

$$\mathrm{PVPRODTAX}_{i,r,k,t} = \mathrm{PVREV}_{i,r,k,t} * (1 - \mathrm{ROYRT}) * \mathrm{PRODTAX}_{r,k} \tag{11}$$

Present value of expected costs

Drilling costs

$$\mathrm{PVDRILLCOST}_{i,r,k,t} = \sum_{T=t}^{t+n} \Big[\big[\mathrm{DRILL}_{1,r,k,t} * \mathrm{SR}_{1,r,k} * \mathrm{WELL}_{1,k,T} + \mathrm{DRILL}_{2,r,k,t} * \mathrm{SR}_{2,r,k} * \mathrm{WELL}_{2,k,T} + \mathrm{DRY}_{1,r,k,t} * (1 - \mathrm{SR}_{1,r,k}) * \mathrm{WELL}_{1,k,T} + \mathrm{DRY}_{2,r,k,t} * (1 - \mathrm{SR}_{2,r,k}) * \mathrm{WELL}_{2,k,T}\big] * \left(\frac{1}{1+\mathrm{disc}}\right)^{T-t} \Big] \tag{12}$$

Lease equipment costs

$$\mathrm{PVEQUIP}_{i,r,k,t} = \sum_{T=t}^{t+n} \left[\mathrm{EQUIP}_t * \left(\mathrm{SR}_{1,r,k} * \mathrm{WELL}_{1,k,T} + \mathrm{SR}_{2,r,k} * \mathrm{WELL}_{2,k,T}\right) * \left[\frac{1}{1+\mathrm{disc}}\right]^{T-t} \right] \tag{13}$$

Capital costs

$$\mathrm{PVKAP}_{i,r,k,t} = \sum_{T=t}^{t+n} \left[\mathrm{KAP}_{i,r,k,T} * \left[\frac{1}{1+\mathrm{disc}}\right]^{T-t} \right] \tag{14}$$

Operating costs

$$\mathrm{PVOPERCOST}_{i,r,k,t} = \sum_{T=t}^{t+n} \left[\mathrm{OPCOST}_{i,r,k,t} * \sum_{k=1}^{T} \left[\mathrm{SR}_{1,r,k} * \mathrm{WELL}_{1,k,T} + \mathrm{SR}_{2,r,k} * \mathrm{WELL}_{2,k,T} \right] * \left(\frac{1}{1+\mathrm{disc}}\right)^{T-t} \right] \tag{15}$$

Abandonment costs

$$\mathrm{PVABANDON}_{i,r,k,t} = \sum_{T=t}^{t+n} \left[\mathrm{COSTABN}_{i,r,k} * \left[\frac{1}{1+\mathrm{disc}}\right]^{T-t} \right] \tag{16}$$

Present value of expected tax base

$$PVTAXBASE_{i,r,k,t} = \sum_{T=t}^{t+n} \Big[(REV - ROY - PRODTAX - OPERCOST - ABANDON - XIDC - AIDC - DEPREC - DHC)_{i,r,k,t} * \left(\frac{1}{1+disc}\right)^{T-t} \Big]$$

Expected expensed costs

$$XIDC_{i,r,k,t} = DRILL_{1,r,k,t} * (1 - EXKAP) * (1 - XDCKAP) * SR_{1,r,k} * WELL_{1,k,t} + DRILL_{2,r,k,t} * (1 - DVKAP) * (1 - XDCKAP) * SR_{2,r,k} * WELL_{2,k,t} \quad (18)$$

Expected dry hole costs

$$DHC_{i,r,k,t} = DRY_{1,r,k,t} * (1 - SR_{1,r,k}) * WELL_{1,k,t} + DRY_{2,r,k,t} * (1 - SR_{2,r,k}) * WELL_{2,k,t} \quad (19)$$

Expected depreciable costs

$$DEPREC_{i,r,k,t} = \sum_{j=\beta}^{t} \Big[\big[(DRILL_{1,r,k,T} * EXKAP + EQUIP_{1,r,k,T}) * SR_{1,r,k} * WELL_{1,k,j} + (DRILL_{2,r,k,T} * DVKAP + EQUIP_{2,r,k,T}) * SR_{2,r,k} * WELL_{2,k,j} + KAP_{r,k,j} \big] * DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \quad (20)$$

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

Present value of expected state income taxes

$$PVSIT_{i,r,k,t} = PVTAXBASE_{i,r,k,t} * STRT \quad (21)$$

Present value of expected federal income taxes

$$PVFIT_{i,r,k,t} = PVTAXBASE_{i,r,k,t} * (1 - STRT) * FDRT \quad (22)$$

Discounted cash flow for a representative developmental well

$$DCF_{2,r,k,t} = PROJDCF_{2,r,k,t} * SR_{2,r,k} \quad (23)$$

Discounted cash flow for a representative exploratory well

$$DCF_{1,r,k,t} = PROJDCF_{1,r,k,t} * SR_{1,r,k} \quad (24)$$

Lower 48 Onshore Expenditures and Well Determination

Expected DCF for shallow gas recovery

$$SGDCFON_{i,r,t} = \frac{\sum_k (WELLS_{i,r,k,t-1} * DCFON_{i,r,k,t})}{\sum_k WELLS_{i,r,k,t-1}}, \text{ for } k = 3, 5 \text{ to } 7 \tag{25}$$

Expected oil DCF

$$ODCFON_{i,r,t} = \frac{\sum_k (WELLS_{i,r,k,t-1} * DCFON_{i,r,k,t})}{\sum_k WELLS_{i,r,k,t-1}}, \text{ for } k = 1 \text{ to } 2 \tag{26}$$

Lower 48 Onshore Well Forecasting Equations

Exploratory Oil

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & e^{m0_{i,k}} * DCFON_{i,r,k,t-1}^{m1_{i,k}} * CASHFLOW_{t}^{m2_{i,k}} \\ & * WELLSON_{i,r,k,t-1}^{r_{i,k}} e^{-r_{i,k} m0_{i,k}} * DCFON_{i,r,k,t-2}^{-r_{i,k} m1_{i,k}} * CASHFLOW_{t-1}^{-r_{i,k} m2_{i,k}} \end{aligned} \tag{27}$$

Developmental Oil

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & e^{m0_{i,k}} * DCFON_{i,r,k,t-1}^{m1_{i,k}} * CASHFLOW_{t}^{m2_{i,k}} \\ & * WELLSON_{i,r,k,t-1}^{\rho_{i,k}} e^{-\rho_{i,k} m0_{i,k}} * DCFON_{i,r,k,t-2}^{-\rho_{i,k} m1_{i,k}} * CASHFLOW_{t-1}^{-\rho_{i,k} m2_{i,k}} \end{aligned} \tag{28}$$

Exploratory Shallow Gas

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & e^{m0_{i,k} + \sum_r m00_{i,r,k} REGr} DCFON_{r,k,t}^{m1_{i,k}} CASHFLOW_{t}^{m2_{i,k}} WELLSON_{i,r,k,t-1}^{\rho_{i,k}} \\ & e^{-\rho_{i,k} (m0_{i,k} + \sum_r m00_{i,r,k} REGr)} DCFON_{r,k,t-1}^{-\rho_{i,k} m1_{i,k}} CASHFLOW_{t-1}^{-\rho_{i,k} m2_{i,k}} \end{aligned} \tag{29}$$

Developmental Shallow Gas

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & e^{m0_{i,k}} * DCFON_{i,r,k,t}^{m1_{i,k}} * CASHFLOW_{t}^{m2_{i,k}} \\ & * WELLSON_{i,r,k,t-1}^{\rho_{i,k}} e^{-\rho_{i,k} m0_{i,k}} * DCFON_{i,r,k,t-1}^{-\rho_{i,k} m1_{i,k}} * CASHFLOW_{t-1}^{-\rho_{i,k} m2_{i,k}} \end{aligned} \tag{30}$$

Exploratory Deep Gas

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & e^{m0_{i,k} + \sum_r m00_{i,r,k} REGr} * DCFON_{i,r,k,t-1}^{m1_{i,k}} * CASHFLOW_{t}^{m2_{i,k}} * WELLSON_{i,r,k,t-1}^{\rho_{i,k}} \\ & * e^{-\rho_{i,k} (m0_{i,k} + \sum_r m00_{i,r,k} REGr)} * DCFON_{i,r,k,t-2}^{-\rho_{i,k} m1_{i,k}} * CASHFLOW_{t-1}^{-\rho_{i,k} m2_{i,k}} \end{aligned} \tag{31}$$

Developmental Deep Gas

$$WELLSON_{i,r,k,t} = e^{m0_{i,k} + \sum_r m00_{i,r,k} REGr} * DCFON_{i,r,k,t-1}^{m1_{i,k}} * CASHFLOW_t^{m2_{i,k}} * WELLSON_{i,r,k,t-1}^{r_{i,k}} * e^{-r_{i,k}(m0_{i,k} + \sum_r m00_{i,r,k} REGr)} * DCFON_{i,r,k,t-2}^{-r_{i,k} m1_{i,k}} * CASHFLOW_{t-1}^{-r_{i,k} m2_{i,k}} \tag{32}$$

Calculation of success rate

$$\begin{aligned} LSR_{i,r,t} = {} & a0_{i,r} + a1_i * \ln(CUMSUCWELLS_{i,r,t}) + a2_r * \ln(TOTWELLS_{i,r,t}) + a3_i * YEAR_t + \rho_i * \ln\left(\frac{SR_{i,r,t-1}}{1 - SR_{i,r,t-1}}\right) \\ & - \rho_i * \left[a0_{i,r} + a1_i * \ln(CUMSUCWELLS_{i,r,t-1}) + a2_r * \ln(TOTWELLS_{i,r,t-1}) + a3_i * YEAR_{t-1}\right] \end{aligned} \tag{33}$$

$$SR_{i,r,t} = \frac{e^{LSR_{i,r,t}}}{1 + e^{LSR_{i,r,t}}} \tag{34}$$

Calculation of successful onshore wells

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, r = \text{onshore regions}, \\ k = 1 \text{ thru } 7 \tag{35}$$

Calculation of onshore dry holes

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t}, \text{ for } i = 1, 2, \\ r = \text{onshore regions}, k = 1 \text{ thru } 7 \tag{36}$$

Lower 48 Onshore Reserve Additions

New reserve discoveries

$$NRD_{r,k,t} = FR1_{r,k,t} * SW1_{r,k,t} \tag{37}$$

$$\begin{aligned} FR1_{r,k,t} = {} & \exp(\alpha_{r,k}) * SW1_{r,k,t}^{\beta 1_k} * \exp(\beta 2_k * year_t) * \exp(\beta 3_{r,k} * CUMSW1_{r,k,t}) * FR1_{r,k,}^{\rho_k} \\ & * \exp(-\rho_k * \alpha_{r,k}) * SW1_{r,k,t-1}^{-\rho_k * \beta 1_k} * \exp(-\rho_k * \beta 2_k * year_{t-1}) * \exp(-\rho_k * \beta 3_{r,k} * CUM \end{aligned} \tag{38}$$

Inferred reserves

$$I_{r,k,t} = NRD_{r,k,t} * (RSVGR - 1) \tag{39}$$

Reserve extensions

$$EXT_{r,k,t} = FR2_{r,k,t} * SW2_{r,k,t} \tag{40}$$

$$FR2_{r,k,t} = \exp(\alpha_{r,k}) * \exp(\beta 1_k * SW2_{r,k,t}) * \exp(\beta 2_{r,k} * CUMSW1_{r,k,t}) * \exp(\beta 3_{r,k} * CUM$$

$$* FR2_{r,k,t-1}^{\rho_k} * \exp(\alpha_{r,k}) * \exp(\beta 1_k * SW2_{r,k,t-1}) * \exp(\beta 2_{r,k} * CUMSW1_{r,k,t-1}) \qquad (41)$$

$$* \exp(\beta 3_{r,k} * CUMSW2_{r,k,t-1}) * \exp(\beta 4_k * year_{t-1})$$

Reserve revisions

$$REV_{r,k,t} = FR3_{r,k,t} * SW3_{r,k,t} \qquad (43)$$

$$FR3_{r,k,t} = AVGFR3_{r,k,t} \qquad (42)$$

Total reserve additions

$$RA_{r,k,t} = NRD_{r,k,t} + EXT_{r,k,t} + REV_{r,k,t} \qquad (44)$$

End-of-year reserves

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \qquad (45)$$

Lower 48 Onshore & Offshore Production to Reserves Ratio

$$PR_{t+1} = \frac{(R_{t-1} * PR_t * (1 - PR_t)) + (PRNEW * RA_t)}{R_t} \qquad (46)$$

$$Q_{r,k,t+1} = [R_{r,k,t}] * [PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})] \qquad (47)$$

Associated-dissolved gas production

$$ADGAS_{r,t} = e^{\ln(\alpha 0)_r + \ln(\alpha 1)_r * DUM86_t} * OILPROD_{r,t}^{\beta 0_r + \beta 1_r * DUM86_t} \qquad (48)$$

Enhanced Oil Recovery Supply

Proved Reserves

Thermal (not region 6) and Gas EOR Proved Reserves

$$PRV\_RES_{r,e} = T\_PRV\_RES_{r,e,t-1} * (1. - PRV\_PR_{tc,r,e,t}) \qquad (49)$$

Thermal EOR Proved Reserves in OGSM Region 6

$$PRV\_RES_{r,e} = \sum_{f} \left(\frac{TF\_ECONPRD_{f}}{DCL\_RATE_{f}} * \frac{365.25}{1000000.} \right) * PRV\_RESADJ_{e} \quad (50)$$

$$PRV\_RESADJ_{e} = \frac{\left(\frac{TOT\_RES_{r,e,t}}{1000.} - TRP\_RES_{r,e} \right)}{PRV\_RES_{r,e}} \quad (51)$$

Unit Revenue for Thermal EOR Proved Reserves in OGSM Region 6

$$ADJ\_RWOP_{f} = (ROPRICE_{r,e,t} + ((API\_GRV_{f} - 13.) * 0.15)) * (1. - ROYALTY - ADVALRM) \quad (52)$$

Fixed and variable operating costs per field for Thermal EOR Proved Reserves in OGSM Region 6

$$INITVOC_{f} = \frac{(FUELVOC_{f} + OTHOMC_{f}) * EORWELLS_{f}}{(1,000,000. * TF\_EORPROD_{f})} \quad (53)$$

$$EORVOC_{f} = INITVOC_{f} * \frac{RGPRICE_{r,t,2}}{INITPNG} \quad (54)$$

$$EORFXOC_{f,cat} = \frac{WELLFXOC_{f}}{MIDPRD_{f,cat} * 365.} \quad (55)$$

Production for EOR Proved Reserves

$$PRV\_PROD_{r,e} = PRV\_PR_{tc,r,e,t} * \frac{PRV\_RES_{r,e}}{(1. - PRV\_PR_{tc,r,e,t})} \quad (56)$$

Inferred (new) Reserves

EOR Reserve Additions

$$NEW\_PRV\_RES_{r,e,i} = \frac{INF\_PS\_TBL_{tc,r,e,t,i}}{DEV\_SCHED_{i}} \quad (57)$$

$$TNP\_RES_{r,e} = \sum_{i} NEW\_PRV\_RES_{r,e,i} \quad (58)$$

Production and End-of-Year Reserves from New Additons

$$CUR\_PRV\_RES_{r,e,i} = P\_CUR\_PRV\_RES_{r,e,i} + NEW\_PRV\_RES_{r,e,i} \tag{59}$$

$$NEW\_PROD_{r,e,t,i} = INF\_PR_{tc,r,e,t} * CUR\_PRV\_RES_{r,e,i} \tag{60}$$

$$TN\_PROD_{r,e} = \sum_{i} NEW\_PROD_{r,e,t,i} \tag{61}$$

$$TRP\_RES_{r,e} = \sum_{i} (CUR\_PRV\_RES_{r,e,i} - NEW\_PROD_{r,e,t,i}) \tag{62}$$

Average Threshold Price for Thermal EOR Inferred Reserves

$$AVGPR\_THRSHLD_{f,t} = TANGCC_{f,t} + ITANGCC_{f,t} + EORVOC_{f,t} + EORFXOC_{f,t} \tag{63}$$

Potential Reserves for Development for Thermal EOR Inferred Reserves

$$TOT\_RESV_{f,t} = VINF\_RESV_{f} * (1. + HIMPRV\_REC * PCTPEN_{t}) \tag{64}$$

Gas Miscible EOR Inferred Resource Base

$$CO2RES\_INF_{r,t} = (CO2RES\_INF_{r,t-1} * MULT\_INF_{r}) + CONST\_INF_{r} \tag{65}$$

Thermal (not region 6) and Gas EOR Proved Reserves

$$INF\_PS\_TBL_{tc,r,e,t,i} = CO2RES\_INF_{r,t} * \frac{SPLIT\_INF_{m,r}}{10.} \tag{66}$$

Cogeneration from EOR Production

Capacity for EOR Cogeneration

$$PRV\_COGEN_{r,1} = PRV\_STEAM_{r} * PRV\_COGENPEN * COGFAC \tag{67}$$

$$INF\_COGEN_{r,1} = INF\_STEAM_{r} * INF\_COGENPEN * COGFAC \tag{68}$$

Electricity Generated from EOR Cogeneration

$$PRV\_COGEN_{r,4} = PRV\_COGEN_{r,1} * PRV\_UTIL_{r,1,t,2} * \frac{24 * 365}{1000} \tag{69}$$

$$INF\_COGEN_{r,4} = INF\_COGEN_{r,1} * INF\_UTIL_{r,1,t,2} * \frac{24 * 365}{1000} \tag{70}$$

Alaska Supply

Expected Costs

Drilling costs

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1)**(t - T_b) \tag{71}$$

Lease equipment costs

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2)**(t - T_b) \tag{72}$$

Operating costs

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3)**(t - T_b) \tag{73}$$

Tariffs

$$\begin{aligned} TRR_t = {} & OPERCOST_t + DRR_t + TOTDEP_t + MARGIN_t + DEFRETREC_t + TXALLW_t \\ & NONTRANSREV_t + CARRYOVER_t \end{aligned} \tag{74}$$

$$TOTDEP_t = DEP_t * \left(DEPPROP_{t-2} + ADDS_{t-1} - PROCEEDS_{t-1} - TOTDEP_{t-1}\right) \tag{75}$$

$$MARGIN_t = ALLOW_t * THRUPUT_t + 0.064 * \left(DEPPROP_{NEW,t} + DEFRET_{NEW,t} - DEFTAX_{NEW,t}\right) \tag{76}$$

$$DEFRETREC_t = DEP_t * \left(DEFRET_{t-2} + INFLADJ_{t-1} + AFUDC_{t-1} - DEFRETREC_{t-1}\right) \tag{77}$$

$$TXALLW_t = TXRATE * \left(MARGIN_t + DEFRETREC_t\right) \tag{78}$$

Canadian Gas Trade

Calculation of successful wells drilled in Western Canada

$$SUCWELL_t = e^{(\beta 0 + \beta 3)} * GPRICE_t^{\beta 2} * SUCWELL_{t-1}^{\rho} * e^{[\ -\rho * (\beta 0 + \beta 3)\ ]} * GPRICE_{t-1}^{-\rho * \beta 2} \tag{79}$$

Finding rate and reserve additions

$$FRCAN_t = e^{-115.706} * CUMGWELLS_t^{-0.763412} * e^{-0.000278607*SUCWELL+0.066231*YEAR} \quad (80)$$

$$RESADCAN_t = FRCAN_t * SUCWELL_t \quad (81)$$

End-of-year reserves

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \quad (82)$$

Remaining economically recoverable resources

$$URRCAN_t = RESBASE_{resbasyr} * (1. + RESTECH)^T - CUMRCAN_{t-1} \quad (83)$$

Production to reserves ratio

$$PR_{t+1} = \frac{Q_t * (1-PR_t) + PRNEW * RA_t}{R_t} \quad (84)$$

Offshore Supply

COSTING AND CASH-FLOW ROUTINES

Geological and Geophysical Costs Per Year:

$$GNG\_CAP_t = \frac{GNGCAP}{GNG\_TIM},\ t = IYREXP \text{ to } (IYREXP+GNG\_TIM-1) \quad (85)$$

$$GNG\_EXP_t = \frac{GNGEXP}{GNG\_TIM},\ t = IYREXP \text{ to } (IYREXP+GNG\_TIM-1) \quad (86)$$

Exploration Drilling Costs Per Year

$$EXPDCST_t = DNCEXP * \frac{EXPWEL}{EXPTIM},\ t = IYREXP \text{ to } (IYREXP+EXPTIM-1) \quad (87)$$

Delineation Drilling Costs Per Year

$$DELDCST_t = DNCDEL * \frac{DELWEL}{DELTIM},\ t = IYRDEL \text{ to } (IYRDEL+DELTIM-1) \quad (88)$$

Pre-drilled Development Well Costs Per Year

$$PREDCST_t = DNCPRE * \frac{PREDEV}{PRETIM}, \; t = IYRPRE \text{ to } (IYRPRE + PRETIM - 1) \tag{89}$$

Pre-drilled Dry Development Well Costs Per Year

$$PDRDCST_t = PREDRY * \frac{DELWEL}{PRETIM}, \; t = IYRPRE \text{ to } (IYRPRE + PRETIM - 1) \tag{90}$$

Development Drilling Costs Per Year

$$DEVDCST_t = DNCDEV * \frac{DEVWEL}{DEVTIM}, \; t = IYRDEV \text{ to } (IYRDEV + DEVTIM - 1) \tag{91}$$

Dry Development Drilling Costs Per Year

$$DDRDCST_t = DNCDRY * \frac{DEVDRY}{DEVTIM}, \; t = IYRDEV \text{ to } (IYRDEV + DEVTIM - 1) \tag{92}$$

Production Structure Installation Costs Per Year

$$STRYCST_t = STRCST * \frac{NSTRUC}{STRTIM}, \; t = IYRSTR \text{ to } (IYRSTR + STRTIM - 1) \tag{93}$$

Template Installation Costs Per Year

$$TMPYCST_t = TEMCST * \frac{NTEMP}{TEMTIM}, \; t = IYRTEM \tag{94}$$

Pipeline and Gathering System Installation Costs Per Year

$$PIPECST_t = PIPECO, \; t = IYRPIP \tag{95}$$

Production Structure Abandonment Costs Per Year

$$ABNDCST_t = ABNCST, \; t = IYRABN \tag{96}$$

Intangible Capital Investments Per Year

$$\begin{aligned} INTANG_t = {} & EXPDCST_t + DELDCST_t + 0.7 * PERIT * PREDCST_t + PDRDCST_t + 0.7 * PERIT * DEVDCST_t + \\ & DDRDCST_t + 0.9 * PERIT * STRYCST_t + ABNDCST_t + GNG\_EXP_t, \; t = 1 \text{ to } IYRABN \end{aligned} \tag{97}$$

Tangible Capital Investments Per Year

$$\begin{aligned} TANG_t = {} & PERT * PREDCST_t + 0.3 * PERIT * PREDCST_t + PERT * DEVDCST_t + 0.3 * PERIT * DEVDCST_t + \\ & PERT * STRYCST_t + 0.1 * PERIT * STRYCST_t + PIPECST_t + GNG\_\bigcap_t, \; t = 1 \text{ to } IYRABN \end{aligned} \tag{98}$$

Total Investments Per Year

$$INVEST_t = TANG_t + INTANG_t, \; t = 1 \text{ to } IYRABN \tag{99}$$

Gross Revenues Per Year

$$REV_{OIL_t} = QOIL_t * OILPRC_t, \; t = 1 \text{ to } IYRABN \tag{100}$$

$$REV\_GAS_t = QGAS_t * GASPRC_t, \; t = 1 \text{ to } IYRABN \tag{101}$$

$$REV\_GROS_t = REV\_OIL_t + REV\_GAS_t, \; t = 1 \text{ to } IYRABN \tag{102}$$

Gravity Penalties Per Year

$$GRAV\_ADJ_t = QOIL_t * GRADJ_t, \; t = 1 \text{ to } IYRABN \tag{103}$$

Transportation Costs Per Year

$$TRAN\_CST_t = QOIL_t * TARF\_OIL_t + QGAS_t * TARF\_GAS_t, \; t = 1 \text{ to } IYRABN \tag{104}$$

Adjusted Revenues Per Year

$$REV\_ADJ_t = REV\_GROS_t - GRAV\_ADJ_t - TRAN\_CST_t, \; t = 1 \text{ to } IYRABN \tag{105}$$

Royalty Payments Per Year

$$ROYALTY_t = REV\_ADJ_t * ROYL\_RAT, \; t = 1 \text{ to } IYRABN \tag{106}$$

$$ROYALTY_t = 0.00, \; IF \; QCBOE \le RELIEF_{WDC} \tag{107}$$

Net Producer Revenue Per Year

$$REV\_PROD_t = REV\_ADJ_t - ROYALTY_t, \; t = 1 \text{ to } IYRABN \tag{108}$$

G & A on Investments and Operation Costs

$$GNA\_CST_t = TANG_t * GNATAN + INTANG_t * GNAINT, \; t = 1 \text{ to } IYRABN \tag{109}$$

$$GNA\_OPN_t = OPCOST_t * OPOVHD, \; t = 1 \text{ to } IYRABN \tag{110}$$

Net Revenue from Operations Per Year

$$REV\_NET_t = REV\_PROD_t - OPCOST_t - GNA\_CST_t - GNA\_OPN_t, \; t = 1 \text{ to } IYRABN \qquad (111$$

Net Income Before Taxes Per Year

$$NET\_BTCF_t = REV\_NET_t - INTANG_t - DEPR_t - GNGRC_t, \; t = 1 \text{ to } IYRABN \qquad (112)$$

Federal Tax Bill Per Year

$$FED\_TAXS_t = NET\_BTCF_t * FTAX\_RAT, \; t = 1 \text{ to } IYRABN \qquad (113)$$

Income Tax Credits Per Year

$$FED\_INTC_t = INVEST_t * XINTC, \; t = 1 \text{ to } IYRABN \qquad (114)$$

Net Income After Taxes Per Year

$$NET\_INCM_t = NET\_BTCF_t - FED\_TAXS_t + FED\_INTC_t, \; t = 1 \text{ to } IYRABN \qquad (115)$$

Annual After-Tax Cash Flow

$$ANN\_ATCF_t = NET\_INCM_t - TANG_t + DEPR_t + GNGRC_t, \; t = 1 \text{ to } IYRABN \qquad (116)$$

Discounted After-Tax Cash Flow Per Year

$$NPV\_ATCF_t = \frac{ANN\_ATCF_t}{DISCRT^{I}}, \; t = 1 \text{ to } IYRABN \qquad (117)$$

RESERVES DEVELOPMENT AND PRODUCTION TIMING

Inferred Oil Reserve Additions

IF POOLTYPE $_{ipool}$ = ‘OIL’, and IF OILPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$INFR\_OIL_{iyr} = INFR\_OIL_{iyr} + RSRV\_OIL_{ipool}, \; iyr = \text{Current Year}, \; ipool = 1 \text{ to } NFIEL \qquad (118)$$

$$INFR\_AGS_{iyr} = INFR\_AGS_{iyr} + RSRV\_GAS_{ipool}, \; iyr = \text{Current Year}, \; ipool = 1 \text{ to } NFIELD \qquad (119$$

Inferred Gas Reserve Additions

IF POOLTYPE $_{ipool}$ = ‘GAS’, and IF GASPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$INFR\_GAS_{iyr} = INFR\_GAS_{iyr} + RSRV\_GAS_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{120}$$

$$INFR\_CND_{iyr} = INFR\_CND_{iyr} + RSRV\_OIL_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{121}$$

Average Supply Price for Inferred Oil Reserves

IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$MSP\_INFO_{iyr} = \frac{MSP\_INFO_{iyr} * INFR\_OIL_{iyr} + MASP\_TOT_{ipool} * RSRV\_OIL_{ipool}}{INFR\_OIL_{iyr} + RSRV\_OIL_{ipool}}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{122}$$

Average Supply Price for Inferred Gas Reserves

IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$MSP\_INFG_{iyr} = \frac{MSP\_INFG_{iyr} * INFR\_GAS_{iyr} + MASP\_TOT_{ipool} * RSRV\_GAS_{ipool}}{INFR\_GAS_{iyr} + RSRV\_GAS_{ipool}}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{123}$$

Wells Required for Inferred Oil Reserves

IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$WEL\_EXPO_{iyr} = WEL\_EXPO_{iyr} + EXPL\_WEL_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{124}$$

$$WEL\_DEVO_{iyr} = WEL\_DEVO_{iyr} + DEVL\_WEL_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{125}$$

$$WEL\_DRYO_{iyr} = WEL\_DRYO_{iyr} + DRY\_HOLE_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{126}$$

Wells Required for Inferred Gas Reserves

IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$WEL\_EXPG_{iyr} = WEL\_EXPG_{iyr} + EXPL\_WEL_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{127}$$

$$WEL\_DEVG_{iyr} = WEL\_DEVG_{iyr} + DEVL\_WEL_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{128}$$

$$WEL\_DRYG_{iyr} = WEL\_DRYG_{iyr} + DRY\_HOLE_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{129}$$

Number of Structures Required for Inferred Oil Reserves

IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$NUM\_STRO_{iyr} = NUM\_STRO_{iyr} + STRUC\_NO_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{130}$$

Number of Structures Required for Inferred Gas Reserves

IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr}$ ≥ MASP_TOT $_{ipool}$

$$NUM\_STRG_{iyr} = NUM\_STRG_{iyr} + STRUC\_NO_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; NFIELD \tag{131}$$

Relative Price Differential for Oil Reserves Vs. Gas Reserves Development

$$RATIO1 = \frac{OILPRICE_{iyr} - MSP\_INFO_{iyr}}{OILPRICE_{iyr}}, \; iyr = Current \; Year \tag{132}$$

$$RATIO1 = \frac{GASPRICE_{iyr} - MSP\_INFG_{iyr}}{GASPRICE_{iyr}}, \; iyr = Current \; Year \tag{133}$$

$$PRP\_OIL_{iyr} = \frac{RATIO1}{RATIO1 + RATIO2}, \; iyr = Current \; Year \tag{134}$$

Oil Well Drilling Activity

$$RIGS_{iyr} = rig\_B0 + rig\_B1 * RIGS_{iyr-1} + rig\_B2 * gasprice_{iyr} + rig\_B3 * oilprice_{iyr} \tag{135}$$

$$ExpWell_{iyr} = exp\_B0 + exp\_B1 * RIGS_{iyr} \tag{136}$$

$$DevWell_{iyr} = dev\_B0 + dev\_B1 * ExpWell_{iyr-5} + dev\_B2 * RIGS_{iyr} + rig\_B3 * DevWell_{iyr-1} \tag{137}$$

$$WEL\_LIMT_{iyr} = DevWell_{iyr}, \; iyr = Current \; Year \tag{138}$$

$$WEL\_LIMO_{iyr} = PRP\_OIL_{iyr} * WEL\_LIMIT_{iyr}, \; iyr = Current \; Year \tag{139}$$

$$WEL\_DRLO_{iyr} = \begin{cases} WEL\_LIMO_{iyr} & if \; WEL\_LIMO_{iyr} \le WEL\_DEVO_{iyr}, \; iyr = Current \; Year \\ WEL\_DEVO_{iyr} & if \; WEL\_LIMO_{iyr} \ge WEL\_DEVO_{iyr}, \; iyr = Current \; Year \end{cases} \tag{140}$$

Gas Well Drilling Activity

$$WEL\_LIMG_{iyr} = WEL\_LIMIT_{iyr} - WEL\_LIMO_{iyr}, \; iyr = Current \; Year \tag{141}$$

$$WEL\_DRLG_{iyr} = \begin{cases} WEL\_LIMG_{iyr} & if \; WEL\_LIMG_{iyr} \le WEL\_DEVG_{iyr}, \; iyr = Current \; Year \\ WEL\_DEVG_{iyr} & if \; WEL\_LIMG_{iyr} \ge WEL\_DEVG_{iyr}, \; iyr = Current \; Year \end{cases} \tag{142}$$

Booked Oil Reserve Additions

$$RTIO\_OIL = \frac{WEL\_DRLO_{iyr}}{WEL\_DEVO_{iyr}}, \; iyr = Current \; Year \tag{143}$$

$$BKED\_OIL_{iyr} = RTIO\_OIL * INFR\_OIL_{iyr}, \; iyr = Current \; Year \tag{144}$$

$$BKED\_AGS_{iyr} = RTIO\_OIL * INFR\_AGS_{iyr}, \; iyr = Current \; Year \tag{145}$$

Booked Gas Reserve Additions

$$RTIO\_GAS = \frac{WEL\_DRLG_{iyr}}{WEL\_DEVG_{iyr}}, \; iyr = Current \; Year \tag{146}$$

$$BKED\_GAS_{iyr} = RTIO\_GAS * INFR\_GAS_{iyr}, \; iyr = Current \; Year \tag{147}$$

$$BKED\_CND_{iyr} = RTIO\_GAS * INFR\_CND_{iyr}, \; iyr = Current \; Year \tag{148}$$

Oil Production Accounting

Beginning of the Year Reserves

$$BEG\_RSVO_{iyr} = XPVD\_OIL + XPVD\_CND, \; iyr = 1 \tag{149}$$

$$BEG\_RSVO_{iyr} = END\_RSVO_{iyr-1}, \; iyr = Current \; Year \neq 1 \tag{150}$$

Production in the Year

$$RATIO\_RP_{iyr} = rp\_B0 + rp\_B1 * \ln(iyr + ModelStartYear - rp\_B2) \tag{151}$$

$$PROD\_OIL_{iyr} = \frac{BEG\_RSVO_{iyr}}{RATIO\_RP} \tag{152}$$

Reserves Growth

$$GRO\_RSVO_{iyr} = (BEG\_RSVO_{iyr} - PROD\_OIL_{iyr}) * RES\_GROW, \; iyr = Current \; Year$$ (153

Reserve Additions

$$ADD\_RSVO_{iyr} = BKED\_OIL_{iyr} + BKED\_CND_{iyr}, \ iyr = Current \ Year \quad (154)$$

End of the Year Reserves

$$END\_RSVO_{iyr} = BEG\_RSVO_{iyr} + GRO\_RSVO_{iyr} + ADD\_RSVO_{iyr} - PROD\_OIL_{iyr}, \ iyr = Current \ Year \quad (155$$

Gas Production Accounting

Beginning of the Year Reserves

$$BEG\_RSVG_{iyr} = XPVD\_GAS + XPVD\_AGS, \ iyr = 1 \quad (156)$$

$$BEG\_RSVG_{iyr} = END\_RSVG_{iyr}, \ iyr = Current \ Year \neq 1 \quad (157)$$

Production in the Year

$$PROD\_GAS_{iyr} = \frac{BEG\_RSVG_{iyr}}{RATIO\_RP}, \ iyr = Current \ Year \quad (158)$$

Reserves Growth

$$GRO\_RSVG_{iyr} = (BEG\_RSVG_{iyr} - PROD\_GAS_{iyr}) * RES\_GROW, \ iyr = Current \ Year \quad (159)$$

Reserve Additions

$$ADD\_RSVG_{iyr} = BKED\_GAS_{iyr} + BKED\_AGS_{iyr}, \ iyr = Current \ Year \quad (160)$$

End of the Year Reserves

$$END\_RSVG_{iyr} = BEG\_RSVG_{iyr} + GRO\_RSVG_{iyr} + ADD\_RSVG_{iyr} - PROD\_GAS_{iyr}, \ iyr = Current \ Year \quad (161$$

Advanced Technology Impacts on Exploration

$$MASP\_EXP_{ipool,new} = \frac{MASP\_EXP_{ipool,old}}{ADT\_EXPL}, \ ipool = 1 \ to \ NFIELD \quad (162)$$

$$MASP\_TOT = MASP\_TOT - \left(MASP\_EXP_{ipool,old} - MASP\_EXP_{ipool,new}\right), \ ipool = 1 \ to \ NFIELD \quad (163$$

Advanced Technology Impacts on Drilling

$$MASP\_DRL_{ipool,new} = \frac{MASP\_DRL_{ipool,old}}{ADT\_DRLG}, \; ipool = 1 \; to \; NFIELD \tag{164}$$

$$MASP\_TOT = MASP\_TOT - \left(MASP\_DRL_{ipool,old} - MASP\_DRL_{ipool,new}\right), \; ipool = 1 \; to \; NFIELD \quad (165$$

Advanced Technology Impacts on Structure

$$MASP\_STR_{ipool,new} = \frac{MASP\_STR_{ipool,old}}{ADT\_STRC}, \; ipool = 1 \; to \; NFIELD \tag{166}$$

$$MASP\_TOT = MASP\_TOT - \left(MASP\_STR_{ipool,old} - MASP\_STR_{ipool,new}\right), \; ipool = 1 \; to \; NFIELD \quad (167$$

Advanced Technology Impacts on Operations

$$MASP\_OPR_{ipool,new} = \frac{MASP\_OPR_{ipool,old}}{ADT\_OPER}, \; ipool = 1 \; to \; NFIELD \tag{168}$$

$$MASP\_TOT = MASP\_TOT - \left(MASP\_OPR_{ipool,old} - MASP\_OPR_{ipool,new}\right), \; ipool = 1 \; to \; NFIELD \quad (169$$

Unconventional Gas Recovery Supply

<u>Resource Base/Well Productivity</u>

Undrilled Locations Under Current Technology

$$CTUL = BASAR * WSPAC\_CT - DEV\_CEL \tag{170}$$

Undrilled Locations Under Advanced Technology

$$ATUL = BASAR * WSPAC\_AT - DEV\_CEL \tag{171}$$

Weighted Average of the Expected Ultimate Recovery for Each (Entire) Basin

$$MEUR1_{1,1} = \left(.10 * RW10 + .20 * RW20 + .30 * RW30 + .40 * RW40\right) \tag{172}$$

Expected Ultimate Recovery for the Best 30% of the wells in the Basin

$$\begin{aligned} MEUR1_{iyr,2} = MEUR_{1,1} + (((((RW10*(1/3)) + (RW20*(2/3) - MEUR1_{1,1}))/DEVPER) \\ *TECHYRS)*(TECHYRS*(REDAM\%/20) + (TECHYRS*(FRCLEN\%/20)) \\ +(TECHYRS*(PAYCON\%/20)) + 1)) \end{aligned} \tag{173}$$

Expected Ultimate Recovery for the middle 30% of the wells in the Basin

$$MEUR1_{iyr,3} = RW30 \tag{174}$$

Expected Ultimate Recovery for the Worst 40% of the Wells in the Basin

$$MEUR1_{iyr,4}=(MEUR1_{1,1})-(((RW30_1-RW40_1)/DEVPER)*TECHYRS)*(TECHYRS)*(REDAM\%/20)) \\ +(TECHYRS*(FRCLEN\%/20))+(TECHYRS)*(PAYCON\%/20))+1) \tag{175}$$

Expected Ultimate Recovery adjusted for Technological Progress in the Development of New Cavity Fairways

$$MEUR2 = \begin{cases} MEUR1*CAVFRWY\% \Leftarrow IF(NEWCAVFRWY = 1) \\ MEUR1 \Leftarrow IF(NEWCAVFRWY = 0) \end{cases} \tag{176}$$

Expected Ultimate Recovery adjusted for Technological Progress in the Commercialization of Enhanced Coalbed Methane

$$MEUR3 = \begin{cases} MEUR2*ENCBM\% \Leftarrow IF(ENCBM = 1) \\ MEUR2 \Leftarrow IF(ENCBM = 0) \end{cases} \tag{177}$$

Technically Recoverable Wells

$$TRW_1 = (ATUL*SCSSRT_1*PLPROB2_1) \tag{178}$$

Undeveloped Resources

$$UNDEV\_RES_{iyr} = (MEUR3_{iyr}*TRW_{iyr}) \tag{179}$$

Reserves and Cumulative Production

$$RESNPROD_{iyr}=RESNPROD_{iyr-1}+RESADD_{iyr} \tag{180}$$

Ultimate Recoverable Resources

$$URR_{iyr} = RESNPROD_{iyr}+UNDEV\_RES_{iyr} \tag{181}$$

Economics and Pricing

Discounted Reserves

$$DISCRES_{iyr}=(DIS\_FAC*MEUR3_{iyr}) \tag{182}$$

Expected Net Present Value Revenues

$$ENPVR_{iyr} = \left(WHGP_{iyr} + BASNDIF\right) * \left(DISCRES_{iyr}\right) * 1{,}000{,}000\right) \tag{183}$$

Drilling and Completion Costs

$$DACC = \begin{cases} AVGDPTH * DCC\_L2K + DCC\_G\&G \Leftarrow IF(AVDPTH < 2000) \\ 2000 * DCC\_L2K + (AVGDPTH - 2000) * DCC\_G2K) + DCC\_G\&G \Leftarrow IF(AVDPTH \geq 2000) \end{cases} \tag{184}$$

Stimulation Costs

$$STIMC = SZONE * STM\_CST \tag{185}$$

Pumping and Surface Equipment Costs

$$PASE = \begin{cases} BASET + 5 * AVGDPTH \Leftarrow IF(WATR\_DISP = 1) \\ 10000 \Leftarrow IF(WATR\_DISP \neq 1) \end{cases} \tag{186}$$

Lease Equipment Costs

$$LSE\_EQ = \begin{cases} \begin{bmatrix} WOMS\_LE + WOML\_WTR \Leftarrow IF\left\{(WATR\_DISP = 1) AND (MEUR3 < .5)\right\} \\ WOMM\_LE + WOML\_WTR \Leftarrow IF\left\{(WATR\_DISP = 1) AND (MEUR3 \geq .5) AND (MEUR3 \leq 1.0)\right\} \\ WOML\_LE + WOML\_WTR \Leftarrow IF\left\{(WATR\_DISP = 1) AND (MEUR3 > 1.0)\right\} \end{bmatrix} \\ \begin{bmatrix} WOMS\_LE \Leftarrow IF\left\{(WATR\_DISP = 0) AND (MEUR3 < .5)\right\} \\ WOMM\_LE \Leftarrow IF\left\{(WATR\_DISP = 0) AND (MEUR \geq .5) AND (MEUR3 \leq 1.0)\right\} \\ WOML\_LE \Leftarrow IF\left\{(WATR\_DISP = 0) AND (MEUR3 > 1.0)\right\} \end{bmatrix} \end{cases} \tag{187}$$

General and Administrative Costs

$$GAA10 = RST * (LSE\_EQ + PASE + STIMC + DACC) \tag{188}$$

Total Capital Costs

$$TCC = \left(DACC + STIMC + PASE + LSE\_EQ + GAA10\right) \tag{189}$$

Dry Hole Costs

$$DHC = (DACC + STIMC) * ((1/SCSSRT) - 1) \tag{190}$$

Capital and Dry Hole Costs per Mcf

$$CCWDH = (TTC + DHC)/(DISCRES * 1000000) \tag{191}$$

Variable Operating Costs

$$VOC=\begin{cases}\dfrac{\begin{array}{c}WTR\_DSPT*TECHYRS*(WDT\%/20)+WOMS*TECHYRS*(PUMP\%/20)\\+GASTR*TECHYRS*(GTF\%/20)+OCWW\$\end{array}}{} \Leftarrow IF(WAT\_DISP>.4)\\ \begin{array}{c}WTR\_DSPT*TECHYRS*(WDT\%/20)+WOMS*TECHYRS*(PUMP\%/20)\\+GASTR*TECHYRS*(GTF\%/20)+OCNW\$\end{array} \Leftarrow IF(WAT\_DISP\le .4)\end{cases} \quad (192)$$

Variable Operating Costs with Enhanced Coalbed Methane

$$VOC2=\begin{cases}VOC+((ECBM\_OC+VOC)*(ENH\_CBM\%))/(1+ENH\_CBM\%)\Leftarrow IF(ECBMR=1)\\ VOC\Leftarrow IF(ECBMR\ne 1)\end{cases} \quad (193)$$

Fixed Operating and Maintenance Costs

$$FOMC=\begin{cases}\left[\begin{array}{l}\underline{IF(WATR\_DISP=1)}\\ DIS\_FACT*WOMS\_OMW+VOC*DISCRES*1000000\Leftarrow IF(MEUR3<.5)\\ DIS\_FACT*WOMM\_OMW+VOC*DISCRES*1000000\Leftarrow IF(MEUR3\ge .5)AND(MEUR3\le 1.0)\\ DIS\_FACT*WOMM\_OMW+VOC*DISCRES*1000000\Leftarrow IF(MEUR3>1.0)\end{array}\right.\\ \left[\begin{array}{l}\underline{IF(WATR\_DISP=0)}\\ .6*DIS\_FACT*WOMS\_OMW+VOC*DISCRES*1000000\Leftarrow IF(MEUR3<.5)\\ .6*DIS\_FACT*WOMM\_OMW+VOC*DISCRES*1000000\Leftarrow IF(MEUR3\ge .5)AND(MEUR3\le 1.0)\\ .6*DIS\_FACT*WOMM\_OMW+VOC*DISCRES*1000000\Leftarrow IF(MEUR3>1.0)\end{array}\right.\end{cases} \quad (194)$$

Total Costs

$$TOTL\_CST=FOMC/(DISCRES*1000000)+CCWDH \quad (195)$$

Net Price

$$NET\_PRC=(1-RST)*(WHGP+BASNDIF) \quad (196)$$

Net Profitability

$$NET\_PROF=NET\_PRC-TOTL\_CST \quad (197)$$

$$NET\_PROFIT2=\begin{cases}NET\_PROFIT\Leftarrow IF(NET\_PROFIT>0)\\ 0\Leftarrow IF(NET\_PROFIT\le 0)\end{cases} \quad (198)$$

Model Outputs

Undeveloped Wells

$$UNDV\_WELLS = \begin{cases} TRW * (ENV\% + (LOW\% / LOWYRS) * TECHYRS) \Leftarrow IF(NET\_PROF2 > 0) AND (ENPRGS = 1) \\ TRW \Leftarrow IF(NET\_PROF2 > 0) AND (ENPRGS = 0) \\ 0 \Leftarrow IF(NET\_PROF2 = 0) \end{cases} \quad (199)$$

Expected Ultimate Recovery Adjusted for Profitability

$$MEUR4 = \begin{cases} MEUR3 \Leftarrow IF(NET\_PROF2 > 0) \\ 0 \Leftarrow IF(NET\_PROF2 = 0) \end{cases} \quad (200)$$

Drilling Schedule

$$DRL\_SCHED = \begin{cases} 0 \Leftarrow IF(HYP\% \neq 0) \\ 0 \Leftarrow IF(HYP\% = 0) AND (NET\_PROF2 = 0) \\ USLOW \Leftarrow IF(HYP\% = 0) AND (NET\_PROF2 > 0) AND (NET\_PROF < LOW\$) \\ SLOW \Leftarrow IF(HYP\% = 0) AND (NET\_PROF2 \geq LOW\$) AND (NET\_PROF < SMAL\$) \\ MED \Leftarrow IF(HYP\% = 0) AND (NET\_PROF2 \geq SMAL\$) AND (NET\_PROF < MED\$) \\ FAST \Leftarrow IF(HYP\% = 0) AND (NET\_PROF2 \geq MED\$) AND (NET\_PROF < LAR\$) \\ SLOW \Leftarrow IF(HYP\% = 0) AND (NET\_PROF2 \geq LAR\$) \end{cases} \quad (201)$$

Drilling Schedule Adjusted for Technological Advancement

$$DRL\_SCHED2 = \begin{cases} DRL\_SCHED + EMRG\% - EMERG\# \Leftarrow IF(DRL\_SCHED > 0) AND (EMRG = 1) \\ DRL\_SCHED \Leftarrow IF(DRL\_SCHED > 0) AND (EMRG \neq 1) \\ 0 \Leftarrow IF(DRL\_SCHED \leq 0) \end{cases} \quad (202)$$

$$DRL\_SCHED3 = \begin{cases} DRL\_SCHED \Leftarrow IF(DRL\_SCHED2 < DRL\_SCHED) \\ DRL\_SCHED2 \Leftarrow IF(DRL\_SCHED2 \geq DRL\_SCHED) \end{cases} \quad (203)$$

New Wells

$$NW\_WELLS = \begin{cases} \left[\begin{array}{l} \underline{IF(DRL\_SCHED3 > 0} \\ \left(\begin{array}{l} \underline{IF(YEAR > 1)AND(NW\_WELLS\_LAG > 0)} \\ 1.3 * NW\_WELLS\_LAG \Leftarrow IF(UNDV\_WELLS / DRL\_SCHED3 > 1.3 * NW\_WELLS\_LAG) \\ .7 * NW\_WELLS\_LAG \Leftarrow IF(UNDV\_WELLS / DRL\_SCHED3 < 0.7 * NW\_WELLS\_LAG) \\ UNDV\_WELLS / DRL\_SCHED3 \Leftarrow IF(UNDV\_WELLS / DRL\_SCHED3 \\ \qquad\qquad\qquad\qquad ((< 1.3 * NW\_WELLS\_LAG)AND(> 0.7 * NW\_WELLS\_LAG))) \end{array} \right. \\ \left(\begin{array}{l} \underline{IF(YEAR = 1)OR(NW\_WELLS\_LAG = 0)} \\ UNDV\_WELLS / DRL\_SCHED3 \end{array} \right. \end{array} \right. \\ \left[\begin{array}{l} \underline{IF(DRL\_SCHED3 = 0)} \\ 0 \end{array} \right. \end{cases} \tag{204}$$

$$NW\_WELLS2 = \begin{cases} UNDV\_WELLS \Leftarrow IF(UNDV\_WELLS < NW\_WELLS) \\ NW\_WELLS \Leftarrow IF(UNDV\_WELLS \geq NW\_WELLS) \end{cases} \tag{205}$$

Reserve Additions from New Wells

$$DRA = NW\_WELLS2 * MEUR4 \tag{206}$$

Reserve Additions from New Growth

$$RGA = \begin{cases} RGR * PROV\_RES + .025 * (MEUR3 - MEUR2) \Leftarrow IF(RES\_GR = 1)AND(ENCBM = 1) \\ RGR * PROV\_RES \Leftarrow IF(RES\_GR = 1)AND(ENCBM = 0) \\ 0 \Leftarrow IF(RES\_GR \neq 1) \end{cases} \tag{207}$$

Total Reserve Additions

$$R\_ADD = DRA + RGA \tag{208}$$

Proved Reserves for the Next Year

$$PROV\_RES2 = \begin{cases} PRO\_RES + R\_ADD - PROD \Leftarrow IF((PROV\_RES + R\_ADD - PROD) > 0) \\ 0 \Leftarrow IF((PROV\_RES + R\_ADD - PROD) \leq 0) \end{cases} \tag{209}$$

Reserves-to-Production Ratio for the Next Year

$$RP\_RAT2 = \begin{cases} RP\_RAT - 1 \Leftarrow IF(RP\_RAT > 10) \\ RP\_RAT \Leftarrow IF(RP\_RAT \leq 10) \end{cases} \tag{210}$$

Production for the Next Year

$$PROD2 = \begin{cases} 0 \Leftarrow IF(RP\_RAT2 = 0) \\ PRO\_RES / RP\_RAT2 \Leftarrow IF(RP\_RAT2 \neq 0) \end{cases} \tag{211}$$

Undeveloped Wells for the Next Year

$$UNDV\_WELLS2 = \begin{cases} \left[\dfrac{IF(ENPRGS = 1)}{TRW - NW\_WELLS2} \right. \\ \left[\begin{array}{l} \dfrac{IF(ENPRGS \neq 1)}{0 \Leftarrow IF(UNDV\_WELLS = 0)} \\ .1 \Leftarrow IF(UNDV\_WELLS \neq 0) AND (UNDV\_WELLS - NW\_WELLS = 0) \\ NW\_WELLS2 \Leftarrow IF(UNDV\_WELLS \neq 0) AND (UNDV\_WELLS - NW\_WELLS \neq 0) \end{array} \right. \end{cases} \tag{212}$$

Appendix C. Bibliography

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 Division 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
   2000

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: Oil and Gas Analysis
   - Model Contact: Ted McCallister
   - Telephone: (202) 586-4820

9. Documentation Reference
   U.S. Department of Energy. 2000. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, Energy Information Administration, Washington, DC.

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U.S. Department of Energy. 1994. *Documentation of the Oil and Gas Supply Module (OGSM), Appendix: Model Developers Report*, Energy Information Administration, Washington, DC.

10. Archive Media and Installation Manual
    NEMS2001

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 seven 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 Supply Submodule
      - Unconventional Gas Recovery Supply Submodule
      - 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 (1970-1998)*, 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 (1970-1998)*, 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)

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- Canadian Recoverable Resource Base - National Energy Board. *Canadian Energy Supply and Demand 1990 - 2010*, June 1991

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- 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 - 1998)*, DOE/EIA-0815(80-98)

    - Onshore Operating Cost - Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 1998)*, DOE/EIA-0815(80-98)

    - 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*, (1977-1998), DOE/EIA-0216(77-98)

16. Computing Environment
    - Hardware Used: PC
    - Operating System: Windows 95/Windows NT
    - 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 Submodule - 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
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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 for possible use in short run supply functions. The econometric software packages, SAS and TSP, were used for the estimations.

Lower 48 Estimated Wells Equations

The equations for onshore total and successful wells were estimated using time series data for the onshore Lower 48 over the time period 1970 through 1998. The equations were estimated with correction for first order serial correlation using version 4.4 of TSP.

$$LESTWELLS_t = b0 + b1 * LPOIL_t + b2 * LPGAS_t + \rho * LESTWELLS_{t-1} - \rho * (b0 + b1 * LPOIL_{t-1} + b2 * LPGAS_{t-}$$

Dependent variable: $lnESTWELLS_t$
Number of observations: 29

(Statistics based on transformed data)		(Statistics based on original data)	
Mean of dep. var. =	.773259	Mean of dep. var. =	10.5283
Std. dev. of dep. var. =	.571719	Std. dev. of dep. var. =	.458516
Sum of squared residuals =	.327719	Sum of squared residuals =	.421251
Variance of residuals =	.012605	Variance of residuals =	.016202
Std. error of regression =	.112270	Std. error of regression =	.127287
R-squared =	.967485	R-squared =	.930147
Adjusted R-squared =	.964984	Adjusted R-squared =	.924773
Durbin-Watson =	2.12057	Durbin-Watson =	1.92563

ρ (autocorrelation coef.) = .935763
Standard error of ρ = .056575
t-statistic for ρ = 16.5402
Log likelihood = 22.8104

Parameter	Estimate	Standard Error	t-statistic	P-value
b0	9.24194	.345360	26.7603	[.000]
b1	.384673	.150670	2.55308	[.011]
b2	.364478	.104591	3.48478	[.000]

$$LESTSUCWELLS_t = b0 + b1*LPOIL_t + b2*LPGAS_t + \rho*LESTSUCWELLS_{t-1} - \rho*(b0 + b1*LPOIL_{t-1} + b2*LPGAS_{t-1})$$

```
Dependent variable: lnESTSUCWELLS_t
Number of observations:  29

 (Statistics based on transformed data)  (Statistics based on original data)
           Mean of dep. var. = 1.26568          Mean of dep. var. = 10.1632
      Std. dev. of dep. var. = .645064     Std. dev. of dep. var. = .450947
    Sum of squared residuals = .333911   Sum of squared residuals = .373656
       Variance of residuals = .012843      Variance of residuals = .014371
    Std. error of regression = .113326   Std. error of regression = .119881
                   R-squared = .973012                  R-squared = .935106
          Adjusted R-squared = .970936         Adjusted R-squared = .930114
               Durbin-Watson = 2.10554              Durbin-Watson = 2.02018
 ρ (autocorrelation coef.) = .887343
       Standard error of ρ = .077178
         t-statistic for ρ = 11.4974
              Log likelihood = 22.8072
```

Parameter	Estimate	Standard Error	t-statistic	P-value
b0	8.79205	.307779	28.5661	[.000]
b1	.401503	.144735	2.77406	[.006]
b2	.389798	.106397	3.66361	[.000]

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]
```

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

$$\begin{aligned}LDRILLCOST_{r,k,t} = {} & \ln(\delta 0)_{r,k} + \ln(\delta 1)_{d,k} + \ln(\delta 2)_{r,k} + \delta 3_k * LESTWELLS_t + \delta 4_k * LRIGSL48_t + \delta 5_k * TIME_t + \\ & \rho_k * LDRILLCOST_{r,k,t-1} - \rho_k * \left(\ln(\delta 0)_{r,k}\right) + \ln(\delta 1)_{d,k} + \ln(\delta 2)_{r,k} + \\ & \delta 3_k * LESTWELLS_{t-1} + \delta 4_k * LRIGSL48_{t-1} + \delta 5_k * TIME_{t-1}\Big)\end{aligned}$$

Results

Mapping of variable names from the above equation to the following SAS output.

Variable/Parameter	Successful		Dry	
	Oil	Gas	Oil	Gas
LDRILLCOST	LNROCOST	LNRGCOST	LNROCOST_D	LNRGCOST_D
$\ln(\delta 0)_1$	C(1)	C(20)	C(34)	C(49)
$\ln(\delta 0)_2$	C(2)	C(21)	C(35)	C(50)
$\ln(\delta 0)_3$	C(3)	C(22)	C(36)	C(51)
$\ln(\delta 0)_4$	C(4)	C(23)	C(37)	C(52)
$\ln(\delta 0)_5$	C(5)	C(24)	C(38)	C(53)
$\ln(\delta 0)_6$	C(6)	C(25)	C(39)	C(54)
$\ln(\delta 1)_{r,2500}$	C(12)	C(27)	C(42)	C(55)
$\ln(\delta 1)_{r,3750}$	C(13)	C(28)	C(43)	C(56)
$\ln(\delta 1)_{r,5000}$	C(14)	C(29)	C(44)	C(57)
$\ln(\delta 1)_{r,7500}$	C(15)	C(30)	C(45)	C(58)
$\ln(\delta 1)_{r,10000}$	C(16)	C(31)	C(46)	C(59)
$\ln(\delta 1)_{r,12500}$	C(17)	C(32)	C(47)	C(60)
$\ln(\delta 2)_{1,5000}$	C(10)	C(10)	C(10)	C(10)
$\ln(\delta 2)_{6,5000}$	C(10)	C(10)	C(10)	C(10)
$\delta 3$	C(8)	C(8)	C(40)	C(40)
$\delta 4$	C(7)	C(7)	C(7)	C(7)

Variable/Parameter	Successful		Dry	
	Oil	Gas	Oil	Gas
δ5 (shallow wells)	C(9)	C(9)	C(9)	C(9)
δ5 (deep wells)	C(99)	C(99)	C(99)	C(99)
ρ	C(19)	C(33)	C(48)	C(61)

System: AEO_2001_F
Estimation Method: Iterative Seemingly Unrelated Regression
Date: 09/20/00 Time: 10:34
Sample: 6 57 6 57 93 898 6 57 6 57 93 898 934 956 IF YEAR > 1974 AND YEAR <1998
Included observations: 713
Total system (balanced) observations 2852
Sequential weighting matrix & coefficient iteration
Convergence achieved after: 12 weight matricies, 53 total coef iterations

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	24.25918	3.304791	7.340610	0.0000
C(2)	24.88064	3.304618	7.529053	0.0000
C(3)	24.72937	3.304617	7.483277	0.0000
C(4)	24.72683	3.304619	7.482505	0.0000
C(5)	25.01116	3.304617	7.568551	0.0000
C(6)	25.55093	3.305186	7.730557	0.0000
C(7)	-0.088246	0.036531	-2.415632	0.0158
C(8)	0.425956	0.034442	12.36746	0.0000
C(9)	-0.008935	0.001596	-5.596720	0.0000
C(99)	-0.026133	0.002303	-11.34846	0.0000
C(10)	0.166083	0.061113	2.717648	0.0066
C(12)	0.974295	0.028107	34.66423	0.0000
C(13)	1.332262	0.028147	47.33222	0.0000
C(14)	1.779968	0.028107	63.32862	0.0000
C(15)	2.307466	0.028147	81.97864	0.0000
C(16)	36.97176	4.745437	7.791013	0.0000
C(17)	37.56541	4.745434	7.916116	0.0000
C(19)	0.073977	0.009855	7.506344	0.0000
C(20)	24.65881	3.307187	7.456128	0.0000
C(21)	25.18631	3.306815	7.616486	0.0000
C(22)	25.02422	3.306746	7.567627	0.0000
C(23)	24.99565	3.306807	7.558847	0.0000
C(24)	25.24418	3.306829	7.633953	0.0000
C(25)	25.50997	3.308419	7.710622	0.0000
C(27)	0.838687	0.055929	14.99549	0.0000
C(28)	1.109365	0.057037	19.44998	0.0000
C(29)	1.492164	0.055927	26.68037	0.0000
C(30)	2.068727	0.057036	36.27045	0.0000
C(31)	36.88822	4.748538	7.768333	0.0000
C(32)	37.78648	4.748525	7.957520	0.0000
C(33)	0.560553	0.025764	21.75749	0.0000
C(34)	24.13609	3.305548	7.301692	0.0000
C(35)	24.41156	3.305207	7.385789	0.0000

C(36)	24.24764	3.305205	7.336198	0.0000
C(37)	24.24753	3.305206	7.336165	0.0000
C(38)	24.56812	3.305205	7.433163	0.0000
C(39)	25.00196	3.306137	7.562286	0.0000
C(40)	0.433339	0.034774	12.46160	0.0000
C(42)	0.686925	0.042565	16.13843	0.0000
C(43)	1.129007	0.043218	26.12348	0.0000
C(44)	1.711027	0.042565	40.19775	0.0000
C(45)	2.329225	0.043218	53.89442	0.0000
C(46)	37.02891	4.745452	7.803030	0.0000
C(47)	37.81010	4.745448	7.967657	0.0000
C(48)	0.036671	0.005944	6.169089	0.0000
C(49)	24.48903	3.307903	7.403188	0.0000
C(50)	24.26911	3.304703	7.343810	0.0000
C(51)	24.08199	3.304586	7.287445	0.0000
C(52)	24.05932	3.304644	7.280457	0.0000
C(53)	24.37562	3.304852	7.375706	0.0000
C(54)	24.46261	3.306813	7.397640	0.0000
C(55)	0.223647	0.082585	2.708083	0.0068
C(56)	0.680311	0.080444	8.456903	0.0000
C(57)	1.346420	0.075562	17.81863	0.0000
C(58)	2.113822	0.076784	27.52954	0.0000
C(59)	37.02298	4.748322	7.797065	0.0000
C(60)	38.30820	4.747883	8.068482	0.0000
C(61)	0.533145	0.026629	20.02151	0.0000

Determinant residual covariance 4.20E-08

Equation: LNROCOST = C(1)*REG1 + C(2)*REG2 + C(3)*REG3 + C(4)*REG4 + C(5)*REG5 + C(6)*REG6 + C(7)*LNRC + C(8)*LNALLWELLS + C(9)*SYEAR + C(99)*DYEAR + C(10)*D5000_16 + C(12)*D_2500 + C(13)*D_3750 + C(14)*D_5000 + C(15)*D_7500 + C(16)*D_10000 + C(17)*D_12500 + C(19)*LNROCOST(-1) - C(19)*(C(1)*REG1 + C(2)*REG2 + C(3)*REG3 + C(4)*REG4 + C(5)*REG5 + C(6)*REG6 + C(7)*LNRC(-1) + C(8)*LNALLWELLS(-1) + C(9)*SYEAR(-1) + C(99)*DYEAR(-1) + C(10)*D5000_16 + C(12)*D_2500 + C(13)*D_3750 + C(14)*D_5000 + C(15)*D_7500 + C(16)* D_10000 + C(17)* D_12500)

Observations: 713

R-squared	0.974768	Mean dependent var	12.67881
Adjusted R-squared	0.974151	S.D. dependent var	1.113646
S.E. of regression	0.179049	Sum squared resid	22.28067
Durbin-Watson stat	0.743885		

Equation: LNRGCOST = C(20)*REG1 + C(21)*REG2 + C(22)*REG3 + C(23)*REG4 + C(24)*REG5 + C(25)*REG6 + C(7)*LNRC + C(8)*LNALLWELLS + C(9)*SYEAR + C(99)*DYEAR + C(10)*D5000_16 + C(27)*D_2500 + C(28)*D_3750 + C(29)*D_5000 + C(30)*D_7500 + C(31)* D_10000 + C(32)* D_12500 + C(33)*LNRGCOST(-1) - C(33)*(C(20)*REG1 + C(21)*REG2 + C(22)*REG3 + C(23)*REG4 + C(24)*REG5 + C(25)*REG6 + C(7)*LNRC(-1) + C(8)*LNALLWELLS(-1) + C(9)*SYEAR(-1) + C(99)*DYEAR(-1) + C(10)*D5000_16 + C(27)*D_2500 + C(28)*D_3750 + C(29)*D_5000 + C(30)*D_7500 + C(31)* D_10000 + C(32)* D_12500)

Observations: 713

R-squared	0.978157	Mean dependent var	12.81577
Adjusted R-squared	0.977623	S.D. dependent var	1.151026
S.E. of regression	0.172182	Sum squared resid	20.60441

Durbin-Watson stat	1.866286

Equation: LNROCOST_D = C(34)*REG1 + C(35)*REG2 + C(36)*REG3

+ C(37)*REG4 + C(38)*REG5 + C(39)*REG6 + C(7)*LNRC + C(40)*LNALLWELLS + C(9)*SYEAR + C(99)*DYEAR + C(10) *D5000_16 + C(42)*D_2500 + C(43)*D_3750 + C(44)*D_5000 + C(45)*D_7500 + C(46)* D_10000 + C(47)* D_12500 + C(48) *LNROCOST_D(-1) - C(48)*(C(34)*REG1 + C(35)*REG2 + C(36) *REG3 + C(37)*REG4 + C(38)*REG5 + C(39)*REG6 + C(7) *LNRC(-1) + C(40)*LNALLWELLS(-1) + C(9)*SYEAR(-1) + C(99) *DYEAR(-1) + C(10)*D5000_16 + C(42)*D_2500 + C(43)*D_3750 + C(44)*D_5000 + C(45)*D_7500 + C(46)* D_10000 + C(47)* D_12500)

Observations: 713

R-squared	0.947781	Mean dependent var	12.26473
Adjusted R-squared	0.946503	S.D. dependent var	1.236514
S.E. of regression	0.285998	Sum squared resid	56.84737
Durbin-Watson stat	0.672211		

Equation: LNRGCOST_D = C(49)*REG1 + C(50)*REG2 + C(51)*REG3

+ C(52)*REG4 + C(53)*REG5 + C(54)*REG6 + C(7)*LNRC + C(40)*LNALLWELLS + C(9)*SYEAR + C(99)*DYEAR + C(10) *D5000_16 + C(55)*D_2500 + C(56)*D_3750 + C(57)*D_5000 + C(58)*D_7500 + C(59)* D_10000 + C(60)* D_12500 + C(61) *LNRGCOST(-1) - C(61)*(C(49)*REG1 + C(50)*REG2 + C(51) *REG3 + C(52)*REG4 + C(53)*REG5 + C(54)*REG6 + C(7) *LNRC(-1) + C(40)*LNALLWELLS(-1) + C(9)*SYEAR(-1) + C(99) *DYEAR(-1) + C(10)*D5000_16 + C(55)*D_2500 + C(56)*D_3750 + C(57)*D_5000 + C(58)*D_7500 + C(59)* D_10000 + C(60)* D_12500)

Observations: 713

R-squared	0.963423	Mean dependent var	12.40283
Adjusted R-squared	0.962528	S.D. dependent var	1.271566
S.E. of regression	0.246146	Sum squared resid	42.10852
Durbin-Watson stat	1.156273		

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

$$\begin{aligned} LLEQC_{r,k,t} = {} & \ln(\varepsilon 0)_{r,k} + \ln(\varepsilon 1)_k * DEPTH_{r,k,t} + \varepsilon 2_k * LESUCWELL_{k,t} + \varepsilon 3_k * TIME_t + \rho_k * LLEQC_{r,k,t-1} - \\ & \rho_k * (\ln(\varepsilon 0)_{r,k} + \ln(\varepsilon 1)_k * DEPTH_{r,k,t-1} * \varepsilon 2_k * LESUCWELL_{k,t-1} + \varepsilon 3_k * TIME_{t-1}) \end{aligned}$$

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
$\ln(\varepsilon 0)_1$	SOREG1	SGREG1	--	--
$\ln(\varepsilon 0)_2$	SOREG2	SGREG2	DOREG2	DGREG2
$\ln(\varepsilon 0)_3$	SOREG3	SGREG3	DOREG3	DGREG3
$\ln(\varepsilon 0)_4$	SOREG4	SGREG4	DOREG4	DGREG4
$\ln(\varepsilon 0)_5$	SOREG5	SGREG5	DOREG5	DGREG5
$\ln(\varepsilon 0)_6$	SOREG6	SGREG6	--	--
ε1	SODEPTH	SGDEPTH	DODEPTH	DGDEPTH
ε2	SOWELL	SGWELL	DOWELL	DGWELL
ε3	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

Parameter	Estimate	Standard 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

Parameter	Estimate	Standard 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

$$
\begin{aligned}
LOPC_{r,k,t} = {} & \ln(\varphi 0)_{r,k} + \ln(\varphi 1)_k * DEPTH_{r,k,t} + \varphi 2_k * LESUCWELL_{k,t} + \varphi 3_k * TIME_t + \rho_k * LOPC_{r,k,t-1} - \\
& \rho_k * (\ln(\varphi 0)_{r,k} + \ln(\varphi 1)_k * DEPTH_{r,k,t-1} * \varphi 2_k * LESUCWELL_{k,t-1} + \varphi 3_k * TIME_{t-1})
\end{aligned}
$$

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
$\ln(\varphi 0)_1$	SOREG1	SGREG1	--	--
$\ln(\varphi 0)_2$	SOREG2	SGREG2	DOREG2	DGREG2
$\ln(\varphi 0)_3$	SOREG3	SGREG3	DOREG3	DGREG3
$\ln(\varphi 0)_4$	SOREG4	SGREG4	DOREG4	DGREG4
$\ln(\varphi 0)_5$	SOREG5	SGREG5	DOREG5	DGREG5
$\ln(\varphi 0)_6$	SOREG6	SGREG6	--	--
$\varphi 1$	SODEPTH	SGDEPTH	DODEPTH	DGDEPTH
$\varphi 2$	SOWELL	SGWELL	DOWELL	DGWELL
$\varphi 3$	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

Parameter	Estimate	Standard 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

Parameter	Estimate	Standard 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]

Lower 48 Onshore Well Equations

Each of the onshore wells equations were estimated using panel data, i.e., data across regions over time. For oil and shallow gas, this included data for each of the six onshore regions over the sample period 1980-1997; for deep gas, this included data for onshore regions 2 through 5 over the same time period. The estimation procedures employed tested and corrected for the two econometric problems of cross sectional heteroscedasticity and first order serial correlation. Offshore wells equations were estimated using time series data for each of the offshore regions over the 1980-1997 time period. Where necessary, the estimation corrected for first-order serial correlation. The econometric software package used for all estimations was TSP Version 4.4.

Oil Exploratory

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m1_{i,k} \ln DCFON_{i,r,k,(t-1)} + m2_{i,k} \ln CASHFLOW_{t} + \rho_{i,k} \ln WELLSON_{i,r,k,(t-1)}$$
$$-\rho_{i,k}(m0_{i,k} + m00_{i,r,k} + m1_{i,k} \ln DCFON_{i,r,k,(t-2)} + m2_{i,k} \ln CASHFLOW_{t-1})$$
$$i=1,\ r=1\text{-}6,\ k=1$$

Dependent variable: lnWELLSON
Number of observations: 120

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = .272773	Mean of dep. var. = 8.79150
Std. dev. of dep. var. = .695386	Std. dev. of dep. var. = 4.31780
Sum of squared residuals = 13.9730	Sum of squared residuals = 22.1964
Variance of residuals = .120457	Variance of residuals = .191348
Std. error of regression = .347070	Std. error of regression = .437433
R-squared = .779552	R-squared = .990130
Adjusted R-squared = .773851	Adjusted R-squared = .989875
Durbin-Watson = 1.75198	Durbin-Watson = 1.44469
r (autocorrelation coef.) = .967220	
Log likelihood = -49.4749	

Parameter	Estimate	Standard Error	t-statistic	P-value
m0	-1.86098	1.87303	-.993563	[.320]
m1	.532879	.118398	4.50073	[.000]
m2	.657113	.102776	6.39363	[.000]
r	.967220	.016021	60.3725	[.000]

Oil Development

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m1_{i,k} \ln DCFON_{i,r,k,(t-1)} + m2_{i,k} \ln CASHFLOW_{t} + \rho_{i,k} \ln WELLSON_{i,r,k,(t-1)}$$
$$-\rho_{i,k}(m0_{i,k} + m00_{i,r,k} + m1_{i,k} \ln DCFON_{i,r,k,(t-2)} + m2_{i,k} \ln CASHFLOW_{t-1})$$
$$i=2,\ r=1\text{-}6,\ k=1$$

Dependent variable: lnWELLSON
Number of observations: 120

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = .573268	Mean of dep. var. = 13.8410
Std. dev. of dep. var. = .950374	Std. dev. of dep. var. = 3.84565
Sum of squared residuals = 17.9341	Sum of squared residuals = 31.6654
Variance of residuals = .154604	Variance of residuals = .272978
Std. error of regression = .393197	Std. error of regression = .522473
R-squared = .838939	R-squared = .982088
Adjusted R-squared = .834774	Adjusted R-squared = .981625
Durbin-Watson = 1.81781	Durbin-Watson = 1.32038
r (autocorrelation coef.) = .963245	
Log likelihood = -64.1119	

Parameter	Estimate	Standard Error	t-statistic	P-value
m0	-13.8335	12.0858	-1.14461	[.252]
m1	1.35980	.738841	1.84045	[.066]
m2	.987340	.097528	10.1236	[.000]
r	.963245	.017183	56.0589	[.000]

Shallow Gas Exploratory

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m00_{i,6,k} * REG6 + m1_{i,k} \ln DCFON_{i,r,k,t} + m2_{i,k} \ln CASHFLOW_{t} + \rho_{i,k} \ln WELLSON_{i,r,k,(t-1)}$$
$$-\rho_{i,k}(m0_{i,k} + m00_{i,6,k} * REG6 + m1_{i,k} \ln DCFON_{i,r,k,(t-1)} + m2_{i,k} \ln CASHFLOW_{t-1})$$
$$i = 1,\ r = 1-6,\ k = 3$$

Dependent variable: lnWELLSON
Number of observations: 120

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = 1.21052	Mean of dep. var. = 13.2689
Std. dev. of dep. var. = 1.27113	Std. dev. of dep. var. = 3.25408
Sum of squared residuals = 39.2772	Sum of squared residuals = 51.9648
Variance of residuals = .341541	Variance of residuals = .451868
Std. error of regression = .584415	Std. error of regression = .672211
R-squared = .816139	R-squared = .959276
Adjusted R-squared = .809744	Adjusted R-squared = .957859
Durbin-Watson = 2.10334	Durbin-Watson = 1.81515
r (autocorrelation coef.) = .916197	
Log likelihood = -108.749	

Parameter	Estimate	Standard Error	t-statistic	P-value
m0	2.56315	1.97507	1.29775	[.194]
$m00_{1,6,3}$	-1.58445	.451039	-3.51289	[.000]
m1	.229208	.123827	1.85104	[.064]
m2	.252902	.114576	2.20729	[.027]
r	.916197	.033774	27.1275	[.000]

Shallow Gas Development

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m1_{i,k} \ln SGDCFON_{i,r,k,t} + m2_{i,k} \ln CASHFLOW_t + \rho_{i,k} \ln WELLSON_{i,r,k,(t-1)}$$
$$-\rho_{i,k}(m0_{i,k} + m1_{i,k} \ln SGDCFON_{i,r,k,(t-1)} + m2_{i,k} \ln CASHFLOW_{t-1})$$
$$i = 2,\ r = 1\text{-}6,\ k = 3$$

Dependent variable: lnWELLSON
Number of observations: 126

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = .660969	Mean of dep. var. = 7.88006
Std. dev. of dep. var. = .807666	Std. dev. of dep. var. = 4.14766
Sum of squared residuals = 16.8229	Sum of squared residuals = 23.3818
Variance of residuals = .137893	Variance of residuals = .191654
Std. error of regression = .371339	Std. error of regression = .437783
R-squared = .796889	R-squared = .989159
Adjusted R-squared = .791894	Adjusted R-squared = .988892
Durbin-Watson = 1.77331	Durbin-Watson = 1.54501
r (autocorrelation coef.) = .928670	
Log likelihood = -57.8839	

Parameter	Estimate	Standard Error	t-statistic	P-value
m0	2.44052	1.02931	2.37102	[.018]
m1	.274578	.063012	4.35758	[.000]
m2	.442637	.117165	3.77790	[.000]
r	.928670	.026952	34.4566	[.000]

Deep Gas Exploratory

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m00_{i,r,k} + m1_{i,k} \ln DCFON_{i,r,k,(t-1)} + m2_{i,k} \ln CASHFLOW_{t} + \rho_{i,k} \ln WELLSON_{i,r,k,(t-1)}$$
$$-\rho_{i,k}(m0_{i,k} + m00_{i,r,k} + m1_{i,k} \ln DCFON_{i,r,k,(t-2)} + m2_{i,k} \ln CASHFLOW_{t-1})$$
$$i=1,\ r=2\text{-}5,\ k=4$$

Dependent variable: lnWELLSON
Number of observations: 80

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = 2.10083	Mean of dep. var. = 4.18386
Std. dev. of dep. var. = .829043	Std. dev. of dep. var. = 1.14869
Sum of squared residuals = 12.7195	Sum of squared residuals = 13.1668
Variance of residuals = .174240	Variance of residuals = .180367
Std. error of regression = .417420	Std. error of regression = .424697
R-squared = .773384	R-squared = .874359
Adjusted R-squared = .754758	Adjusted R-squared = .864032
Durbin-Watson = 1.84095	Durbin-Watson = 1.81002
r (autocorrelation coef.) = .515216	
Log likelihood = -40.5764	

Parameter	Estimate	Standard Error	t-statistic	P-value
m0	-3.22228	2.60766	-1.23570	[.217]
$m00_{1,3,4}$	-1.53099	.268439	-5.70330	[.000]
$m00_{1,4,4}$	-2.30603	.253552	-9.09489	[.000]
$m00_{1,5,4}$	-2.36421	.276191	-8.56008	[.000]
m1	.576516	.162177	3.55486	[.000]
m2	.869795	.331244	2.62585	[.009]
r	.515216	.179759	2.86614	[.004]

Deep Gas Development

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m1_{i,k} \ln SGDCFON_{i,r,k,t} + m2_{i,k} \ln CASHFLOW_t + \rho_{i,k} \ln WELLSON_{i,r,k,(t-1)}$$
$$-\rho_{i,k}(m0_{i,k} + m1_{i,k} \ln SGDCFON_{i,r,k,(t-1)} + m2_{i,k} \ln CASHFLOW_{t-1})$$
$$i = 2,\ r = 2 - 5,\ k = 4$$

Dependent variable: lnWELLSON
Number of observations: 80

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = .435518	Mean of dep. var. = 6.86263
Std. dev. of dep. var. = .651934	Std. dev. of dep. var. = 4.00727
Sum of squared residuals = 9.85529	Sum of squared residuals = 14.7076
Variance of residuals = .129675	Variance of residuals = .193521
Std. error of regression = .360104	Std. error of regression = .439910
R-squared = .709230	R-squared = .988471
Adjusted R-squared = .697752	Adjusted R-squared = .988015
Durbin-Watson = 2.15053	Durbin-Watson = 1.75599
r (autocorrelation coef.) = .951978	
Log likelihood = -34.4889	

Parameter	Estimate	Standard Error	t-statistic	P-value
m0	-11.6539	8.16904	-1.42660	[.154]
m1	1.09045	.495430	2.20101	[.028]
m2	.440384	.166315	2.64789	[.008]
r	.951978	.024258	39.2440	[.000]

Lower 48 Onshore Success Rates

Exploratory and developmental success rate equations were estimated using pooled cross section/time series for the six onshore regions over the 1978-1998 time period. Since success rates are bounded between 0 and 1, the logistical form of the dependent variable was employed in the estimation. Estimation corrected for cross sectional heteroscedasticity and first order serial correlation. The form of the estimating equation is the same for both exploratory and development and is given by:

$$\ln\left(\frac{SR_{i,r,t}}{1-SR_{i,r,t}}\right) = u0_{i,r} + u1_i \ln CUMSUCWELLS_{i,r,t} + u2_i \ln TOTWELLS_{i,r,t} + u3_i YEAR_t$$
$$+\rho_i \ln\left(\frac{SR_{i,r,t-1}}{1-SR_{i,r,t-1}}\right) - \rho_i(u0_{i,r} + u1_i \ln CUMSUCWELLS_{i,r,t-1}$$
$$+u2_i \ln TOTWELLS_{i,r,t-1} + u3_i YEAR_{t-1})$$

Exploratory Success Rate

Dependent variable: $\ln[SR_{1,r,t} /(1- SR_{1,r,t})]$
Number of observations: 120

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = -.829780	Mean of dep. var. = -1.91468
Std. dev. of dep. var. = .477446	Std. dev. of dep. var. = .642208
Sum of squared residuals = 21.8345	Sum of squared residuals = 22.6661
Variance of residuals = .198496	Variance of residuals = .206055

Std. error of regression = .445529	Std. error of regression = .453933
R-squared = .195971	R-squared = .538616
Adjusted R-squared = .130187	Adjusted R-squared = .500866
Durbin-Watson = 1.88853	Durbin-Watson = 1.85061
r (autocorrelation coef.) = .582240	
Log likelihood = -69.2747	

Parameter	Estimate	Standard Error	t-statistic	P-value
$u0_{1,1}$	-165.827	35.8322	-4.62788	[.000]
$u0_{1,2}$	-165.423	35.8081	-4.61970	[.000]
$u0_{1,3}$	-166.023	35.8686	-4.62863	[.000]
$u0_{1,4}$	-166.260	35.8766	-4.63422	[.000]
$u0_{1,5}$	-166.027	35.9042	-4.62417	[.000]
$u0_{1,6}$	-166.902	36.0164	-4.63405	[.000]
u1	-.814954	.206834	-3.94013	[.000]
u2	.298743	.101428	2.94537	[.003]
u3	.085581	.018491	4.62819	[.000]
r	.582240	.080790	7.20681	[.000]

Development Success Rate

Dependent variable: $\ln[SR_{2,r,t} /(1- SR_{2,r,t})]$
Number of observations: 120

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = 1.03314	Mean of dep. var. = 2.59280
Std. dev. of dep. var. = .361724	Std. dev. of dep. var. = .476061
Sum of squared residuals = 6.41503	Sum of squared residuals = 6.56417
Variance of residuals = .058318	Variance of residuals = .059674
Std. error of regression = .241492	Std. error of regression = .244283
R-squared = .589674	R-squared = .756667
Adjusted R-squared = .556102	Adjusted R-squared = .736758
Durbin-Watson = 1.69080	Durbin-Watson = 1.67556
r (autocorrelation coef.) = .623924	
Log likelihood = 3.97889	

Parameter	Estimate	Standard Error	t-statistic	P-value
$u0_{2,1}$	-127.132	22.4827	-5.65466	[.000]
$u0_{2,2}$	-128.053	22.5314	-5.68331	[.000]
$u0_{2,3}$	-127.994	22.4995	-5.68872	[.000]
$u0_{2,4}$	-127.493	22.5058	-5.66489	[.000]
$u0_{2,5}$	-127.444	22.6020	-5.63858	[.000]
$u0_{2,6}$	-126.023	22.6164	-5.57220	[.000]
u1	-.455754	.141497	-3.22094	[.001]
u2	.199023	.058337	3.41158	[.001]
u3	.066667	.011915	5.59505	[.000]
r	.623924	.074111	8.41878	[.000]

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. The section below documents the estimations.

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:

$$\begin{aligned} LCRUDE_t = \; & a0 + a1*LOILRES_t + a2*LPOIL_t + \rho*LCRUDE_{t-1} \\ & - \rho*(a0 + a1*LOILRES_{t-1} + a2*LPOIL_{t-1}) \end{aligned}$$

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:

$$\begin{aligned} LCRUDE_t = {} & a0 + a1*LOILRES_t + a2*LPOIL_t + a3*LPDUM3_t + a4*LPDUM4_t + \\ & a5*LPDUM5_t + \rho*LCRUDE_{t-1} - \rho*(a0 + a1*LOILRES_{t-1} + \\ & a2*LPOIL_{t-1} + a3*LPDUM3_{t-1} + a4*LPDUM4_{t-1} + a5*LPDUM5_{t-1}) \end{aligned}$$

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:

$$\mathrm{LPROD} = \mathrm{A0} + (\mathrm{A1} + \sum_r \mathrm{Ar} * \mathrm{DUMr}) * \mathrm{LGASRES} + (\mathrm{B1} + \sum_r \mathrm{Br} * \mathrm{DUMr}) * \mathrm{LPGAS} + \mathrm{C} * \mathrm{DEDSHR}$$

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

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 :

$$\mathrm{LADGAS}_{r,t} = \ln(\alpha 0)_r + \ln(\alpha 1)_r * \mathrm{DUM86}_t + \left(\beta 0_r + \beta 1_r * \mathrm{DUM86}_t\right) * \mathrm{LOILPROD}_{r,t}$$

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

Variable	Estimated Coefficient	Standard 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

Variable	Estimated Coefficient	Standard 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

Variable	Estimated Coefficient	Standard 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

Variable	Estimated Coefficient	Standard 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

Variable	Estimated Coefficient	Standard 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

Variable	Estimated Coefficient	Standard 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

Variable	Estimated Coefficient	Standard 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

Variable	Estimated Coefficient	Standard 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

$$\ln(SUCWELL_t) = \beta 0 + \beta 1 * \ln(GPRICE_t) + \beta 2 * DUM8392_t + \beta 3 * DUM93_t + \rho * \ln(SUCWELLS_{t-1})$$

$$- \rho * (\beta 0 + \beta 1 * \ln(GPRICE_{t-1}) + \beta 2 * DUM8392_{t-1} + \beta 3 * DUM93_{t-1})$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Objective function: Exact ML (keep first obs.)
CONVERGENCE ACHIEVED AFTER 5 ITERATIONS

Dependent variable: lnSUCWELL
Current sample: 17 to 42 (1971-1996)
Number of observations: 26

(Statistics based on transformed data)	(Statistics based on original data)
Mean of dep. var. = 4.71886	Mean of dep. var. = 7.71709
Std. dev. of dep. var. = .463605	Std. dev. of dep. var. = .473590
Sum of squared residuals = 1.38669	Sum of squared residuals = 1.40746
Variance of residuals = .066033	Variance of residuals = .067022
Std. error of regression = .256969	Std. error of regression = .258886
R-squared = .764453	R-squared = .750931
Adjusted R-squared = .719587	Adjusted R-squared = .703489
Durbin-Watson = 1.69225	Durbin-Watson = 1.68653
Rho (autocorrelation coef.)= .402134	
Log likelihood = 1.12466	

Parameter	Estimate	Standard Error	t-statistic	P-value
C	7.66066	.105422	72.6663	[.000]
LNGPRICE	.589360	.130191	4.52688	[.000]
DUM8392	-.449912	.153359	-2.93373	[.003]
DUM93	.656529	.193371	3.39517	[.001]
RHO	.402134	.204330	1.96806	[.049]

Standard Errors computed from analytic second derivatives
(Newton)

Deep Water Offshore Capacity Calculations

Offshore Rig Capacity

$$RIGS_{iyr} = rig\_B0 + rig\_B1 * RIGS_{iyr-1} + rig\_B2 * gasprice_{iyr} + rig\_B3 * oilprice_{iyr}$$

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.976
R Square	0.953
Adjusted R Square	0.935
Standard Error	4.555
Observations	12

ANOVA

	df	SS	MS	F	Significance F
Regression	3	3352.692	1117.56	53.867	0.000
Residual	8	165.975	20.747		
Total	11	3518.667			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
rig_B0	-19.631	6.301	-3.115	0.014	-34.162	-5.100
rig_B1	0.760	0.088	8.666	0.000	0.558	0.962
rig_B2	21.357	4.574	4.669	0.002	10.809	31.904
rig_B3	-1.078	0.407	-2.646	0.029	-2.017	-0.138

Exploration Drilling Capacity

$$ExpWell_{iyr} = exp\_B0 + exp\_B1 * RIGS_{iyr}$$

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.749
R Square	0.561
Adjusted R Square	0.517
Standard Error	13.712
Observations	12

ANOVA

	df	SS	MS	F	Significance F
Regression	1	2400.010	2400.01	12.764	0.005
Residual	10	1880.240	188.024		
Total	11	4280.250			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
exp_B0	9.569	9.076	1.054	0.317	-10.655	29.792
exp_B1	0.826	0.231	3.573	0.005	0.311	1.341

Developmental Drilling Capacity

$$DevWell_{iyr} = dev\_B0 + dev\_B1 * ExpWell_{iyr-5} + dev\_B2 * RIGS_{iyr} + rig\_B3 * DevWell_{iyr-1}$$

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.730
R Square	0.533
Adjusted R Square	0.358
Standard Error	13.683

Observations	12				

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1711.117	570.37	3.046	0.092
Residual	8	1497.800	187.225		
Total	11	3208.917			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
dev_B0	-16.130	23.094	-0.698	0.505	-69.386	37.126
dev_B1	0.727	0.271	2.684	0.028	0.102	1.352
dev_B2	0.648	0.308	2.101	0.069	-0.063	1.359
dev_B3	0.264	0.232	1.139	0.288	-0.271	0.799