DOE/EIA-M063(97)

Documentation of the Oil and Gas Supply Module (OGSM)

January 1997

Energy Information Administration
Oil and Gas Analysis Branch
Energy Supply and Conversion Division
Office of Integrated Analysis and Forecasting

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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 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 drilling expenditures and average drilling costs to determine exploratory and developmental drilling levels for each region and fuel type. These projected drilling levels translate into reserve additions, as well as a modification of the production capacity for each region.

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

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

Outputs from OGSM go to other oil and gas modules (NGTDM and PMM) and to other modules of NEMS. NGTDM and PMM employ short-term supply functions, the parameters for which are provided by OGSM for oil and gas production and natural gas imports. The short-term supply functions reflect potential oil or gas flows to the market for a one year period. These functions are used by NGTDM and 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, as well as capital expenditures at the wellhead, go to the Macroeconomic Module to assist in forecasting aggregate measures of capital and output.

OGSM is archived as part of the National Energy Modeling System (NEMS). The archival package of NEMS is located under the model acronym NEMS96. The version is that used to produce the *Annual Energy Outlook 1996 (AEO96)*. The package is available through the National Technical Information Service. The model contact for OGSM is:

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

- Model purpose
- Model overview and rationale
- Model structure
- Inventory of input data, parameter estimates, and model output
- Detailed mathematical description.

2. Model Purpose

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

PMM and NGTDM utilize 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 and quantities received from PMM and NGTDM. OGSM then sends the revised parameters to NGTDM and PMM, which update the short-term supply functions for use in the following forecast year. The determination of the projected natural gas and crude oil wellhead prices and quantities supplied occurs within the NGTDM and PMM. 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.

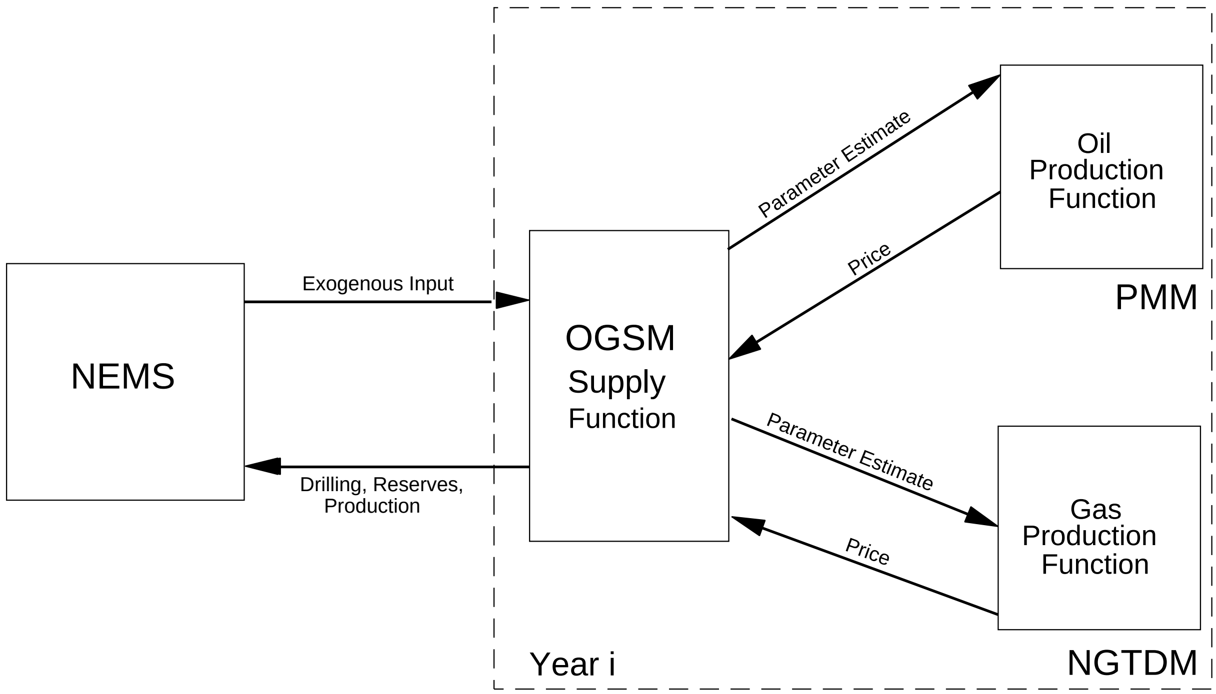
OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 2). The primary fuel types are crude oil and natural gas, 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 15,000 feet and those at greater than 15,000 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 shale, and coal bed methane formations.

OGSM provides mid-term (15 to 20 year) forecasts, as well as serving as an analytical tool for the assessment of various policy alternatives. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues OGSM can address involve policies that affect the profitability of drilling through impacts on certain variables including:

- drilling costs,
- production costs,
- regulatory or legislatively mandated environmental costs,

[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 national expenditure 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.

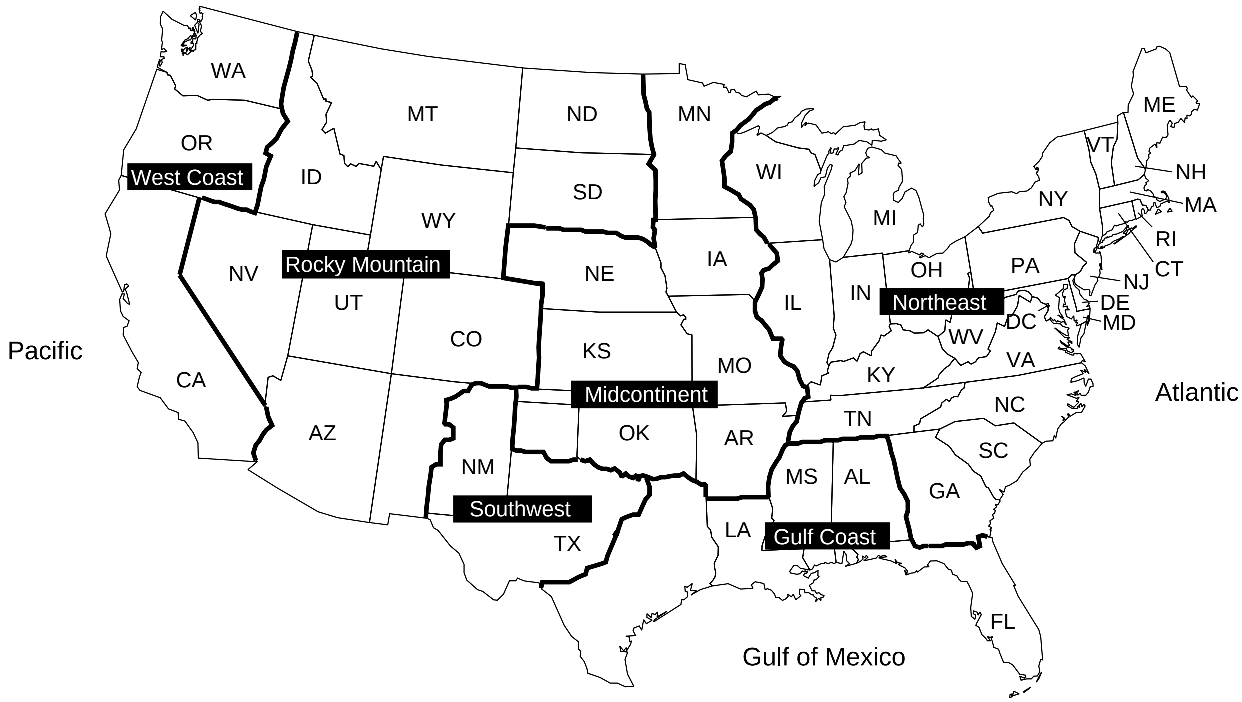
OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for economically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). This feature allows the model to be used for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

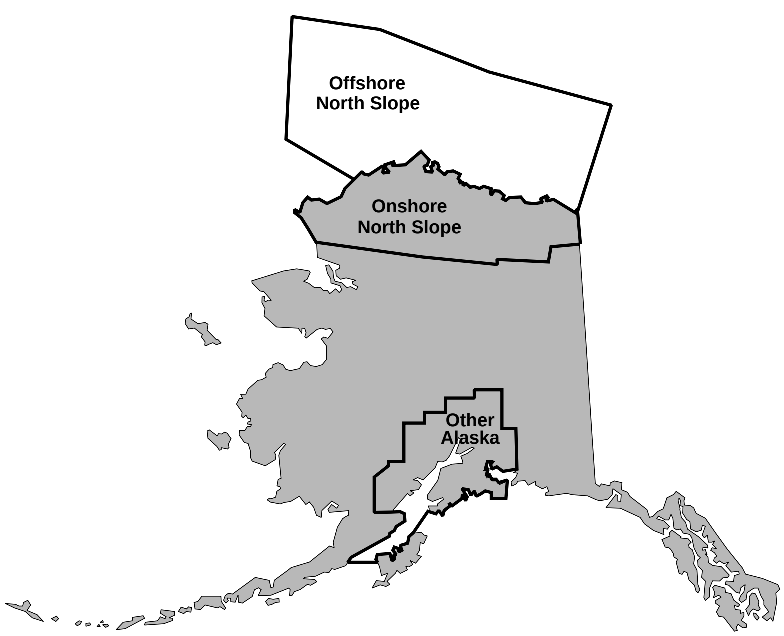
- the uncertainty surrounding the economically recoverable oil and gas resource estimates, and

- 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 (excluding enhanced oil recovery), the foreign natural gas supply submodule, and the Alaska submodule.

Overview of Oil and Gas Supply Modeling Methods

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

Geologic/Engineering Models

Play Analysis

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

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

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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.

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, © a relatively sophisticated treatment of uncertainty, and (d) explicit consideration of investment decisions at the bidding, development, and production stages, in addition to the exploration stage.

Although the OCSM had many superior qualities, it was highly resource intensive. In particular, the OCSM required (a) maintenance of a large database on more than 2000 prospects in thirty offshore plays, (b) considerable mainframe CPU time to execute completely, reflecting the highly complex algorithmic and programming routines, and © 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. Typically factors such as cash flow or the availability of rigs are constrained to enable the model to forecast satisfactorily.

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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

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

Econometric Models

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

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

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

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

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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.)

[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.

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 recent *National Energy Strategy* and numerous related studies.

The Gas Research Institute's (GRI) 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 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 uses some features of the discovery-process approach, but does not employ any of the traditional discovery process models discussed earlier because they are too data intensive. The chosen OGSM 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. The OGSM, as a regionally aggregated discovery-process model, does not determine activity levels on the basis of an explicit economic evaluation of discrete production units, such as individual producing fields (oil and gas from Alaska is the exception). 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. The OGSM, however, simulates endogenously 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) and the liquefied natural gas (LNG) component of the Foreign Natural Gas Supply Submodule (FNGSS) are the exceptions to the above paragraph. Both methodologies

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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.

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. 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.

The Lower 48 states component is comprised of 118 equations, with 311 parameters. Exploration and development expenditures are determined using a partial recursive model, with oil and gas prices the principal driving variables as they affect expected profitability for drilling investments. 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.

Drilling levels are determined by the industry's overall level of investment in exploration and development. Relying on basic research on the determinants of business investment, it is assumed that the industry's level of domestic exploration and developmental drilling expenditures is determined by several major factors, including: the expected profitability of domestic exploration and developmental drilling and the economic and geologic risk associated with exploration and developmental drilling. This model thus assumes that the firms in the industry are profit maximizers and that resources tend to flow into activities with relatively higher expected profitability, *ceteris paribus*. The number of wells drilled in each region is derived by dividing regional expenditures by average drilling costs.

The expenditure equations are econometrically based. Specifically, the levels of exploration and developmental expenditures are forecast on the basis of econometrically estimated equations that relate historical exploration and developmental drilling expenditures 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 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.

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[10] A slightly different approach was employed to represent EOR supply activities and this method is described in the following section.

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 exploration and developmental drilling expenditures, which in turn are based on 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 Gas Research Institute (GRI) 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.

Spending levels for each specific drilling activity are converted to the total number of wells drilled by dividing the expenditure 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 GRI's HSM, though the separate impacts of new field wildcats and other exploratory wells on the reserves discovery process is not modeled there.

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.

Foreign Natural Gas Supply

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

The Foreign Natural Gas Supply Submodule is comprised of approximately 23 equations, with 8 parameters. 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 discounted cash flows constructed for a representative Canadian oil and gas project. Within the DCF, variables such as prices, flow rates, costs, and taxes are specified and can be manipulated for analysis purposes. The discovery process component relates reserve additions per period to wells drilled. Like the Lower 48 module, it is assumed that the size of the find declines exponentially with cumulative drilling.

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 (for example, explicit drilling expenditures are not estimated in the Canadian model), 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.

Gas Trade with Mexico

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

A scenario basis was chosen to handle gas imports from Mexico because of uncertainty and the significant influence of noneconomic factors that affect Mexican gas trade with the United States. Much of the source material for the construction of these scenarios was drawn from the National Petroleum Council's 1992 study, *The Potential for Natural Gas in 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.

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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.

Alaskan Oil and Gas Supplies

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

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

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

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

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.

The AOGSS is comprised of approximately 11 basic equations. 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.

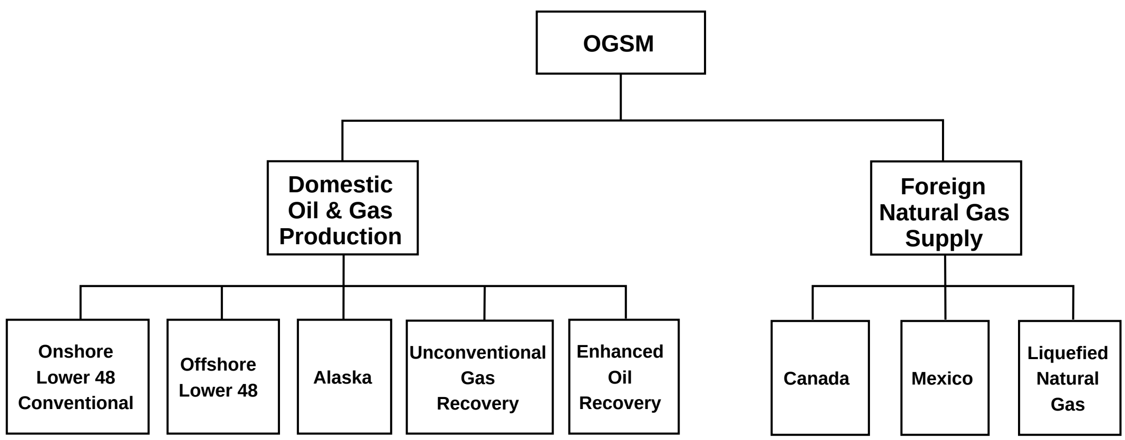
[12]Mortada International, *The Determination of Equitable Pricing Levels for North-Slope Alaskan Crude Oil*, (October 1976).

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 parameter estimates representing crude oil and natural gas supplies by selected fuel types on a regional basis to support the market equilibrium determination conducted within other modules of the National Energy Modeling System (NEMS). The oil and gas supplies in each period are balanced against the regional derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the disjoint wellhead and enduse markets. The description of the market analysis models may be found in the separate methodology documentation reports for the Petroleum Market Module (PMM) and the Natural Gas Transmission and Distribution Model (NGTDM).

Figure 3. Submodules Within the Oil and Gas Supply Module



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

The model's methodology is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. In particular, the model assumes that investment in exploration and development drilling, by fuel type and geographic region, is a function of the expected profitability of exploration and development drilling, disaggregated by fuel type and geographic region.

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

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

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

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

The breadth of supply processes that are encompassed within OGSM results in methodological differences between the lower 48 methodology and that for Alaska oil and gas production and foreign gas trade. The present OGSM consequently comprises a set of three distinct approaches and corresponding submodules. The label OGSM as used in this report generally refers to the overall framework and the implementation of lower 48 oil and gas supply in both onshore and offshore regions. 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.

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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.

Several changes were made to OGSM for the *AEO97*. A new finding rate function was incorporated that allows technology to offset the effects of resource depletion. In the offshore submodule, the royalty calculations were adjusted to account for the Outer Continental Shelf Deep Water Royalty Relief Act (Public Law 105-58) (see Appendix 4-A).

The following sections describe OGSM grouped into four conceptually distinct divisions. The first section describes most oil and gas supply in the lower 48 states, including onshore lower 48 conventional oil and gas supply, offshore oil and gas supply, and Unconventional Gas Recovery.[6] This is followed by the methodology of the Enhanced Oil Recovery Supply Submodule, then the Alaska Oil and Gas Supply Submodule. The chapter concludes with the presentation of the Foreign Natural Gas Supply Submodule. A set of three 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, and the finding rate function.

Lower 48 Onshore and Offshore Supply Submodule

Introduction

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

The OGSM receives regional oil and gas prices from the PMM and NGTDM, respectively. The PMM calculates the regional oil prices as functions of the world oil price. Using demand functions received from the demand modules, data on transportation costs, and short-run supply functions of gas, the NGTDM determines the equilibrium wellhead price of natural gas for each region. 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 (oil, shallow gas, deep gas, and unconventional gas).

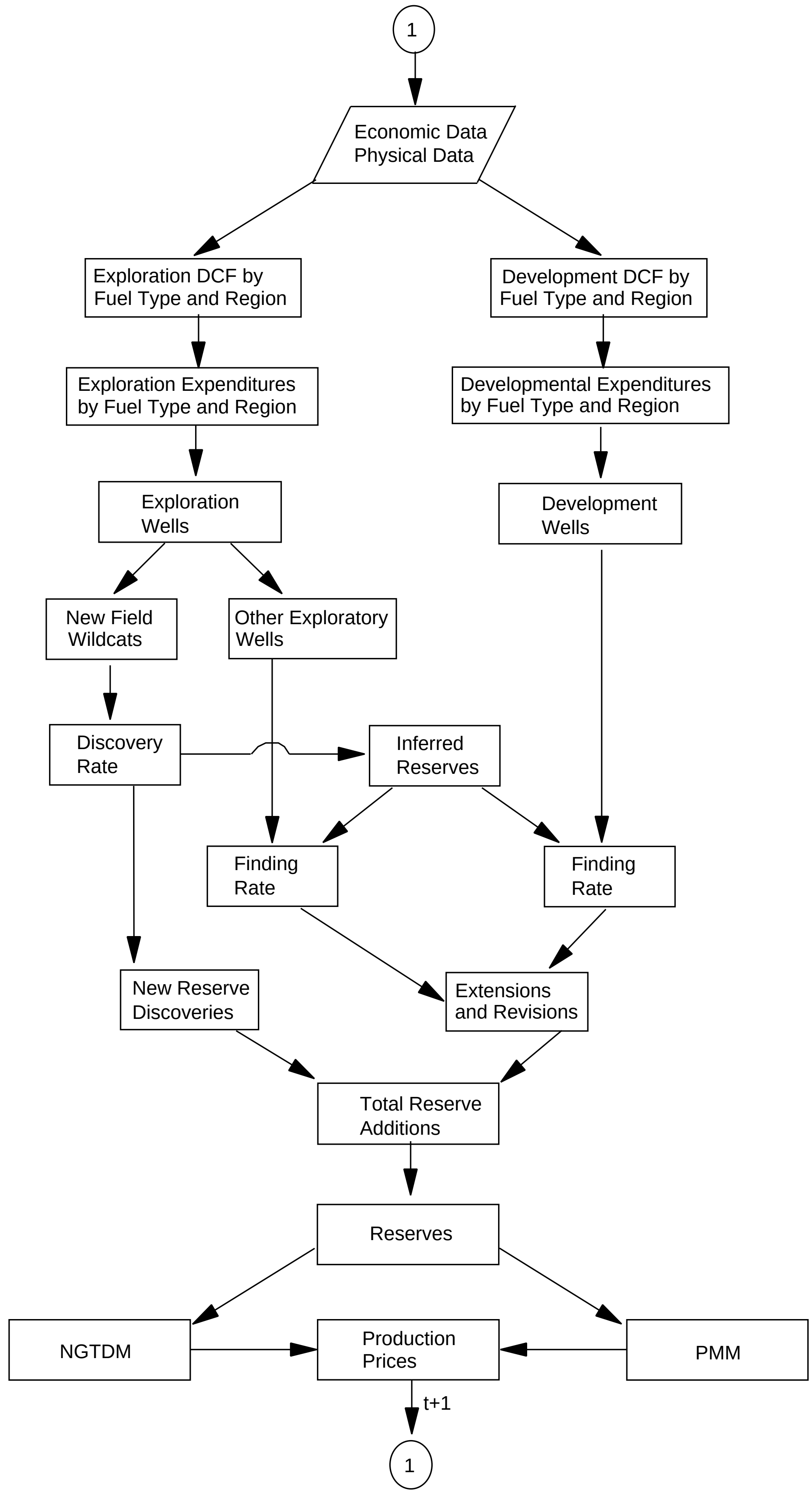
Intraregional E&D drilling expenditures by fuel type and region are predicted as functions of the expected profitabilities of the fuel and region-specific drilling activity.

The fuel and region-specific E&D drilling expenditures are divided by regional estimates of representative drilling costs to determine the number of wells drilled within each region per period for each well and fuel type. Based on region-specific historical patterns, exploration wells are broken down into new field wildcats and other exploratory wells.

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

[6]Enhanced oil recovery (EOR) supply was not implemented as an endogenous source of produced oil as described in the Component Design Report for EOR. EOR production for the *AEO94* was incorporated into the model as an exogenous input to OGSM.

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



additions to proved reserves and inferred reserves. Inferred reserves are converted into proved reserves (extensions and revisions) in later periods by drilling other exploratory wells and development wells.

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

The Expected Discounted Cash Flow Algorithm

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

Onshore Lower 48 Development

A representative onshore developmental project[7] consists of one successful developmental well along with the associated number of dry holes. The number of dry developmental wells associated with one successful development well is given by [(1/SR) - 1] where SR represents the success rate for a development well in a particular region r and of a specific fuel type. Therefore, (1/SR) represents the total number of wells associated with one successful developmental well. All wells are assumed to be drilled in the current year with production from the successful well assumed to commence in the current year.

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

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

where,

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

[7]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.

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.[8]

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

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

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:

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

it is easily calculated as:

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

[8]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.

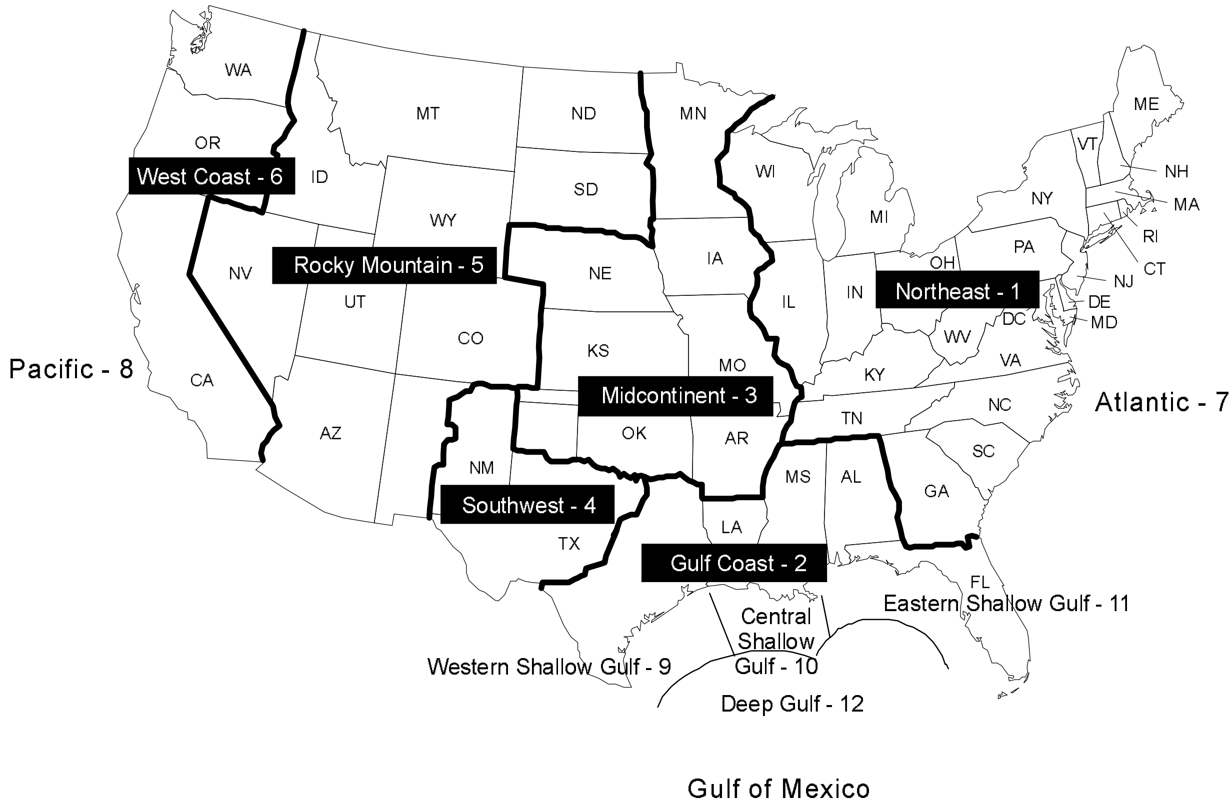


Figure 5. Lower 48 Oil and Gas Supply Regions with Region Codes

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:

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

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:

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

Since the OGSM forecasts an aggregate level of drilling expenditures for unconventional gas recovery rather than forecasting separately drilling expenditures for tight sands, devonian shale, and coalbed methane, an aggregate expected DCF for unconventional gas recovery is calculated for each onshore region except region 6. This aggregate expected DCF for unconventional gas recovery is calculated for each well class and region as a weighted average of the expected DCF's for each unconventional gas category. The weights are equal to the share of total unconventional gas wells in a particular unconventional gas category in the previous period. Specifically,

$$w_{i,r,k,t} = WELLS_{i,r,k,t-1} / \sum_{k} WELLS_{i,r,k,t-1}, \quad \text{for } k = 4,\ 5,\ 6 \tag{7}$$

and

$$UGDCFON_{i,r,t} = \sum_{k=4} w_{i,r,k,t} DCFON_{i,r,k,t}, \quad \text{for } i = 1,2,\ r = 1,2,3,4,5 \tag{8}$$

where,

WELLS	=	wells drilled
UGDCFON	=	expected DCF for unconventional gas recovery.

While most of the expenditure forecasting equations use the expected DCF of the specific drilling activity at the well, region, and fuel type level as the proxy for expected profitability, there are a few instances where more aggregated measures of expected profitability are used, e.g., expected DCF's aggregated at the regional and/or national levels. A description of these weighted-average calculations are described below.

Offshore Exploration and Development

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

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

Calculation of Regional and National Expected DCF's

For each well type I, weighted average expected DCF's for each lower 48 onshore and offshore region are calculated. The weights are equal to the share of total wells of type I drilled in region r of fuel type k in the previous period. Specifically,

$$w_{i,r,k,t} = WELLS_{i,r,k,t-1} / \sum_k WELLS_{i,r,k,t-1}, \quad \text{for each } i, r, k \tag{9}$$

where,

WELLS = wells drilled.

The regional onshore and offshore DCF's for a representative well are derived using the following equations:

$$RDCFON_{i,r,t} = \sum_k w_{i,r,k,t} * DCFON_{i,r,k,t}, \quad \text{for } i = 1, 2,\ r = \text{onshore regions},\ k = 1 \text{ thru } 6 \tag{10}$$

$$RDCFOFF_{i,r,t} = \sum_k w_{i,r,k,t} * DCFOFF_{i,r,k,t}, \quad \text{for } i = 1, 2,\ r = \text{offshore regions},\ k = 1, 2 \tag{11}$$

where,

RDCFON = onshore regional expected discounted cash flow per well
RDCFOFF = offshore regional expected discounted cash flow per well.

Similarly, for each well type I, the national onshore and offshore DCF's are calculated as weighted averages of the regional DCF's. The weights are equal to the regional shares of total wells of type I drilled nationwide in the previous period. Algebraically, the weights are calculated as:

$$w_{i,r,t} = WELLS_{i,r,t-1} / \sum_r WELLS_{i,r,t-1}, \quad \text{for each } i, r \tag{12}$$

The national onshore and offshore expected DCF's for each well type are equal to:

$$NDCFON_{i,t} = \sum_r w_{i,r,t} * RDCFON_{i,r,t}, \quad \text{for } i = 1, 2,\ r = \text{onshore regions} \tag{13}$$

$$NDCFOFF_{i,t} = \sum_r w_{i,r,t} * RDCFOFF_{i,r,t}, \quad \text{for } i = 1, 2,\ r = \text{offshore regions} \tag{14}$$

where,

NDCFON = national onshore expected discounted cash flow per well
NDCFOFF = national offshore expected discounted cash flow per well.

Lower 48 Exploration and Developmental Drilling Expenditures

Lower 48 Onshore Expenditure Forecasting Equations

The level of drilling expenditures by well class, onshore region, and fuel type is forecasted, generally, as a function of expected profitability as proxied by the expected DCF for a representative well of class I, in region r, for fuel type k. In some specific cases, a forecasting equation may use an alternative proxy for expected profitability and may incorporate the impact of structural changes through the inclusion of dummy variables.[9] For unconventional gas recovery, expenditures for each unconventional gas type are determined by applying regional historical shares to total unconventional gas drilling expenditures for each onshore region. The specific forms of the equations used in forecasting onshore Lower 48 drilling expenditures are given in Appendix B. These equations can be expressed in the following generalized forms.

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM1_t) + (m3_{i,r,k} * DUM2_t) \quad (15)$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * RDCFON^2_{i,r,t}) \quad (16)$$

where,

SPENDON	=	lower 48 onshore drilling expenditures by fuel type, region and well type
DCFON	=	expected DCF for a representative onshore well for a specific fuel type, region, and well type
RDCFON	=	expected DCF for a representative onshore well by well class and region
DUM1, DUM2	=	dummy variables (equal to 1 or 0)
m0, m1, m2	=	estimated parameters
I	=	well type
r	=	lower 48 onshore regions
k	=	fuel type
t	=	year.

Additionally, a few equations include a correction for autocorrelation as given by:

$$\begin{aligned} SPENDON_{i,r,k,t} = {} & m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM1_t) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + (m2_{i,r,k} * DUM1_{t-1})) \end{aligned} \quad (17)$$

where,

ρ	=	autocorrelation parameter.

Lower 48 Offshore Exploration and Developmental Drilling Expenditures

The level of offshore drilling expenditures is generally forecasted as a function of the expected profitability of the specific offshore drilling activity as measured by the expected DCF. Some specifics, however, should be noted. For each of the Gulf of Mexico regions (Western, Central, and Deep waters), the model forecasts total exploration drilling expenditures as a function of a proxy for the expected profitability of exploratory drilling in the offshore. These expenditures are then allocated to oil and gas on the basis of historical average shares. For

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

the Pacific offshore region, both exploration and development expenditures are allocated entirely to oil. The forms of the forecasting equations are given below, with further explanation provided where necessary.

Offshore Exploration Expenditure Forecasting Equations

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} RDCFOFF_{i,r,t-1}} \text{ for } i = 1,\ r = 8,\ k = 1 \tag{18}$$

$$SPENDOFF_{i,r,k,t} = [e^{\alpha 0_{i,r} + \alpha 1_{i,r} DCFOFF_{i,r,2,t} + \alpha 2_{i,r} DUM82}] * [SHARE_{i,r,k}] \text{ for } i = 1,\ r = 9,\ k = 1,2 \tag{19}$$

$$SPENDOFF_{i,r,k,t} = [e^{\alpha 0_{i,r} + \alpha 1_{i,r} RDCFOFF_{i,r,t} + \alpha 2_{i,r} DUM89}] * [SHARE_{i,r,k}] \text{ for } i = 1,\ r = 10,\ k = 1,2 \tag{20}$$

$$SPENDOFF_{i,r,k,t} = [e^{\alpha 0_{i,r} + \alpha 1_{i,r} RDCFOFF_{i,r,t-1} + \alpha 2_{i,r} TREND}] * [SHARE_{i,r,k}] \text{ for } i = 1,\ r = 12,\ k = 1,2 \tag{21}$$

Offshore Development Expenditure Forecasting Equations

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} RDCFOFF_{i,r,t}}, \text{ for } i = 2,\ r = 8,\ k = 1 \tag{22}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t}}, \text{ for } i = 2,\ r = 9,\ k = 1 \tag{23}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} NDCFOFF_{i,t} + \alpha 2_{i,r,k} DUM82}, \text{ for } i = 2,\ r = 9,\ k = 2 \tag{24}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t-1} + \alpha 2_{i,r,k} DUM86}, \text{ for } i = 2,\ r = 10,\ k = 1 \tag{25}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t} + \alpha 2_{i,r,k} DUM81}, \text{ for } i = 2,\ r = 10,\ k = 2 \tag{26}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t-1} + \alpha 2_{i,r,k} TREND}, \text{ for } i = 2,\ r = 12,\ k = 1 \tag{27}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t-1}}, \text{ for } i = 2,\ r = 12,\ k = 2 \tag{28}$$

where,

SPENDOFF	=	lower 48 offshore drilling expenditures by fuel type, region and well type
DCFOFF	=	expected DCF for a representative offshore well by wellclass, region, and fuel type
RDCFOFF	=	expected DCF for a representative offshore well by well class and region
NDCFOFF	=	expected DCF for a representative offshore well by well class
SHARE	=	average share of total exploratory drilling expenditures by region, accounted for by fuel type: 0.06375 for I=1, r=9, k=1 0.93625 for I=1, r=9, k=2 0.134 for I=1, r=10, k=1 0.866 for I=1, r=10, k=2 0.5 for I=1, r=12, k=1 and 2
TREND	=	a time trend beginning in 1986
DUM81	=	dummy variable equal to 1 from 1981 onward
DUM82	=	dummy variable equal to 1 from 1982 onward
DUM86	=	dummy variable equal to 1 from 1986 onward
DUM89	=	dummy variable equal to 1 from 1989 onward
$\alpha 0, \alpha 1, \alpha 2$	=	estimated parameters

I	=	well type, 1 for exploratory, 2 for development
r	=	lower 48 offshore regions
k	=	fuel type (1 = oil, 2 = gas)
t	=	year.

Wells Determination

The number of wells drilled in each region by class and fuel type is forecasted by dividing the relevant regional drilling expenditures by the corresponding drilling cost per well. Specifically,

$$WELLSON_{i,r,k,t} = \frac{SPENDON_{i,r,k,t}}{COST_{i,r,k,t}}, \text{ for } i = 1,\ 2,\ r = \text{onshore regions},\ k = 1 \text{ thru } 6 \tag{29}$$

$$WELLSOFF_{i,r,k,t} = \frac{SPENDOFF_{i,r,k,t}}{COST_{i,r,k,t}}, \text{ for } i = 1,\ 2,\ r = \text{offshore regions},\ k = 1,\ 2 \tag{30}$$

where,

WELLSON	=	onshore lower 48 wells drilled by fuel type, region, and well type
WELLSOFF	=	offshore lower 48 wells drilled by fuel type, region, and well type
SPENDON	=	onshore lower 48 drilling expenditures by fuel type, region and well type
SPENDOFF	=	offshore lower 48 drilling expenditures by fuel type, region and well type
COST	=	expected drilling cost per well, the sum of successful and dry well drilling costs weighted respectively by the success rate and the failure rate
I	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 regions, onshore and offshore
k	=	fuel type (1 = oil, 2 = shallow gas, 3 = deep gas, 4 = tight sands gas, 5 = Devonian shale gas, 6 = coalbed methane)
t	=	year.

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

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1,\ 2,\ r = \text{onshore regions}, \\ k = 1 \text{ thru } 6 \tag{31}$$

$$SUCWELSOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1,\ 2,\ r = \text{offshore regions},\ k = 1,\ 2 \tag{32}$$

where,

SUCWELSON	=	successful onshore lower 48 wells drilled
SUCWELSOFF	=	successful offshore lower 48 wells drilled
WELLSON	=	onshore lower 48 wells drilled
WELLSOFF	=	offshore lower 48 wells drilled
SR	=	drilling success rate
I	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 regions, onshore and offshore

k	=	fuel type (1 = oil, 2 = shallow gas, 3 = deep gas, 4 = tight sands gas, 5 = Devonian shale gas, 6 = coalbed methane)
t	=	year.

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

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t}, \text{ for } i = 1, 2, \quad r = \text{onshore regions}, \ k = 1 \text{ thru } 6 \tag{33}$$

$$DRYWELOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} - SUCWELSOFF_{i,r,k,t}, \text{ for } i = 1, 2, \quad r = \text{offshore regions}, \ k = 1, 2 \tag{34}$$

where,

DRYWELON	=	number of dry wells drilled onshore
DRYWELOFF	=	number of dry wells drilled offshore
SUCWELSON	=	successful lower 48 onshore wells drilled by fuel type, region, and well type
SUCWELSOFF	=	successful lower 48 offshore wells drilled by fuel type, region, and well type
WELLSON	=	onshore lower 48 wells drilled by fuel type, region, and well type
WELLSOFF	=	offshore lower 48 wells drilled by fuel type, region, and well type
I	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 regions, onshore and offshore
k	=	fuel type (1 = oil, 2 = shallow gas, 3 = deep gas, 4 = tight sands gas, 5 = Devonian shale gas, 6 = coalbed methane)
t	=	year.

Drilling, Lease Equipment, and Operating Cost Calculations

The cost of complying with environmental regulations is accounted for in OGSM through adjustments to the drilling costs and operating costs. These adjustments are based on work done by Energy and Environmental Analysis, Inc. (EEA) in support of the National Petroleum Council (NPC) study "The Potential for Natural Gas Supply in the United States." EEA developed factors that could be applied to drilling and operating cost estimates to account for the additional costs of complying with impending environmental regulations. The factors are expressed as proportional adjustments to estimates of drilling costs and operating costs. These factors were developed by depth class and region, with the regions being those of the EEA's Hydrocarbon Supply Model (HSM).

These environmental compliance adjustment factors were incorporated into OGSM through a weighting scheme. Each state within an OGSM region was assigned the compliance factor of the HSM region in which the state is located. American Petroleum Institute (API) well data were used to weight each state level factor by that state's share of drilling within the OGSM region.

The implementation in OGSM of the environmental cost adjustment factors occurs incrementally over the period 1992 to 1996. During each of these five years an equal share of the total proportional adjustment is introduced. After reaching their full magnitudes in 1996, the factors remain at those levels throughout the remainder of the forecast period.

The environmental cost adjustment factor for drilling costs is determined as specified below:

$$ECCDRL48_{r,k,t} = \begin{cases} 0;\ \text{if } t < 1992 \\ \overline{ECCDRL48}_{r,k,t} * (t-1992+1)/5;\ \text{if } 1992 \le t \le 1996 \\ \overline{ECCDRL48}_{r,k,t};\ \text{if } t > 1996 \end{cases} \tag{35}$$

where,

$\overline{ECCDRL48}$ = incremental cost of environmental compliance measured as a fraction of drilling costs.

The environmental cost adjustment factor for operating costs is determined as shown below:

$$ECCOPL48_{r,k,t} = \begin{cases} 0;\ \text{if } t < 1992 \\ \overline{ECCOPL48}_{r,k,t} * (t-1992+1)/5;\ \text{if } 1992 \le t \le 1996 \\ \overline{ECCOPL48}_{r,k,t};\ \text{if } t > 1996 \end{cases} \tag{36}$$

where,

$\overline{ECCOPL48}$ = incremental cost of environmental compliance measured as a fraction of operating costs.

Drilling Costs

Onshore

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

$$\begin{aligned} DRILLCOST_{r,k,t} = {} & e^{\ln(\delta 0)_{r,k}} * WELLSON_{t-1}^{\delta 1_k} * e^{\delta 2_k * DEPTH_{r,k}} * e^{\delta 3_k * TIME_t} * \\ & (1 + ECCDRL48_{r,k,t}), \\ & \text{for } r = 2 \text{ through } 5,\ k = 1,\ 2,\ 3; \\ & \text{for } r = 1,\ 6,\ k = 1,\ 2 \end{aligned} \tag{37}$$

where,

DRILLCOST	=	drilling cost per well
WELLSON	=	total onshore lower 48 wells drilled
DEPTH	=	depth per well
TIME	=	time trend - proxy for technology
r	=	OGSM lower 48 onshore region
k	=	fuel type (1 = oil, 2 = shallow gas, 3 = deep gas)
$\delta 0$, $\delta 1$, $\delta 2$, $\delta 3$	=	estimated parameters
t	=	year.

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

$$\begin{aligned} DRYCOST_{r,k,t} = {} & e^{\ln(\delta 0)_{r,k}} * WELLSON_{t-1}^{\delta 1_k} * e^{\delta 2_k * DEPTH_{r,k}} * e^{\delta 3_k * TIME_t} * (1 + ECCDRL48)\ , \\ & \text{for } r = 2 \text{ through } 5,\ k = 1,\ 2,\ 3; \\ & \text{for } r = 1,\ 6,\ k = 1,\ 2 \end{aligned} \tag{38}$$

where,

DRYCOST = drilling cost per dry well.

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

$$DRILLCOST_{r,k,t} = e^{\ln(\delta 0)_{r,k}} * WELLSOFF_{t-1}^{\delta 1_k} * e^{\delta 2_k * DEPTH_{r,k}} * e^{\delta 3_k * TIME_t} * (1 + ECCDRL48_{r,k,t}), \quad \text{for } r = \text{Gulf of Mexico},\ k = 1, 2, \tag{39}$$

where,

DRILLCOST	=	drilling cost per well
WELLSOFF	=	total offshore lower 48 wells drilled
DEPTH	=	depth per well
TIME	=	time trend - proxy for technology
k	=	fuel type (1 = oil, 2 = gas)
$\delta 0$, $\delta 1$, $\delta 2$, $\delta 3$	=	estimated parameters
t	=	year.

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

$$DRYCOST_{r,t} = e^{\ln(\delta 0)_r} * WELLSOFF_{t-1}^{\delta 1} * e^{\delta 2 * DEPTH_r} * e^{\delta 3 * TIME_t} * (1 + ECCDRL48_{r,k,t}), \quad \text{for } r = \text{Gulf of Mexico} \tag{40}$$

where,

DRYCOST = drilling cost per dry well.

Lease Equipment Costs

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

$$LEQC_{r,k,t} = e^{\ln(\epsilon 0)_{r,k}} * SUCWELL_{k,t-1}^{\epsilon 1_k} * e^{\epsilon 2_k * TIME_t}, \quad \text{for } r = 2 \text{ through } 5,\ k = 1, 2, 3; \quad \text{for } r = 1, 6,\ k = 1, 2 \tag{41}$$

where,

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

Operating Costs

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

$$OPC_{r,k,t} = e^{\ln(\phi 0)_{r,k}} * SUCWELL_{k,t-1}^{\phi 1_k} * e^{\phi 2_k * DEPTH_{r,k}} * e^{\phi 3_k * TIME_t} * (1 + ECCOPL48_{r,k,t}) \quad (42)$$

for r = 2 through 5, k = 1, 2, 3;
for r = 1, 6, k= 1, 2

where,

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

The effects of technological change also are reflected in adjustments to the resource base, as shown in equations in the section below that discusses the finding rates.

Reserve Additions

The Reserve Additions algorithm calculates units of oil and gas added to the stocks proved and inferred reserves.[10] 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.

Discoveries of previously unknown fields per period are modeled as a function of the number of new field wildcats drilled per period. 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.[11]

[10] An important advantage inherent in OGSM's design is its modularity. The present finding rate specification of OGSM was developed to meet the analytical requirements and schedule for NEMS. Modifications will be made to the present discovery process methodology and resource accounting in the future.

[11] 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 number of successful new field wildcats drilled, the initial estimate of economically recoverable resources for the fuel, and the rate of technological change.[12]

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

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

This approach relies on the finding rate equation:

$$FR1_{r,k,t} = FR1_{r,k,t-1}(1+\beta 1) * \exp(-\delta 1_{r,k,t} * SW1_{r,k,t}) \tag{43}$$

where,

FR1	=	new field wildcats finding rate
SW1	=	successful new field wildcats
$\delta 1$	=	finding rate decline parameter
$\beta 1$	=	finding rate technology parameter
r	=	region
k	=	fuel type (oil or gas)
t	=	year.

Under the above specification, the yield from new fieldcat drilling in the absence of technological change declines exponentially as cumulative drilling increases. Specifically, in the absence of technological change, the finding rate at the end of period t is lower than the finding rate in period t-1 by $\delta 1$, the decline rate, times the number of wells drilled in period t. Technological change expands the economically recoverable resource volume beyond the initial estimate. Within OGSM, this is represented in two ways. First, the increase in the resource base is presumed to increase the finding rate by β percent. Under this approach, the finding rate in period t can be higher, lower, or equal to the finding rate in t-1 depending on the value of β, δ, and the number of wells drilled in period t. The increase in the economically recoverable can also affect the decline paramater, $\delta 1$. Accordingly, $\delta 1$ is recalculated in each period using the following equation:

$$\delta 1_{r,k,t} = \frac{FR1_{r,k,t-1}(1+\beta 1) - FRMIN1_{r,k}}{QTECH_{r,k,t} - CUMRES_{r,k,t-1}} \tag{44}$$

where,

FR1	=	new field wildcats finding rate
FRMIN1	=	minimum economic finding rate for new field wildcat wells
QTECH	=	undiscovered economically recoverable resource estimate adjusted for expansion due to technological change

[12] A more complete discussion of the finding rate equations and the enhancement to include technological change is available in Appendix 4-C of this report.

CUMRES	=	cumulative proved and inferred reserve discoveries over the projection period (initial value = 0)
t	=	forecast year.

In the numerator, the minimum economic finding rate is set as a percentage of the initial finding rate. The percentage is constant over the forecast, but varies among fuels and regions. The denominator represents the *remaining* economically recoverable resource estimate in undiscovered fields, so the cumulative reserves found over time must be deducted. δ1 is constrained not to fall below 0.

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

$$\begin{aligned} \Delta R_{r,k,t} &= \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t}\ d(SW1) \\ & \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t-1}(1+\beta 1) * \exp(-\delta 1_{r,k,t} * SW1_{r,k,t}) d(SW1) \end{aligned} \tag{45}$$

where,

X	=	reserves growth factor
ΔR	=	additions to proved reserves.

The terms in equation (47) are all constants in period t, except for the SW1. X is derived from historical data and it is assumed to be constant during the forecast period. $FR1_{r,k,t-1}$ and $\delta 1_{r,k,t}$ are calculated, prior to period t, based on lagged variables and fixed parameters as shown in equations (45) and (46).

Reserves move from the realm of inferred to proved with the drilling of other exploratory wells or developmental wells in much the same 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:

$$FR2_{r,k,t} = FR2_{r,k,t-1}(1+\beta 2) * \exp(-\delta 2_{r,k,t} * SW2_{r,k,t}) \tag{46}$$

where,

FR2	=	other exploratory wells finding rate
SW2	=	successful other exploratory wells
β2	=	technology parameter for FR2.

$$FR3_{r,k,t} = FR3_{r,k,t-1}(1+\beta 3) * \exp(-\delta 3_{r,k,t} * SW3_{r,k,t}) \tag{47}$$

where,

FR3	=	developmental wells finding rate

SW3	=	successful development wells
$\beta 3$	=	technology parameter for FR3.

The derivation of updated decline factors for the exponentially declining functions are shown in the following equations for other exploratory drilling and developmental drilling, respectively.

$$\delta 2_{r,k,t} = \left[\frac{(FR2_{r,k,t-1}(1+\beta 2) - FRMIN2_{r,k}) * DECFAC}{I_{r,k}(1+TECH)^{t-T} + \sum_{T+1}^{t-1} (\frac{X-1}{X}) \int FR1_{r,k,t} d(SW1) - \sum_{T+1}^{t-1} [\int FR2_{r,k,t} d(SW2) + \int FR3_{r,k,t} d(SW3)]} \right] \quad (48)$$

$$\delta 3_{r,k,t} = \left[\frac{(FR3_{r,k,t-1}(1+\beta 3) - FRMIN3_{r,k}) * DECFAC}{I_{r,k}(1+TECH)^{t-T} + \sum_{T+1}^{t-1} (\frac{X-1}{X}) \int FR1_{r,k,t} d(SW1) - \sum_{T+1}^{t-1} [\int FR2_{r,k,t} d(SW2) + \int FR3_{r,k,t} d(SW3)]} \right] \quad (49)$$

where,

I	=	initial inferred reserves estimate
DECFAC	=	decline rate adjustment factor.
FRMIN2	=	minimum economic finding rate for other exploratory wells
FRMIN3	=	minimum economic finding rate for developmental wells

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 specification of equations (50) and (51) has the characteristic that 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. This is because in a given year the same initial recoverable resource value (i.e., the denominator expression in the derivation of δ_2 and δ_3) is decremented by either type of drilling.

DECFAC is present in the computation of δ_2 and δ_3 to account for the simultaneous drawdown from inferred reserves by both other exploratory wells and developmental wells. DECFAC is a user-specified parameter that should be greater than or equal to 1.0. Values greater than 1.0 accelerate the productivity decline in finding rates. The parameter values for the *Annual Energy Outlook 1996* are 1.0 for both the onshore and the offshore. Subsequent to recent resource updates, the relative drawdown of inferred reserves in any year was judged insufficient to significantly impact the resource accounting in either case.

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

$$RA_{r,k,t} = \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t} d(SW1) + \int_0^{SW2_{r,k,t}} FR2_{r,k,t} d(SW2) + \int_0^{SW3_{r,k,t}} FR3_{r,k,t} d(SW3) \quad (50)$$

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

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \tag{51}$$

where,

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

Production to Reserves Ratio

The production to reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves. For each year t, it is calculated as:

$$PR_t = \frac{Q_t}{R_{t-1}} \tag{52}$$

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:

$$PR_{t+1} = \frac{(R_{t-1} * PR_t * (1 - PR_t)) + (PRNEW * RA_t)}{R_t} \tag{53}$$

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 5 percent. It is also constrained not to exceed 30 percent.

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

$$Q_{r,k,t+1} = [R_{r,k,t}] * [PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})] \tag{54}$$

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. The OGSM passes estimates of β to the NGTDM and PMM that can be used in solving for the market equilibria. Documentation of the equations used to estimate β is provided in Appendix E, pp. E-29 through E-37.

Associated Dissolved Gas

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

$$ADGAS_{r,t} = e^{\ln(\alpha)_r} * OILPROD_{r,t}^{\beta} \tag{55}$$

where,

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

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

$$ADGAS_{r,t} = e^{\ln(\alpha 0)_r + \ln(\alpha 1)_r * DUM86_t} * OILPROD_{r,t}^{\beta 0_r + \beta 1_r * DUM86_t} \tag{56}$$

where,

DUM86 = dummy variable (1 if t>1985, otherwise 0)
$\alpha 0,\alpha 1,\beta 0,\beta 1$ = estimated parameters.

Enhanced Oil Recovery Supply Submodule

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

Introduction

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

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

The EORSS uses discovery factors that convert a specified fraction of unproven resources into proved reserves. These factors depend on the expected profitability of EOR investment opportunities. This approach is a substitute for the approach used elsewhere in OGSM in which the transfer of resource stocks from unproven to proved status is accomplished by use of finding rate functions that relate reserve additions to cumulative drilling levels. Greater expected financial returns motivate the conversion of larger fractions of the resource base into proved reserves. This is consistent with the principle that funds are directed toward projects with relatively higher returns.

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

EOR Production from Proved Reserves

Input: reserves differentiated by unit operating costs (constitutes price-supply table)[13]

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[13]The EOR price-supply tables used in this submodule are of critical importance to any outlook. The estimates provided in these tables are generated from an elaborate preprocessor routine, that performs economic evaluations intended to be consistent with the detailed geological, engineering, and economic information maintained in the Tertiary Oil Recovery Information System (TORIS). TORIS is a large analysis system maintained by the Bartlesville Project Office of the DOE Office of Fossil Energy (OFE). TORIS originally was developed for use in the analysis sponsored by the National Petroleum Council in their comprehensive 1984 study on EOR. A complete description of the EORSS preprocessor and its relationship to the EORSS will be published in the spring of 1996 as a special appendix to this document.

For every year of the forecast horizon, the remaining proved reserves in the price-supply table that continue to be economic are identified. Proved reserves that have unit operating costs that exceed the current net price do not contribute to current production. The net price is the current price less royalty payments and severance taxes, which are unavoidable costs per unit. Thus, the net price measures the unit revenue that accrues to the producing firms.

Production from a given stock of proved reserves is determined by the application of an assumed production-to-reserves ratio (Figure 6).

New EOR Projects

Input: reserves differentiated by unit operating costs (constitutes price-supply table)

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

Figure 6. Procedure for EOR Production from Proved Reserves

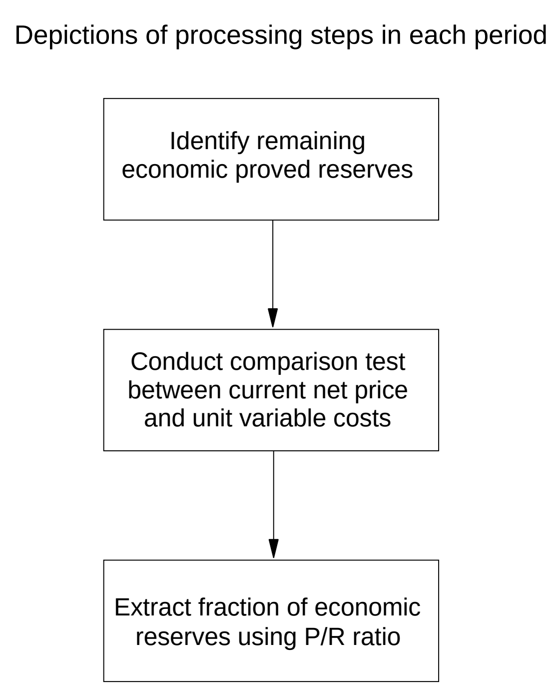
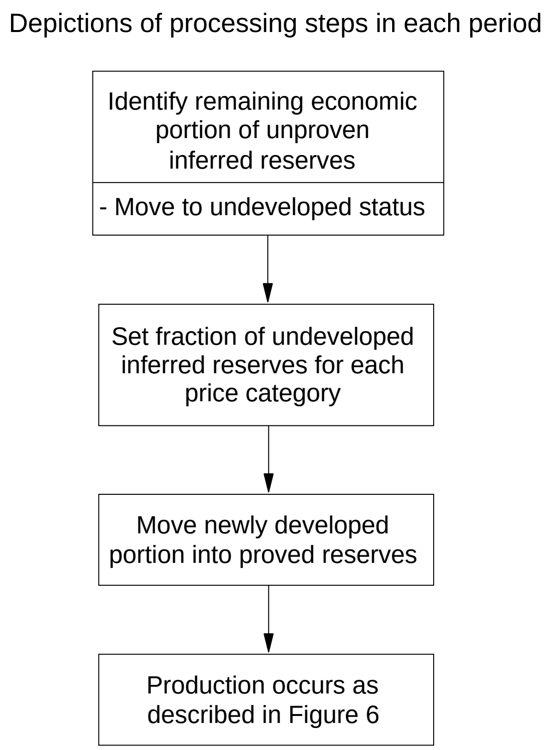


Figure 7. Development of New EOR Projects



Expected Development Schedule for Economic Undeveloped Inferred Reserves EOR Projects

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

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

Cogeneration

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

Alaska Oil and Gas Supply Submodule

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

AOGSS Overview

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

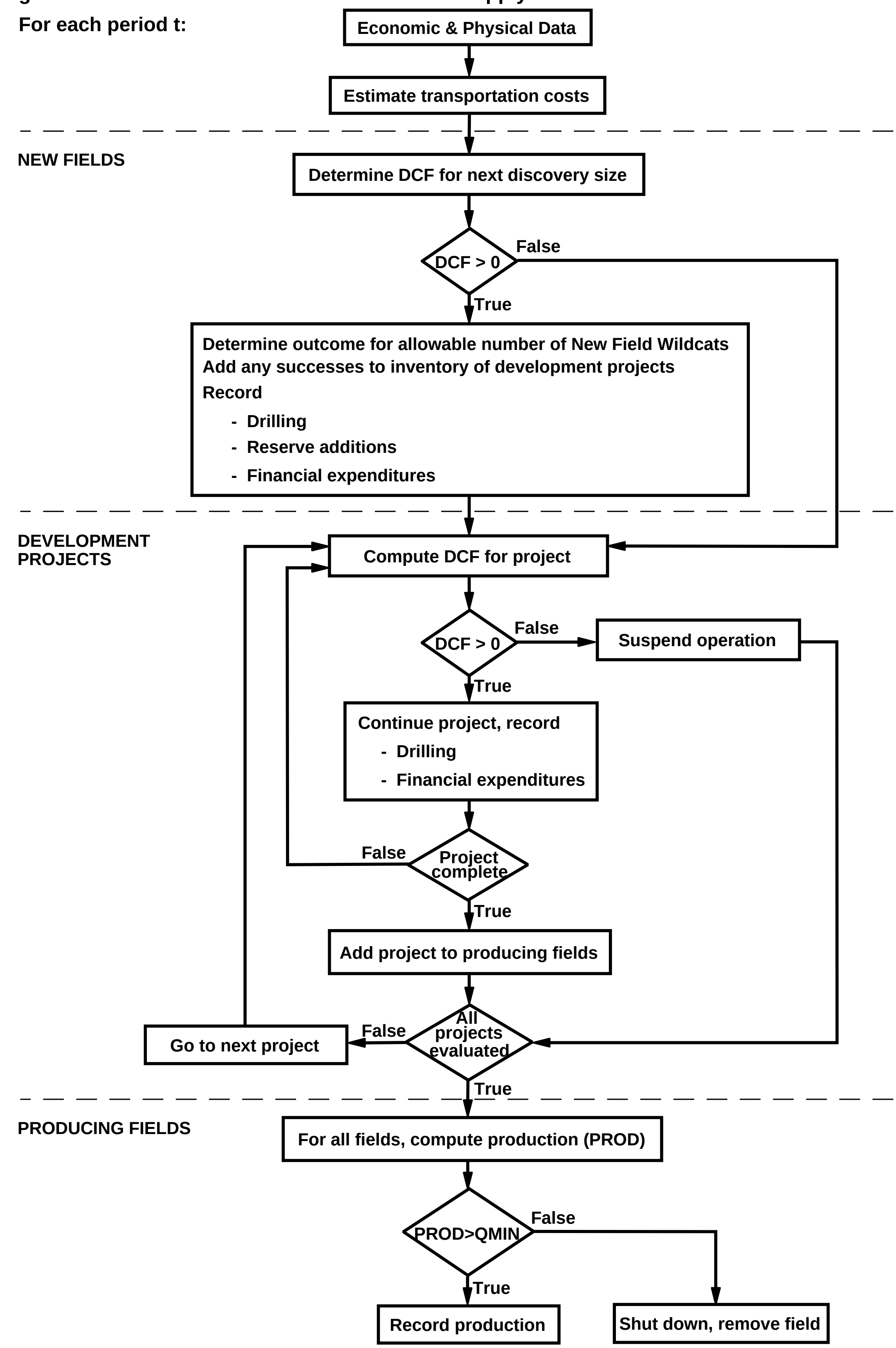
Calculation of Costs

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

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

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

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



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:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1)**(t-T_b) \tag{57}$$

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:

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2)**(t - T_b) \tag{58}$$

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:

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3)**(t - T_b) \tag{59}$$

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.

$$\begin{aligned} TRR_t = {} & OPERCOST_t + DRR_t + TOTDEP_t + MARGIN_t + DEFRETREC_t + TXALLW_t \\ & NONTRANSREV_t + CARRYOVER_t \end{aligned} \tag{60}$$

where,

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

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

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

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

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

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

$$TOTDEP_t = DEP_t * \left(DEPPROP_{t-2} + ADDS_{t-1} - PROCEEDS_{t-1} - TOTDEP_{t-1}\right) \tag{61}$$

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.

$$MARGIN_t = ALLOW_t * THRUPUT_t + 0.064 * \left(DEPPROP_{NEW,t} + DEFRET_{NEW,t} - DEFTAX_{NEW,t}\right) \tag{62}$$

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

$$DEFRETREC_t = DEP_t * \left(DEFRET_{t-2} + INFLADJ_{t-1} + AFUDC_{t-1} - DEFRETREC_{t-1}\right) \tag{63}$$

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.

$$TXALLW_t = TXRATE * \left(MARGIN_t + DEFRETREC_t\right) \tag{64}$$

where,

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

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

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

Discounted Cash Flow Analysis

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

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

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_{f,t}) \tag{65}$$

where,

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

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

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

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

$$DCF_{f,t} = (PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP - PVOPCOST - PVPRODTAX - PVSIT - PVFIT - PVWPT)_{f,t} \tag{66}$$

where,

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

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

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \tag{67}$$

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:

$$PROF_{f,t} = DCF_{f,t} \;/\; COST_{f,t} \tag{68}$$

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

New Field Discovery

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

- technically recoverable oil and gas resource estimates by region

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

- distribution of technically recoverable field sizes[18] within each region
- the maximum number of new field wildcat wells drilled in any year
- new field wildcat success rate
- any restrictions on the timing of drilling.

The endogenous procedure generates:

- the set of individual fields to be discovered, specified with respect to size and location
- an order for the discovery sequence
- a schedule for the discovery sequence.

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

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

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

Development Projects

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

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

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

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

development of this project is suspended in the year in which this occurs. The DCF for each project is evaluated in subsequent years for a positive value; at which time, exploration and development will resume.

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

- a two to four year build-up period from initial production to peak rate,
- peak rate sustained for three to eight years, and
- production rates decline by 12 or 15 percent after peak rate is no longer maintained.

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

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

Producing Fields

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

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

Foreign Natural Gas Supply Submodule

This chapter describes the proposed structure for the Foreign Natural Gas Supply Submodule (FNGSS) within the Oil and Gas Supply Module (OGSM). FNGSS includes U.S. trade in foreign natural gas via either the North American pipeline network or ocean-going tankers.[23] Gas is traded with Canada and Mexico via pipelines. Gas

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

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

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

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

trade with other, nonadjacent, countries is in the form of liquefied natural gas (LNG) and involves liquefaction, transportation by tanker and subsequent regasification. To date, the United States has imported LNG almost exclusively from Algeria.

A detailed representation of Canadian gas trade has been developed. Since forecasts of fixed volumes are not adequate for the purposes of equilibrating supply and demand, the submodule provides the Natural Gas Transmission and Distribution Module (NGTDM) with supply functions of Canadian gas at the U.S./Canadian border points. 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 from Canada and LNG imports 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.

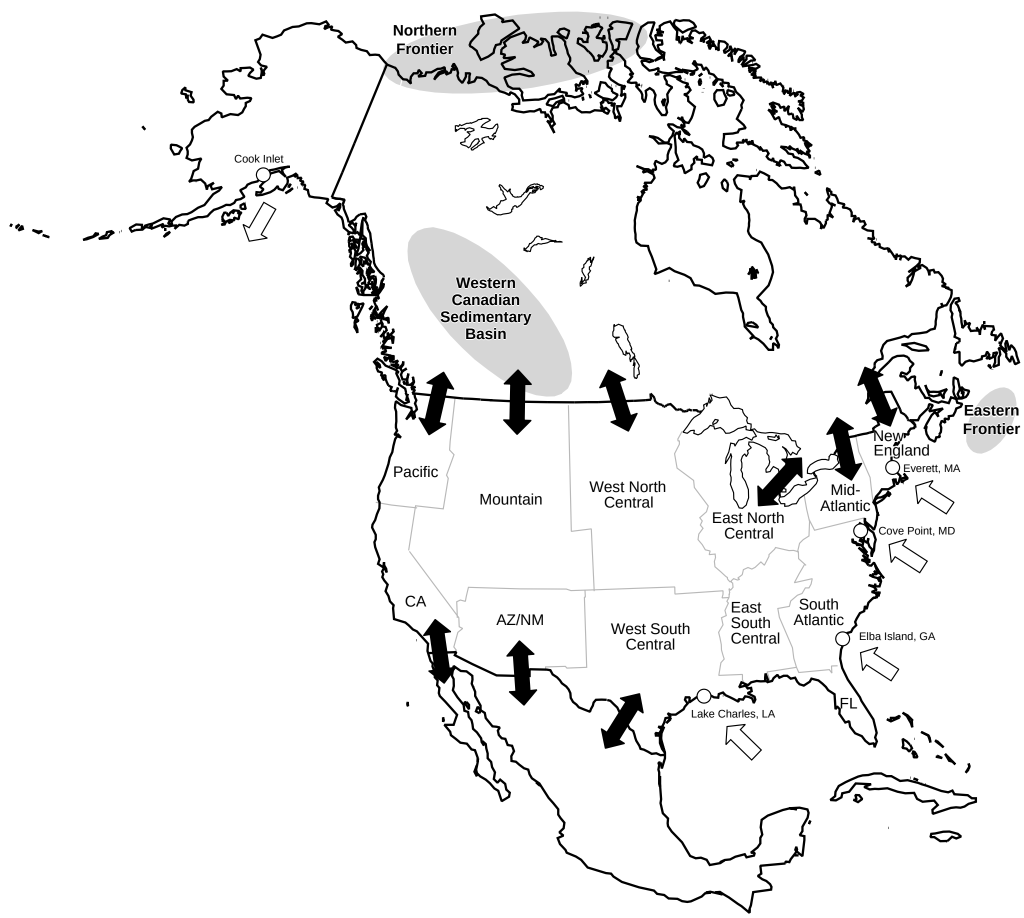
Canadian Gas Trade

This submodule determines net Canadian natural gas supplies over a range of gas prices to the United States at the six border crossing locations identified in Figure 9. The initial step in this procedure produces projections of regional Canadian drilling activity and supply. Canadian demand is subtracted from supply to determine gas available for export. Gas supply is allocated to regional Canadian/U.S border crossing points using an allocation algorithm that accounts for the associated pipeline capacities and the price responsiveness of supplies at the border points. The determination of the import volumes themselves occurs in the equilibration process of the NGTDM.

The approach taken to determine Canadian gas supply differs from that used in the domestic submodules of the OGSM. Drilling activity is determined using an econometric model. Drilling activity, measured as the number of successful wells drilled, is estimated directly as a function of expected profitability rather than being derived from a process of estimating and allocating drilling expenditures. Successful wells are disaggregated by two fuel types: oil and gas. No distinction is made between exploration and development. Production from three Canadian regions is estimated -- the Western Canadian Sedimentary Basin (WCSB) (Alberta, British Columbia, and Saskatchewan), the Northern Frontier (Arctic Islands and Mackenzie Delta), and Eastern Canada. Drilling activity for the WCSB is determined using an econometric model. Finding rate equations are used to determine reserve additions; a reserves accounting procedure yields reserve estimates; and an estimated extraction rate determines production potential for the WCSB. 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.

Forecasts of Canadian gas demand are based on estimates made by the Canadian National Energy Board. Western Canadian gas demand is subtracted from total Canadian supply to determine available export supply. The general methodology employed for estimating Canadian gas trade is depicted in Figure 10.

Figure 9. Foreign Natural Gas Trade via Pipeline



Western Canadian Sedimentary Basin

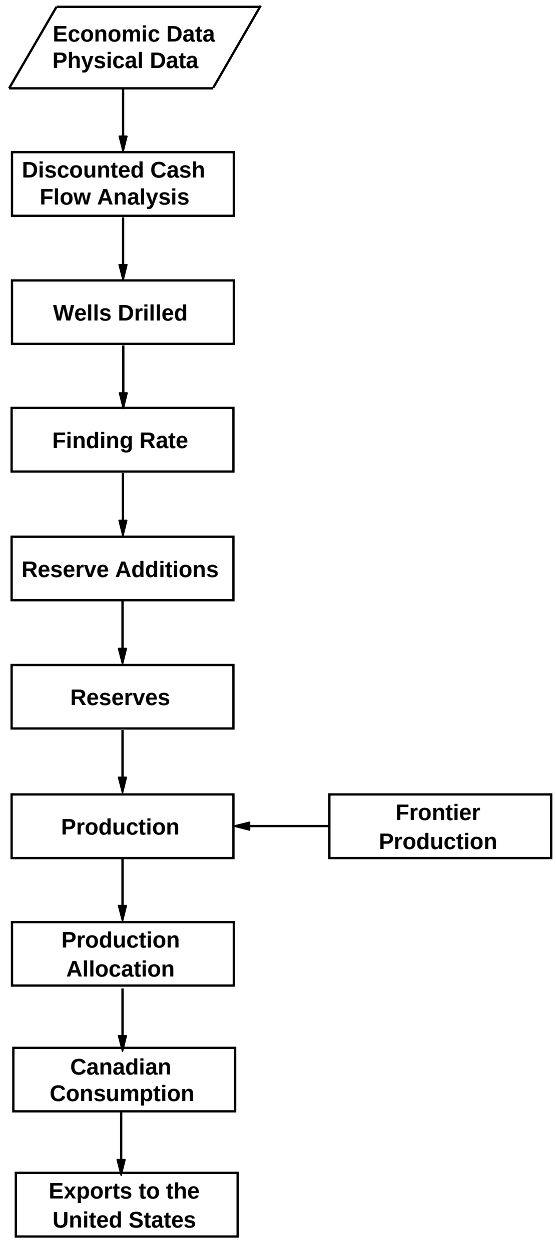
Calculation of Discounted Cash Flows

Expected discounted cash flows (DCF) associated with drilling representative oil and gas wells in the WCSB are calculated for each year t.[24] The DCF reflects expected revenues, less expected costs and taxes, all in present value terms. Expected revenue is based on expected production, over the life of the well, and expected prices. Expected production over the life of a representative well is based on the well's first year of production and the associated decline rate, by fuel type.

The world oil price and regional gas prices at the U.S./Canadian border for year t are received from the Petroleum Marketing Module (PMM) and the NGTDM respectively. An average Canadian wellhead gas price is determined as the weighted average of border prices less the markups from the field to the border crossing points. The weights are based on the flows of gas from the field to each border crossing point in the prior period. The Canadian wellhead prices for oil and gas, together with the expectations assumed, generate future price streams on which expected revenues are based. The subject of price expectations is presented in Appendix 4-A.

[24]See Appendix 4-A at the end of this chapter for a detailed discussion of the basic DCF methodology. The tax provisions described in this appendix are based on U.S. tax laws. The applicable provisions of Canadian tax law have been incorporated into the implemented DCF routine in the FNGSS.

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



Drilling, lease equipment, and operating costs per well for year t are received from the cost routines described below. The drilling and lease equipment costs per well constitute the initial capital costs and are assumed to be incurred entirely in year t.[25] Operating costs are incurred over the life of the well beginning with a half year of operation (assuming uniform occurrence of initial production for each new well throughout the year). The estimate of operating costs per well in year t yields the future stream of expected operating costs per well.

Calculation of Costs

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

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

Relevant cost functions include TECH factors that proportionately adjust costs to reflect an annual decline due to technological improvements over time measured from the base year of the model. Such declines would be relative to what costs would otherwise be. TECH is a user specific input in the model with a prespecified default value. Enhancements to this approach is an area for consideration in later data and model development.

Drilling Costs. Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through to the "Christmas tree" installation. The "Christmas tree" refers to 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, direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Lease equipment required for production is included as a separate cost component, and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in the WCSB in year t is given by:

$$DRILLCOST_{k,t} = DRILLCOST_{k,t-1} * (1 - TECH1) \tag{69}$$

where,

t	=	forecast year
k	=	fuel type (1 for oil, 2 for gas)
DRILLCOST	=	drilling costs, in Canadian dollars, of a successful oil or gas well
TECH1	=	assumed annual decline in costs due to improved technology.

The costs of drilling a dry hole are formulated in a like fashion:

$$DRYCOST_{t} = DRYCOST_{t-1} * (1 - TECH1) \tag{70}$$

[25]Western Canadian Sedimentary Basin oil and gas prospects will be modeled as single year investments.

where,

t	=	forecast year
DRYCOST	=	drilling costs for a dry well in Canadian dollars
TECH1	=	assumed annual decline in costs due to improved technology.

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 lease equipment cost estimate for a new oil or gas well is given by:

$$LEQUIPCOST_{k,t} = LEQUIPCOST_{k,t-1} * (1 - TECH2) \tag{71}$$

where,

t	=	forecast year
k	=	fuel type (1 for oil, 2 for gas)
LEQUIPCOST	=	lease equipment costs in Canadian dollars
TECH2	=	assumed annual decline in lease equipment costs due to improved technology.

Operating Costs. Operating cost data, which are input on a per well basis, 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, are also included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The cost of operating a well is given by:

$$OPCOST_{k,t} = OPCOST_{k,t-1} * (1 - TECH3) \tag{72}$$

where,

t	=	forecast year
k	=	fuel type (1 for oil, 2 for gas)
OPCOST	=	operating cost in Canadian dollars
TECH3	=	assumed annual decline in operating costs due to improved technology.

Drilling costs, lease equipment costs, and operating costs are integral components of the discounted cash flow analysis.

Treatment of Costs in the Model for Tax Purposes. The applicable provisions of Canadian tax law for oil and gas producers[26] have been incorporated into the discounted cash flow (DCF) analysis. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts.

[26]Applicable provisions include such factors as determination and depreciation. The identification of relevant provisions and their representation with the DCF methodology will occur as part of a research effort that is not yet complete.

Discounted Cash Flow Analysis

For each year t, the discounted cash flow for a successful well of fuel type k is calculated as the present value of revenues less the present value to costs and taxes. That is,

$$SUCDCF_{k,t} = (PVREV - PVROY - DRILLCOST - LEQUIPCOST - PVOPCOST - PVPROVTAX - PVFEDTAX)_{k,t} \tag{73}$$

where,

t	=	forecast year
k	=	fuel type (1 for oil, 2 for gas)
$SUCDCF_{k,t}$	=	discounted cash flow for a successful well
PVREV	=	present value of expected revenues including the expected revenues from the sale of the co-product fuel
PVROY	=	present value of expected royalty payments
DRILLCOST	=	drilling cost in year t
LEQUIPCOST	=	lease equipment costs in year t
PVOPCOST	=	present value of expected operating cost
PVPROVTAX	=	present value of expected income taxes to Canadian Provinces
PVFEDTAX	=	present value of expected federal corporate income taxes.

The associated DCF for an unsuccessful well in year t is equal to:

$$DRYDCF_t = -(1 - FEDTXR) * (1 - PROVTXR) * DRYCOST_t \tag{74}$$

where,

DRYDCF	=	discounted cash flow for a dry well
FEDTXR	=	Canadian corporate tax rate
PROVTXR	=	weighted average provincial corporate tax rate
DRYCOST	=	dry hole costs.

The expected DCF from drilling a representative prospect of fuel type k is a weighted sum of the representative DCF's of a successful and unsuccessful well, where the weights are the respective probabilities. In other words,

$$DCF_{k,t} = SR * SUCDCF_{k,t} + (1 - SR) * DRYDCF_t \tag{75}$$

where,

SR	=	success rate.

This expression accounts for the expected discounted cash flow from a representative oil (gas) well, and incorporates expected revenues, expected costs (capital and operating), expected taxes, and the risk associated with drilling an oil (gas) well.

Wells Determination: Econometric model

The total number of successful wells drilled by fuel type in each year t is forecasted econometrically using the representative DCF's for each fuel type. Specifically,

$$\begin{aligned} WELLS_{k,t} = {} & \beta 0_k + \beta 1_k * DCF_{k,t} + \beta 2_k * DUM83_t + \rho_k * WELLS_{k,t-1} - \rho_k * \\ & \beta 0_k - \rho_k * \beta 1_k * DCF_{k,t-1} - \rho_k * \beta 2_k * DUM83_{t-1} , \\ & \text{for } k = \text{oil, gas} \end{aligned} \tag{76}$$

where,

$WELLS_{k,t}$	=	number of successful wells of fuel type k (both exploration and development) drilled in time period t,
$DCF_{k,t}$	=	expected discounted cash flow from drilling a representative prospect of fuel type k in time period t
DUM83	=	dummy variable equal to 1 after 1982
$\beta_o, \beta_1, \beta_2$	=	econometrically estimated parameters.

Reserve Additions

The Reserve Additions algorithm calculates units of oil and gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of oil or gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which oil and gas become 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.

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

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

The finding rate equation for each fuel type is defined by:

$$FR_{k,t} = FR_{k,t-1} * \exp(-\delta_{k,t} * SUCWELLS_{k,t}) * (1 + FRTECH_k) \tag{77}$$

where,

k	=	fuel type (1 for oil, 2 for gas)
FR	=	finding rate
$SUCWELLS_{k,t}$	=	successful wells of type k drilled in time period t
δ	=	finding rate decline parameter (δ>0)
$FRTECH_k$	=	finding rate technology factor.

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

$$\delta_{k,t} = \frac{FR_{k,t-1} - FRMIN_k}{Q_k * (1.0 + TECH)^{t-T} - CUMRES_{k,t-1}} \tag{78}$$

where,

t	=	forecast year
k	=	fuel type (1 for oil, 2 for gas)
FR	=	finding rate (millions of barrels in the case of oil, billion of cubic feet in the case of gas)
FRMIN	=	minimum economic finding rate
Q	=	economically recoverable resource estimate
TECH	=	technology factor
T	=	base year of the forecast
CUMRES	=	cumulative reserve discoveries over the projection period (initial value = 0).

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

The minimum economic finding rate, FRMIN, is incorporated into equation (80) so that the cumulative reserve discoveries match the *economically* recoverable resource estimate when the yield from wells drilled falls to the economic minimum. Equation (80) also incorporates the benefits of technological change. Technological change is expected to improve the productivity of drilling by increasing the physical returns per drilling unit from what it otherwise would have been. Technological change is introduced through modifications of the initial economically recoverable resource estimate, thus affecting the value of the finding rate decline parameter, δ. It reflects the assumptions that technological change occurs over time and its effect is realized in the expansion of the resource estimate, thus lessening the decline rate of productivity and resulting in higher yields to drilling, relative to what they otherwise would have been. The growing recoverable volume necessitates recomputing δ in each period.

Total reserve additions in period t is given by:

$$RA_{k,t} = \int_{WELLS_{k,t-1}}^{WELLS_{k,t}} FR_{k,t} \; d(WELLS) \tag{79}$$

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

$$R_{k,t} = R_{k,t-1} + RA_{k,t} - Q_{k,t} \tag{80}$$

where,

t	=	forecast year
k	=	fuel type (1 for oil, 2 for gas)
R	=	end-of-year reserves
Q	=	production
RA	=	reserve additions.

(All volumes in millions of barrels or billions of cubic feet.)

Gas Production

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

Canadian gas production in year t is given by:

$$Q_{gas,t} = R_{gas,t-1} * \Omega_{gas,t} * (1 + \beta_{gas} * \frac{\Delta P_{gas,t}}{P_{gas,t-1}}) \tag{81}$$

where,

$R_{gas,t-1}$	=	end-of-year gas reserves in period t-1
$\Omega_{gas,t}$	=	gas extraction rate in period t-1 (measured as the production to reserves ratio at the end of period t-1)
$P_{Gas,t}$	=	gas netback price at the wellhead in period t
β	=	estimated short run price elasticity of extraction
$\Delta P_{gas,\,t}$	=	$(P_{gas,t}-P_{gas,t-1})$, the change in price from t-1 to t.

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

Supplies from the Northern Canadian Frontier and Eastern Canada

Frontier production in FNGSS was to be determined as a sequence of predetermined estimates drawn from analysis of other analysis groups, such as the National Energy Board (NEB) of Canada[27] and the National Petroleum Council (NPC). The NEB work published in June 1991 indicates that the economics of frontier gas recovery and transportation prevent the occurrence of frontier flows until at least 2004. Subsequent communication with NEB staff indicate that their reassessment of frontier potential would delay frontier development until after 2010. Similarly, NPC analysis[28] showed that northern frontier gas would not be developed until after 2010 under most scenarios. Eastern Canada gas would occur only at the end of this period.

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

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

The present implementation of OGSM reflects the assumption that neither the northern nor eastern frontier Canadian gas sources will be developed until after 2010. 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.

Allocation of Natural Gas Production to Canada and the Canadian/U.S. Border

Canadian natural gas production for export to the United States is estimated in several stages. First, an initial estimate of the wellhead price ($P_{gas,t}$) is used to determine aggregate Canadian gas production at the wellhead and aggregate Canadian demand. Total gas production available for export is estimated as,

$$Q_{ex,t} = Q_{gas,t} - D_{gas,t} \tag{82}$$

where,

$Q_{ex,t}$ = Canadian gas available for export
$Q_{gas,t}$ = Canadian gas production
$D_{gas,t}$ = Canadian gas consumption.[29]

The second stage of the procedure determines the allocation of the gas available for export among the six Canadian/U.S. border points. This aspect of the methodology is intrinsic to the U.S. market equilibration that occurs in the NGTDM. 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.[30]

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.

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[29]Consumption will be determined endogenously from demand functions, depending on availability of appropriate functional forms and parameter estimates from external sources, such as the Canadian National Energy Board. If these analytical elements are not available, Canadian consumption will be an exogenous input based on published outlooks from other agencies.

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

Liquefied Natural Gas

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

Determining U.S. Imports and Exports of LNG

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

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

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

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

LNG Imports from Existing Capacity

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

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

LNG Imports from Capacity Expansion

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

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

New Construction

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

- Selected start dates before which construction of LNG terminals on new sites would not be allowed
- Design capacity and utilization rates for the newly constructed capacity
- Regional locations for new construction sites[31]
- Price increments that would bring forth additional LNG import capacity.

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

Appendix 4-A. Discounted Cash Flow Algorithm

Introduction

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

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

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

[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.

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.

[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.

Deep Offshore Royalty Relief

The Outer Continental Shelf Deep Water Royalty Relief Act (Public Law 104-58) gives the Secretary of Interior the authority to suspend royalty requirements on new production from qualifying existing leases and requires that royalty payments be waived on new leases sold in the next five years. The OGSM evaluates profitability on a project basis not by lease, therefore assumptions are made as to how many projects will be affected and when. The basic approach is to assume the maximum percent of projects that will be granted royalty relief, the number of years to reach this maximum, the number of years at the maximum, and then how many years it will take until no projects are granted relief. Based on these user specified values, the initial royalty rate (ROYRT) is adjusted.

$$ROYRT = ROYRT * (1 - frac) \tag{5}$$

where,

frac = fraction of deep water projects with no royalty requirements.

The present value of the expected royalty payments is calculated as shown in equation (4).

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:

$$PVPRODTAX_T = PVREV_{T,1} * (1 - ROYRT_1) * PRODTAX_1 + PVREV_{T,2} * (1 - ROYRT_2) * PRODTAX_2 \tag{6}$$

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

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

direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals.

The present value of expected drilling costs is given by:

$$PVDRILLCOST_T = \sum_{t=T}^{T+n} \Big[[COSTEXP_T * SR_1 * NUMEXP_t + COSTDEV_T * SR_2 * NUMDEV_T + COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t] * \left(\frac{1}{1 + disc}\right)^{t-T} \Big] \tag{7}$$

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

$$PVEQUIP_T = \sum_{t=T}^{T+n} \left[EQUIP_T * \left(SR_1 * NUMEXP_t + SR_2 * NUMDEV_t\right) * \left[\frac{1}{1 + disc}\right]^{t-T} \right] \tag{8}$$

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:

$$PVKAP_T = \sum_{t=T}^{T+n} \left[KAP_t * \left[\frac{1}{1 + disc}\right]^{t-T} \right] \tag{9}$$

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:

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[OPCOST_T * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left(\frac{1}{1 + disc} \right)^{t-T} \right] \qquad (10)$$

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

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[COSTABN_T * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \qquad (11)$$

where,

COSTABN = abandonment costs.

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

Present Value of Expected Income Taxes

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

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

- Windfall Profits Tax on oil was repealed.
- Investment Tax Credits were eliminated.
- 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.

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

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

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	**Cost Depletion** 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

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

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

$$\mathrm{PVTAXBASE}_T = \sum_{t=T}^{T+n} \left[(\mathrm{TREV}_t - \mathrm{ROY}_t - \mathrm{PRODTAX}_t - \mathrm{OPCOST}_t - \mathrm{ABANDON}_t - \mathrm{XIDC}_t - \mathrm{AIDC}_t - \mathrm{DEPREC}_t - \mathrm{DHC}_t) * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-T} \right] \tag{12}$$

where,

T	=	year of evaluation
t	=	time period
n	=	number of years in the evaluation period
TREV	=	expected revenues
ROY	=	expected royalty payments
PRODTAX	=	expected production tax payments
OPCOST	=	expected operating costs

ABANDON	=	expected abandonment costs
XIDC	=	expected expensed intangible drilling costs
AIDC	=	expected amortized intangible drilling costs[6]
DEPREC	=	expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC	=	expected dry hole costs
disc	=	expected discount rate.

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

Expected Expensed Costs

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

Expected Intangible Drilling Costs

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

$$\begin{aligned} XIDC_t = {} & COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t + \\ & COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t \end{aligned} \tag{13}$$

where,

COSTEXP	=	drilling cost for a successful exploratory well
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:

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

[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.

$$
\begin{aligned}
AIDC_t = \sum_{j=\beta}^{t} \Bigg[& \big(COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j \; + \\
& COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j\big) \; * \\
& DEPIDC_{t-j+1} \; * \left(\frac{1}{1 + infl}\right)^{t-j} * \left(\frac{1}{1 + disc}\right)^{t-j} \Bigg], \qquad (14) \\
& \beta = \begin{cases} T \text{ for } t \le T+m-1 \\ t-m+1 \text{ for } t > T+m-1 \end{cases}
\end{aligned}
$$

where,

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

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

Expected Dry Hole Costs

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

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t \; + \; COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \qquad (15)$$

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.

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

Table 2. MACRS Schedules
(Percent)

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

Source: U.S. Master Tax Guide.

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

$$\begin{aligned} DEPREC_t = \sum_{j=\beta}^{t} \Big[& \big[(COSTEXP_T * EXKAP + EQUIP_T) * SR_1 * NUMEXP_j + \\ & (COSTDEV_T * DVKAP + EQUIP_T) * SR_2 * NUMDEV_j + KAP_j\big] * \\ & DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \end{aligned} \tag{16}$$

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

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 $t \leq n+T-m$, MACRS with half year convention; otherwise, $1/(n+T-t)$ in each period
infl	=	expected inflation rate[9]
disc	=	expected discount rate.

Present Value of Expected State and Federal Income Taxes

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

$$PVSIT_T = PVTAXBASE_T * STRT \tag{17}$$

where,

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

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

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \tag{18}$$

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

[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.

decision to invest does not reflect a firm's comprehensive tax plan that achieves aggregate tax benefits that would not accrue to the particular project under consideration.

Appendix 4-B. LNG Cost Determination Methodology

Introduction

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

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

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

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

where,

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

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

Liquefaction

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

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

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

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

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:

$$CAPCSTS_{L,t} = DEP_{L,t} + INTR_{L,t} + ROE_{L,t} + TAX_{L,t} \tag{3}$$

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 are as follows:

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

where,

$RSDEP_{r,t}$ = depreciation ($RSINVST_r * RSDRATE_{r,t}$)
$RSINVST_r$ = capital investment in re-activation (millions of dollars)
$RSDRATE_{r,t}$ = depreciation rate

$RSINTR_{r,t}$ = interest on debt ($RSRBASE_{r,t} * d_r * kd_r$)
$RSRBASE_{r,t}$ = rate base ($RSINVST_r$ - $RSACCDEP_{r,t}$)
$RSACCDEP_{r,t}$ = accumulated depreciation ($\sum_{y=1}^{t} RSDEP_{r,y}$)
d_r = debt financing amount (fraction)
kd_r = cost of debt (percent)
y = year of re-activation

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

$RSTAX_{r,t}$ = tax on capital ($RSINVST_r * RSTRATE_r$)
$RSTRATE_r$ = tax rate (percent).

and,

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

where,

$EXDEP_{r,t}$ = depreciation ($EXINVST_r * EXDRATE_{r,t}$)
$EXINVST_r$ = capital investment in expansion (millions of dollars)
$EXDRATE_{r,t}$ = depreciation rate

$EXINTR_{r,t}$ = interest on debt ($EXRBASE_{r,t} * d_r * kd_r$)
$EXRBASE_{r,t}$ = rate base ($EXINVST_r$ - $EXACCDEP_{r,t}$)

$EXACCDEP_{r,t}$ = accumulated depreciation ($\sum_{y=1}^{t} EXDEP_{r,y}$)

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

d_r = debt financing amount (fraction)
kd_r = cost of debt (percent)
y = year of expansion

$EXROE_{r,t}$ = 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. Finding Rate Methodology

Introduction

The purpose of this appendix is to describe the finding rate methodology in the Oil and Gas Supply Module (OGSM). The finding rate methodology represents the process by which oil and gas in the unproved portion of the economically recoverable resource base[1] convert to proved reserves.[2] This appendix begins with a discussion of the basic finding rate methodology utilized in OGSM. This includes a presentation of a simple finding rate equation, as well as successive adaptations to accommodate the particular nature of the resource estimates and to incorporate the effects of technological change. Next, there is a description of the implementation of this methodology in OGSM, focusing on modifications consistent with the model's resource accounting system.

Basic Finding Rate Methodology

The finding rate measures the yield from exploratory drilling, that is, the amount of reserves discovered per unit of exploratory drilling. A basic assumption underlying the finding rate methodology in OGSM is that the larger the oil or gas field, the greater the probability that it will be discovered. Another is that large oil and gas fields, though fewer in number, contain a disproportionate amount of total resources. These assumptions suggest that finding rates will decline as drilling progresses. The exact nature of this decline is subject to debate, but one or another form of exponential decline has been utilized by several well known discovery process models.[3] OGSM borrows from these models in assuming an exponentially declining finding rate relationship between cumulative reserves discovered and cumulative exploratory drilling. The basic finding rate equation in OGSM reflects this relationship. Given an initial finding rate, FR0, an increase in the cumulative drilling leads to an exponential decline in the finding rate.[4] This may be expressed in equation form as:

$$FR = FR0 * \exp(-\delta * SW) \tag{1}$$

where,

FR	=	finding rate (Mbbl per well or MMcf per well)
SW	=	cumulative successful exploratory wells
δ, FR0	=	parameters.

The derivation of the parameter δ, the exponential decline factor, is based on the properties inherent in Equation (1). In the limit, the amount of economic oil or gas discovered equals the level of undiscovered oil or gas (Q). This relationship can be expressed as the integral of the finding rate over an infinite number of successful wells (Equation (2)).

---

[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. On the other hand, *technically recoverable resources* 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]See, for example, Arps, J.J. and T.G. Roberts. 1958.

[4]As will be shown, the finding rate implemented in OGSM declines exponentially within each period, but not exponentially over the entire forecast, as δ is recalculated each year based on a different estimate for the remaining economically recoverable resource base.

$$Q = \int_0^\infty FRO * \exp(-\delta * SW)d(SW) \tag{2}$$

It follows that the rate of decline (δ) can be expressed as the simple ratio of the initial finding rate (FR0) to the remaining undiscovered resource base (Q). From Equation (2),

$$\begin{aligned} Q &= \int_0^\infty FR0 * \exp(-\delta * SW)d(SW) \\ &= \frac{FR0}{-\delta}\int_0^\infty \exp(-\delta * SW) * (-\delta) * d(SW) \\ &= (-\frac{FR0}{\delta}) * \exp(-\delta * SW)\Big|_{SW=0}^{SW=\infty} \\ &= (-\frac{FR0}{\delta}) * (0-1) \\ &= \frac{FR0}{\delta} \end{aligned} \tag{3}$$

or,

$$\delta = \frac{FR0}{Q} \tag{4}$$

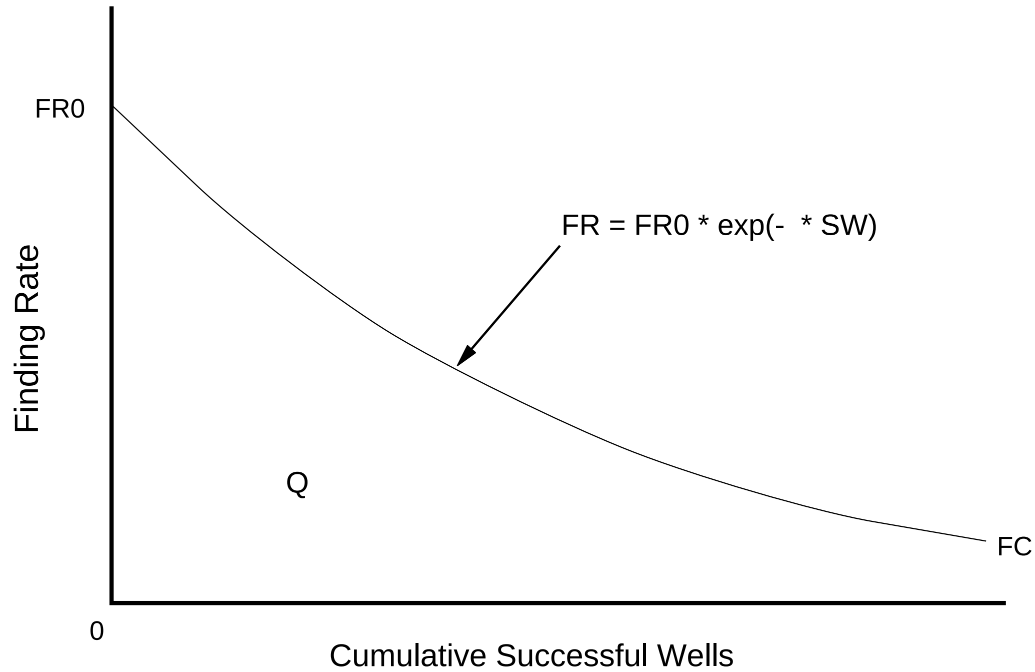
From Equation (4) one can see that a smaller resource base estimate would result in a more rapid decrease in productivity, indicated by a larger value of δ. An important aspect of Equation (4) is that the denominator represents *remaining* recoverable resources as of the period corresponding to the origin for the specified function. This attribute is especially germane to the introduction of technology into the finding rate, which is discussed later in this appendix.

The basic finding rate methodology in OGSM can be further illustrated by a simple graphic presentation of the preceding concepts. The curve FC in Figure 11 represents the finding rate function described by Equation (1). The point at which FC intersects with the y-axis is the initial finding rate, FR0. In accordance with the previous discussion, the finding rate decreases exponentially along the x-axis, which represents cumulative drilling (SW). The decline in the finding rate curve FC is determined by the exponential rate of decline (δ), derived in Equation (4) above as a function of the initial finding rate and the ultimate resource target, Q.

Given this methodology, the level of reserve additions in period t can be calculated as the integral of the finding rate Equation (1) over the range of cumulative successful exploratory wells from the previous period, t-1, through the current forecast year. This may be expressed in equation form as:

$$RA_t = (\frac{FR0}{\delta}) * \left[\exp(-\delta * SW_{t-1}) - \exp(-\delta * SW_t)\right] \tag{5}$$

Figure 11. Basic Finding Rate Function



where,

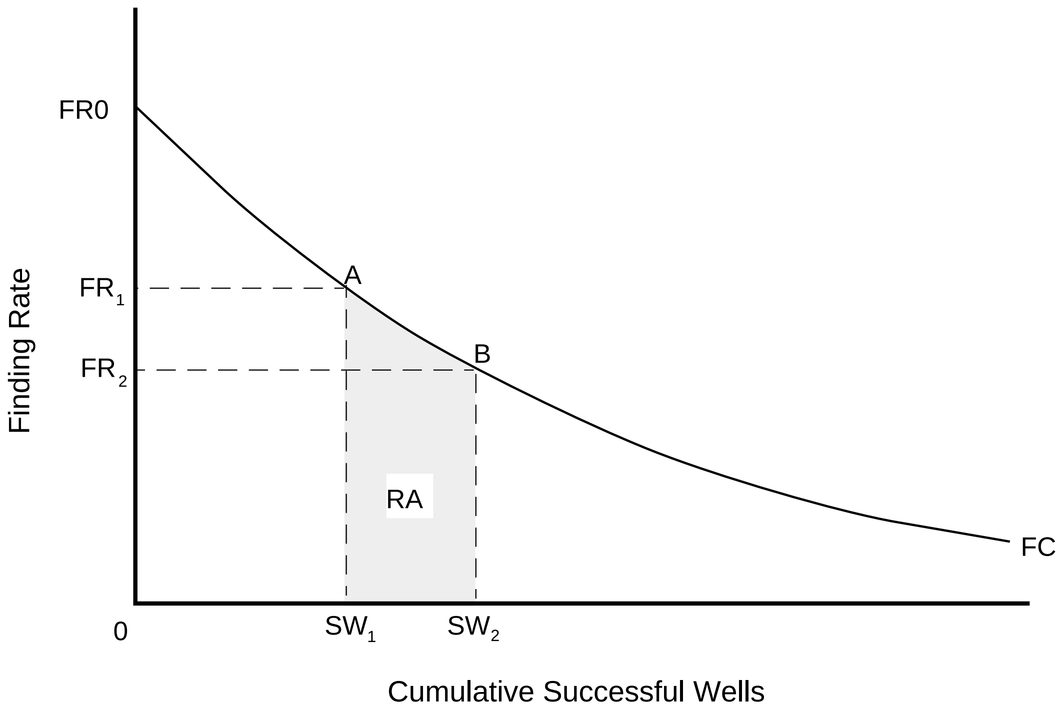
t	=	forecast year
RA	=	reserve additions from exploratory drilling
SW	=	cumulative successful exploratory wells
δ, FR0	=	parameters.

Reserve additions are graphically represented in Figure 12. The area beneath the curve FC stands for the remaining undiscovered resource base (Q). Any segment of this total area, as determined by movement along the x-axis, represents the amount of reserve additions (RA) discovered as a result of the indicated change in cumulative drilling. Accordingly, an increase in cumulative drilling from SW_1 to SW_2 would result in a quantity of discoveries defined by the segment A-B-SW_2-SW_1. In this case the finding rate declines from FR_1 to FR_2 as drilling increases from SW_1 to SW_2.

Minimum Economic Finding Rate

The Q parameter as described previously is the total resource base, which is recoverable only with an infinite number of wells. The resource estimates employed in OGSM, however, represent only the resources that are economically recoverable. Implicit in these estimates is the existence of some minimum physical return to exploratory drilling that would make such activities profitable enough to be undertaken. This concept is represented in OGSM in the form of a minimum economic finding rate (FRMIN). The minimum economic finding

Figure 12. Reserve Additions

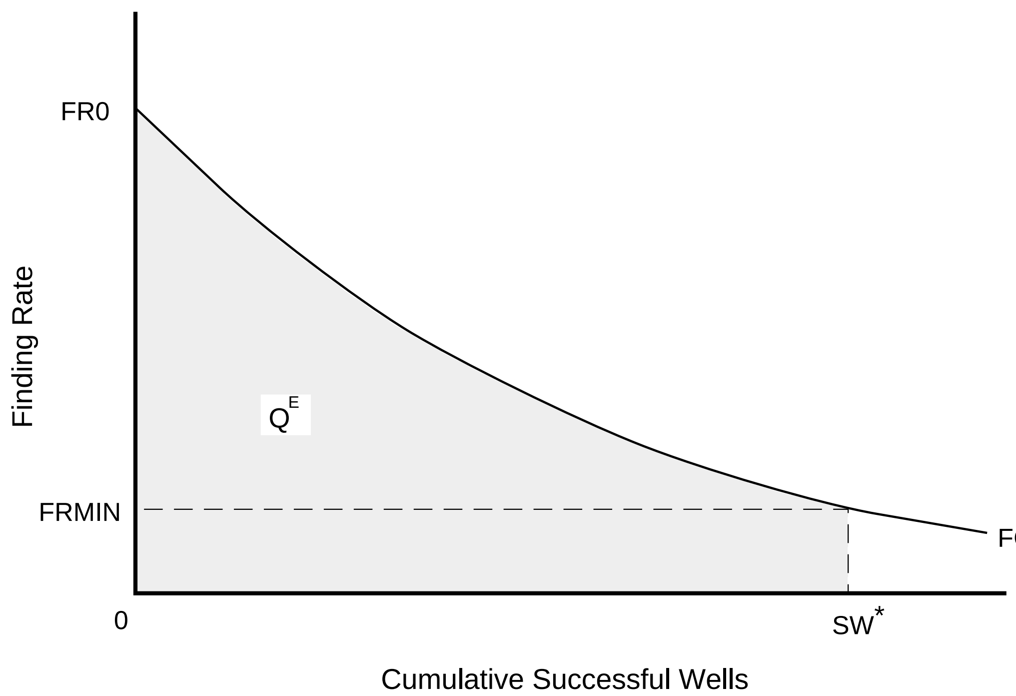


rate is presented in Figure 13. FRMIN is reached when cumulative successful wells increase to SW^*. The undiscovered economically recoverable resource base (Q^E) is represented by the shaded area beneath the finding rate curve (FC) and left of the drilling level at which the curve intersects with FRMIN.

By utilizing the concept of a minimum economic finding rate, it is possible to obtain an estimate of δ that is based on the economically recoverable resource base, yet is consistent with the methodology proposed in Equations (3) and (4). Equation (3) now becomes:

$$
\begin{aligned}
Q^E &= \int_0^{SW^*} FR0 * \exp(-\delta * SW) d_{SW} \\
&= \frac{FR0}{-\delta} \int_0^{SW^*} \exp(-\delta * SW) * (-\delta) * d_{SW} \\
&= \left(-\frac{FR0}{\delta}\right) * \exp(-\delta * SW) \Big|_{SW=0}^{SW=SW^*} \\
&= \left(-\frac{FR0}{\delta}\right) * (\exp(-\delta * SW^*) - 1) \\
&= \frac{FR0 - FR0 * (\exp(-\delta * SW^*))}{\delta}
\end{aligned}
\tag{6}
$$

Figure 13. Minimum Economic Finding Rate



where,

SW^*	=	level of cumulative drilling at which minimum economic finding rate is attained
Q^E	=	undiscovered economically recoverable resource base.

Since $FR0*exp(-\delta*SW^*)$ is equivalent to FRMIN, Equation (4) converts to:

$$\delta = \frac{(FR0 - FRMIN)}{Q^E} \tag{7}$$

Technological Change

While the OGSM methodology assumes that increases in cumulative drilling lowers the finding rate, the methodology permits this decline to be partially, fully, or more than fully offset by improvements in technology. Specifically, the methodology adopts the "Technological Stretch" approach advanced by William Fisher.[5] In this paradigm, technological change shifts the finding rate function upwards, mitigating the progression from larger to smaller fields. The advantage of this approach is that it is capable of modeling finding rates that rise, remain constant, or decline over time depending on the values of the technology and resource decline parameters.

[5]Fisher, W.L. "U.S. Oil and Gas Resources: Their Critical Dependency on Technology," unpublished manuscript, 1994.

The treatment of technological change is illustrated in Figure 14. Given an intial economically recoverable resource base Q^E, the section A-B- SW_2-SW_1 represents the reserves that that would be added as a result of a drilling increase from SW_1 to SW_2. If, concurrent to this increase in drilling, there are technological advances that cause the remaining economically recoverable resource base to increase by an amount $\Delta_1 Q^E$, the operative finding rate curve becomes FC_1. FC_1 reflects the increase in the finding rate brought about by expanded resource base. The amount of extra reserve additions due to technological change is then defined by the area A-A'-C-B. Simarily, when cumulative drilling increases from SW_2 to SW_3, and accompany advances in technology cause the remaining economically recoverable resource base to expand by an amount $\Delta_2 Q^E$, there is a further shift in the finding rate function to FC_2. Reserve additions are again increased over what they otherwise would have been, this time by the area C-C'-F-E. This latter increase is incremental to the extra reserves discovered as a result of the technological advances that transpired as drilling progressed from SW_1 to SW_2. (The area defined by B-C-E-D).

From equation (1), in the absence of technological change, the finding rate at the end of period t is lower than the finding rate in period t-1 by δ times the number of wells drilled in period t, i.e.

$$FR_t = FR_{t-1} EXP(-\delta(SW_t - SW_{t-1})). \tag{8a}$$

In the presence of technological change this relationship is amended to incorporate the technology parameter β:

$$FR_t = FR_{t-1} (1+ \beta) EXP(-\delta(SW_t - SW_{t-1})). \tag{8b}$$

The inclusion of this parameter permits the finding rate in period t to be higher, lower, or equal to the finding rate in t-1 depending on the value of β, δ, and the number of wells drilled in period t.

Technological change also impacts the rate of decline in the finding rate with respect to cumulative drilling. Specifically, because the remaining recoverable volume is expanding relative to what it otherewise would have been, δ must be recalculated in each period as shown in equation (9). Note that the denominator of (9) is the remaining economically recoverable resource base estimate calculated as the initial economically recoverable resource base adjusted for expansion due to technological change, less the cumulative reserves found over time.

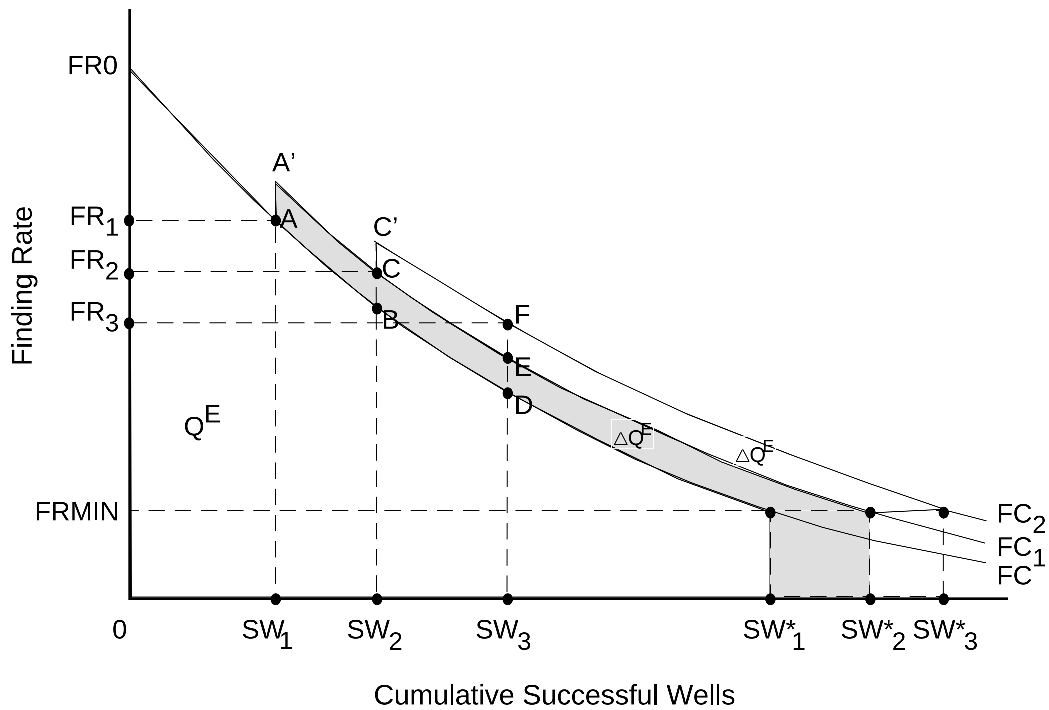
$$\delta_t = \frac{FR_{t-1}(1+\beta) - FRMIN}{QTECH_t - CUMRES_{t-1}} \tag{9}$$

where,

FR	=	finding rate at the beginning of period
FRMIN	=	minimum economic finding rate
QTECH	=	initial economically recoverable resource base adjusted for expansion due to technological change
t	=	forecast year
CUMRES	=	cumulative reserve discoveries over the projection period (initial value = 0).

As indicated in Equation (8) the resource base is assumed to expand over time due to the development of new discovery and extraction technologies, as well as the increased penetration of existing technologies. This technologically induced expansion is modeled in two ways in OGSM.

Figure 14. Technological Change



One method of modeling technological expansion involves simply allowing the initial resource base to expand each year at an assumed constant rate. This methodology is used in OGSM to expand inferred reserves, those unproven resources converted to proven reserves by developmental and other exploratory (non-new field wildcat) drilling. In this case the representation of the technologically expanded resource base becomes:

$$QTECH_t = I * (1 + TECH)^{t-T} \tag{10}$$

where,

I	=	initial inferred reserves estimate in year T
TECH	=	annual percentage expansion of resource base due to technological change.

A different method is used to represent the effect of technology upon undiscovered economically recoverable resources, the resource base from which reserves are added in OGSM by the drilling of new field wildcats. In order to not allow undiscovered recoverable resources to expand infinitely yet at the same time allow for a reasonable degree of technologically induced growth, these resources expand asymptotically toward a target resource value. The target represents the ultimate long-term expansion that is expected to occur in the undiscovered economically recoverable resource base as a result of technological progress. The functional form shows continuous expansion of the recoverable resource base, but at diminishing rates. This specification is consistent with a view of the endless potential of technological improvement and the increasing difficulties encountered with additional recovery from a finite resource base. The OGSM representation of this new field resource base, as adjusted for technological expansion, is as follows:

$$QTECH_t = Q^E + (Q^* - Q^E) * (1 - \exp(-\gamma * t)) \tag{11}$$

where,

Q^*	=	ultimate undiscovered economically recoverable resource level given long-term technological change
γ	=	parameter that determines the incremental expansion of the undiscovered economically recoverable resource base due to technological change

The value of γ in Equation (11) can be derived based on several assumptions. The first assumption is that the expanded resource base will in the last forecast year (2015;t-T=25) reflect an implied rate of annual percentage expansion, TECH, such that:

$$QTECH_{25} = Q^E * (1 + TECH)^{25} \tag{12}$$

The second assumption is that the expanded recoverable resource base in 2015 equals a given fraction, ϕ, of the ultimate expansion target. This relation can be expressed as:

$$QTECH_{25} = \phi * Q^* \tag{13}$$

Which implies:

$$Q^* = \frac{QTECH_{25}}{\phi} \tag{14}$$

Substituting the right side of Equation (11) into Equation (13), and using that expression to replace for Q^* in Equation (10), yields:

$$QTECH_{25} = Q^E + (Q^E*(1+TECH)^{25}/\phi - Q^E) * (1 - \exp(-\gamma * t)) \tag{15}$$

Because $QTECH_{25} = Q^E*(1+TECH)^{25}$, Equation (14) for 2015 appears as the following equation:

$$Q^E*(1+TECH)^{25} = Q^E + (Q^E*(1+TECH)^{25}/\phi - Q^E) * (1 - \exp(-\gamma * 25)) \tag{16}$$

One can then solve for γ as follows:

$$Q^E*((1+TECH)^{25}-1) = Q^E * (((1+TECH)^{25}/\phi - 1) * (1 - \exp(-\gamma * 25)) \tag{17}$$

$$\frac{(1+TECH)^{25} - 1}{(1+TECH)^{25}/\phi - 1} = 1 - \exp(-\gamma * 25) \tag{18}$$

$$\exp(-\gamma * 25) = 1 - \frac{(1+TECH)^{25} - 1}{(1+TECH)^{25}/\phi - 1} \tag{19}$$

$$\gamma = - \frac{\ln\left[1 - \frac{(1+TECH)^{25} - 1}{(1+TECH)^{25}/\phi - 1}\right]}{25} \tag{20}$$

The level of undiscovered, economically recoverable resources in any given year depends on the initial level and certain factors that determine the rate of resource expansion. In the previous version of OGSM these factors included only the expanded economic resource level in the last year of the forecast period and the proportion (ϕ) of ultimate economically recoverable resources that this level represents. The value of ϕ is based on analytical judgment. The economic resource level in the last forecast year was assumed to equal an amount that would have been achieved by a continuous annual percentage expansion at a given rate. The assumed ultimate level of economically recoverable resources could be inferred from these two values.

In the current version of OGSM the resource expansion that would have been calculated for each year under the previous methodology is scaled. It is scaled by a ratio. The first element of the ratio is the difference between the technically recoverable resource level under existing technology and the initial resource level. The second element is the difference between the level of economically recoverable resources that had been assumed for the last year of the forecast period and the initial resource level. If the calculated scaling factor is greater than 1.0 then it is reset to 0.99. This adjustment to the resource expansion curve introduces a constraint to reflect the existing limits of technical recoverability. The resulting curve is still hyperbolic and it is closing at the same rate. However, it is approaching a target which may be significantly lower, if the level of technically recoverable resources under existing technology is significantly below what would have been assumed for economic resources in the last year of the forecast under the previous methodology.[6]

In Figure 14 the total expected expansive effect of advancing technology upon the recoverable resource base is introduced in increments. This approach compares to one in which a larger initial resource value is used to determine a δ that remains constant over time. With that the full long-term benefits of tecnological change are factored into the determination of the finding rate curve for all years of the forecast horizon. Figure 15 provides a graphical comparison of these two approaches in the early years. FC_x is the finding rate curve derived by calculating a constant δ based on FR0 and a resource base, $QTECH_{25}$, that reflects the full expected benefits of technological change for the entire forecast horizon. In this case the section defined by FR0-G-SW_3-0 represents the reserve additions that would be estimated as a result of utilizing the "full benefit" approach.

The finding rate curves relating to onshore conventional inferred reserves and offshore gas inferred reserves partially reflect the “full benefit” approach. This is because estimates of these resources inherently contain some

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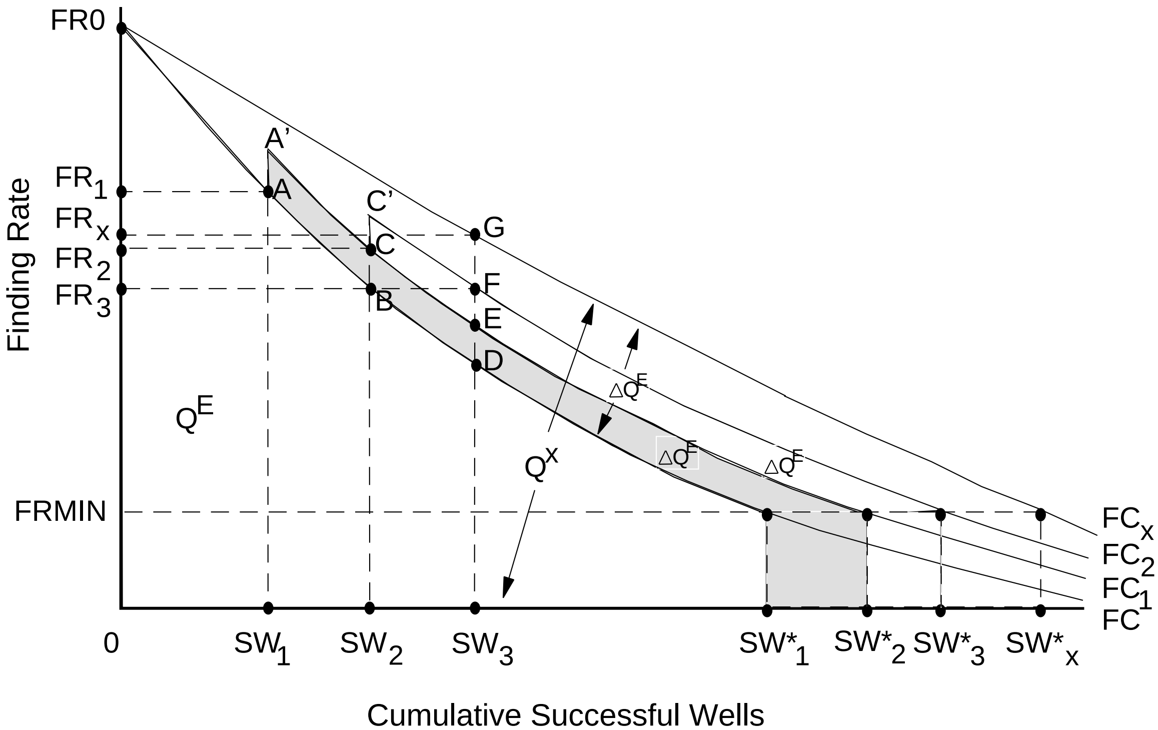
[6]In the AEO97 version of OGSM, the value of ϕ also affected the ultimate upper limit of the technological expansion of economic resources. When the resource expansion was calculated for a particular year, the value representing the ultimate level of resource expansion was inadvertently multiplied by ϕ. This latter adjustment was the result of a previously undetected coding error. The same coding error, however, had resulted in an unintended upward bias in the ϕ values. That is, the original intent for AEO97 was to calculate ϕ as the ratio of the existing technically recoverable resource level (or some proportion thereof) to an assumed ultimate economically recoverable resource level. A misinterpretation stemming from observation of the incorrect code resulted in the (lower) last-forecast-year assumed level of economic resources being used instead for the denominator in the ϕ calculation. The end result of these two developments was that the resource expansion reached a higher proportion than intended - of a lower ultimate level than intended. Fortunately, these effects largely offset each other in the determination of the level of resource expansion actually allowed to occur during the forecast period. In the current version of OGSM, the aforementioned coding error has been corrected and the methodology described in the text above has been implemented.

Figure 15. Technological Change: Incremental versus Full Benefit Approach



allowance for long-term technological progress due to their incorporation of historical rates of reserve growth. In previous versions of the model this approach was considered inappropriate from a theoretical standpoint. That is, it was thought that technological developments in the later years of the forecast period should not be "providing benefits" in the early years of the forecast. After further analysis, however, it has been determined that this approach is acceptable in these cases, given the nature of inferred reserves and the manner in which estimates of inferred reserves are utilized to determine the rate of decline in the finding rate function.

Implementation of the Finding Rate Methodology

The finding rate process actually implemented in OGSM is somewhat more complex than the simple structure portrayed above, although the underlying concepts remain the same. The changes to the basic design mostly reflect the reserve accounting system instituted in OGSM. In the previous Energy Information Administration (EIA) supply model, the Production of Onshore Lower 48 Oil and Gas Model (PROLOG), reserve additions were treated 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. Reserve additions from developmental drilling were not related directly to exploratory activity.

In the Oil and Gas Supply Model (OGSM) there is a distinction between exploratory drilling for new fields and exploratory drilling for additional deposits within old fields.[7] This enhancement recognizes important differences

[7]Exploratory wells are drilled in relatively untested or unproven areas and can result in the discovery of new fields or new pools within known fields. Exploratory drilling in OGSM is divided between two major types. *New field wildcats* are exploratory 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. *Developmental wells* are primarily within or near proven areas and can result in extensions or revisions.

in exploratory drilling, both by nature and in its physical and economic returns. New field wildcats convert resources in previously undiscovered fields into both proved reserves (as new discoveries) and inferred reserves.[8] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves by a phenomenon termed reserves growth, the process by which initial assessments of proved reserves from a new field discovery grow over time. The volumetric returns to other exploratory and developmental drilling in OGSM are referred to as extensions and revisions, respectively. Other exploratory drilling accounts for proved reserves added through new pools or extensions (generally referred to only as extensions within the context of the model), and development drilling accounts for reserves added as net revisions (including adjustments). The finding rate equations vary in OGSM among new field wildcats, other exploratory drilling, and developmental drilling. Finding rates are defined separately for each fuel type category (k) in each region (r).

New Field Wildcat Finding Rates

The finding rate equation (Equation (21)) for new field wildcats[9] follows rather closely the basic methodology described above. In the OGSM specification, the yield from new field wildcat drilling begins at the initial finding rate, FR1, and declines exponentially thereafter. This specification conforms to the design of Equation (1).

$$FR1_{r,k,t} = FR1_{r,k,t-1}(1+\beta 1)*\exp(-\delta 1_{r,k,t}*SW1_{r,k,t}) \tag{21}$$

where,

FR1	=	finding rate (Mbbl per well or MMcf per well)
SW1	=	successful new field wildcats
$\delta 1$	=	finding rate decline parameter
$\beta 1$	=	technology parameter for FR1
r	=	region
k	=	fuel type (oil or gas).

New field reserve additions are determined as the integral of the finding rate function over the given drilling interval, ($SW1_{r,k,t}$). The resource base enters the equation as an exogenous input that influences the derivation of $\delta 1$, the finding rate decline parameter. The value of the technology parameter, $\beta 1$, was based on an econometric analysis of the impact of technology on the new field wildcat finding rate. The decline parameter, $\delta 1$, is estimable from Equation (9) in combination with the terms of Equations (10) and (13). Substituting values specific to new field wildcat wells yields the following equation:

$$\delta 1_{r,k,t} = \frac{FR1_{r,k,t-1}(1+\beta 1) - FRMIN1_{r,k}}{Q^E_{r,k} + (Q^E_{r,k}*(1+TECH)^{25}/\phi - Q^E_{r,k})*(1-\exp(-\gamma t)) - \sum_{T+1}^{t-1}\int FR1_{r,k,t}\,d(SW1)} \tag{22}$$

where,

FRMIN1 = minimum economic finding rate for new field wildcat wells.

---

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

[9]Total successful exploratory wells as described previously are disaggregated into successful new field wildcats and other exploratory wells. The disaggregation is based on average historical ratios of successful new field wildcats to total successful exploratory wells. For the rest of this appendix, successful new field wildcats will be designated by the variable SW1, other successful exploratory wells by SW2, and successful development wells by SW3.

The initial estimate for proved reserves are reserves that can be certified using mainly the original discovery wells, while inferred reserves are those hydrocarbons that will require additional drilling before they can be considered proved. Subsequent drilling takes the form of 'other exploratory' drilling and development drilling. The finding rates for these latter two types of drilling are based on the same methodology described above, with appropriate modifications to account for differences in the nature of the resource target and the process by which it is converted to proved reserves.

The volumetric yield from a successful new field wildcat well is divided into proved reserves and inferred reserves based on historical reserves growth statistics. More specifically, the allocation of reserves between proved and inferred reserves is based on the average ratio of initial reserves estimated for a newly discovered field relative to ultimate recovery from the field.[10] 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. The new fields discovered by new field wildcats yield not only proved reserves but also a much larger amount of inferred reserves. Specifically, the change in proved reserves from new field discoveries for each period is given by:

$$\Delta R_{r,k,t} = \frac{1}{X_{r,k}} \int_{0}^{SW1_{r,k,t}} FR1_{r,k,t} \; d(SW1) \tag{23}$$

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

where,

X	=	reserves growth factor
ΔR	=	additions to proved reserves.

The terms in Equation (23) are all constants in period t, except for the SW1. X is derived from the historical data and it is assumed to be constant during the forecast period. $FR1_{r,k,t-1}$ and $\delta 1_{r,k,t}$ are calculated prior to period t, based on lagged variables and fixed parameters as shown in Equations (21) and (22).

Finding Rates for Other Types of Drilling

Reserves are assumed to move from the realm of inferred to proved with the drilling of other exploratory wells or developmental wells in much the same way as volumes of both proved and inferred reserves are modeled as moving from the undiscovered economically recoverable resource base as described above. The volumetric return to other exploratory wells and developmental wells is shown in Equations (24) and and (25), respectively.

$$FR2_{r,k,t} = FR2_{r,k,t-1}(1+\beta 2) * \exp(-\delta 2_{r,k,t} * SW2_{r,k,t}) \tag{24}$$

where,

FR2	=	other exploratory wells finding rate
SW2	=	successful other exploratory wells

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

$\beta 2$ = technology parameter for FR2.

$$FR3_{r,k,t} = FR3_{r,k,t-1}(1+\beta 3) * \exp(-\delta 3_{r,k,t} * SW3_{r,k,t}) \tag{25}$$

where,

$FR3$ = development well finding rate
$SW3$ = successful development wells
$\beta 3$ = technology parameter for FR3.

The derivation of updated decline factors for the exponentially declining functions are shown in Equations (26) and (27) for other exploratory drilling and developmental drilling, respectively.

$$\delta 2_{r,k,t} = \left[\frac{(FR2_{r,k,t-1}(1+\beta 2) - FRMIN2_{r,k}) * DECFAC}{I_{r,k}(1+TECH)^{t-T} + \sum_{T+1}^{t-1} (\frac{X-1}{X}) \int FR1_{r,k,t} d(SW1) - \sum_{T+1}^{t-1} [\int FR2_{r,k,t} d(SW2) + \int FR3_{r,k,t} d(SW3)]} \right] \tag{26}$$

$$\delta 3_{r,k,t} = \left[\frac{(FR3_{r,k,t-1}(1+\beta 3) - FRMIN3_{r,k}) * DECFAC}{I_{r,k}(1+TECH)^{t-T} + \sum_{T+1}^{t-1} (\frac{X-1}{X}) \int FR1_{r,k,t} d(SW1) - \sum_{T+1}^{t-1} [\int FR2_{r,k,t} d(SW2) + \int FR3_{r,k,t} d(SW3)]} \right] \tag{27}$$

where,

I = initial inferred reserves estimate
DECFAC = decline rate adjustment factor.
FRMIN2 = minimum economic finding rate for other exploratory wells
FRMIN3 = minimum economic finding rate for developmental wells

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 specification of Equations (26) and (27) has the characteristic that the entire stock of inferred reserves can be exhausted through sufficiently large numbers of 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. This is because in a given year the same initial recoverable resource value (i.e., the denominator expression in the derivation of δ_2 and δ_3) is decremented by either type of drilling. DECFAC is present in the computation of δ_2 and δ_3 to account for the simultaneous drawdown from inferred reserves by both other exploratory wells and developmental wells. DECFAC is a user-specified parameter that should be greater than or equal to 1.0. Values greater than 1.0 accelerate the productivity decline in the finding rate.

Integration of the preceding finding rate functions with the new field wildcat function yields the following equation for total reserve additions in period t:

$$RA_{r,k,t} = \frac{1}{X_{r,k}} \int_{0}^{SW1_{r,k,t}} FR1_{r,k,t} d(SW1) + \int_{0}^{SW1_{r,k,t}} FR2_{r,k,t} d(SW2) + \int_{0}^{SW1_{r,k,t}} FR3_{r,k,} \tag{28}$$

Conclusion

This completes a description of the finding rate methodology utilized in OGSM. A simple basic methodology was presented upon which the OGSM finding rate functions are based. Included in this discussion were descriptions of two modifications to that basic structure—one to account for the economic nature of the resource estimates and another to incorporate the effect of technological advancements. Subsequently, the implementation of this methodology in OGSM was described, with the resulting finding rate functions shown to vary from the basic structure primarily because of the resource accounting system employed in OGSM.

The methodology for conversion of oil or gas resources into proved reserves is a critically important aspect of supply modeling. While the actual process through which oil and gas become proved reserves is a highly complex one, the methodology presented here is representative only of the major phases that occur. By necessity, it is a simplification from a highly complex reality.

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.

All regions specified under classification are OGSM regions unless otherwise noted.

	Variables					
Appendix B Equation	Subroutine	Variable Name Code	Variable Name Text	Description	Unit	Classification
1	OGFOR_L48	DRILLL48	DRILLCOST	Successful well drilling costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas)
2	OGFOR_L48	DRYL48	DRYCOST	Dry well drilling costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas)
3	OGFOR_OFF	DRILLOFF	DRILLCOST	Successful well drilling costs	1987$ per well	Class(Exploratory,Developmental);8 Lower 48 offshore regions,Fuel(oil,gas)
4	OGFOR_OFF	DRYOFF	DRYCOST	Dry well drilling costs	1987$ per well	Class(Exploratory,Developmental);8 Lower 48 offshore regions,Fuel(oil,gas
5	OGFOR_L48 OGFOR_OFF	LEASL48 LEASOFF	LEQC	Lease equipment costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
6	OGFOR_L48 OGFOR_OFF	OPERL48 OPEROFF	OPC	Operating costs	1987$ per well	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
7	OG_DCF	DCFTOT	PROJDCF	Discounted cash flow for a representative project	1987$ per project	Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas); 3 Alaska regions, Fuel (oil,gas)
8	OG_DCF	PVSUM(1)	PVREV	Present value of expected revenue	1987$ per project	(Above)
9	OG_DCF	PVSUM(2)	PVROY	Present value of expected royalty payments	1987$ per project	(Above)
10	OG_DCF	PVSUM(3)	PVPRODTAX	Present value of expected production taxes	1987$ per project	(Above)
11	OG_DCF	PVSUM(4)	PVDRILLCOST	Present value of expected drilling costs	1987$ per project	(Above)
12	OG_DCF	PVSUM(5)	PVEQUIP	Present value of expected lease equipment costs	1987$ per project	(Above)
13	OG_DCF	PVSUM(8)	PVKAP	Present value of expected capital costs	1987$ per project	(Above)
14	OG_DCF	PVSUM(6)	PVOPERCOST	Present value of expected operating costs	1987$ per project	(Above)

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
15	OG_DCF	PVSUM(7)	PVABANDON	Present value of expected abandonment costs	1987$ per project	(Above)
16	OG_DCF	PVSUM(13)	PVTAXBASE	Present value of expected tax base	1987$ per project	(Above)
17	OG_DCF	XIDC	XIDC	Expensed Costs	1987$ per project	(Above)
18	OG_DCF	DHC	DHC	Dry hole costs	1987$ per project	(Above)
19	OG_DCF	DEPREC	DEPREC	Depreciable costs	1987$ per project	(Above)
20	OG_DCF	PVSUM(15)	PVSIT	Expected value of state income taxes	1987$ per project	(Above)
21	OG_DCF	PVSUM(16)	PVFIT	Expected value of federal income taxes	1987$ per project	(Above)
22-23	OG_DCF	OG_DCF	DCF	Discounted cash flow for a representative well	1987$ per well	(Above)
24	OGEXP_CALC	W1UNC	w	Share of total lower 48 onshore wells at class,region, fuel(unconventional gas) level	Fraction	Class(Exploratory,Developmental);6 Lower 48 onshore regions;Fuel(3 unconventional gas)
25	OGEXP_CALC	DCFUNC	UGDCFON	Discounted cash flow for unconventional gas	1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions
26	OGEXP_CALC	W1	w	Share of total Lower 48 wells at class,region,fuel level	Fraction	Class(Exploratory,Developmental);6 Lower 48 onshore regions;Fuel(oil,5 gas)
27	OGEXP_CALC	WDCFIR	RDCFON	Lower 48 onshore discounted cash flow	1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions
28	OGEXP_CALC	WDCFOFFIR	RDCFOFF	Lower 48 offshore discounted cash flow	1987$	Class(Exploratory,Developmental) ;8 Lower 48 offshore regions
29	OGEXP_CALC	W2	w	Share of total Lower 48 wells at class,region,fuel level	Fraction	Class(Exploratory,Developmental);6 Lower 48 onshore regions
30	OGEXP_CALC	WDCFL48	NDCFON	Lower 48 onshore discounted cash flow	1987$	Class(Exploratory,Developmental)
31	OGEXP_CALC	WDCFOFF	NDCFOFF	Lower 48 offshore discounted cash flow	1987$	Class(Exploratory,Developmental)

Appendix B Equation	Variables					
	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
32-53	OGEXP_CALC	SPENDIRK_L48	SPENDON	Lower 48 onshore expenditures	Million 1987$	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas)
54-64	OGEXP_CALC	SPENDIRK_OFF	SPENDOFF	Lower 48 offshore expenditures	Million 1987$	Class(Exploratory,Developmental) ;8 Lower 48 offshore regions,Fuel(oil,gas)
65	OGEXP_CALC	WELLSL48	WELLSON	Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas)
66	OGEXP_CALC	SUCWELLL48	SUCWELSON	Successful Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas)
67	OGEXP_CALC	DRYWELLL48	DRYWELON	Dry Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas)
68	OGALL_OFF	WELLSOFF	WELLSOFF	Lower 48 offshore wells drilled	Wells	Class(Exploratory,Developmental) ;8 Lower 48 offshore regions,Fuel(oil,gas)
69	OGALL_OFF	SUCWELLOFF	SUCWELSOFF	Successful Lower 48 offshore wells drilled	Wells	Class(Exploratory,Developmental) ;8 Lower 48 offshore regions,Fuel(oil,gas)
70	OGALL_OFF	DRYWELLOFF	DRYWELOFF	Dry Lower 48 offshore wells drilled	Wells	Class(Exploratory,Developmental) ;8 Lower 48 offshore regions,Fuel(oil,gas)
71	OGOUT_L48 OGOUT_OFF	FR1L48 FR1OFF	FR1	Finding rates for new field wildcat drilling	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
72	OGOUT_L48 OGOUT_OFF	DELTA1L48 DELTA1OFF	δ1	Finding rate decline parameters for new field wildcat drilling	Fraction	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
73	OGOUT_L48 OGOUT_OFF	CUMR1L48 CUMR1OFF	CUMRES1	Cumulative proved reserves added by new field discoveries	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
74	OGOUT_L48 OGOUT_OFF	NDRL48 NDROFF	NRD	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
75	OGOUT_L48 OGOUT_OFF	NDIRL48 NDIROFF	I	Inferred reserves added by new field discoveries	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
76	OGOUT_L48 OGOUT_OFF	FR2L48 FR2OFF	FR2	Finding rates for developmental wells	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
77	OGOUT_L48 OGOUT_OFF	DELTA2L48 DELTA2OFF	$\delta 2$	Finding rate decline parameters for developmental wells	Fraction	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
78	OGOUT_L48 OGOUT_OFF	CUMR2L48 CUMR2OFF	CUMRES2	Cumulative reserve revisions	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
79	OGOUT_L48 OGOUT_OFF	REVL48 REVOFF	REV	Reserve revisions	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
80	OGOUT_L48 OGOUT_OFF	FR3L48 FR3OFF	FR3	Finding rates for other exploratory drilling	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
81	OGOUT_L48 OGOUT_OFF	DELTA3L48 DELTA3OFF	$\delta 3$	Finding rate decline parameters for other exploratory wells	Fraction	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
82	OGOUT_L48 OGOUT_OFF	CUMR3L48 CUMR3OFF	CUMRES3	Cumulative reserve extensions	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
83	OGOUT_L48 OGOUT_OFF	EXTL48 EXTOFF	EXT	Reserve extensions	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
84	OGOUT_L48 OGOUT_OFF	RESADL48 RESADOFF	RA	Total additions to proved reserves	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)
85	OGOUT_L48 OGOUT_OFF OGFOR_AK	RESBOYL48 RESBOYOFF BOYRESCOAK BOYRESNGAK	R	End of year reserves for current year	Oil-MMB Gas-BCF	6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas);3 Alaska regions,Fuel(oil,gas)
86	OGOUT_L48 OGOUT_OFF	PRRATL48 PRRATOFF	PR	Production to reserves ratios	Fraction	Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas)

Appendix B Equation	Variables					
	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
87	OGCOMP_AD	OGPRDAD	ADGAS	Associated-dissolved gas production	BCF	6 Lower 48 onshore regions, 3 Lower 48 offshore regions
88	OGCOST_AK	DRILLAK	DRILLCOST	Drilling costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
89	OGCOST_AK	LEASAK	EQUIP	Lease equipment costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
90	OGCOST_AK	OPERAK	OPCOST	Operating costs	1987$ per well	Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas)
91	OGFOR_AK	TOTGRR	TRR	Alaska total gross revenue requirements	Million 1987$	NA
92	OGFOR_AK	TOTDEP	TOTDEP	Alaska total depreciation	Million 1987$	NA
93	OGFOR_AK	MARTOT	MARGIN	Alaska total after tax margin	Million 1987$	NA
94	OGFOR_AK	RECTOT	DEFRETREC	Alaska total recovery of differed returns	Million 1987$	NA
95	OGFOR_AK	TXALLW	TXALLW	Alaska income tax allowance	Million 1987$	NA
96	OGCAN_DCF	CF	NCF	Net cash flow	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
97	OGCAN_DCF	OGCAN_DCF	PROJDCF	Discounted cash flow	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
98	OGCAN_DCF	REV	REV	Revenues	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
99	OGCAN_DCF	ROY	ROY	Royalty payments	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
100	OGCAN_DCF	DRILL	DRILLCOST	Successful well drilling costs	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
101	OGCAN_DCF	DRILL	DRYCOST	Dry hole drilling costs	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
102	OGCAN_DCF	EQUIP	EQUIP	Lease equipment costs	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
103	OGCAN_DCF	OPER	OPERCOST	Operating costs	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)

	Variables					
Appendix B Equation	Subroutine	Variable Name		Description	Unit	Classification
		Code	Text			
104	OGCAN_DCF	FTI	FTI	Federal tax base	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
105	OGCAN_DCF	XIDC	XIDC	Expensed costs	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
106	OGCAN_DCF	AIDC	DEPREC	Depreciable costs	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
107	OGCAN_DCF	RA	RA	Resource allowance	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
108	OGCAN_DCF	DA	DA	Depletion allowance	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
109	OGCAN_DCF	PTI	PTI	Provincial tax base	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
110	OGCAN_DCF	PROVTAX	PROVTAX	Provincial income taxes	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
111	OGCAN_DCF	FEDTAX	FEDTAX	Federal income taxes	1987$ per project	Class(exploratory,developmental); Fuel(oil,gas)
112	OGOUT_IMP	WELLSCAN	WELLS	Canadian wells drilled	Wells	Fuel(oil,gas)
113	OGOUT_IMP	FRCAN	FR	Canadian finding rate	Oil:MMB per well Gas:BCF per well	Fuel(oil,gas)
114	OGOUT_IMP	DELTACAN	δ	Canadian finding rate decline parameter	Fraction	Fuel(oil,gas)
115	OGOUT_IMP	RESADCAN	RA	Canadian reserve additions	Oil:MMB Gas:BCF	Fuel(oil,gas)
116	OGOUT_IMP	CUMRCAN	CUMRES	Cumulative Canadian reserve additions	Oil:MMB Gas:BCF	Fuel(oil,gas)
117	OGOUT_IMP	RESBOYCAN	R	Canadian reserves	Oil:MMB Gas:BCF	Fuel(oil,gas)
118	OGOUT_IMP	PRRATCAN	PR	Canadian production to reserves ratio	Fraction	Fuel(oil,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 (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	8 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
OGINIT_EOR OGOUT_EOR	BGQEORCOGC	--	EOR cogeneration electric capacity (reference case)	MW	6 Lower 48 onshore regions; 2 usages (utility,non-utility)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	BGQEORCOGG	--	EOR cogeneration electric generation (reference case)	MWh	6 Lower 48 onshore regions; 2 usages (utility,non-utility)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	BGQEORCON	--	EOR crude oil consumption (reference case)	MB	6 Lower 48 onshore regions	Not Used
OGINIT_EOR OGOUT_EOR	BGQEORNGC	--	EOR natural gas consumption (reference case)	MCF	6 Lower 48 onshore regions; 2 EOR technologies (primary,other)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	BGQEORNGP	--	EOR natural gas production (reference case)	MCF	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	BGQEORPR	--	EOR crude oil production (reference case)	MB	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGEXPAND_LNG OGINIT_LNG	BUILDLAG	--	Buildup period for expansion of LNG facilities	Year	NA	Office of Integrated Analysis and Forecasting

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGFOR_IMP OGINIT_IMP	CPRDCAN	COPRD	Canadian coproduct rate	Fraction	Canada; Fuel (oil, gas)	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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	CPRDOFF	COPRD	Offshore coproduct rate	Fraction	8 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP OGINIT_RES OGOUT_IMP	CURPRRCAN	omega	Canadian 1989 P/R ratio	Fraction	Canada; Fuel (oil, 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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGINIT_RES OGOUT_OFF	CURPRROFF	omega	Offshore initial P/R ratios	Fraction	8 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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_IMP OGINIT_RES OGOUT_IMP	CURRESCAN	R	Canadian 1989 end of year reserves	MMB BCF	Canada; Fuel (oil, gas)	Canadian Petroleum Association
OGINIT_L48 OGINIT_RES OGOUT_L48	CURRESL48	R	Lower 48 onshore initial reserves	MMB BCF	6 Lower 48 onshore regions; Fuel (oil, 5 gas)	Derived from Annual Reserves Report Data
OGINIT_OFF OGINIT_RES OGOUT_OFF	CURRESOFF	R	Offshore initial reserves	MMB BCF	8 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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGOUT_L48	DECFAC	DECFAC	Inferred resource simultaneous draw down decline rate adjustment factor	Fraction	NA	Office of Integrated Analysis and Forecasting

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGFOR_IMP OGINIT_IMP	DECLCAN	--	Canadian decline rates	Fraction	Canada; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48 WELL	DECLL48	--	Lower 48 onshore decline rates	Fraction	6 Lower 48 onshore regions; Fuel (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF WELL	DECLOFF	--	Offshore decline rates	Fraction	8 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
OGFOR_IMP OGINIT_IMP	DEPLETERT	DEPLRT	Depletion rate	Fraction	NA	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
OGFOR_IMP OGINIT_IMP	DISRT	disc	Discount rate	Fraction	Canada	Office of Integrated Analysis and Forecasting
OGCOST_AK OGINIT_AK	DRILLAK	DRILL	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_IMP OGINIT_IMP	DRILLCAN	DRILL	Canadian initial drilling costs	1987$	Canada; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGALL_OFF OGFOR_OFF OGINIT_OFF	DRILLOFF	DRILL	Offshore drilling cost	1987$	8 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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGDCF_AK OGDEV_AK OGINIT_AK OGNEW_AK	DRYAK	DRY	Alaska dry hole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_IMP OGINIT_IMP	DRYCAN	DRY	Canadian dry hole cost	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
OGALL_OFF OGEXP_CALC OGFOR_OFF OGINIT_OFF	DRYOFF	DRY	Offshore dry hole cost	1987$	Class (exploratory, developmental); 8 Lower 48 offshore subregions	Minerals Management Service
OGFOR_OFF OGINIT_OFF	DVWELLOFF	--	Offshore development project drilling schedules	wells per year	8 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
OGFOR_IMP OGINIT_IMP	DVWLGASCAN	--	Canadian development gas drilling schedule	wells per project per year	Canada	Not Used
OGFOR_IMP 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

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	8 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); 8 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
OGCAN_DCF OGFOR_IMP OGINIT_IMP	EXPENSE	EXP	Fraction of drill costs that are expensed	fraction	Class (exploratory, developmental)	Canadian Tax Code
OGFOR_OFF OGINIT_OFF	EXWELLOFF	--	Offshore exploratory project drilling schedules	wells per year	8 Lower 48 offshore subregions	Minerals Management Service
OGFOR_L48 OGINIT_L48	EXWLCBML48	--	Lower 48 exploratory project drilling schedules for coalbed methane	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	EXWLDGSL48	--	Lower 48 exploratory and developmental project drilling schedules for deep gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	EXWLDVSL48	--	Lower 48 exploratory project drilling schedules for devonian shale	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGFOR_IMP OGINIT_IMP	EXWLGASCAN	--	Canadian exploratory gas drilling schedule	wells per year	Canada	Not Used
OGFOR_IMP 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$/bls	Field size class	U.S. Geological Survey
OGFOR_IMP OGINIT_IMP	FEDTXCAN	FDRT	Canadian corporate tax rate	fraction	Canada	Petroleum Fiscal Systems in Canada - Energy, Mines & Resources
OGDCF_AK OGEXP_CALC OGFOR_L48 OGFOR_OFF OGINIT_BFW	FEDTXR	FDRT	U.S. federal tax rate	fraction	Canada	U.S. Tax Code
OGFOR_IMP OGINIT_IMP	FLOWCAN	--	Canadian flow rates	bls, MCF per year	Canada; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	FLOWL48	--	Lower 48 onshore flow rates	bls, MCF per year	6 Lower 48 onshore regions; Fuel (oil, 5 gas)	EIA, Office of Oil and Gas
OGFOR_OFF OGINIT_OFF	FLOWOFF	--	Offshore flow rates	bls, MCF per year	8 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGINIT_LNG OGPROF_LNG	FPRDCST	--	Foreign production costs	1991$/MCF per year	LNG Source Country	National Petroleum Council

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGINIT_IMP OGOUT_IMP	FRCAN	FR	Canadian initial finding rate	MMB BCF per well	Canada	Office of Integrated Analysis and Forecasting
OGINIT_IMP OGOUT_IMP	FRMINCAN	FRMIN	Canadian minimum economic finding rate	MMB 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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	FRMINOFF	FRMIN	Offshore minimum exploratory well finding rate	MMB BCF per well	8 Lower 48 offshore subregions; Fuel (oil, gas)	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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	FR1OFF	FR1	Offshore new field wildcat well finding rate	MMB BCF per well	8 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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	FR2OFF	FR3	Offshore developmental well finding rate	MMB BCF per well	8 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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	FR3OFF	FR2	Offshore other exploratory well finding rate	MMB BCF per well	8 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_AK OGINIT_AK OGNEW_AK	FSZCOAK	—	Alaska oil field size distributions	MMB	3 Alaska regions	U.S. Geological Survey

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGFOR_AK OGINIT_AK OGNEW_AK	FSZNGAK	--	Alaska gas field size distributions	BCF	3 Alaska regions	U.S. Geological Survey
OGINIT_EOR OGOUT_EOR	HGQEORCOGC	--	EOR cogeneration electric capacity (high oil price case)	MW	6 Lower 48 onshore regions; 2 usages (utility,non-utility)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	HGQEORCOGG	--	EOR cogeneration electric generation (high oil price case)	MWh	6 Lower 48 onshore regions; 2 usages (utility,non-utility)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	HGQEORCON	--	EOR crude oil consumption (high oil price case)	MB	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	HGQEORNGC	--	EOR natural gas consumption (high oil price case)	MCF	6 Lower 48 onshore regions; 2 EOR technologies (primary,other)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	HGQEORNGP	--	EOR natural gas production (high oil price case)	MCF	6 Lower 48 onshore regions	Not Used
OGINIT_EOR OGOUT_EOR	HGQEORPR	--	EOR crude oil production (high oil price case)	MB	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
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_AK OGPRO_AK	HISTPRDCO	--	Alaska historical crude oil production	MB/D	Field	Alaska Oil and Gas Conservation Commission
OGINIT_L48	HISTPRRL48	--	Lower 48 historical P/R ratios	fraction	6 Lower 48 onshore regions; Fuel (oil, 5 gas)	Derived from Annual Reserves Report
OGINIT_OFF	HISTPRROFF	--	Offshore historical P/R ratios	fraction	8 Lower 48 offshore subregions; Fuel (oil, gas)	Derived from Annual Reserves Report
OGINIT_L48	HISTPRRTDM	--	Lower 48 onshore historical P/R ratios at the NGTDM level	fraction	17 OGSM/NGTDM regions; Fuel (oil, 5 gas)	Office of Integrated Analysis and Forecasting

Data						
Subroutine	Variable Name: Code	Variable Name: Text	Description	Unit	Classification	Source
OGINIT_L48	HISTRESL48	--	Lower 48 onshore historical beginning-of-year reserves	MMB BCF	6 Lower 48 onshore regions; Fuel (oil, 5 gas)	Annual Reserves Report
OGINIT_OFF	HISTRESOFF	--	Offshore historical beginning-of-year reserves	MMB BCF	8 Lower 48 offshore subregions; Fuel (oil, gas)	Annual Reserves Report
OGINIT_L48	HISTRESTDM	--	Lower 48 onshore historical beginning-of-year reserves atthe NGTDM level	MMB BCF	17 OGSM/NGTDM regions; Fuel (oil, 5 gas)	Annual Reserves Report
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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGINIT_OFF OGOUT_OFF	INFRSVOFF	I	Offshore inferred reserves	MMB BCF	8 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_IMP OGINIT_IMP	INFRT	infl	Canadian inflation rate	fraction	Canada	Office of Integrated Analysis and Forecasting
OGFOR_IMP OGINIT_IMP	INVESTRT	INVESTCR	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 (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); 8 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 (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 (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 (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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGFOR_IMP OGINIT_IMP	LEASCAN	EQUIP	Canadian lease equipment cost	1987$	Canada; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	LEASOFF	EQUIP	Offshore lease equipment cost	1987$ per project	Class (exploratory, developmental); 8 Lower 48 offshore subregions	Minerals Mangement Service
OGINIT_EOR OGOUT_EOR	LGQEORCOGC	--	Electric cogeneration capacity from EOR	MW	6 Lower 48 onshore regions; 2 usages (utility,non-utility)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	LGQEORCOGG	--	Electric cogeneration volumes from EOR	MWh	6 Lower 48 onshore regions; 2 usages (utility,non-utility)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	LGQEORCON	--	EOR crude oil consumption	MB	6 Lower 48 onshore regions	Not Used

Data

Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGINIT_EOR OGOUT_EOR	LGQEORNGC	--	EOR natural gas consumption	MCF	6 Lower 48 onshore regions; 2 EOR technologies (primary,other)	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	LGQEORNGP	--	EOR natural gas production	MCF	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGINIT_EOR OGOUT_EOR	LGQEORPR	--	EOR crude oil production	MB	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
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); 8 Lower 48 offshore subregions	Minerals Management Service
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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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	Derived from Natural Gas Annual
OGINIT_IMP	OGCNCAPH	--	Canadian capacities at borders - high WOP case	BCF	6 US/Canadian border crossing	Derived from Natural Gas Annual
OGINIT_IMP	OGCNCAPL	--	Canadian capacities at borders - low WOP case	BCF	6 US/Canadian border crossing	Derived from Natural Gas Annual
OGINIT_IMP OGOUT_IMP	OGCNCON	--	Canadian gas consumption	BCF	Canada; Fuel (oil, 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	Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNEXLOSS	--	Gas lost from US export to Canadian demand	BCF	Canada	Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNFLW	--	1989 flow volumes by border crossing	BCF	6 US/Canadian border crossings	Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNPARM1	--	Actual gas allocation factor	fraction	Canada	Office of Integrated Analysis and Forecasting
OGINIT_IMP	OGCNPARM2	--	Responsiveness of flow to different border prices	fraction	Canada	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
OGFOR_IMP OGINIT_IMP	OPERCAN	OPCOST	Canadian operating cost	$ 1987	Canada; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGFOR_OFF OGINIT_OFF	OPEROFF	OPCOST	Offshore operating cost	1987$ per well per year	Class (exploratory, developmental); 8 Lower 48 offshore subregions	Mineral Management Service
OGDCF_AK OGINIT_AK	PRJAK	n	Alaska oil project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_L48 OGINIT_L48	PRJL48	n	Lower 48 project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_OFF OGINIT_OFF	PRJOFF	n	Offshore project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
OGFOR_IMP OGINIT_IMP	PROVTXCAN	PROVRT	Canadian provincial corporate tax rates	fraction	Canada	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
OGFOR_IMP OGINIT_IMP	RCPRDCAN	m	Canada recovery period of intangible & tangible drill cost	Years	Canada	Petroleum Fiscal Systems in Canada - Energy, Mines & Resources
OGFOR_L48 OGINIT_L48	RCPRDL48	m	Lower 48 recovery period for intangible & tangible drill cost	Years	Lower 48 Onshore	U.S. Tax Code
OGFOR_OFF OGINIT_OFF	RCPRDOFF	m	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore	U.S. Tax Code
OGFOR_AK OGINIT_AK OGPRO_AK	RECRES	--	Alaska crude oil resources for known fields	MMB	Field	OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity*

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGINIT_LNG OGPROF_LNG	REGASCST	--	Regasification costs	1991$/MCF per year	Operational Stage; LNG destination points	National Petroleum Council
OGEXPAND_LNG OGINIT_LNG	REGASEXPAN	--	Regasification capacity	BCF	LNG destination points	National Petroleum Council
OGEXPAND_LNG OGINIT_LNG OGPROF_LNG	REGASSTAGE	--	Regasification stage	NA	NA	National Petroleum Council
OGINIT_IMP OGOUT_IMP	RESBASE	Q	Canadian recoverable resource estimate	MMB BCF	Canada	Canadian Geological Survey
OGFOR_IMP OGINIT_IMP	ROYRATE	ROYRT	Canadian royalty rate	fraction	Canada	Petroleum Fiscal Systems in Canada - Energy, Mines & Resources
OGDCF_AK OGFOR_L48 OGINIT_BFW	ROYRT	ROYRT	Alaska royalty rate	fraction	Alaska	U.S. Geological Survey
OGINIT_AK OGSEVR_AK	SEVTXAK	PRODTAX	Alaska severance tax rates	fraction	Alaska	U.S. Geological Survey
OGFOR_L48 OGINIT_L48	SEVTXL48	PRODTAX	Lower 48 onshore severance tax rates	fraction	6 Lower 48 onshore regions; Fuel (oil, 5 gas)	Commerce Clearing House
OGFOR_OFF OGINIT_OFF	SEVTXOFF	PRODTAX	Offshore severance tax rates	fraction	8 Lower 48 offshore subregions; Fuel (oil, gas)	Commerce Clearing House
OGEXP_CALC OGINIT_BFW	SPENDIRKLAG	--	1989 Lower 48 exploration & development expenditures	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	SPENDLAGL48	--	1989 Lower 48 onshore exploration & development expenditures	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (oil, 5 gas)	Office of Integrated Analysis and Forecasting

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGEXP_CALC OGINIT_BFW	SPENDLAGOFF	--	1989 offshore exploration & development expenditures	1987$	Class (exploratory, developmental); 8 Lower 48 offshore subregions; Fuel (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	SPENDRGNLAG	--	1989 Lower 48 exploration & development regional expenditures	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	SPEXLAGL48	--	1988 Lower 48 onshore exploration expenditures	1987$	Lower 48	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	SPEXLAGOFF2	--	1988 offshore exploration expenditures	1987$	Lower 48	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	SPEXOFFIRKLAG	--	1989 offshore exploration & development expenditures	1987$	Class (exploratory, developmental); 8 Lower 48 offshore subregions; Fuel (oil, gas)	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
OGFOR_IMP OGINIT_IMP OGFOR_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 (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); 8 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	8 Lower 48 offshore subregions	Commerce Clearing House
OGCOST_AK OGINIT_AK	TECHAK	TECH	Alaska technology factors	fraction	Alaska	Office of Integrated Analysis and Forecasting
OGFOR_IMP OGINIT_IMP	TECHCAN	TECH	Canada technology factors applied to costs	fraction	Canada	Office of Integrated Analysis and Forecasting
OGFOR_IMP OGINIT_IMP	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
OGFOR_L48 OGINIT_L48	TRANSL48	TRANS	Lower 48 onshore expected transportation costs	NA	6 Lower 48 onshore regions; Fuel (oil, 5 gas)	Not Used
OGFOR_OFF OGINIT_OFF	TRANSOFF	TRANS	Offshore expected transportation costs	NA	8 Lower 48 offshore subregions; Fuel (oil, gas)	Not Used
OGINIT_OFF OGOUT_OFF	UNRESOFF	Q	Offshore undiscovered resources	MMB BCF	8 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

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
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 (oil, 5 gas)	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	WDCFIRLAG	--	1989 Lower 48 regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions;	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	WDCFL48LAG	--	1989 Lower 48 onshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
OGEXP_CALC OGINIT_BFW	WDCFOFFIRKLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 8 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); 8 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 OGOUT_IMP	WELLAGCAN	WELLS	1989 wells drilled in Canada	Wells per year	Fuel (oil, 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 (oil, 5 gas)	Office of Oil & Gas

Data						
Subroutine	Variable Name		Description	Unit	Classification	Source
	Code	Text				
OGALL_OFF OGEXP_CALC OGINIT_OFF	WELLAGOFF	WELLSOFF	1989 offshore wells drilled	Wells per year	Class (exploratory, developmental); 8 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Oil & Gas
OGCANDCF OGFOR_IMP OGINIT_IMP	WELLLIFE	n	Canadian project life	Years	Canada	Office of Integrated Analysis and Forecasting
OGDCF_AK OGINIT_AK	XDCKAPAK	XDCKAP	Alaska intangible drill costs that must be depreciated	fraction	Alaska	U.S. Tax Code
OGFOR_L48 OGINIT_L48	XDCKAPL48	XDCKAP	Lower 48 intangible drill costs that must be depreciated	fraction	NA	U.S. Tax Code
OGFOR_OFF OGINIT_OFF	XDCKAPOFF	XDCKAP	Offshore intangible drill costs that must be depreciated	fraction	NA	U.S. Tax Code

Parameters					
Appendix B Equation Number	Subroutine	Parameter Name		Associated Variable	Classification
		Code	Text		
1	OGCST_L48	ALPHA_DRL	ln(δ0)	Constant coefficient	6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas)
1	OGCST_L48	b0_DRL	ln(δ2)	Depth per well	Fuel (oil, shallow gas, deep gas)
1	OGCST_L48	B1_DRL	ln(δ1)	Total onshore lower 48 wells drilled	Fuel (oil, shallow gas, deep gas)
1	OGCST_L48	B2_DRL	ln(δ3)	Time trend - proxy for technology	Fuel (oil, shallow gas, deep gas)
2	OGCST_L48	ALPHA_DRY	ln(δ0)	Constant coefficient	6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas)
2	OGCST_L48	B0_DRY	ln(δ2)	Depth per well	Fuel (oil, shallow gas, deep gas)
2	OGCST_L48	B1_DRY	ln(δ1)	Total onshore lower 48 wells drilled	Fuel (oil, shallow gas, deep gas)
2	OGCST_L48	B2_DRY	ln(δ3)	Time trend - proxy for technology	Fuel (oil, shallow gas, deep gas)
3	OGFOR_OFF	ALPHA_DRL_OFF	ln(δ0)	Constant coefficient	Fuel (oil, gas)
3	OGFOR_OFF	B0_DRL_OFF	ln(δ2)	Depth per well	Fuel (oil, gas)
3	OGFOR_OFF	B1_DRL_OFF	ln(δ1)	Offshore wells drilled in the Gulf of Mexico	NA
3	OGFOR_OFF	B2_DRL_OFF	ln(δ3)	Time trend - proxy for technology	Fuel (oil,gas)
4	OGFOR_OFF	ALPHA_DRL_OFF	ln(δ0)	Constant coefficient	Dry
4	OGFOR_OFF	B0_DRL_OFF	ln(δ2)	Depth per well	Dry
4	OGFOR_OFF	B1_DRL_OFF	ln(δ1)	Offshore wells drilled in the Gulf of Mexico	NA
4	OGFOR_OFF	B2_DRL_OFF	ln(δ3)	Time trend - proxy for technology	Dry
5	OGCST_L48	ALPHA_LEQ	ln(ϵ0)	Constant coefficient	6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas)
5	OGCST_L48	b1_LEQ	ln(ϵ1)	Lower 48 successful wells by fuel (oil, gas)	Fuel (oil, shallow gas, deep gas)
5	OGCST_L48	B2_LEQ	ln(ϵ2)	Time trend - proxy for technology	Fuel (oil, shallow gas, deep gas)
6	OGCST_L48	ALPHA_OPR	ln(ϕ0)	Constant coefficient	6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas)
6	OGCST_L48	B0_OPR	ln(ϕ2)	Depth per well	Fuel (oil, shallow gas, deep gas)

Parameters					
Appendix B Equation Number	Subroutine	Parameter Name		Associated Variable	Classification
		Code	Text		
6	OGCST_L48	B1_OPR	$\ln(\phi1)$	Lower 48 successful wells by fuel (oil, gas)	Fuel (oil, shallow gas, deep gas)
6	OGCST_L48	B2_OPR	$\ln(\phi3)$	Time trend - proxy for technology	Fuel (oil, shallow gas, deep gas)
92	OGCOMP_AD	ALPHA_AD	$\ln(\alpha0)+\ln(\alpha1)$	Constant coefficient plus regional dummy	Lower 48 regions (6 onshore, 3 offshore
92	OGCOMP_AD	BETA_AD	$\ln(\beta0)+\ln(\beta1)$	Crude oil production plus regional dummy	Lower 48 regions (6 onshore, 3 offshore)
117	OGOUT_IMP	AWELLS1	$-\rho * \beta0$	Exploratory constant coefficient	NA
117	OGOUT_IMP	BWELLS1	$-\rho * \beta1$	Exploratory oil DCF coefficient	NA
117	OGOUT_IMP	CWELLS1	$-\rho * \beta2$	Exploratory dummy constant	NA
117	OGOUT_IMP	AWELLS2	$-\rho * \beta0$	Developmental constant coefficient	NA
117	OGOUT_IMP	BWELLS2	$-\rho * \beta1$	Developmental oil DCF coefficient	NA
117	OGOUT_IMP	CWELLS2	$-\rho * \beta2$	Developmental dummy constant	NA
117	OGOUT_IMP	RHOCAN(1)	ρ	Exploratory auto correlation (Rho)	NA
117	OGOUT_IMP	RHOCAN(2)	ρ	Developmental auto correlation (Rho)	NA

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
OGINIT_IMP	OGCNCAP	Canadian capacities by border crossing	BCF	6 US/Canadian border crossings	NGTDM
OGINIT_IMP OGOUT_IMP	OGCNCON	Canada gas consumption	Oil: MMB Gas: BCF	Fuel(oil,gas)	NGTDM
OGINIT_IMP	OGCNDMLOSS	Gas lost from wellhead to Canadian demand	BCF	NA	NGTDM
OGINIT_IMP	OGCNEXLOSS	Gas lost from US export to Canadian demand	BCF	NA	NGTDM
OGINIT_IMP	OGCNFLW	1989 flow volumes by border crossing	BCF	6 US/Canadian border crossings	NGTDM
OGINIT_IMP	OGCNPARM1	Actual gas allocation factor	fraction	NA	NGTDM
OGINIT_IMP	OGCNPARM2	Responsiveness of flow to different border prices	fraction	NA	NGTDM
OGINIT_IMP	OGCNPMARKUP	Transportation mark-up at border	1987$	6 US/Canadian border crossings	NGTDM
OGINIT_RES OGOUT_IMP	OGELSCAN	Canadian price elasticity	fraction	Fuel (oil, gas)	NGTDM
OGINIT_RES OGOUT_L48 OGOUT_OFF	OGELSCO	Oil production elasticity	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGINIT_RES OGOUT_OFF	OGELSNGOF	Offshore nonassociated dry gas production elasticity	fraction	3 Lower 48 offshore regions	NGTDM
OGINIT_RES OGOUT_L48	OGELSNGON	Onshore nonassociated dry gas production elasticity	fraction	17 OGSM/NGTDM regions	NGTDM
OGOUT_EOR	OGEORCOGC	Electric cogeneration capacity from EOR	MWH	6 Lower 48 onshore regions	Industrial
OGOUT_EOR	OGEORCOGG	Electric cogeneration volumes from EOR	MWH	6 Lower 48 onshore regions	Industrial
OGCOMP_AD	OGPRDAD	Associated-dissolved gas production	BCF	6 Lower 48 onshore regions & 3 Lower 48 offshore regions	NGTDM
OGINIT_RES OGOUT_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

Outputs					
OGSM Subroutine	**Variable Name**	**Description**	**Unit**	**Classification**	**Passed To Module**
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
OGCOMP_EMIS OGOUT_EOR	OGQEORPR	Oil supply from EOR	MB	6 Lower 48 onshore regions	PMM
OGINIT_IMP OGOUT_IMP OGOUT_MEX	OGQNGEXP	Natural gas exports	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM
OGLNG_OUT OGOUT_IMP OGOUT_MEX	OGQNGIMP	Natural gas imports	BCF	3 US/Mexico border crossings; 4 LNG terminals	NGTDM
OGINIT_RES OGOUT_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

Appendix B. Mathematical Description

Calculation of Costs

Drilling Costs

Onshore

$$DRILLCOST_{r,k,t} = e^{\ln(\delta 0)_{r,k}} * WELLSON_{t-1}^{\delta 1_k} * e^{\delta 2_k * DEPTH_{r,k,t}} * e^{\delta 3_k * TIME_t} * DRILLCOST_{r,k,t-1}^{\rho_k} * e^{-\rho_k * \ln(\delta 0)_{r,k}} * WELLSON_{t-2}^{-\rho_k * \delta 1_k} * e^{-\rho_k * \delta 2_k * DEPTH_{r,k,t-1}} * e^{-\rho_k * \delta 3_k * TIME_{t-1}} * (1 + ECCDRL48) \tag{1}$$

$$DRYCOST_{r,k,t} = e^{\ln(\delta 0)_{r,k}} * WELLSON_{t-1}^{\delta 1_k} * e^{\delta 2_k * DEPTH_{r,k}} * e^{\delta 3_k * TIME_t} * DRYCOST_{r,k,t-1}^{\rho_k} * e^{-\rho_k * \ln(\delta 0)_{r,k}} * WELLSON_{t-2}^{-\rho_k * \delta 1_k} * e^{-\rho_k * \delta 2_k * DEPTH_{r,k}} * e^{-\rho_k * \delta 3_k * TIME_{t-1}} * (1 + ECCDRL48) \tag{2}$$

Offshore

$$DRILLCOST_{r,k,t} = e^{\ln(\delta 0)_{r,k}} * WELLSOFF_{t-1}^{\delta 1_k} * e^{\delta 2_k * DEPTH_{r,k}} * e^{\delta 3_k * TIME_t} * DRILLCOST_{r,k,t-1}^{\rho_k} * e^{-\rho_k * \ln(\delta 0)_{r,k}} * WELLSOFF_{t-2}^{-\rho_k * \delta 1_k} * e^{-\rho_k * \delta 2_k * DEPTH_{r,k}} * e^{-\rho_k * \delta 3_k * TIME_{t-1}} * (1 + ECCDRL48) \tag{3}$$

$$DRYCOST_{r,k,t} = e^{\ln(\delta 0)_{r,k}} * WELLSOFF_{t-1}^{\delta 1_k} * e^{\delta 2_k * DEPTH_{r,k}} * e^{\delta 3_k * TIME_t} * DRYCOST_{r,k,t-1}^{\rho_k} * e^{-\rho_k * \ln(\delta 0)_{r,k}} * WELLSOFF_{t-2}^{-\rho_k * \delta 1_k} * e^{-\rho_k * \delta 2_k * DEPTH_{r,k}} * e^{-\rho_k * \delta 3_k * TIME_{t-1}} * (1 + ECCDRL48) \tag{4}$$

Lease equipment costs

$$LEQC_{r,k,t} = e^{\ln(\epsilon 0)_{r,k}} * SUCWELL_{k,t-1}^{\epsilon 1_k} * e^{\epsilon 2_k * TIME_t} * LEQC_{r,k,t-1}^{\rho_k} * e^{-\rho_k * \ln(\epsilon 0)_{r,k}} * SUCWELL_{k,t-2}^{-\rho_k * \epsilon 1_k} * e^{-\rho_k * \epsilon 2_k * TIME_{t-1}} \tag{5}$$

Operating Costs

$$OPC_{r,k,t} = e^{\ln(\phi 0)_{r,k}} * SUCWELL_{k,t-1}^{\phi 1_k} * e^{\phi 2_k * DEPTH_{r,k}} * e^{\phi 3_k * TIME_t} * OPC_{r,k,t-1}^{\rho_k} * e^{-\rho_k * \ln(\phi 0)_{r,k}} * SUCWELL_{k,t-2}^{-\rho_k * \phi 1_k} * e^{-\rho_k * \phi 2_k * DEPTH_{r,k}} * e^{-\rho_k * \phi 3_k * TIME_{t-1}} * (1 + ECCOPL48) \tag{6}$$

Discounted Cash Flow Algorithm

Expected discounted cash flow

$$PROJDCF_{i,r,k,t} = (PVREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP - PVKAP - PVOPERCOST - PVABANDON - PVSIT - PVFIT)_{i,r,k,t} \quad (7)$$

Present value of expected revenues

$$PVREV_{i,r,k,t} = \sum_{T=t}^{t+n} \left[Q_{r,k,T} * \lambda * (P_{r,k,T} - TRANS_{r,k}) * \left[\frac{1}{1+disc}\right]^{T-t} \right], \; \lambda = \begin{cases} 1 & \text{if primary fuel} \\ COPRD & \text{if secondary fuel} \end{cases} \quad (8)$$

Present value of expected royalty payments

$$PVROY_{i,r,k,t} = ROYRT * PVREV_{i,r,k,t} \quad (9)$$

Present value of expected production taxes

$$PVPRODTAX_{i,r,k,t} = PVREV_{i,r,k,t} * (1 - ROYRT) * PRODTAX_{r,k} \quad (10)$$

Present value of expected costs

Drilling costs

$$\begin{aligned} PVDRILLCOST_{i,r,k,t} = \sum_{T=t}^{t+n} \Big[& [DRILL_{1,r,k,t} * SR_{1,r,k} * WELL_{1,k,T} + DRILL_{2,r,k,t} * SR_{2,r,k} * \\ & WELL_{2,k,T} + DRY_{1,r,k,t} * (1 - SR_{1,r,k}) * WELL_{1,k,T} + \\ & DRY_{2,r,k,t} * (1 - SR_{2,r,k}) * WELL_{2,k,T}] * \left(\frac{1}{1 + disc}\right)^{T-t} \Big] \end{aligned} \quad (11)$$

Lease equipment costs

$$PVEQUIP_{i,r,k,t} = \sum_{T=t}^{t+n} \left[EQUIP_t * (SR_{1,r,k} * WELL_{1,k,T} + SR_{2,r,k} * WELL_{2,k,T}) * \left[\frac{1}{1 + disc}\right]^{T-t} \right] \quad (12)$$

Capital costs

$$PVKAP_{i,r,k,t} = \sum_{T=t}^{t+n} \left[KAP_{i,r,k,T} * \left[\frac{1}{1 + disc}\right]^{T-t} \right] \quad (13)$$

Operating costs

$$PVOPERCOST_{i,r,k,t} = \sum_{T=t}^{t+n} \left[OPCOST_{i,r,k,t} * \sum_{k=1}^{T} [SR_{1,r,k} * WELL_{1,k,T} + SR_{2,r,k} * WELL_{2,k,T}] * \left(\frac{1}{1 + disc}\right)^{T-t} \right] \quad (14)$$

Abandonment costs

$$PVABANDON_{i,r,k,t} = \sum_{T=t}^{t+n} \left[COSTABN_{i,r,k} * \left[\frac{1}{1+disc}\right]^{T-t} \right] \quad (15)$$

Present value of expected tax base

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

Expected expensed costs

$$\begin{aligned} \text{XIDC}_{i,r,k,t} = {} & \text{DRILL}_{1,r,k,t} * (1 - \text{EXKAP}) * (1 - \text{XDCKAP}) * \text{SR}_{1,r,k} * \text{WELL}_{1,k,t} + \\ & \text{DRILL}_{2,r,k,t} * (1 - \text{DVKAP}) * (1 - \text{XDCKAP}) * \text{SR}_{2,r,k} * \text{WELL}_{2,k,t} \end{aligned} \tag{17}$$

Expected dry hole costs

$$\text{DHC}_{i,r,k,t} = \text{DRY}_{1,r,k,t} * (1 - \text{SR}_{1,r,k}) * \text{WELL}_{1,k,t} + \text{DRY}_{2,r,k,t} * (1 - \text{SR}_{2,r,k}) * \text{WELL}_{2,k,t} \tag{18}$$

Expected depreciable costs

$$\begin{aligned} \text{DEPREC}_{i,r,k,t} = \sum_{j=\beta}^{t} \Bigg[& \Big[(\text{DRILL}_{1,r,k,T} * \text{EXKAP} + \text{EQUIP}_{1,r,k,T}) * \text{SR}_{1,r,k} * \text{WELL}_{1,k,j} + \\ & (\text{DRILL}_{2,r,k,T} * \text{DVKAP} + \text{EQUIP}_{2,r,k,T}) * \text{SR}_{2,r,k} * \text{WELL}_{2,k,j} + \text{KAP}_{r,k,j} \Big] * \\ & \text{DEP}_{t-j+1} * \left(\frac{1}{1+\text{infl}}\right)^{t-j} * \left(\frac{1}{1+\text{disc}}\right)^{t-j} \Bigg], \end{aligned} \tag{19}$$

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

Present value of expected state income taxes

$$\text{PVSIT}_{i,r,k,t} = \text{PVTAXBASE}_{i,r,k,t} * \text{STRT} \tag{20}$$

Present value of expected federal income taxes

$$\text{PVFIT}_{i,r,k,t} = \text{PVTAXBASE}_{i,r,k,t} * (1 - \text{STRT}) * \text{FDRT} \tag{21}$$

Discounted cash flow for a representative developmental well

$$\text{DCF}_{2,r,k,t} = \text{PROJDCF}_{2,r,k,t} * \text{SR}_{2,r,k} \tag{22}$$

Discounted cash flow for a representative exploratory well

$$\text{DCF}_{1,r,k,t} = \text{PROJDCF}_{1,r,k,t} * \text{SR}_{1,r,k} \tag{23}$$

Lower 48 Onshore & Offshore Expenditures and Well Determination

Share of unconventional gas well

$$w_{i,r,k,t} = WELLS_{i,r,k,t-1} / \sum_k WELLS_{i,r,k,t-1}, \quad \text{for } k = 4,\ 5,\ 6 \tag{24}$$

Expected DCF for unconventional gas recovery

$$UGDCFON_{i,r,t} = \sum_{k=4}^{6} w_{i,r,k,t} DCFON_{i,r,k,t}, \quad \text{for } i = 1,2,\ r = 1,2,3,4,5 \tag{25}$$

Share of total wells

$$w_{i,r,k,t} = WELLS_{i,r,k,t-1} / \sum_k WELLS_{i,r,k,t-1}, \quad \text{for each } i,\ r,\ k \tag{26}$$

Regional expected discounted cash flow

$$RDCFON_{i,r,t} = \sum_k w_{i,r,k,t} * DCFON_{i,r,k,t}, \quad \text{for } i = 1,\ 2,\ r = \text{onshore regions},\ k = 1 \text{ thru } 6 \tag{27}$$

$$RDCFOFF_{i,r,t} = \sum_k w_{i,r,k,t} * DCFOFF_{i,r,k,t}, \quad \text{for } i = 1,\ 2,\ r = \text{offshore regions},\ k = 1,\ 2 \tag{28}$$

Regional share of total wells

$$w_{i,r,t} = WELLS_{i,r,t-1} / \sum_r WELLS_{i,r,t-1}, \quad \text{for each } i,\ r \tag{29}$$

National expected discounted cash flow

$$NDCFON_{i,t} = \sum_r w_{i,r,t} * RDCFON_{i,r,t}, \quad \text{for } i = 1,\ 2,\ r = \text{onshore regions} \tag{30}$$

$$NDCFOFF_{i,t} = \sum_r w_{i,r,t} * RDCFOFF_{i,r,t}, \quad \text{for } i = 1,\ 2,\ r = \text{offshore regions} \tag{31}$$

Lower 48 Onshore Exploration Expenditures by Region and Fuel Type

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}), \quad \text{for } i = 1, \ (r=1,\ k=1),\ (r=5,\ k=3) \tag{32}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM82_t), \quad \text{for } i = 1, \ r=1,3,5\ k=2 \tag{33}$$

$$SPENDON_{i,r,k,t} = \left[m0_{i,r,k} + (m1_{i,r,k} * RDCFON^2_{i,r,t})\right] * SHARE_{i,r,k}, \quad \text{for } i = 1, \; r = 1, \; k = 4,5,6 \tag{34}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1})), \quad \text{for } i = 1, \; r = 2, \; k = 1 \tag{35}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}), \quad \text{for } i = 1, \; (r=2,\ k=2-3),\ (r=3,\ k=4),\ (r=4,\ k=2),\ (r=5,\ k=1),\ (r=6,\ k=1-2) \tag{36}$$

$$SPENDON_{i,r,k,t} = \left[m0_{i,r,k} + (m1_{i,r,k} * RDCFON_{i,r,t})\right] * SHARE_{i,r,k}, \quad \text{for } i = 1, \; r=2, \; k=4,5,6 \tag{37}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + (m2_{i,r,k} * DUM87_t), \quad \text{for } i = 1, \; r = 3, \; k = 1 \tag{38}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + (m2_{i,r,k} * DUM84_t), \quad \text{for } i = 1, \; r = 3, \; k = 3 \tag{39}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-2})), \quad \text{for } i = 1, \; r=4, \; k=1,3 \tag{40}$$

$$SPENDON_{i,r,k,t} = \left[m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM80_t)\right] * SHARE_{i,r,k}, \quad \text{for } i = 1, \; r = 4, \; k = 4,5,6 \tag{41}$$

$$SPENDON_{i,r,k,t} = \left[m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,2,t})\right] * SHARE_{i,r,k}, \quad \text{for } i = 1, \; r = 5, \; k = 4,5,6 \tag{42}$$

Lower 48 Onshore Development Expenditures by Region and Fuel Type

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM87_t), \quad \text{for } i = 2, \; r=1,3,5 \; k=1 \tag{43}$$

$$SPENDON_{i,r,k,t} = \left[m0_{i,r,k} + (m1_{i,r,k} * UGDCFON^2_{i,r,t})\right] * SHARE_{i,r,k}, \quad \text{for } i = 2, \; r = 1, \; k = 4,5,6 \tag{44}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}), \quad \text{for } i = 2, \; (r=1,\ k=2),\ (r=2,\ k=1-3),\ (r=3,\ k=2),\ (r=5,\ k=3), (r=6,\ k=1) \tag{45}$$

$$SPENDON_{i,r,k,t} = \left[m0_{i,r,k} + (m1_{i,r,k} * RDCFON_{i,r,t})\right] * SHARE_{i,r,k}, \quad \text{for } i = 2, \; r=2,4 \; k=4,5,6 \tag{46}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}), \quad \text{for } i = 2, \; r = 3, \; k = 3 \tag{47}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM80_t), \quad \text{for } i = 2, r = 3, k = 4 \tag{48}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1})), \quad \text{for } i = 2, (r=4, k=1), (r=6, k=2) \tag{49}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM76_t), \quad \text{for } i = 2, r = 4, k = 2 \tag{50}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM79_t), \quad \text{for } i = 2, r = 4, k = 3 \tag{51}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM82_t) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + (m2_{i,r,k} * DUM82_{t-1})), \quad \text{for } i = 2, r = 5, k = 2 \tag{52}$$

$$SPENDON_{i,r,k,t} = \left[m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,2,t})\right] * SHARE_{i,r,k}, \quad \text{for } i = 2, r = 5, k = 4,5,6 \tag{53}$$

Offshore Exploration Expenditure Forecasting Equations

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} RDCFOFF_{i,r,t-1}} \text{ for } i = 1, r = 8, k = 1 \tag{54}$$

$$SPENDOFF_{i,r,k,t} = [e^{\alpha 0_{i,r} + \alpha 2_{i,r} DCFOFF_{i,r,2,t} + \alpha 1_{i,r} DUM82}] * [SHARE_{i,r,k}] \text{ for } i = 1, r = 9, k = 1,2 \tag{55}$$

$$SPENDOFF_{i,r,k,t} = [e^{\alpha 0_{i,r} + \alpha 2_{i,r} RDCFOFF_{i,r,t} + \alpha 1_{i,r} DUM89}] * [SHARE_{i,r,k}] \text{ for } i = 1, r = 10, k = 1,2 \tag{56}$$

$$SPENDOFF_{i,r,k,t} = [e^{\alpha 0_{i,r} + \alpha 2_{i,r} RDCFOFF_{i,r,t-1} + \alpha 1_{i,r} TREND}] * [SHARE_{i,r,k}] \text{ for } i = 1, r = 12, k = 1,2 \tag{57}$$

Offshore Development Expenditure Forecasting Equations

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} RDCFOFF_{i,r,t}}, \text{ for } i = 2, r = 8, k = 1 \tag{58}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t}}, \text{ for } i = 2, r = 9, k = 1 \tag{59}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} NDCFOFF_{i,t} + \alpha 2_{i,r,k} DUM82}, \text{ for } i = 2, r = 9, k = 2 \tag{60}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 2_{i,r,k} DCFOFF_{i,r,k,t-1} + \alpha 1_{i,r,k} DUM86}, \text{ for } i = 2, r = 10, k = 1 \tag{61}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 2_{i,r,k} DCFOFF_{i,r,k,t} + \alpha 1_{i,r,k} DUM81}, \text{ for } i = 2, r = 10, k = 2 \tag{62}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 2_{i,r,k} DCFOFF_{i,r,k,t-1} + \alpha 1_{i,r,k} TREND}, \text{ for } i = 2, r = 12, k = 1 \tag{63}$$

$$SPENDOFF_{i,r,k,t} = e^{\alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t-1}}, \text{ for } i = 2, r = 12, k = 2 \tag{64}$$

Calculation of total onshore wells

$$WELLSON_{i,r,k,t} = \frac{SPENDON_{i,r,k,t}}{COST_{i,r,k,t}}, \text{ for } i = 1, 2, r = \text{onshore regions}, k = 1 \text{ thru } 6 \tag{65}$$

Calculation of successful onshore wells

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, r = \text{onshore regions}, k = 1 \text{ thru } 6 \tag{66}$$

Calculation of onshore dry holes

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t}, \text{ for } i = 1, 2, r = \text{onshore regions}, k = 1 \text{ thru } 6 \tag{67}$$

Calculation of total offshore wells

$$WELLSOFF_{i,r,k,t} = \frac{SPENDOFF_{i,r,k,t}}{COST_{i,r,k,t}}, \text{ for } i = 1, 2, r = \text{offshore regions}, k = 1, 2 \tag{68}$$

Calculation of successful offshore wells

$$SUCWELSOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, r = \text{offshore regions}, k = 1, 2 \tag{69}$$

Calculation of offshore dry holes

$$DRYWELOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} - SUCWELSOFF_{i,r,k,t}, \text{ for } i = 1, 2, r = \text{offshore regions}, k = 1, 2 \tag{70}$$

Lower 48 Onshore & Offshore Reserve Additions

New reserve discoveries

$$FR1_{r,k,t} = FR1_{r,k,t-1}(1+\beta 1) * e^{-\delta 1_{r,k,t} * SW1_{r,k,t}} \tag{71}$$

$$\delta 1_{r,k,t} = \frac{(FR1_{r,k,t-1}(1+\beta 1) - FRMIN_{r,k}) * RSVGR}{QTECH_{r,k,t} - CUMRES1_{r,k,t-1}} \tag{72}$$

$$CUMRES1_{r,k,t} = \sum_{T=1}^{t} (NRD_{r,k,T} * RSVGR) \tag{73}$$

$$NDR_{r,k,t} = \frac{FR1_{r,k,t-1}(1+\beta 1)}{\delta 1_{r,k,t}} * \left(1 - e^{-\delta 1_{r,k,t} * SW1}\right) \tag{74}$$

Inferred reserves

$$I_{r,k,t} = NDR_{r,k,t} * (RSVGR - 1) \tag{75}$$

Reserve extensions

$$FR2_{r,k,t} = FR2_{r,k,t-1}(1+\beta 2) * e^{-\delta 2_{r,k,t} * SW2_{r,k,t}} \tag{76}$$

$$\delta 2_{r,k,t} = \frac{FR2_{r,k,t-1}(1+\beta 2) * DECFAC}{I_{r,k} * (1+TECH)^{t-T} + CUMRES2_{r,k,t-1} - CUMRES3_{r,k,t-1}} \tag{77}$$

$$CUMRES2_{r,k,t} = \sum_{T=1}^{t} I_{r,k,T} \tag{78}$$

$$EXT_{r,k,t} = \frac{FR2_{r,k,t-1}(1+\beta 2)}{\delta 2_{r,k,t}} * \left(1 - e^{-\delta 2_{r,k,t} * SW2}\right) \tag{79}$$

Reserve revisions

$$FR3_{r,k,t} = FR3_{r,k,t-1}(1+\beta 3) * e^{-\delta 3_{r,k,t} * SW3_{r,k,t}} \tag{80}$$

$$\delta 3_{r,k,t} = \frac{FR3_{r,k,t-1}(1+\beta 3) * DECFAC}{I_{r,k} * (1+TECH)^{t-T} + CUMRES2_{r,k,t-1} - CUMRES3_{r,k,t-1}} \tag{81}$$

$$CUMRES3_{r,k,t} = \sum_{T=1}^{t} (EXT_{r,k,T} + REV_{r,k,T}) \tag{82}$$

$$REV_{r,k,t} = \frac{FR3_{r,k,t-1}(1+\beta 3)}{\delta 3_{r,k,t}} * \left(1 - e^{-\delta 3_{r,k,t} * SW3}\right) \tag{83}$$

Total reserve additions

$$RA_{r,k,t} = \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t} d(SW1) + \int_0^{SW2_{r,k,t}} FR2_{r,k,t} d(SW2) + \int_0^{SW3_{r,k,t}} FR3_{r,k,t} d(SW3) \tag{84}$$

End-of-year reserves

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \tag{85}$$

Lower 48 Onshore & Offshore Production to Reserves Ratio

$$PR_{t+1} = \frac{(R_{t-1} * PR_t * (1 - PR_t)) + (PRNEW * RA_t)}{R_t} \tag{86}$$

Associated-dissolved gas production

$$ADGAS_{r,t} = e^{\ln(\alpha 0)_r + \ln(\alpha 1)_r * DUM86_t} * OILPROD_{r,t}^{\beta 0_r + \beta 1_r * DUM86_t} \tag{87}$$

Alaska Supply

Expected Costs

Drilling costs

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1) ** (t - T_b) \tag{88}$$

Lease equipment costs

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2) ** (t - T_b) \tag{89}$$

Operating costs

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3) ** (t - T_b) \tag{90}$$

Tariffs

$$\begin{aligned} TRR_t = {} & OPERCOST_t + DRR_t + TOTDEP_t + MARGIN_t + DEFRETREC_t + TXALLW_t \\ & NONTRANSREV_t + CARRYOVER_t \end{aligned} \tag{91}$$

$$TOTDEP_t = DEP_t * \left(DEPPROP_{t-2} + ADDS_{t-1} - PROCEEDS_{t-1} - TOTDEP_{t-1}\right) \tag{92}$$

$$MARGIN_t = ALLOW_t * THRUPUT_t + 0.064 * \left(DEPPROP_{NEW,t} + DEFRET_{NEW,t} - DEFTAX_{NEW,t}\right) \tag{93}$$

$$DEFRETREC_t = DEP_t * \left(DEFRET_{t-2} + INFLADJ_{t-1} + AFUDC_{t-1} - DEFRETREC_{t-1}\right) \tag{94}$$

$$TXALLW_t = TXRATE * \left(MARGIN_t + DEFRETREC_t\right) \tag{95}$$

Canadian Gas Trade

Net cash flow

$$NCF_{i,k,T} = (REV - ROY - DRILLCOST - EQUIPCOST - OPERCOST - DRYCOST - PROVTAX - FEDTAX)_{i,k,T} \tag{96}$$

Expected discounted cash flow

$$PROJDCF_{i,k,t} = \sum_{T=t}^{t+n} \left[NCF_{i,k,T} * \left[\frac{1}{1+disc} \right]^{T-t} \right] \tag{97}$$

Expected revenues

$$REV_{i,k,t} = Q_{k,t} * (P_{k,t} - TRANS_k) + Q_{COP,t} * (P_{COP,t} - TRANS_{COP}), \quad COP = \text{coproduct} \tag{98}$$

Expected royalty payments

$$ROY_{i,k,t} = ROYRT * REV_{i,k,t} \tag{99}$$

Expected costs

Successful drilling costs

$$DRILLCOST_{i,k,t} = DRILL_{1,k,t} * SR_{1,k} * WELL_{1,k,T} + DRILL_{2,k,t} * SR_{2,k} * WELL_{2,k,T} \tag{100}$$

Dry hole costs

$$DRYCOST_{i,k,t} = DRY_{1,k,t} * (1 - SR_{1,k}) * WELL_{1,k,T} + DRY_{2,k,t} * (1 - SR_{2,k}) * WELL_{2,k,T} \tag{101}$$

Lease equipment costs

$$EQUIP_{i,k,t} = EQUIP_t * \left(SR_{1,k} * WELL_{1,k,T} + SR_{2,k} * WELL_{2,k,T} \right) \tag{102}$$

Operating costs

$$OPERCOST_{i,k,t} = OPCOST_{i,k,t} * \sum_{k=1}^{T} \left[SR_{1,k} * WELL_{1,k,T} + SR_{2,k} * WELL_{2,k,T} \right] \tag{103}$$

Expected federal tax base

$$FIT_{i,k,t} = (REV - OPERCOST - XIDC - DEPREC - RA - DA - DRYCOST)_{i,k,t} \tag{104}$$

Expected expensed costs

$$XIDC_{i,k,t} = DRILL_{1,k,t} * EXP_1 * SR_{1,k} * WELL_{1,k,t} + DRILL_{2,k,t} * EXP_2 * SR_{2,k} * WELL_{2,k,t} \tag{105}$$

Expected depreciable costs

$$\begin{aligned} DEPREC_{i,k,t} = \sum_{j=\beta}^{t} \Bigg[& \big[(DRILL_{1,k,T} * (1 - EXP_1) + EQUIP_{1,k,T}) * SR_{1,k} * WELL_{1,k,j} + \\ & (DRILL_{2,k,T} * (1 - EXP_2) + EQUIP_{2,k,T}) * SR_{2,k} * WELL_{2,k,j}\big] * \\ & DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j}\Bigg], \\ & \beta = \begin{cases} T \text{ for } t \le T+m-1 \\ t-m+1 \text{ for } t > T+m-1 \end{cases} \end{aligned} \tag{106}$$

Expected resource allowance

$$RA_{i,k,t} = 0.25 * (REV_{i,k,t} - ROY_{i,k,t} - OPERCOST_{i,k,t} - DEPREC_{i,k,t}) \tag{107}$$

Expected depletion allowance

$$DA_{i,k,t} = (DRILLCOST_{i,k,t} + DRYCOST_{i,k,t}) * (1 - INVESTCR) * DEPLRT \tag{108}$$

Expected provincial tax base

$$PTI_{i,k,t} = FTI_{i,k,t} - ROY_{i,k,t} - RA_{i,k,t} - DRYCOST_{i,k,t} \tag{109}$$

Expected provincial income taxes

$$PROVTAX_{i,k,t} = FTI_{i,k,t} * PROVRT \tag{110}$$

Expected federal income taxes

$$FEDTAX_{i,k,t} = FTI_{i,k,t} * FDRT \tag{111}$$

Calculation of successful Canadian wells

$$\begin{aligned} WELLS_{k,t} = & \beta 0_k + \beta 1_k * DCF_{k,t} + \beta 2_k * DUM83_t + \rho_k * WELLS_{k,t-1} - \rho_k * \\ & \beta 0_k - \rho_k * \beta 1_k * DCF_{k,t-1} - \rho_k * \beta 2_k * DUM83_{t-1}, \\ & \text{for } k = \text{oil, gas} \end{aligned} \tag{112}$$

Reserve additions

$$FR_{k,t} = FR_{k,t-1} * e^{-\delta_{k,t} * WELLS_{k,t}} * (1 + FRTECH_k) \tag{113}$$

$$\delta_{k,t} = \frac{(FR_{k,t-1} - FRMIN_k) * RSVGR}{Q_k * (1.0 + TECH)^{t-T} - CUMRES_{k,t-1}} \tag{114}$$

$$RA_{k,t} = \frac{FR_{k,t-1}}{\delta_{k,t}} * (1 - e^{-\delta_{k,t} * WELLS_{k,t}}) \tag{115}$$

$$CUMRES_{k,t} = \sum_{T=1}^{t} RA_{k,T} \tag{116}$$

End-of-year reserves

$$R_{k,t} = R_{k,t-1} + RA_{k,t} - Q_{k,t} \tag{117}$$

Production to reserves ratio

$$PR_{k,t+1} = \frac{Q_{k,t} * (1 - PR_{k,t}) + PRNEW * RA_{k,t}}{R_{k,t}} \tag{118}$$

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Appendix D. Model Abstract

1. Model Name
   Oil and Gas Supply Module

2. Acronym
   OGSM

3. Description
   OGSM projects the following aspects of the crude oil and natural gas supply industry:
   - production
   - reserves
   - drilling activity
   - natural gas imports and exports

4. Purpose
   OGSM is used by the Oil and Gas Analysis Branch in the Office of Integrated Analysis and Forecasting as an analytic aid to support preparation of projections of reserves and production of crude oil and natural gas at the regional and national level. The annual projections and associated analyses appear in the Annual Energy Outlook (DOE/EIA-0383) of the Energy Information Administration. The projections also are provided as a service to other branches of the U.S. Department of Energy, the Federal Government, and non-Federal public and private institutions concerned with the crude oil and natural gas industry.

5. Date of Last Update
   1996

6. Part of Another Model
   National Energy Modeling System (NEMS)

7. Model Interface References
   Coal Module
   Electricity Module
   Industrial Module
   International Module
   Natural Gas Transportation and Distribution Model (NGTDM)
   Macroeconomic Module
   Petroleum Market Module (PMM)

8. Official Model Representative
   - Office: Integrating Analysis and Forecasting
   - Division: Energy Supply and Conversion
   - Branch: Oil and Gas Analysis
   - Model Contact: Ted McCallister
   - Telephone: (202) 586-4820

9. Documentation Reference
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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

    NEMS97

11. Energy Systems Described

    The OGSM forecasts oil and natural gas production activities for six onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling are treated separately, with exploratory drilling further differentiated as new field wildcats or other exploratory wells. New field wildcats are those wells drilled for a new field on a structure or in an environment never before productive. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proven areas and can result in extensions or revisions. Exploration yields new additions to the stock of reserves and development determines the rate of production from the stock of known reserves.

    The OGSM also projects natural gas trade via pipeline with Canada and Mexico, as well as liquefied natural gas (LNG) trade. U.S. natural gas trade with Canada is represented by six entry/exit points and trade with Mexico by three entry/exit points. Four LNG receiving terminals are represented.

12. Coverage
    - Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
    - Time Units/Frequency: Annually 1990 through 2015
    - 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 five major components
      - Lower 48 Onshore Supply Submodule
      - Lower 48 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 and Canada 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 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

    - 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 - American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-1990)*, Washington, D.C.

- Offshore Drilling Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Offshore Platform Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Offshore Lease Equipment and Operating Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Offshore Wells Drilled per Project - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Offshore Expected Recovery of Oil and Gas - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Canadian Royalty Rate, Corporate Tax Rate, Provincial Corporate Tax Rate- Energy Mines and Resources Canada. *Petroleum Fiscal Systems in Canada*, (Third Edition - 1988)

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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 - 1991)*, DOE/EIA-0815(80-91)

- Onshore Operating Cost - Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 1991)*, DOE/EIA-0815(80-91)

- Emissions Factors - Energy Information Administration.

- Canadian Gas Imports Border Crossing Point Capacities - Energy Information Administration. *Capacity and Service on the Interstate Natural Gas Pipeline System 1990*, DOE/EIA-0556

- 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*, (1977-1995), DOE/EIA-0216(77-95)

16. Computing Environment
    - Hardware Used: RS/6000
    - Operating System: UNIX
    - Language/Software Used: FORTRAN
    - Memory Requirement: Unknown
    - Storage Requirement: 992 bytes for input data storage; 180,864 bytes for output storage; 1280 bytes for code storage; and 5736 bytes for compiled code storage
    - Estimated Run Time: 9.8 seconds

17. Reviews conducted
    Independent Expert Reviews, Model Quality Audit

18. Status of Evaluation Efforts
    Not applicable

19. Bibliography
    See Appendix C of this document.

Appendix E. Parameter Estimation

The major portion of the lower 48 oil and gas supply component of the OGSM consists of a system of equations that are used to forecast exploratory and developmental drilling expenditures. The equations, the estimation techniques, and the statistical results are documented below. Documentation is also provided for the estimation of the drilling, lease equipment, and operating cost equations as well as the associated-dissolved gas equations and the Canadian oil and gas wells equations. Finally, the appendix documents the estimation of oil and gas supply price elasticities that are passed to the PMM and the NGTDM for (possible) use in their short run supply functions. The econometric software packages, SAS and TSP, were used for the estimations.

Onshore Expenditure Equations

Lower 48 Onshore Exploration Expenditures by Region and Fuel Type

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}), \quad \text{for } i = 1, \; (r=1,\ k=1),\ (r=5,\ k=3) \tag{1}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM82_t), \quad \text{for } i = 1, \; r=1,3,5\ \ k=2 \tag{2}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * RDCFON^2_{i,r,t}), \quad \text{for } i = 1, \; r = 1,\ k = UGR \tag{3}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1})), \quad \text{for } i = 1, \; r = 2,\ k = 1 \tag{4}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}), \quad \text{for } i = 1, \; (r=2,\ k=2-3),\ (r=4,\ k=2),\ (r=5,\ k=1),\ (r=6,\ k=1-2) \tag{5}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * RDCFON_{i,r,k,t}), \quad \text{for } i = 1, \; r=2,\ k=UGR \tag{6}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + (m2_{i,r,k} * DUM87_t), \quad \text{for } i = 1, \; r = 3,\ k = 1 \tag{7}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + (m2_{i,r,k} * DUM84_t), \quad \text{for } i = 1, \; r = 3,\ k = 3 \tag{8}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM7880_t) + (m3_{i,r,k} * DUM8286_t), \quad \text{for } i = 1, \; r = 3,\ k = 4 \tag{9}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-2})), \quad \text{for } i = 1, \; r=4,\ k=1,3 \tag{10}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * UGDCFON_{i,r,t}) + (m2_{i,r,k} * DUM80_t), \quad \text{for } i = 1, \; r = 4,\ k = UGR \tag{11}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,2,t}) , \quad \text{for } i = 1, \; r = 5, \; k = UGR \tag{12}$$

Lower 48 Onshore Development Expenditures by Region and Fuel Type

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM87_t) , \quad \text{for } i = 2, \; r=1,3,5 \; k=1 \tag{13}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM7579_t) + (m3_{i,r,k} * DUM8388_t) , \quad \text{for } i = 2, \; r = 1, \; k = 2 \tag{14}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * UGDCFON^2_{i,r,t}) , \quad \text{for } i = 2, \; r = 1, \; k = UGR \tag{15}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) , \quad \text{for } i = 2, \; (r=2, \; k=1-3), \; (r=5, \; k=3), (r=6, \; k=1) \tag{16}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * RDCFON_{i,r,t}) , \quad \text{for } i = 2, \; r=2,4 \; k=UGR \tag{17}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM8082_t) , \quad \text{for } i = 2, \; r = 3, \; k = 2 \tag{18}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) , \quad \text{for } i = 2, \; r = 3, \; k = 3 \tag{19}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM80_t) , \quad \text{for } i = 2, \; r = 3, \; k = 4 \tag{20}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1})) , \quad \text{for } i = 2, \; r = 4, \; k = 1 \tag{21}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM76_t) , \quad \text{for } i = 2, \; r = 4, \; k = 2 \tag{22}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM79_t) , \quad \text{for } i = 2, \; r = 4, \; k = 3 \tag{23}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM82_t) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + (m2_{i,r,k} * DUM82_{t-1})) , \quad \text{for } i = 2, \; r = 5, \; k = 2 \tag{24}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,2,t}) , \quad \text{for } i = 2, \; r = 5, \; k = UGR \tag{25}$$

$$SPENDON_{i,r,k,t} = m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t}) + (m2_{i,r,k} * DUM7983_t) + \rho_{i,r,k} * SPENDON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + (m1_{i,r,k} * DCFON_{i,r,k,t-1}) + (m2_{i,r,k} * DUM7983_{t-1})) , \quad \text{for } i = 2, \; r = 6, \; k = 2 \tag{26}$$

Draft Onshore Drilling Expenditure Equations for the Oil and Gas Supply Module of the National Energy Modeling System

As of December 8, 1995 Ned W. Dearborn (202) 586-6018		Intercept Value	Dummy Var. #1: Value	Dummy Var. #1: Years	Dummy Var. #2: Value	Dummy Var. #2: Years	Regressor #1: Coef.	Regressor #1: Name	AR?	Rho: Value
Region 1 (Northeast) Exploratory Exp. Equations	Oil	-7,122,930	N/A	N/A	N/A	N/A	72.367260	LAG(OSX1DCF)	No	N/A
	Sh.Gas	112,833,095	-64,413,053	1982 onward	N/A	N/A	43.097824	GSX1DCF	No	N/A
	Un.Gas	-5,399,461.80	N/A	N/A	N/A	N/A	.000021593	$(\_\_X1DCF)^2$	No	N/A
Region 1 (Northeast) Developmental Exp. Equations	Oil	6,959,289.80	-239,630,486	1987 onward	N/A	N/A	2,800.96	OSD1DCF	No	N/A
	Sh.Gas	-9,655,973.12	536,159,870	1975-1979	-192,980,736	1983-1988	1,686.56	GSD1DCF	No	N/A
	Un.Gas	38,015,651	N/A	N/A	N/A	N/A	.018005	$(\_\_D1DCF)^2$	No	N/A
Region 2 (Gulf Coast) Exploratory Expenditure Equations	Oil	11,412,307	N/A	N/A	N/A	N/A	78.613362	OGX2DCF	Yes	0.688177
	Sh.Gas	-574,253,931	N/A	N/A	N/A	N/A	451.024285	GSX2DCF	No	N/A
	Dp.Gas	56,957,341	N/A	N/A	N/A	N/A	16.945556	GDX2DCF	No	N/A
	Un.Gas	-36,377,813	N/A	N/A	N/A	N/A	14.524202	__X2DCF	No	N/A
Region 2 (Gulf Coast) Developmental Expenditure Equations	Oil	-543,798,278	N/A	N/A	N/A	N/A	6,227.75	OSD2DCF	No	N/A
	Sh.Gas	-593,711,452	N/A	N/A	N/A	N/A	4,039.68	GSD2DCF	No	N/A
	Dp.Gas	110,238,468	N/A	N/A	N/A	N/A	124.505471	GDD2DCF	No	N/A
	Un.Gas	-148,954,736	N/A	N/A	N/A	N/A	921.957292	__D2DCF	No	N/A
Region 3 (Midcontinent) Exploratory Expenditure Equations	Oil	82,891,831	-173,684,671	1987 onward	N/A	N/A	238.817079	LAG(OSX3DCF)	No	N/A
	Sh.Gas	145,001,520	-148,090,582	1982 onward	N/A	N/A	242.231489	GSX3DCF	No	N/A
	Dp.Gas	141,635,072	-287,888,372	1984 onward	N/A	N/A	6.935275	LAG(GDX3DCF)	No	N/A
	Un.Gas	-930,910.42	-3,549,355.37	1978-1980	-3,176216.79	1982-1986	0.325291	GTX3DCF	No	N/A
Region 3 (Midcontinent) Developmental Expenditure Equations	Oil	-414,158,062	-1,368,882,939	1987 onward	N/A	N/A	13,203.77	OSD3DCF	No	N/A
	Sh.Gas	431,824,139	1,340,485,945	1980-1982	N/A	N/A	5,218.64	GSD3DCF	No	N/A
	Dp.Gas	-29,005,226	N/A	N/A	N/A	N/A	262.913972	LAG(GD3DCF)	No	N/A
	Un.Gas	-43,215,579	31,710,201	1980 onward	N/A	N/A	45.745816	GTD3DCF	No	N/A

Draft Onshore Drilling Expenditure Equations for the Oil and Gas Supply Module of the National Energy Modeling System

As of December 8, 1995 Ned W. Dearborn (202) 586-6018		Intercept Value	Dummy Var. #1: Value	Dummy Var. #1: Years	Dummy Var. #2: Value	Dummy Var. #2: Years	Regressor #1: Coef.	Regressor #1: Name	AR?	Rho: Value
Region 4 (Southwest) Exploratory Expenditure Equations	Oil	63,311,810	N/A	N/A	N/A	N/A	165.259627	LAG(OSX4DCF)	Yes	.887183
	Sh.Gas	61,195,231	N/A	N/A	N/A	N/A	243.184775	GSX4DCF	No	N/A
	Dp.Gas	151,279,633	N/A	N/A	N/A	N/A	0.970914	LAG(GDX4DCF)	Yes	1.023543
	Un.Gas	-21,451,213	17,383,557	1980 onward	N/A	N/A	17,383,557	GUX4DCF	No	N/A
Region 4 (Southwest) Developmental Expenditure Equations	Oil	725,876,574	N/A	N/A	N/A	N/A	4,919.49	OSD4DCF	Yes	0.875220
	Sh.Gas	77,351,691	-384,093,895	1976	N/A	N/A	2,111.59	GSD4DCF	No	N/A
	Dp.Gas	82,623,199	-129,736,322	1979 onward	N/A	N/A	11.510333	GDD4DCF	No	N/A
	Un.Gas	-70,062,882	N/A	N/A	N/A	N/A	1,409.78	__D4DCF	No	N/A
Region 5 (Rocky Mountain) Exploratory Expenditure Equations	Oil	-12,727,861	N/A	N/A	N/A	N/A	242.693409	OSX5DCF	No	N/A
	Sh.Gas	236,970,726	-291,111,677	1982 onward	N/A	N/A	203.089609	GSX5DCF	No	N/A
	Dp.Gas	-41,023,162	N/A	N/A	N/A	N/A	1.971069	LAG(GDX5DCF)	No	N/A
	Un.Gas	-23,576,678	N/A	N/A	N/A	N/A	78.161227	GUX5DCF	No	N/A
Region 5 (Rocky Mountain) Developmental Expenditure Equations	Oil	206,103,133	-553,013,710	1987 onward	N/A	N/A	2,361.70	OSD5DCF	No	N/A
	Sh.Gas	460,425,626	-431,408,673	1982 onward	N/A	N/A	1,542.38	GSD5DCF	Yes	0.506810
	Dp.Gas	-13,577,657	N/A	N/A	N/A	N/A	6.834117	GDD5DCF	No	N/A
	Un.Gas	-49,213,027	N/A	N/A	N/A	N/A	1643.72	GUD5DCF	No	N/A
Region 6 (West Coast) Exploratory Exp.Eq.	Oil	-2,950,064.23	N/A	N/A	N/A	N/A	31.167006	OSX6DCF	No	N/A
	Sh.Gas	12,420,368	N/A	N/A	N/A	N/A	29.372770	GSX6DCF	No	N/A
Region 6 (West Coast) Developmental Exp.Eq.	Oil	186,711,689	N/A	N/A	N/A	N/A	835.804297	OSD6DCF	No	N/A
	Sh.Gas	-40,638,292	-50,798,282	1979-1983	N/A	N/A	178.949599	GSD6DCF	Yes	0.496977

Draft Onshore Drilling Expenditure Equations for the Oil and Gas Supply Module of the National Energy Modeling System: Econometric Statistics and Status

As of December 8, 1995
Ned W. Dearborn
(202) 586-6018

Equations	Fuel	No. of Obs.	Dummy Vars.	Lags and Other Variables	Pre-AR DW	Post-AR DW	Rho Sig.	Was AR Used?	Final DCF Sign	Final DCF Sig.	Final Adj. R^2
Region 1 (Northeast) Exploratory Exp. Equations	Oil	15		Lag	1.858	N/A	N/A	No	Positive	.0001	.9276
	Sh.Gas	16	1982-1990		1.714	N/A	N/A	No	Positive	.0103 .0004	.6014
	Un.Gas	13		$(\_\_X1DCF)^2$	2.064	N/A	N/A	No	Positive	.0001	.8800
Region 1 (Northeast) Developmental Exp. Equations	Oil	16	1987-1990		1.498	1.649	.4028	No	Positive	.0001 .0063	.8536
	Sh.Gas	16	1975-1979 1983-1988		1.947	N/A	N/A	No	Positive	.0632 .0022 .0104	.7963
	Un.Gas	13		$(\_\_D1DCF)^2$	1.173	1.891	.3159	No	Positive	.0001	.8272
Region 2 (Gulf Coast) Exploratory Expenditure Equations	Oil	16			0.709	1.898	.0123	Yes	Positive	.0266	.6979
	Sh.Gas	16			1.741	N/A	N/A	No	Positive	.0001	.7649
	Dp.Gas	16			2.091	N/A	N/A	No	Positive	.0001	.6332
	Un.Gas	13		__X2DCF	1.753	N/A	N/A	No	Positive	.0002	.6987
Region 2 (Gulf Coast) Developmental Expenditure Equations	Oil	16			1.178	1.551	.3543	No	Positive	.0001	.8572
	Sh.Gas	16			1.155	1.587	.1689	No	Positive	.0001	.6421
	Dp.Gas	16			2.111	N/A	N/A	No	Positive	.0001	.7436
	Un.Gas	13		__D2DCF	1.781	N/A	N/A	No	Positive	.0006	.6378
Region 3 (Midcontinent) Exploratory Expenditure Equations	Oil	15	1987-1990	Lag	1.702	N/A	N/A	No	Positive	.0271 .0594	.5053
	Sh.Gas	16	1982-1990		0.926	1.061	.0006	No/BCS	Positive	.0008 .0003	.6475
	Dp.Gas	15	1984-1990	Lag	1.591	1.744	.4832	No	Positive	.0011 .0043	.6649
	Un.Gas	13	1978-1980 1982-1986	GTX3DCF	1.935	N/A	N/A	No	Positive	.0050 .0170 .0159	.5215
Region 3 (Midcontinent) Developmental Expenditure Equations	Oil	16	1987-1990		1.332	1.429	.0532	No/BCS	Positive	.0036 .0275	.5912
	Sh.Gas	16	1980-1982		1.677	N/A	N/A	No	Positive	.0034 .0001	.8264
	Dp.Gas	15		Lag	1.596	1.969	.5367	No	Positive	.0007	.5715
	Un.Gas	13	1980-1990	GTD3DCF	2.024	N/A	N/A	No	Positive	.0084 .0915	.4669

Draft Onshore Drilling Expenditure Equations for the Oil and Gas Supply Module of the National Energy Modeling System: Econometric Statistics and Status

As of December 8, 1995
Ned W. Dearborn
(202) 586-6018

		No. of Obs.	Dummy Vars.	Lags and Other Variables	Pre-AR DW	Post-AR DW	Rho Sig.	Was AR Used?	Final DCF Sign	Final DCF Sig.	Final Adj. R^2
Region 4 (Southwest) Exploratory Expenditure Equations	Oil	15		Lag	1.091	1.913	.0001	Yes	Positive	.0608	.6938
	Sh.Gas	16			1.273	1.698	.0907	No/BCS	Positive	.0011	.5140
	Dp.Gas	15		Lag	0.294	1.301	.0001	Yes	Positive	.0022	.7917
	Un.Gas	12	1980-1990	GUX4DCF	1.181	1.946	.1903	No	Positive	.0053 .0539	.5202
Region 4 (Southwest) Developmental Expenditure Equations	Oil	16			0.659	1.685	.0001	Yes	Positive	.0796	.6680
	Sh.Gas	16	1976		1.257	1.706	.1901	No	Positive	.0001 .0218	.6717
	Dp.Gas	16	1979-1990		2.131	N/A	N/A	No	Positive	.0001 .0008	.7049
	Un.Gas	13		__D4DCF	1.851	N/A	N/A	No	Positive	.0016	.5757
Region 5 (Rocky Mountain) Exploratory Expenditure Equations	Oil	16			.972	N/A	N/A	No	Positive	.0001	.7983
	Sh.Gas	16	1982-1990		1.483	1.725	.4197	No	Positive	.0001 .0001	.8164
	Dp.Gas	15		Lag	1.620	N/A	N/A	No	Positive	.0008	.5594
	Un.Gas	13			1.452	1.653	.3994	No	Positive	.0040	.5037
Region 5 (Rocky Mountain) Developmental Expenditure Equations	Oil	16	1987-1990		2.536	2.057	.2706	No	Positive	.0001 .0010	.9115
	Sh.Gas	16	1982-1990		1.071	1.542	.0996	Yes	Positive	.0123 .0029	.7942
	Dp.Gas	16			2.073	N/A	N/A	No	Positive	.0001	.7835
	Un.Gas	13			1.152	1.371	.1888	No	Positive	.0023	.5472
Region 6 (West Coast) Exploratory Exp.Eq.	Oil	16			1.804	N/A	N/A	No	Positive	.0002	.6177
	Sh.Gas	16			1.878	N/A	N/A	No	Positive	.0007	.5377
Region 6 (West Coast) Developmental Exp.Eq.	Oil	16			1.501	1.967	.7622	No	Positive	.0001	.8129
	Sh.Gas	16	1979-1983		0.950	1.377	.0929	Yes	Positive	.0037 .0167	.6750

Offshore Expenditure Equations

Parameter estimates for the offshore expenditure forecasting equations were obtained using theTSP's Seemingly Unrelated Regression method. The results for each offshore region are given below.

Pacific

Exploration

$$LSPENDOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k} RDCFOFF_{i,r,k,t-1}, \text{ for } i = 1, r = 8, k = 1 \tag{27}$$

Parameter	Estimate	Standard Error	t-statistic
α0	17.9402	.232012	77.3243
α1	.279045E-07	.999985E-08	2.79049

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Mean of dependent variable = 18.3979	Std. error of regression = .591625
Std. dev. of dependent var. = .777172	R-squared = .372199
Sum of squared residuals = 4.55027	Durbin-Watson statistic = .927777
Variance of residuals = .350021	

Development

$$LSPENDOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k} RDCFOFF_{i,r,t}, \text{ for } i = 2, r = 8, k = 1 \tag{28}$$

Parameter	Estimate	Standard Error	t-statistic
α0	17.9593	.227513	78.9378
α1	.111280E-06	.227849E-07	4.88394

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Mean of dependent variable = 18.9492	Std. error of regression = .372665
Std. dev. of dependent var. = .650911	R-squared = .644896
Sum of squared residuals = 1.80543	Durbin-Watson statistic = .836535
Variance of residuals = .138879	

Western Gulf of Mexico

Exploration

$$LSPENDOFF_{i,r,k,t} = \alpha 0_{i,r} + \alpha 1_{i,r} DCFOFF_{i,r,2,t} + \alpha 2_{i,r} DUM82 \text{ for } i = 1,\ r = 9,\ k = 1,2 \qquad (29)$$

Parameter	Estimate	Standard Error	t-statistic
$\alpha 0$	19.4068	.312688	62.0645
$\alpha 1$	.350290E-07	.148540E-07	2.35822
$\alpha 2$	-.872022	.307087	-2.83966

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Mean of dependent variable = 19.5542	Std. error of regression = .501824
Std. dev. of dependent var. = .667761	R-squared = .391980
Sum of squared residuals = 3.52559	Durbin-Watson statistic = 1.45152
Variance of residuals = .251828	

Development - Oil

$$LSPENDOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t}, \text{ for } i = 2,\ r = 9,\ k = 1 \qquad (30)$$

Parameter	Estimate	Standard Error	t-statistic
$\alpha 0$	15.1774	.350463	43.3067
$\alpha 1$	.489784E-06	.106228E-06	4.61070

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Mean of dependent variable = 16.7286	Std. error of regression = .367245
Std. dev. of dependent var. = .606968	R-squared = .605782
Sum of squared residuals = 1.88816	Durbin-Watson statistic = 2.37875
Variance of residuals = .134869	

Development - Gas

$$LSPENDOFF_{i,r,k,t} = \alpha0_{i,r,k} + \alpha1_{i,r,k}NDCFOFF_{i,t} + \alpha2_{i,r,k}DUM82, \text{ for } i = 2,\ r = 9,\ k = 2 \tag{31}$$

Parameter	Estimate	Standard Error	t-statistic
α0	18.8803	.239689	78.7699
α1	.788467E-07	.430295E-07	1.83239
α2	-.490411	.210369	-2.33120

Mean of dependent variable = 19.0126
Std. dev. of dependent var. = .434007
Sum of squared residuals = 1.62505
Variance of residuals = .116075
Std. error of regression = .340698
R-squared = .338557
Durbin-Watson statistic = 1.69675

Central Gulf of Mexico

Exploration

$$LSPENDOFF_{i,r,k,t} = \alpha0_{i,r} + \alpha1_{i,r}RDCFOFF_{i,r,t} + \alpha2_{i,r}DUM89, \text{ for } i = 1,\ r = 10,\ k = 1,2 \tag{32}$$

Parameter	Estimate	Standard Error	t-statistic
α0	20.0397	.096929	206.745
α1	.361585E-07	.194169E-07	1.86221
α2	-.844842	.196200	-4.30602

Mean of dependent variable = 20.0013
Std. dev. of dependent var. = .443900
Sum of squared residuals = 1.33885
Variance of residuals = .095632
Std. error of regression = .309244
R-squared = .488141
Durbin-Watson statistic = 1.92762

Development - Oil

$$LSPENDOFF_{i,r,k,t} = \alpha0_{i,r,k} + \alpha1_{i,r,k}DCFOFF_{i,r,k,t-1} + \alpha2_{i,r,k}DUM86, \text{ for } i = 2,\ r = 10,\ k = 1 \tag{33}$$

Parameter	Estimate	Standard Error	t-statistic
α0	19.9828	.197034	101.418
α1	.771624E-07	.389498E-07	1.98107
α2	-.555048	.164449	-3.37520

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Mean of dependent variable = 20.1029
Std. dev. of dependent var. = .476060
Sum of squared residuals = 1.21092
Variance of residuals = .086495
Std. error of regression = .294100
R-squared = .590916
Durbin-Watson statistic = 1.50551

Development - Gas

$$LSPENDOFF_{i,r,k,t} = \alpha0_{i,r,k} + \alpha1_{i,r,k} DCFOFF_{i,r,k,t} + \alpha2_{i,r,k} DUM81, \text{ for } i = 2, r = 10, k = 2 \tag{34}$$

Parameter	Estimate	Standard Error	t-statistic
α0	20.3054	.175785	115.513
α1	.170862E-06	.554934E-07	3.07897
α2	-.912176	.176070	-5.18075

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Mean of dependent variable = 20.2558	Std. error of regression = .279990
Std. dev. of dependent var. = .410704	R-squared = .512182
Sum of squared residuals = 1.09752	Durbin-Watson statistic = 1.79689
Variance of residuals = .078394	

Deep Water Gulf of Mexico

Exploration

$$LSPENDOFF_{i,r,k,t} = \alpha0_{i,r} + \alpha1_{i,r} RDCFOFF_{i,r,t-1} + \alpha2_{i,r} TREND, \text{ for } i = 1, r = 12, k = 1,2 \tag{35}$$

Parameter	Estimate	Standard Error	t-statistic
α0	18.8262	.222349	84.6694
α1	.144612E-07	.750478E-08	1.92693
α2	.504133E-03	.182495E-03	2.76244

Mean of dependent variable = 19.3039	Std. error of regression = .648486
Std. dev. of dependent var. = .921132	R-squared = .466245
Sum of squared residuals = 5.88748	Durbin-Watson statistic = 2.20941
Variance of residuals = .420534	

Development - Oil

$$LSPENDOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t-1} + \alpha 2_{i,r,k} TREND, \text{ for } i = 2, r = 12, k = 1 \tag{36}$$

Parameter	Estimate	Standard Error	t-statistic
α0	16.4725	.339151	48.5697
α1	.546722E-07	.168628E-07	3.24218
α2	.404752E-03	.989956E-04	4.08859

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Mean of dependent variable = 17.7390
Std. dev. of dependent var. = .629309
Sum of squared residuals = 2.08567
Variance of residuals = .148977

Std. error of regression = .385975
R-squared = .594888
Durbin-Watson statistic = 2.12398

Development - Gas

$$LSPENDOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k} DCFOFF_{i,r,k,t-1}, \text{ for } i = 2, r = 12, k = 2 \tag{37}$$

Parameter	Estimate	Standard Error	t-statistic
α0	14.9066	.415808	35.8498
α1	.130858E-06	.286249E-07	4.57146

Mean of dependent variable = 16.6838
Std. dev. of dependent var. = .901396
Sum of squared residuals = 4.26753
Variance of residuals = .304823

Std. error of regression = .552108
R-squared = .595981
Durbin-Watson statistic = 1.65392

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 form of the equation was assumed to be log-linear. The equations were estimated in log-linear form using Seemingly Unrelated Regression (SUR) technique available in SAS. The forms of the equations are:

Onshore Regions 2 through 5

$$
\begin{aligned}
LDRILLCOST_{r,k,t} = \; & \ln(\delta 0)_{2,k} + \sum_{r=3}^{5} \ln(\delta 0)_{r,k} * DUM_r + \delta 1_k * LWELLSON_{t-1} \\
& + \delta 2_k * DEPTH_{r,k,t} + \delta 3_k * TIME_t + \rho_k * LDRILLCOST_{r,k,t-1} \\
& - \rho_k * \Big[\ln(\delta 0)_{2,k} + \sum_{r=3}^{5} \ln(\delta 0)_{r,k} * DUM_r + \delta 1_k LWELLSON_{t-2} \\
& + \delta 2_k * DEPTH_{r,k,t-1} + \delta 3_k * TIME_{t-1} \Big]
\end{aligned} \tag{38}
$$

Results

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

Variable/Parameter	Successful			Dry		
	Oil	Gas	Deep Gas	Oil	Gas	Deep Gas
LDRILLCOST	LOILC	LGASC	LDEPC	LDOLC	LDGSC	LDDPC
$\ln(\delta 0)_2$	O0	G0	D0	DO0	DG0	DD0
$\ln(\delta 0)_3$	O3	G3	D3	DO3	DG3	DD3
$\ln(\delta 0)_4$	O4	G4	D4	DO4	DG4	DD4
$\ln(\delta 0)_5$	O5	G5	D5	DO5	DG5	DD5
δ1	W_SGO	W_SGO	D1	W_DGO	W_DGO	DD1
δ2	O2	G2	D2	DO2	DG2	DD2
δ3	T_ALL	T_ALL	T_ALL	T_ALL	T_ALL	T_ALL
ρ	ORHO	GRHO	DRHO	DORHO	DGRHO	DDRHO

LOWER 48 ONSHORE DRILLING COST - REGIONS 2-5

MODEL Procedure
SUR Estimation

Nonlinear SUR Summary of Residual Errors

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin Watson
LGASC	6.667	61.33	0.80068	0.01305	0.11426	0.9359	0.9300	1.307
LOILC	5.667	62.33	0.53702	0.0086153	0.09282	0.9656	0.9630	1.191
LDGSC	6.667	61.33	0.96777	0.01578	0.12561	0.9487	0.9440	1.271
LDOLC	4.667	63.33	1.63616	0.02583	0.16073	0.9123	0.9072	1.432
LDEPC	7.167	60.83	2.74803	0.04517	0.21254	0.8272	0.8096	1.895
LDDPC	5.167	62.83	7.56055	0.12033	0.34688	0.6843	0.6633	1.855

Nonlinear SUR Parameter Estimates

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
G0	10.325980	0.74969	13.77	0.0001	CONSTANT - SHALLOW GAS
G2	0.00015052	0.00002161	6.97	0.0001	AVG DEPTH - SHALLOW GAS
G3	-0.573811	0.12064	-4.76	0.0001	DUMMY REGION 3 - SHALLOW GAS
G4	-0.576572	0.11130	-5.18	0.0001	DUMMY REGION 4 - SHALLOW GAS
G5	-0.348722	0.09356	-3.73	0.0004	DUMMY REGION 5 - SHALLOW GAS
GRHO	0.659289	0.07165	9.20	0.0001	AUTOCORRELATION - SHALLOW GAS
D0	6.082956	1.00949	6.03	0.0001	CONSTANT - DEEP GAS
D1	0.577466	0.08682	6.65	0.0001	LAGGED LOG TOTAL WELLS - DEEP GAS
D2	0.00021102	0.00001917	11.01	0.0001	AVG DEPTH - DEEP GAS
D3	-0.209031	0.08785	-2.38	0.0205	DUMMY REGION 3 - DEEP GAS
D4	-0.405231	0.09946	-4.07	0.0001	DUMMY REGION 4 - DEEP GAS
D5	0.204136	0.09896	2.06	0.0434	DUMMY REGION 5 - DEEP GAS
DRHO	0.295817	0.10180	2.91	0.0051	AUTOCORRELATION - DEEP GAS
O0	8.927733	0.72772	12.27	0.0001	CONSTANT - OIL
O2	0.00035097	0.0000187	18.77	0.0001	AVG DEPTH - OIL
O3	-0.204729	0.09331	-2.19	0.0320	DUMMY REGION 3 - OIL
O4	-0.142748	0.07752	-1.84	0.0703	DUMMY REGION 4 - OIL
ORHO	0.692312	0.07288	9.50	0.0001	AUTOCORRELATION - OIL
DG0	7.647188	0.91397	8.37	0.0001	CONSTANT - DRY SHALLOW GAS
DG2	0.00023738	0.00003051	7.78	0.0001	AVG DEPTH - DRY SHALLOW GAS
DG3	-0.500289	0.12829	-3.90	0.0002	DUMMY REGION 3 - DRY SHALLOW GAS
DG4	-0.360355	0.11178	-3.22	0.0020	DUMMY REGION 4 - DRY SHALLOW GAS
DG5	-0.197634	0.08996	-2.20	0.0318	DUMMY REGION 5 - DRY SHALLOW GAS
DGRHO	0.639874	0.06755	9.47	0.0001	AUTOCORRELATION - DRY SHAL. GAS
DD0	6.604710	1.17839	5.60	0.0001	CONSTANT - DRY DEEP GAS
DD1	0.637369	0.10632	6.00	0.0001	LAGGED LOG TOTAL WELLS - DRY DEEP GAS
DD2	0.00012392	0.00002027	6.11	0.0001	AVG DEPTH - DRY DEEP GAS
DD4	-0.199621	0.10129	-1.97	0.0531	DUMMY REGION 4 - DRY DEEP GAS
DD5	0.551357	0.10064	5.48	0.0001	DUMMY REGION 5 - DRY DEEP GAS
DO0	7.065139	0.91178	7.75	0.0001	CONSTANT - DRY OIL
DO2	0.00030270	0.00003555	8.51	0.0001	AVG DEPTH - DRY OIL
DO3	-0.397469	0.14637	-2.72	0.0085	DUMMY REGION 3 - DRY OIL
DORHO	0.680692	0.07296	9.33	0.0001	AUTOCORRELATION - DRY OIL
W_SGO	0.221945	0.06258	3.55	0.0007	LAG LOG TOTAL WELLS - SUC. SHAL. GAS & OIL
W_DGO	0.371348	0.07888	4.71	0.0001	LAG LOG TOTAL WELLS - DRY SHAL. GAS & OIL
T_ALL	-0.026888	0.0056351	-4.77	0.0001	TIME TREND

Number of Observations		Statistics for System	
Used	68	Objective	5.0727
Missing	0	Objective*N	344.9429

Onshore Regions 1 and 6

$$\begin{aligned}
LDRILLCOST_{r,k,t} = {} & \ln(\delta 0)_{1,k} + \ln(\delta 0)_{6,k} * DUM_6 + \delta 1_k * LWELLSON_{t-1} \\
& + \delta 2_k * DEPTH_{r,k,t} + \delta 3_k * TIME_t + \rho_k * LDRILLCOST_{r,k,t-1} \\
& - \rho_k * \left[\ln(\delta 0)_{1,k} + \ln(\delta 0)_{6,k} * DUM_6 + \delta 1_k LWELLSON_{t-2} \right. \\
& \left. + \delta 2_k * DEPTH_{r,k,t-1} + \delta 3_k * TIME_{t-1} \right]
\end{aligned} \tag{39}$$

Results

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

Variable/Parameter	Successful		Dry	
	Oil	Gas	Oil	Gas
LDRILLCOST	LOILC	LGASC	LDOLC	LDGSC
$\ln(\delta 0)_1$	O0	G0	DO0	DG0
$\ln(\delta 0)_6$	O6	G6	DO6	DG6
$\delta 1$	W_OIL	W_GAS	W_DRY	W_DRY
$\delta 2$	D_ALL	D_ALL	D_ALL	D_ALL
$\delta 3$	T_ALL	T_ALL	T_ALL	T_ALL
ρ	ORHO	GRHO	DORHO	DGRHO

LOWER 48 ONSHORE DRILLING COST - REGIONS 1&6

MODEL Procedure
SUR Estimation

Nonlinear SUR Summary of Residual Errors

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin Watson
LGASC	4.5	29.5	0.23562	0.0079872	0.08937	0.9826	0.9805	1.551
LOILC	4.5	29.5	0.35381	0.01199	0.10951	0.6234	0.5788	1.596
LDGSC	4	30	0.49474	0.01649	0.12842	0.9423	0.9365	1.651
LDOLC	3	31	1.72973	0.05580	0.23622	0.7733	0.7586	1.233

Nonlinear SUR Parameter Estimates

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
G0	8.374207	0.80760	10.37	0.0001	CONSTANT - SHALLOW GAS
G6	0.639338	0.13536	4.72	0.0001	DUMMY REGION 6 - SHALLOW GAS
GRHO	0.451936	0.12046	3.75	0.0008	AUTOCORRELATION - SHALLOW GAS
O0	9.712163	0.81072	11.98	0.0001	CONSTANT - OIL
O6	0.397184	0.08606	4.62	0.0001	DUMMY REGION 6 - OIL
ORHO	0.480526	0.09237	5.20	0.0001	AUTOCORRELATION - OIL
DG0	8.356993	0.89454	9.34	0.0001	CONSTANT - DRY SHALLOW GAS
DG6	0.331623	0.14184	2.34	0.0262	DUMMY REGION 6 - DRY SHALLOW GAS
DGRHO	0.408926	0.13792	2.96	0.0059	AUTOCORRELATION - DRY SHALLOW GAS
DO0	7.598299	0.87381	8.70	0.0001	CONSTANT - DRY OIL
DO6	0.867189	0.08098	10.71	0.0001	DUMMY REGION 6 - DRY OIL
D_ALL	0.00021980	0.00004557	4.82	0.0001	AVG DEPTH
W_GAS	0.279384	0.06902	4.05	0.0004	LAGGED LOG TOTAL WELLS - SHALLOW GAS
W_OIL	0.131556	0.07080	1.86	0.0733	LAGGED LOG TOTAL WELLS - OIL
W_DRY	0.261473	0.07808	3.35	0.0022	LAGGED LOG TOTAL WELLS - DRY
T_ALL	-0.021851	0.0058953	-3.71	0.0008	TIME TREND

Number of Observations		Statistics for System	
Used	34	Objective	3.2443
Missing	0	Objective*N	110.3054

Offshore Gulf of Mexico

$$\begin{aligned} LDRILLCOST_{k,t} = \; & \ln(\delta 0)_k + \delta 1_k * LWELLSOFF_{t-1} + \delta 2_k * DEPTH_{k,t} \\ & + \delta 3_k * TIME_t + \rho_k * LDRILLCOST_{k,t-1} - \rho_k * [\ln(\delta 0)_k \\ & + \delta 1_k LWELLSOFF_{t-2} + \delta 2_k * DEPTH_{k,t-1} + \delta 3_k * TIME_{t-1}] \end{aligned} \tag{40}$$

Results

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

Variable/Parameter	Oil	Gas	Dry
LDRILLCOST	LOILC	LGASC	LDOLC
$\ln(\delta 0)$	O0	G0	D0
$\delta 1$	W_ALL	W_ALL	W_ALL
$\delta 2$	D_ALL	D_ALL	D_ALL
$\delta 3$	T_ALL	T_ALL	T_ALL
ρ	ORHO	GRHO	DRHO

LOWER 48 OFFSHORE DRILLING COST - GULF

MODEL Procedure
SUR Estimation

Nonlinear SUR Summary of Residual Errors

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin Watson
LGASC	2	9	0.16325	0.01814	0.13468	0.7104	0.6782	2.282
LOILC	2	9	0.03517	0.0039083	0.06252	0.9271	0.9190	2.138
LDRYC	2	9	0.09637	0.01071	0.10348	0.8714	0.8572	2.158

Nonlinear SUR Parameter Estimates

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
G0	12.367200	0.75098	16.47	0.0001	CONSTANT - GAS
D0	12.243413	0.75156	16.29	0.0001	CONSTANT - DRY GAS
O0	12.203351	0.74653	16.35	0.0001	CONSTANT - OIL
D_ALL	0.000059431	0.00002514	2.36	0.0424	DEPTH
W_ALL	0.421795	0.09320	4.53	0.0014	LAGGED LOG TOTAL WELLS
T_ALL	-0.042342	0.0065106	-6.50	0.0001	TIME TREND

Number of Observations		Statistics for System	
Used	11	Objective	2.3169
Missing	0	Objective*N	25.4863

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 Seemingly Unrelated Regression (SUR) technique available in SAS. Where necessary, equations were estimated in generalized difference form to correct for first order serial correlation. The forms of the equations are:

Onshore Regions 2 through 5

$$\begin{aligned} LLEQC_{r,k,t} = {} & \ln(\epsilon 0)_{2,k} + \sum_{r=3}^{5} \ln(\epsilon 0)_{r,k} * DUM_r + \epsilon 1_k * LSUCWELL_{k,t} \\ & + \epsilon 2_k * TIME_t + \rho_k * LLEQC_{r,k,t-1} - \rho_k * \Big[\ln(\epsilon 0)_{2,k} \\ & + \sum_{r=3}^{5} \ln(\epsilon 0)_{r,k} * DUM_r + \epsilon 1_k LSUCWELL_{k,t-2} + \epsilon 2_k * TIME_{t-1} \Big] \end{aligned} \tag{41}$$

Results

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

Variable/Parameter	Oil	Gas	Deep Gas
LLEQC	LOILC	LSGASC	LDGASC
$\ln(\epsilon 0)_2$	O0	SG0	DG0
$\ln(\epsilon 0)_3$	O3	SG3	DG3
$\ln(\epsilon 0)_4$	O4	SG4	DG4
$\ln(\epsilon 0)_5$	O5	SG5	DG5
$\epsilon 1$	W0	W0	W0
$\epsilon 2$	T0	T0	T0
ρ	ORHO	SGRHO	DGRHO

L48 ONSHORE LEASE EQUIPMENT COST DATA, REGIONS 2-5

MODEL Procedure
SUR Estimation

Nonlinear SUR Summary of Residual Errors

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin Watson
LSGASC	5.667	70.33	0.76706	0.01091	0.10443	0.8441	0.8337	1.953
LOILC	4.667	71.33	0.17752	0.0024886	0.04989	0.9571	0.9548	1.789
LDGASC	2.667	73.33	0.48731	0.0066451	0.08152	0.6730	0.6656	2.485

Nonlinear SUR Parameter Estimates

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
SG0	9.721436	0.25249	38.50	0.0001	CONSTANT - SHALLOW GAS
SG3	-0.228770	0.07539	-3.03	0.0034	DUMMY REGION 3 - SHALLOW GAS
SG4	-0.129545	0.07692	-1.68	0.0966	DUMMY REGION 4 - SHALLOW GAS
SG5	0.199034	0.07672	2.59	0.0115	DUMMY REGION 5 - SHALLOW GAS
SGRHO	0.664950	0.06405	10.38	0.0001	AUTOCORRELATION - SHALLOW GAS
O0	10.277236	0.26494	38.79	0.0001	CONSTANT - OIL
O4	0.281201	0.03897	7.22	0.0001	DUMMY REGION 4 - OIL
O5	0.463313	0.03909	11.85	0.0001	DUMMY REGION 5 - OIL
ORHO	0.646574	0.06129	10.55	0.0001	AUTOCORRELATION - OIL
DG0	10.483673	0.25133	41.71	0.0001	CONSTANT - DEEP GAS
DGRHO	0.698442	0.04972	14.05	0.0001	AUTOCORRELATION - DEEP GAS
T0	-0.017028	0.0033965	-5.01	0.0001	TIME TREND
W0	0.120358	0.02418	4.98	0.0001	LAGGED SUCCESSFUL WELLS

Number of Observations		Statistics for System	
Used	76	Objective	2.8214
Missing	0	Objective*N	214.4283

Onshore Regions 1 and 6

$$\begin{aligned}LLEQC_{r,k,t} = {} & \ln(\epsilon 0)_{1,k} + \ln(\epsilon 0)_{6,k} * DUM_6 + \epsilon 1_k * LSUCWELL_{k,t} \\ & + \epsilon 2_k * TIME_t + \rho_k * LLEQC_{r,k,t-1} - \rho_k * \big[\ln(\epsilon 0)_{1,k} \\ & + \ln(\epsilon 0)_{6,k} * DUM_6 + \epsilon 1_k LSUCWELL_{k,t-2} + \epsilon 2_k * TIME_{t-1}\big]\end{aligned} \tag{42}$$

Results

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

Variable/Parameter	Oil	Gas
LLEQC	LOILC	LSGASC
$\ln(\epsilon 0)_1$	O0	SG0
$\ln(\epsilon 0)_6$	O6	SG6
$\epsilon 1$	W0	W0
$\epsilon 2$	T0	T0
ρ	ORHO	SGRHO

L48 ONSHORE LEASE EQUIPMENT COST DATA, REGIONS 1&6

MODEL Procedure
SUR Estimation

Nonlinear SUR Summary of Residual Errors

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin Watson
LSGASC	4	34	0.33267	0.0097845	0.09892	0.9108	0.9030	2.419
LOILC	4	34	0.09134	0.0026864	0.05183	0.9617	0.9583	1.381

Nonlinear SUR Parameter Estimates

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
SG0	9.973246	0.45707	21.82	0.0001	INTERCEPT - SHALLOW GAS
SG6	0.504009	0.11253	4.48	0.0001	DUMMY REGION 6 - SHALLOW GAS
SGRHO	0.714153	0.08399	8.50	0.0001	AUTOCORRELATION - SHALLOW GAS
O0	11.178442	0.47559	23.50	0.0001	INTERCEPT - OIL
O6	0.470496	0.06012	7.83	0.0001	DUMMY REGION 6 - OIL
ORHO	0.717743	0.09023	7.95	0.0001	AUTOCORRELATION - OIL
T0	-0.018528	0.0076118	-2.43	0.0203	TIME TREND
W0	0.021374	0.03987	0.54	0.5953	LAGGED SUCCESSFUL WELLS

Number of Observations		Statistics for System	
Used	38	Objective	1.7799
Missing	0	Objective*N	67.6376

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 Seemingly Unrelated Regression (SUR) technique available in SAS. The forms of the equations are:

Onshore Regions 2 through 5

$$
\begin{aligned}
LOPC_{r,k,t} = \; & \ln(\phi 0)_{2,k} + \sum_{r=3}^{5} \ln(\phi 0)_{r,k} * DUM_r + \phi 1_k * LSUCWELL_{k,t-1} \\
& + \phi 2_k * DEPTH_{r,k,t} + \phi 3_k * TIME_t + \rho_k * LOPC_{r,k,t-1} \\
& - \rho_k * \Big[\ln(\phi 0)_{2,k} + \sum_{r=3}^{5} \ln(\phi 0)_{r,k} * DUM_r + \phi 1_k LSUCWELL_{k,t-2} \\
& + \phi 2_k * DEPTH_{r,k,t-1} + \phi 3_k * TIME_{t-1} \Big]
\end{aligned} \tag{43}
$$

Results

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

Variable/Parameter	Oil	Gas	Deep Gas
LLEQC	LOILC	LSGASC	LDGASC
$\ln(\phi 0)_2$	O0	SG0	DG0
$\ln(\phi 0)_3$	O3	SG3	DG3
$\ln(\phi 0)_4$	O4	SG4	DG4
$\ln(\phi 0)_5$	O5	SG5	DG5
$\phi 1$	W_SGO	W_SGO	W_SGO
$\phi 2$	O1	SG1	DG1
$\phi 3$	T_ALL	T_ALL	T_ALL
ρ	ORHO	SGRHO	DGRHO

L48 ONSHORE OPERATING COST DATA, REGIONS 2-5

MODEL Procedure
SUR Estimation

Nonlinear SUR Summary of Residual Errors

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin Watson
LSGASC	5.833	66.17	0.43560	0.0065834	0.08114	0.8329	0.8207	2.272
LOILC	5.833	66.17	0.14784	0.0022343	0.04727	0.9626	0.9599	1.638
LDGASC	5.333	66.67	0.41407	0.0062111	0.07881	0.8524	0.8428	2.335

Nonlinear SUR Parameter Estimates

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
SG0	8.777050	0.26775	32.78	0.0001	CONSTANT - SHALLOW GAS
SG3	-0.202353	0.07997	-2.53	0.0138	DUMMY REGION 3 - SHALLOW GAS
SG4	-0.114140	0.06125	-1.86	0.0668	DUMMY REGION 4 - SHALLOW GAS
SG5	0.123381	0.06115	2.02	0.0477	DUMMY REGION 5 - SHALLOW GAS
SGRHO	0.695104	0.06137	11.33	0.0001	AUTOCORRELATION - SHALLOW GAS
O0	8.802819	0.28599	30.78	0.0001	CONSTANT - OIL
O3	-0.499312	0.05795	-8.62	0.0001	DUMMY REGION 3 - OIL
O4	-0.382850	0.05715	-6.70	0.0001	DUMMY REGION 4 - OIL
O5	-0.101609	0.05717	-1.78	0.0801	DUMMY REGION 5 - OIL
ORHO	0.726669	0.06864	10.59	0.0001	AUTOCORRELATION - OIL
DG0	8.342671	0.41984	19.87	0.0001	CONSTANT - DEEP GAS
DG1	0.000010088	4.82678E-6	2.09	0.0404	AVERAGE DEPTH - DEEP GAS
DG3	-0.251100	0.04557	-5.51	0.0001	DUMMY REGION 3 - DEEP GAS
DGRHO	0.532580	0.08006	6.65	0.0001	AUTOCORRELATION - DEEP GAS
W_SGO	0.129416	0.02508	5.16	0.0001	LAG SUC. WELLS - SHALLOW GAS & OIL
W_DG	0.238847	0.04179	5.72	0.0001	LAG SUC. WELLS - DEEP GAS
T_ALL	-0.012881	0.0037069	-3.47	0.0009	TIME TREND

Number of Observations		Statistics for System	
Used	72	Objective	2.6703
Missing	0	Objective*N	192.2594

Onshore Regions 1 and 6

$$\begin{aligned} LOPC_{r,k,t} = {} & \ln(\phi 0)_{1,k} + \ln(\phi 0)_{6,k} * DUM_6 + \phi 1_k * LWELLSON_{k,t-1} \\ & + \phi 2_k * DEPTH_{r,k,t} + \phi 3_k * TIME_t + \rho_k * LOPC_{r,k,t-1} \\ & - \rho_k * \Big[\ln(\phi 0)_{1,k} + \ln(\phi 0)_{6,k} * DUM_6 + \phi 1_k * LWELLSON_{k,t-2} \\ & + \phi 2_k * DEPTH_{r,k,t-1} + \phi 3_k * TIME_{t-1} \Big] \end{aligned} \tag{44}$$

Results

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

Variable/Parameter	Successful		Dry	
	Oil	Gas	Oil	Gas
LDRILLCOST	LOILC	LGASC	LDOLC	LDGSC
$\ln(\phi 0)_1$	O0	G0	DO0	DG0
$\ln(\phi 0)_6$	O6	G6	DO6	DG6
$\phi 1$	W_OIL	W_GAS	W_DRY	W_DRY
$\phi 2$	D_ALL	D_ALL	D_ALL	D_ALL
$\phi 3$	T_ALL	T_ALL	T_ALL	T_ALL
ρ	ORHO	GRHO	DORHO	DGRHO

L48 ONSHORE OPERATING COST DATA, REGIONS 1&6

MODEL Procedure
SUR Estimation

Nonlinear SUR Summary of Residual Errors

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin Watson
LSGASC	3.5	34.5	0.34595	0.01003	0.10014	0.8729	0.8636	2.037
LOILC	3.5	34.5	0.33608	0.0097414	0.09870	0.9214	0.9157	2.436

Nonlinear SUR Parameter Estimates

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
SG0	7.492457	0.38254	19.59	0.0001	CONSTANT - SHALLOW GAS
SG6	0.457907	0.04108	11.15	0.0001	DUMMY REGION 6 - SHALLOW GAS
SGRHO	0.208539	0.15749	1.32	0.1943	AUTOCORRELATION - SHALLOW GAS
O0	7.642764	0.41409	18.46	0.0001	CONSTANT - OIL
O6	0.627746	0.11453	5.48	0.0001	DUMMY REGION 6 - OIL
ORHO	0.708934	0.10370	6.84	0.0001	AUTOCORRELATION - OIL
W_ALL	0.176752	0.04126	4.28	0.0001	LAGGED SUCCESSFUL WELLS

Number of Observations		Statistics for System	
Used	38	Objective	1.8152
Missing	0	Objective*N	68.9779

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.

$$\begin{aligned} WELLS_{k,t} = {} & \beta 0_k + \beta 1_k * DCF_{k,t} + \beta 2_k * DUM83_t + \rho_t * WELLS_{k,t-1} \\ & - \rho_k * (\beta 0_k + \beta 1_k * DCF_{k,t-1} + \beta 2_k * DUM83_{t-1}) \end{aligned} \tag{45}$$

where,

WELLS	=	successful Canadian well completions
DCF	=	discounted cash flow for a well
DUM83	=	1 if t >1982, 0 otherwise
β0, β1, β2	=	econometrically estimated parameters
ρ	=	autocorrelation parameter
k	=	fuel type
t	=	year.

Results

Parameter	OIL	GAS
β0	499.230 (1.33979)	1829.02 (2.94956)
β1	0.170973E-02 (4.18866)	0.132393E-02 (3.23435)
β2	949.572 (2.05196)	-1276.28 (-3.06764)
ρ	0.298608 (1.41467)	0.726749 (4.50509)

NUMBER OF OBSERVATIONS = 20

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Dependent variable: WELLS (oil)

Mean of dependent variable	=	2235.30
Std. dev. of dependent var.	=	1467.19
Sum of squared residuals	=	.976854E+07
Variance of residuals	=	488427.
Std. error of regression	=	698.876
R-squared	=	.764132
Durbin-Watson statistic	=	2.10944

Dependent variable: WELLS (gas)

Mean of dependent variable	=	2353.75
Std. dev. of dependent var.	=	958.064
Sum of squared residuals	=	.391239E+07
Variance of residuals	=	195619.
Std. error of regression	=	442.289
R-squared	=	.789470
Durbin-Watson statistic	=	1.95590

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. One option is to employ the price elasticity estimates that are passed from the OGSM to the PMM and NGTDM. The section below documents the estimation of these elasticities.

Onshore Lower 48 States

Oil

Price elasticities were estimated using the AR1 technique in TSP which corrects for serial correlation using the maximum likelihood iterative technique of Beach and MacKinnon (1978). Equations for onshore regions 1 and 6 were estimated separately due to the regions' unique characteristics. The functional form is given by:

$$LCRUDE_t = a0 + a1 * LOILRES_t + a2 * LPOIL_t + \rho * LCRUDE_{t-1} - \rho * (a0 + a1 * LOILRES_{t-1} + a2 * LPOIL_{t-1}) \qquad 44.1)$$

where,

LCRUDE	=	natural log of crude oil production
LOILRES	=	natural log of beginning of year oil reserves
LPOIL	=	natural log of the regional wellhead price of oil in 1987 dollars
ρ	=	autocorrelation parameter
t	=	year.

Region 1

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	-.977125	.680644	-1.43559
LOILRES	.814563	.114311	7.12584
LPOIL	.08385	.040682	2.06115
ρ	.334416	.297765	1.12309

SAMPLE: 1978 to 1990

NUMBER OF OBSERVATIONS = 13

Dependent variable: LCRUDE
(Statistics based on transformed data)

Mean of dependent variable	=	3.03941
Std. dev. of dependent var.	=	.365187
Sum of squared residuals	=	.015765
Variance of residuals	=	.157651E-02
Std. error of regression	=	.039705
R-squared	=	.990477
Adjusted R-squared	=	.988573
Durbin-Watson statistic	=	1.58775
F-statistic (zero slopes)	=	502.556
Log of likelihood function	=	25.1414

(Statistics based on original data)

Mean of dependent variable	=	4.43559
Std. dev. of dependent var.	=	.142410
Sum of squared residuals	=	.015832
Variance of residuals	=	.158323E-02
Std. error of regression	=	.039790
R-squared	=	.936035
Adjusted R-squared	=	.923242
Durbin-Watson statistic	=	1.57879

Region 6

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	6.69155	2.14661	3.11727
LOILRES	-.123763	.255535	-.484329
LPOIL	.031845	.038040	.837163
ρ	.833915	.135664	6.14691

SAMPLE: 1978 to 1990
NUMBER OF OBSERVATIONS = 13

Dependent variable: LCRUDE
(Statistics based on transformed data)

Mean of dependent variable	=	1.13005
Std. dev. of dependent var.	=	.605103
Sum of squared residuals	=	.013218
Variance of residuals	=	.132176E-02
Std. error of regression	=	.036356
R-squared	=	.997230

Adjusted R-squared	=	.996676
Durbin-Watson statistic	=	.896816
F-statistic (zero slopes)	=	1657.10
Log of likelihood function	=	25.7519

(Statistics based on original data)

Mean of dependent variable	=	5.78242
Std. dev. of dependent var.	=	.061666
Sum of squared residuals	=	.014455
Variance of residuals	=	.144552E-02
Std. error of regression	=	.038020
R-squared	=	.707387
Adjusted R-squared	=	.648864
Durbin-Watson statistic	=	.892422

For onshore regions 2 through 5, the data were pooled and regional dummy variables were used to allow the estimated production elasticity to vary across the regions. Region 2 is taken as the base region. The form of the equation is given by:

$$\begin{aligned} LCRUDE_t = {} & a0 + a1*LOILRES_t + a2*LPOIL_t + a3*LPDUM3_t + a4*LPDUM \\ & a5*LPDUM5_t + \rho*LCRUDE_{t-1} - \rho*(a0 + a1*LOILRES_{t-1} + \\ & a2*LPOIL_{t-1} + a3*LPDUM3_{t-1} + a4*LPDUM4_{t-1} + a5*LPDUM5 \end{aligned} \tag{75.2}$$

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 LPDUMr to the coefficient on LPOIL.

Dry Non-Associated Natural Gas

The data for onshore regions 1 through 6 were pooled and a single regression equation estimated with dummy variables used to allow the slope coefficients to vary across regions. Region 1 was taken as the base region. The equation was estimated using the non-linear two stage least squares procedure in TSP. The form of the equation is given by:

$$LPROD = A0 + (A1 + \sum_{r} Ar * DUMr) * LGASRES + (B1 + \sum_{r} Br * DUMr) * LPGAS + C * DEDSHR \tag{75.3}$$

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

Oil

Price elasticities were estimated using OLS. The functional form is given by:

$$LCRUDE = a0 + a1*LOILRES + a2*LPOIL + a3*LCRUDE(-1) + a4*DUM \tag{75.4}$$

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

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:

$$LCRUDE_t = a0 + a1*LOILRES_t + a2*LPOIL_t + \rho*LCRUDE_{t-1} - \rho*(a0 + a1*LOILRES_{t-1} + a2*LPOIL_{t-1}) \qquad (75.5)$$

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 :

$$LADGAS_{r,t} = \ln(\alpha 0)_r + \ln(\alpha 1)_r * DUM86_t + (\beta 0_r + \beta 1_r * DUM86_t) * LOILPROD_{r,t} \tag{76}$$

Results

```
                    Onshore Region   1
                    *****************

          Method of estimation = Ordinary Least Squares

 Dependent variable: LADGAS
 Current sample:  11 to 24
 Number of observations:  14

  Mean of dependent variable = 5.12499
 Std. dev. of dependent var. = .164729
    Sum of squared residuals = .038353
       Variance of residuals = .319609E-02
    Std. error of regression = .056534
                   R-squared = .891278
          Adjusted R-squared = .882218
     Durbin-Watson statistic = 1.75215
   F-statistic (zero slopes) = 98.3730
  Schwarz Bayes. Info. Crit. = -5.52297
  Log of likelihood function = 21.4347

            Estimated    Standard
 Variable  Coefficient     Error       t-statistic
 ln(α0)    2.07491       .307892       6.73908
 β0        .701885       .070766       9.91832

                   OBS        REGION          YEAR
 11            11.00000      1.00000    1980.00000
 24            24.00000      1.00000    1993.00000
```

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

	OBS	REGION	YEAR
35	35.00000	2.00000	1980.00000
48	48.00000	2.00000	1993.00000

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

	OBS	REGION	YEAR
65	65.00000	3.00000	1986.00000

72	72.00000	3.00000	1993.00000

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

	OBS	REGION	YEAR
82	82.00000	4.00000	1979.00000
96	96.00000	4.00000	1993.00000

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

	OBS	REGION	YEAR
107	107.00000	5.00000	1980.00000
120	120.00000	5.00000	1993.00000

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

	OBS	REGION	YEAR
131	131.00000	6.00000	1980.00000
144	144.00000	6.00000	1993.00000

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

	OBS	REGION	YEAR
146	146.00000	7.00000	1982.00000
157	157.00000	7.00000	1993.00000

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

	OBS	REGION	YEAR
159	159.00000	8.00000	1982.00000
170	170.00000	8.00000	1993.00000