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Documentation of the Oil and Gas Supply Module (OGSM)

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1. Introduction

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

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

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

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

Outputs from OGSM go to other oil and gas modules (NGTDM and PMM) and to other modules of NEMS. NGTDM employs short-term supply functions, the parameters for which are provided by OGSM for nonassociated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. The short-term supply functions reflect potential oil or gas flows to the market for a 1-year period. The gas functions are used by NGTDM and the oil volumes are used by PMM for the determination of equilibrium prices and quantities of crude oil and natural gas at the wellhead. OGSM also provides projections of natural gas production to PMM to estimate the corresponding level of natural gas liquids production. Other NEMS modules receive projections of selected OGSM variables for various uses. Oil and gas production is forwarded to the Systems Module. Forecasts of oil and gas production go to the Macroeconomic Module to assist in forecasting aggregate measures of output.

OGSM is archived as part of the National Energy Modeling System (NEMS). The archival package of NEMS is located under the model acronym NEMS2003. The version is that used to produce the *Annual Energy Outlook 2003 (AEO2003)*. The package is available through the National Technical Information Service. The model contact for OGSM is:

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

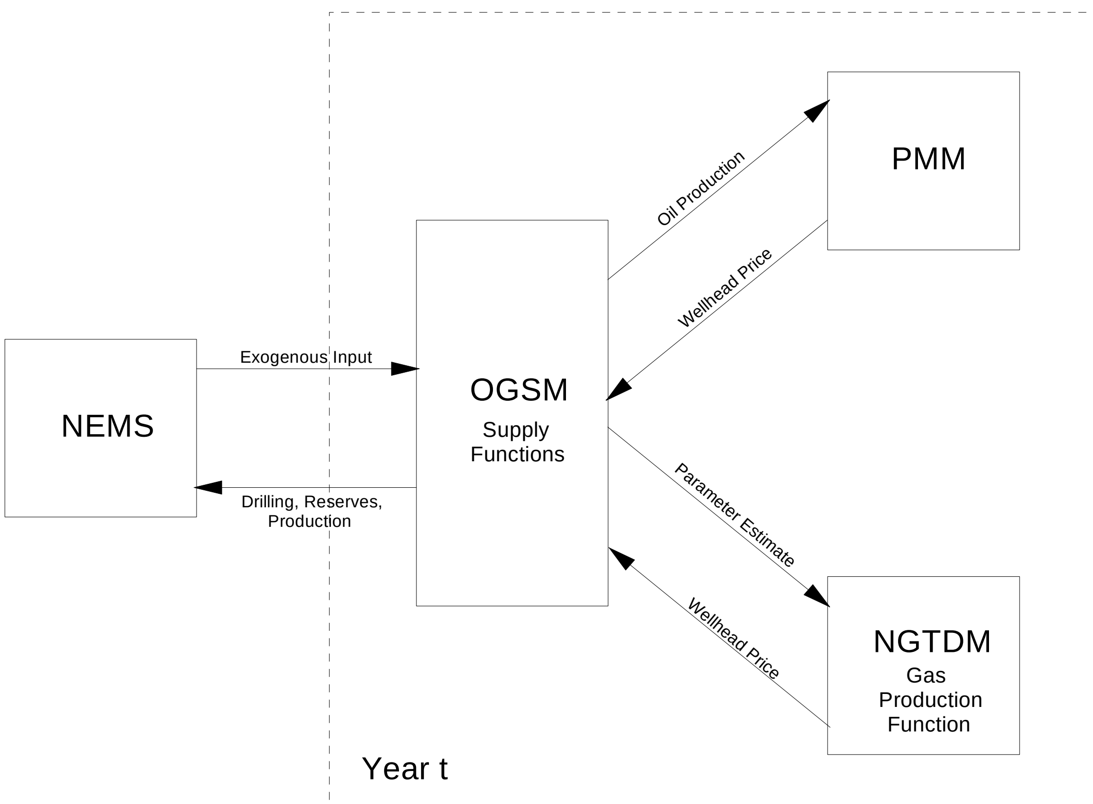
- Model purpose
- Model overview and rationale
- Model structure
- Inventory of input data, parameter estimates, and model output
- Detailed mathematical description.

2. Model Purpose

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

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

Figure 1. OGSM Interface with Other Oil and Gas Modules



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 includes production from conventional and enhanced oil recovery techniques as well as lease condensate. Natural gas is differentiated by nonassociated and associated-dissolved gas.[1] Nonassociated natural gas is categorized by conventional and unconventional types. The unconventional gas category in OGSM consists of resources in tight sands, Devonian/Antrim shale, and coalbed methane formations.

OGSM provides mid-term (through year 2025) 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,
- key taxation provisions such as severance taxes, State or Federal income taxes, depreciation schedules and tax credits, and
- the rate of penetration for different technologies into the industry by fuel type.

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

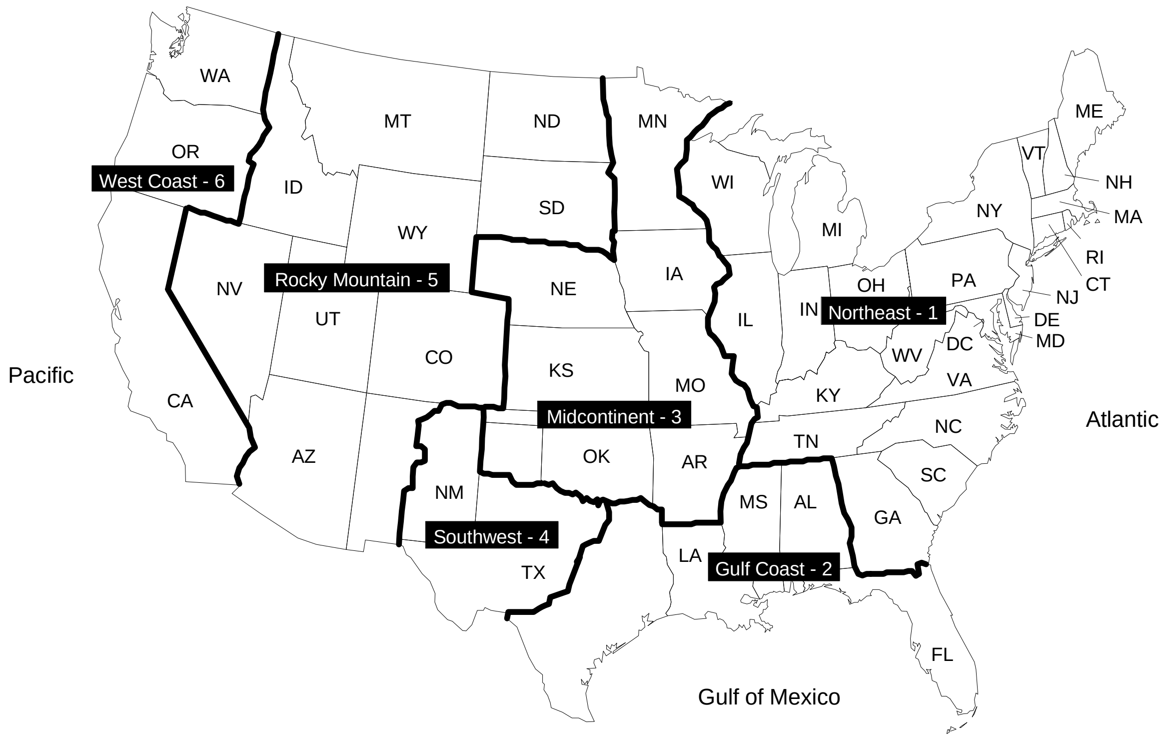
OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). With some modification this feature could allow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

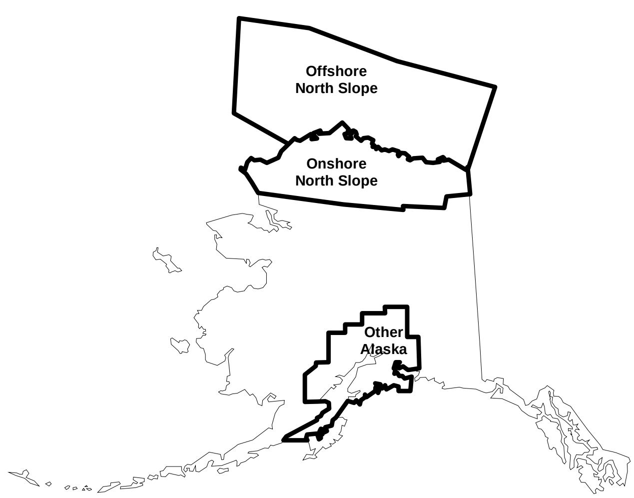
- the uncertainty surrounding the technically recoverable oil and gas resource estimates, and
- access restrictions on much of the offshore Lower 48 states, the wilderness areas of the onshore Lower 48 states, and the 1002 Study Area of the Arctic National Wildlife Refuge (ANWR).

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

[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 2. Oil and Gas Supply Regions





3. Model Rationale and Overview

Introduction

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

Overview of Oil and Gas Supply Modeling Methods

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

Geologic/Engineering Models

Play Analysis

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

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

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

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

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

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

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

Although the OCSM had many superior qualities, it was highly resource intensive. In particular, the OCSM required (a) maintenance of a large database on more than 2000 prospects in 30 offshore plays, (b) considerable mainframe CPU time to execute completely, reflecting the highly complex algorithmic and programming routines, and (c) maintenance of a wide range of staffing skills to support both the model and the underlying data. Since all these problems violate basic key attributes required of an oil and gas supply model operating in the NEMS environment, adopting a similar play analysis approach for the OGSM was rejected.

Discovery Process

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

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

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

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

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

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

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

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

Econometric Models

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

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

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

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

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

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

Hybrid Models

Hybrid models are an improvement in some ways over both the pure process models and the econometric models. They typically combine a relatively detailed description of the geologic relationship between discoveries and drilling with an econometric component that estimates the response of drilling to economic variables. In this way, a time path of drilling may be obtained without sacrificing an accurate description of geologic trends. Such a hybrid approach has been directly implemented (or incorporated indirectly, using the results of hybrid models) under a variety of methodological frameworks. Such frameworks include the system dynamics methodology used in the FOSSIL2 model, which underlies the *1992 National Energy Strategy* and numerous related studies.

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

The American Gas Association's former 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.

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

Market Equilibrium Models

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

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

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

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

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

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

OGSM Rationale

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

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

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

Accordingly, the OGSM lower 48 conventional onshore submodule 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. This design helps to satisfy some of the specification requirements set forth for the NEMS,[9] which emphasize, among other attributes, model transparency and model efficiency. This submodule, which constitutes a major part of the OGSM, does not determine activity levels on the basis of an explicit economic evaluation of discrete production units, such as individual producing fields. The

[8]Mexico has been introduced into the model as a net import flow in 1992 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.

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

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

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

Lower 48 Oil and Gas Supply

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

Conventional Lower 48 Onshore Supply

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

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

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

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

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

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

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

Conventional Offshore Supply

While the hybrid econometric/discovery process approach is a significant improvement over purely process models or econometric models, it is still inherently inadequate when if comes to determining exploration and development activity from predominantly frontier areas. This is due to the reliance of the hybrid model on significant historical information being available to forecast future activity based on historical performance. Deep water offshore Gulf of Mexico is still a relatively new frontier and very little information to develop equations for the discovery process/econometric type models exists. Due to significant differences in technology, costs, and productivity of fields in the deep water areas compared to those from shallow water areas, it would be incorrect to extrapolate the data from shallow water areas to the deep water fields.

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

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

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

Unconventional Gas Recovery Supply

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

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

Foreign Natural Gas Supply

The Foreign Natural Gas Supply Submodule consists of three key components: Canadian gas trade, liquefied natural gas (LNG) trades and gas trade with Mexico. Different methodological approaches were taken for each component in recognition of inherent differences between the various modes of import and the different circumstances affecting both supply capacity in the source country and its potential availability to the United States. The process by which Canadian gas flows to the United States is essentially the same process as that for U.S. supplies in the Lower 48 states. LNG imports are very different however, with available regasification capacity and the unit costs of transportation, liquefaction, and regasification being the most important determinants of import volumes. Production costs in countries currently or potentially providing LNG are a relatively small portion of total unit costs for gas delivered into the U.S. transmission network. Natural gas trade with Mexico is projected using assumptions regarding regional supply and regional/sectoral demand growth for natural gas in Mexico that have 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. Excess supply is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States.

Canadian Gas Supplies

Conventional natural gas supplies from Western 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 the natural gas wellhead price and production in the previous forecast year. The discovery process component relates reserve additions per period to wells drilled. A hybrid method was chosen for modeling Canadian gas supplies since this approach most effectively meets the numerous analytical requirements of OGSM. Also, sufficient data are available for the Canadian oil and gas industry. Finally, although this approach is a somewhat simplified version of the Lower 48 methodology, the two models are methodologically consistent. Natural gas production from other sources in Canada are represented directly in the NGTDM and documented separately.

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.

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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.

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. 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 great enough 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.[12]

Despite the uncertainty and the significant influence of noneconomic factors that influence Mexican gas trade with the United States, a methodology to anticipate the path of future Mexican imports and exports has been incorporated into FNGSS. This outlook is generated using assumptions regarding regional supply and regional/sectoral demand growth for natural gas in Mexico that have 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. Excess supply is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States.

Alaskan Oil and Gas Supplies

Alaska has a limited history as a source of significant volumes of crude oil and natural gas. Initial commercial flows of crude oil from the Alaskan North Slope began on June 17, 1977. Interest in analyzing the volumetric potential of Alaska as a source of oil or gas supplies arose after the late 1960's discovery of the Prudhoe Bay field, which is the largest in North America. During the years since the mid-1970's, there have been numerous special studies of either a one-time nature or limited in scope. An early study by Mortada (1976) projected expected oil production through 2002.[13] 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

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

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

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. Projections in EIA had been for periods of 10 to 15 years, and up to 20 years only in the early 1990s. This period length limits the flexibility in Alaskan activities, where lags of 10 to 15 years affect the discovery and development process. Thus, the bulk of oil production for at least 15 years under virtually any scenario depends almost wholly on the recovery from currently known fields. Marketing of natural gas from the Alaskan North Slope is not expected until later in this decade at the earliest, because of the lack of facilities to move the gas to Lower 48 markets. Absent a pipeline to transport the gas to the lower 48 States, Alaskan natural gas production is set based on a forecast of demand for the fuel in Alaska provided by the NGTDM.

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.

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

4. Model Structure

Introduction

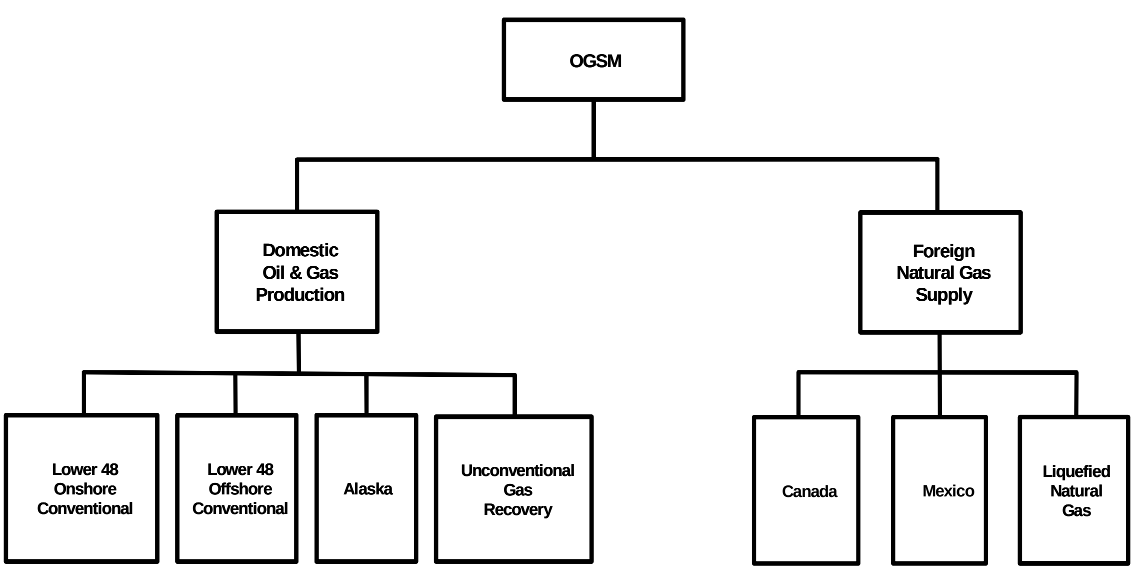
This chapter describes the Oil and Gas Supply Module (OGSM), which consists of a set of submodules (Figure 3) that perform supply analysis of domestic oil and gas production and foreign trade in natural gas between the United States and other countries via pipeline or as liquefied natural gas. The OGSM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

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 unconventional gas recovery (UGR) from low permeability sandstone and shale formations, and coalbeds. Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM represents foreign trade in natural gas as imports and exports by entry region of the United States. These foreign transactions may occur via either pipeline (Canada or Mexico), or via ships transported as liquefied natural gas (LNG).

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

The OGSM includes an enhanced methodology for estimating short-term oil and gas supply functions. Short-term is defined as a 1-year period in the OGSM. This enhancement improves the procedure for equilibrating

Figure 3. Submodule within the Oil and Gas Supply Module



the natural gas and oil markets by allowing for the determination of regional market clearing prices for each fuel, as opposed to the previous modeling system that only equilibrates markets at a national market clearing price.

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

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

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

The breadth of supply processes that are encompassed within OGSM results in methodological differences between the oil and gas production from lower 48 onshore conventional resources, lower 48 onshore unconventional resources, lower 48 offshore, Alaska, and foreign gas trade. The present OGSM consequently comprises a set of four distinct approaches and corresponding submodules. The label OGSM as used in this report generally refers to the overall framework and the implementation of lower 48 onshore oil and conventional gas supply. The Unconventional Gas Recovery Supply Submodule (UGRSS) models gas supply from low permeability sandstone and shale formations, and coalbeds. The Offshore Supply Submodule (OSS) models oil and gas production in the offshore Gulf of Mexico and Pacific 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 AEO2003. Production from enhanced oil recovery is not distinguish from conventional crude oil and lease condensate production -- the Enhanced Oil Recovery Supply Submodule was removed. New finding rate functions for crude oil and conventional natural gas resources were incorporated. Lower 48 onshore and offshore rigs, drilling, and drilling cost equations were re-estimated for conventional sources. Parameters for the Unconventional Gas Recovery Submodule were updated. Oil resource estimates for the National Petroleum Reserve in Alaska (NPR-A) were revised. The drilling equations and finding rate functions for the Canadian Supply Submodule were revised to improve performance. New construction of LNG regasification facilities is possible in each coastal region.

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

Lower 48 Onshore Supply Submodule

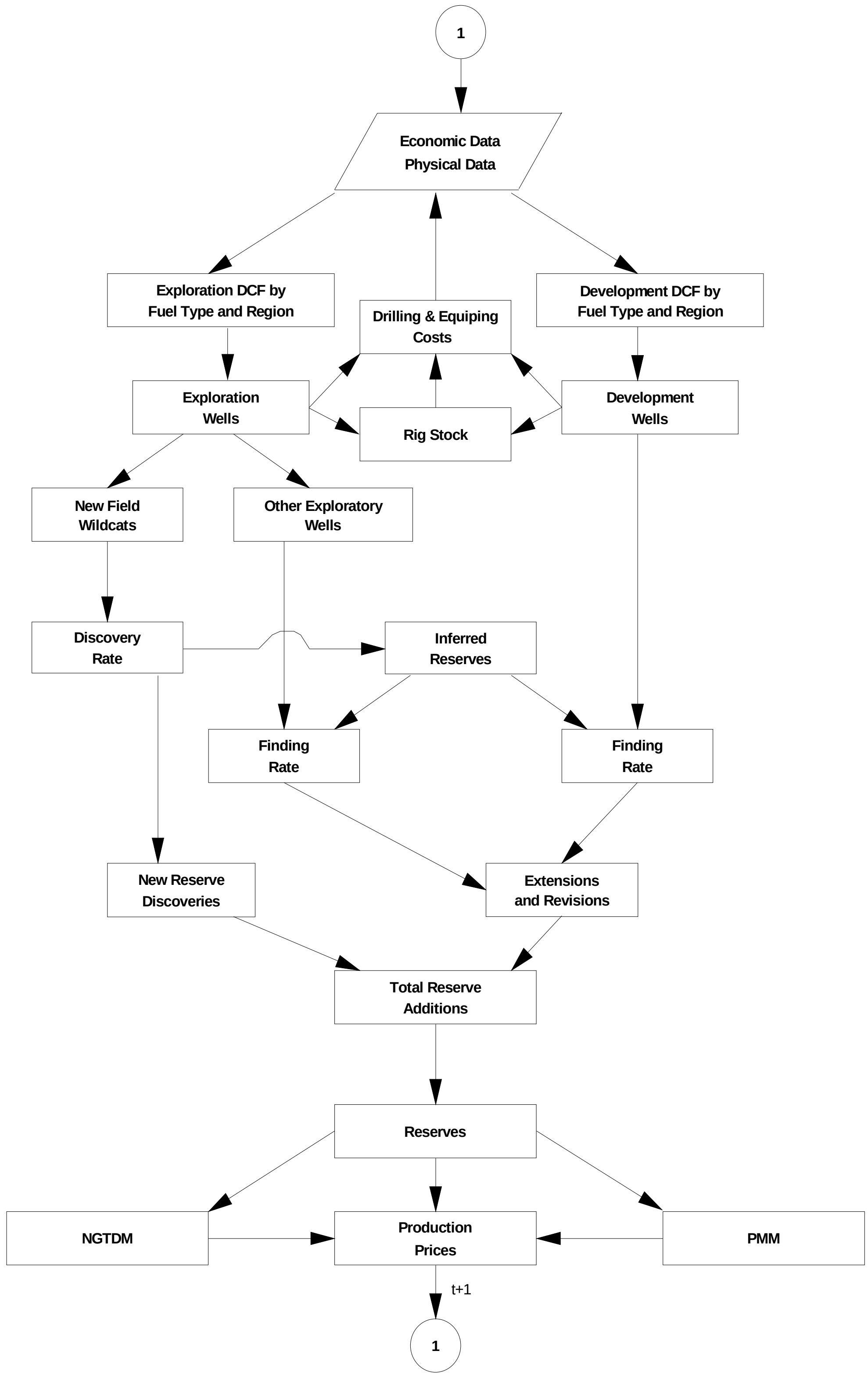
Introduction

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

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

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

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



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

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

The Expected Discounted Cash Flow Algorithm

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

Onshore Lower 48 Development

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

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

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

where,

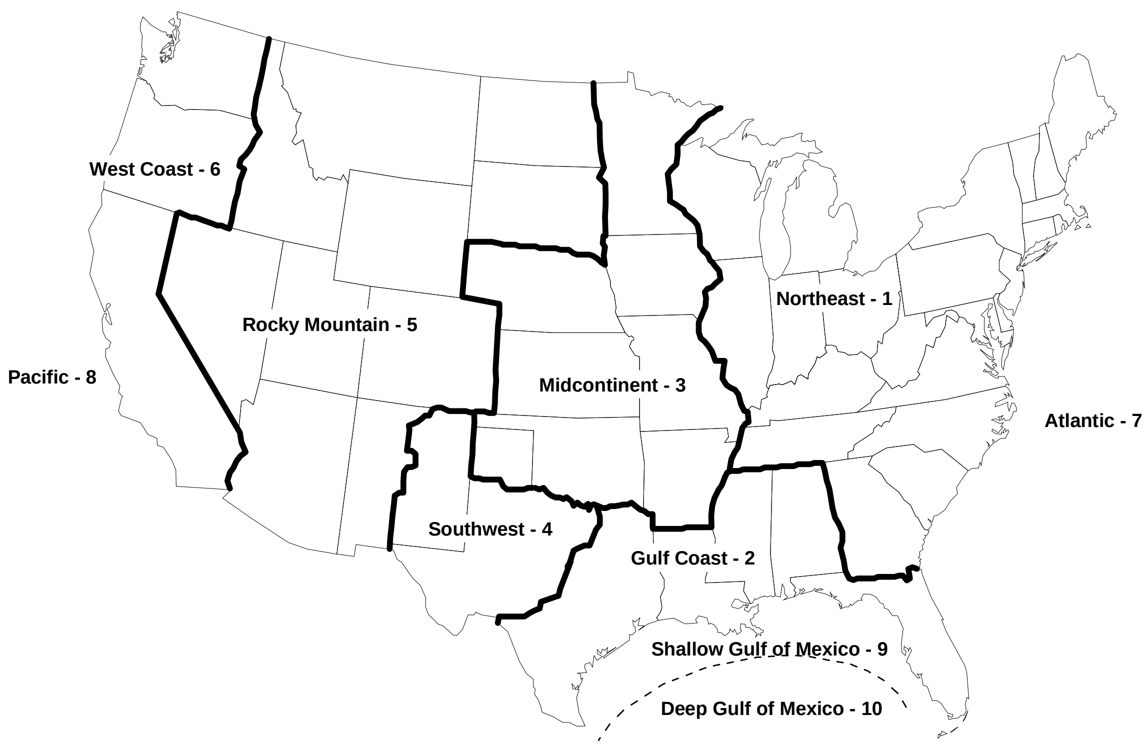
NCFON	=	annual undiscounted net cash flow for a representative onshore development project
REV	=	revenue from the sale of the primary and co-product fuel
ROY	=	royalty taxes
PRODTAX	=	production taxes (severance plus ad valorem)

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

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

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

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



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

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:

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

where,

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

Onshore Lower 48 Exploration

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

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

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

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:

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

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

In some instances, the forecasting equations employ alternative, usually more aggregated, forms of the expected DCF. For example, an aggregate expected fuel level DCF is calculated for each region . This aggregate expected DCF is calculated as a weighted average of the expected exploratory DCF and the expected developmental DCF for each fuel. Specifically,

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

and

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

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

where,

WELLS = wells drilled
ODCFON = expected DCF for oil
SGDCFON = expected DCF for shallow gas
DCFON = expected discounted cash flow for a representative onshore well.

Calculation of Cash Flow for Wells Determination

Expected industry cash flow is calculated as,

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

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

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

Lower 48 Onshore Wells Forecasting Equations

For each onshore Lower 48 region, the number of wells drilled by well class and fuel type is forecasted generally as a function of the expected profitability, proxied by the expected DCF, of a representative well of class i, in region r, for fuel type k, in year t and expected industry cash flow. In some specific cases, however, the forecasting equations may use the lagged value of the expected DCF or a more aggregate form of the expected DCF.

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

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

where,

WELLSON	=	lower 48 onshore wells drilled by class, region, and fuel type
DCFON	=	expected DCF for a representative onshore well of class I, in region r, for fuel type k, in year t
CASHFLOW	=	cash flow in year t
REMAINRES	=	the ratio of remaining undiscovered resources plus inferred reserves in year t and undiscovered resources plus inferred reserve estimates in 1977
m's, α's	=	estimated parameters
ρ	=	estimated serial correlation parameter
i	=	well type
r	=	lower 48 regions
k	=	fuel type
t	=	year.

Successful and Dry Wells Determination

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

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

where,

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

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

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

where,

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

Drilling, Lease Equipment, and Operating Cost Calculations

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

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

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

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

where,

ESTWELLS	=	estimated total onshore lower 48 wells drilled
ESTSUCWELLS	=	estimated successful onshore lower48 wells drilled
POIL	=	average wellhead price of crude oil

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

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

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

where,

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

Drilling Costs

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

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

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

where,

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

Lease Equipment Costs

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

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

where,

LEQC = oil and gas well lease equipment costs
DEPTH = average well depth

ESTSUCWELLS	=	estimated lower 48 successful onshore wells
TIME	=	time trend - proxy for technology
$\varepsilon0, \varepsilon1, \varepsilon2$	=	estimated parameters
r	=	OGSM lower 48 onshore region
k	=	fuel type (1=shallow oil, 2=deep oil, 3=shallow gas, 4=deep gas)
t	=	year.

Operating Costs

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

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

where,

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

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

Reserve Additions

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

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

The volumetric yield from a successful new field wildcat well is divided into proved reserves and inferred reserves. The proportions of reserves allocated to these categories are based on historical reserves growth statistics. Specifically, the allocation of reserves between proved and inferred reserves is based on the ratio of the initial reserves estimated for a newly discovered field relative to ultimate recovery from the field.[8]

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

Functional Forms

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

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

Discoveries per successful new field wildcat are a function of drilling activity, average depth, a time trend that proxies the impact of technological change, and the estimated volume of remaining undiscovered resources. Specifically, the finding rate equation for new field wildcats is

$$FR1_{r,k,t} = e^{\alpha_{r,k}*(1-\rho_k)} * e^{\beta 0_k * DEPTH_{r,k,t}} * e^{\beta 1_k * SW1_{r,k,t}} * RESOURCE_{r,k,t}^{\delta_{r,k}} * FR1_{r,k,t-1}^{\rho_k} * e^{-\rho_k * \beta 0_k * DEPTH_{r,k,t-1}} * e^{-\rho_k * \beta 1_k * SW1_{r,k,t-1}} * RESOURCE_{r,k,t-1}^{-\rho_k * \delta_{r,k}} \tag{21}$$

where,

FR1	=	new field wildcats finding rate
DEPTH	=	average depth
SW1	=	number of successful new field wildcats
RESOURCE	=	remaining undiscovered resources
α, $\beta 1$, $\beta 2$, δ	=	estimated parameters
ρ	=	estimated serial correlation parameter
r	=	region
k	=	fuel type (oil or gas)
t	=	year.

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

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

where,

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

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

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

$$FR2_{r,k,t} = e^{\alpha_{r,k}} * e^{\beta1_k * OEXPWL_{r,k,t}} * INFR_{r,k,t}^{\beta3_{r,k}} * e^{\beta4_k * year_t} * FR2_{r,k,t-1}^{\rho_k} * e^{-\rho_k * \alpha_{r,k}} * e^{-\rho_k * \beta1_k * OEXPWL_{r,k,t-1}} * INFR_{r,k,t-1}^{-\rho_k * \beta3_{r,k}} * e^{-\rho_k * \beta4_k * year_{t-1}} \tag{23}$$

where,

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

Reserve revisions are an extremely important source of reserve additions. For instance, over the period 1990-97, revisions added almost nine Tcf to conventional gas reserves in the onshore Gulf Coast Region alone. Unfortunately, the determinants of revisions and adjustments are not well understood and thus projecting net revisions and adjustments is somewhat problematic. For example, a negative adjustment or revision can be recorded because of a change in ownership and, thus, not linked directly to drilling. Dividing these negative volumes by the number of developmental wells does not result in a meaningful finding rate. As a result, net revisions and adjustments, as opposed to revisions per well drilled, are econometrically estimated using the following general form.

$$REVISIONS_{r,k,t} = (e^{\alpha_{r,k}} * \left(\frac{INFR_{r,k,t} + BOYRES_{r,k,t}}{BOYRES_{r,k,t}}\right)^{\beta1_{r,k}} * e^{\beta2_k * WHP_{r,k,t}} * e^{\beta3_k * WHP^2_{r,k,t}} * e^{\beta4_k * \frac{WHP_{r,k,t}}{WHP_{r,k,t-1}}} * e^{\beta5_k * CUMDWL_{r,k,t}}) - 1) * BOYRES_{r,k,t} \tag{24}$$

where,

REVISIONS	=	net revisions and adjustments
INFR	=	remaining inferred reserves
BOYRES	=	beginning-of-year reserves
WHP	=	wellhead price
CUMDWL	=	cumulative successful development wells
α, $\beta1$, $\beta2$, $\beta3$, $\beta4$, $\beta5$	=	estimated parameters
r	=	region
k	=	fuel type (oil or gas)
t	=	year

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

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

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

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

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

where,

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

Production to Reserves Ratio

The production of nonassociated gas in NEMS is modeled at the "interface" of NGTDM and OGSM while oil production[9] is determined within the OGSM. In both cases, the determinants of production include the lagged production to reserves (PR) ratio and price. The PR ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

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

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

where,

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

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

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

where,

PR_{t+1} = expected production to reserves ratio for year (t+1)

[9]Electricity cogeneration and capacity associated with production from enhance oil recovery techniques is held constant at an average historical level.

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

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

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

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

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

where,

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

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

Associated Dissolved Gas

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

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

where,

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

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

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

where,

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

Unconventional Gas Recovery Supply Submodule

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

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

Offshore Supply Submodule

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

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

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

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

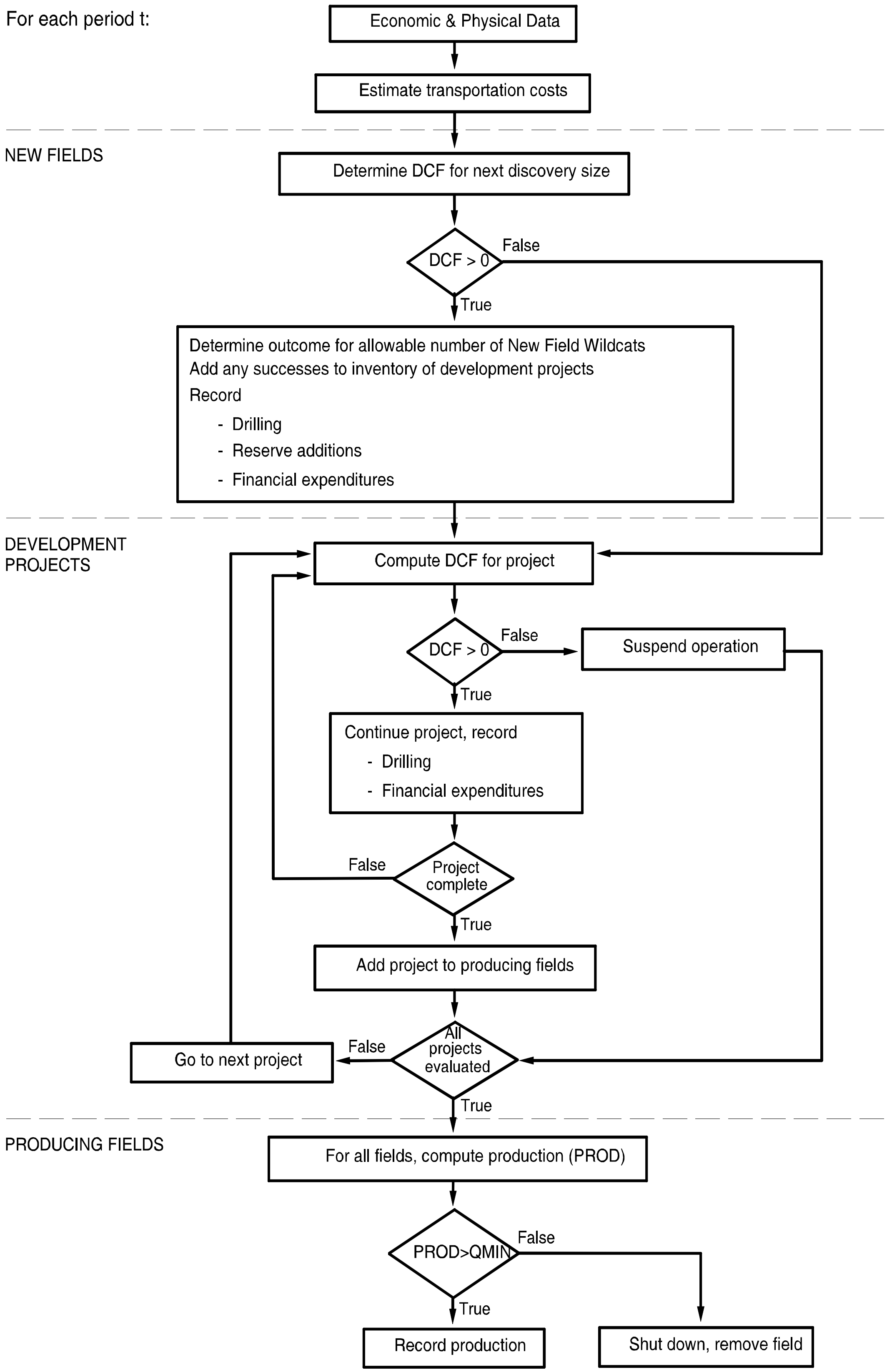
Alaska Oil and Gas Supply Submodule

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). The North Slope region encompasses the National Petroleum Reserve Alaska in the west, the State Lands in the middle, and the Alaskan National Wildlife Refuge area in the east. This section provides an overview of the basic approach including a discussion of the discounted cash flow (DCF) method.

AOGSS Overview

The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 6).Transportation costs are used in conjunction with the relevant market price of oil or gas to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow (DCF) method is used to determine the economic viability of each project at the netback price. Alaskan oil and gas supplies are modeled on the basis of discrete projects, in contrast to the Onshore Lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multi-year projects, as well as the discovery of a new field is dependent on its profitability. Production is determined on the basis of

Figure 6. Flowchart for the Alaska Oil and Gas Supply Submodule



assumed drilling schedules and production profiles for new fields and developmental projects, and historical production patterns and announced plans for currently producing fields.

Calculation of Costs

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

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

All costs in the model incorporate the estimated impact of environmental compliance. Whenever environmental regulations preclude a supply activity outright, that provision is reflected in other adjustments to the model. For example, environmental regulations that preclude drilling in certain locations within a region are modeled by reducing the recoverable resource estimates for that region.

Each cost function includes a variable that reflects the cost savings associated with technological improvements. As a result of technological improvements, average costs decline in real terms relative to what they would otherwise be. The degree of technological improvement is a user specified option in the model. The equations used to estimate costs are similar to those used for the lower 48, but include cost elements that are specific to Alaska. For example, lease equipment includes gravel pads and ice roads.

Drilling Costs

Drilling costs are the expenditures incurred for drilling both successful wells and 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:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1) ** (t - T_b) \qquad (32)$$

where,

I	=	well class(exploratory=1, developmental=2)
r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
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 specified by TECH1. Drilling costs are not modeled as a function of the activity level as they are in the Onshore Lower 48 methodology. Drilling rigs and equipment are designed specifically for the harsh Arctic weather conditions. Once this equipment is moved up to Alaska, it is too expensive to transport back to the lower 48. Consequently, company drilling programs in Alaska are planned to operate at a relatively constant level of activity because of limited number of drilling rigs and equipment available for use.

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 (e.g., oil/gas/water separation), and production related infrastructure such as gravel pads. Producing equipment costs include tubing, pumping equipment. Gathering system costs consist of flowlines and manifolds. The lease equipment cost estimate for a new oil or gas well is given by:

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2)**(t - T_b) \tag{33}$$

where,

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
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:

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3)**(t - T_b) \tag{34}$$

where,

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
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 each of the three Alaskan regions.

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 based on the tax code.
- 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.

Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil and gas projects.[10] 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 for Alaskan oil include both pipeline and tanker shipment costs, while natural gas transportation costs are strictly pipeline costs (tariffs) to the lower 48. Transportation costs are specified for each field, based on the fuel type (i.e., oil or gas) and on the transportation cost of that fuel for that region. This cost directly affects the expected revenues from the production of a field as follows:[11]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_f) \tag{35}$$

where,

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

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

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

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

$$DCF_{f,t} = (PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP - PVOPCOST - PVPRODTAX - PVSIT - PVFIT - PVWPT)_{f,t} \tag{36}$$

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[12]

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

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \tag{37}$$

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:

$$PROF_{f,t} = DCF_{f,t} \;/\; COST_{f,t} \tag{38}$$

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.

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

New Field Discovery

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

- technically recoverable oil and gas resource estimates by region,
- distribution of technically recoverable field sizes[13] within each region,
- the maximum number of new field wildcat wells drilled in any year,
- new field wildcat success rate, and
- any restrictions on the timing of drilling.

The endogenous procedure generates:

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

The new field discovery procedure divides the estimate for technically recoverable oil and gas resources into a set of individual fields. The field size distribution data is obtained from U.S. Geological Survey estimates.[14] The field size distribution is used to determine a largest field size based on the volumetric estimate corresponding to an acceptable percentile of the distribution. The remaining fields within the set are specified such that the distribution of estimated sizes conform to the characteristics of the input distribution. Thus, this estimated set of fields is consistent with the expected geology with respect to expected aggregate recovery and the relative frequency of field sizes.

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

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil

[13]"Size" of a field is measured by the volume of recoverable oil (in barrels) or gas (in cubic feet).

[14]*Estimates of Undiscovered Conventional Oil and Gas Resources in the United States -- A Part of the Nation's Energy Endowment*, USGS (1989); and *Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis*, USGS (April 2001); and *U.S. Geological Survey 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA)* USGS (2002).

deposits. State and Federal lease sale schedules would also restrict the earliest possible date for beginning the development of certain fields. This refinement is implemented by declaring a start date for possible exploration. For example, AOGSS specifies that if Federal leasing in Alaskan National Wildlife Refuge were permitted, then the earliest possible development date would be 2011. Another example is the 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.

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

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[15] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to peak rate,
- peak rate sustained for 3 to 8 years, and
- production rates decline by 5 to 18 percent per year, for known fields under development, after production declines below the peak rate; unknown fields decline by 10 percent per year.

The pace of development and the 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.

Development fields include fields that have already been explored, but that have not begun production. These fields include, for example, a series of expansion fields in the Prudhoe Bay area, and a series of fields in the National Petroleum Reserve, Alaska (NPRA). For these fields, the starting date of production was not determined by the discovery process outlined above, but is based upon estimates of when these fields will come into production, from both the state of Alaska and EIA. (*2000 Annual Report*, Alaska Department of Natural Resources, Division of Oil and Gas, 2000, and *Future Oil Production for the Alaska North Slope*, EIA, Office of Oil and Gas, DOE/EIA-0627, May 2001.)

[15] *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment*, EIA (May 2000) and *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/0570-H1 (January 1991).

Producing Fields

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

Natural gas production from the North Slope for sale to end-use markets depends on the construction of a pipeline to transport natural gas to lower 48 markets.[16] 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.[17]

Over the forecast period, Alaskan natural gas production is limited to natural gas resources in the Prudhoe Bay field and the adjacent Port Thompson field. In all, these fields have estimated reserves of 35 trillion cubic feet of natural gas.[18] Of this, EIA has estimated that 26 trillion cubic feet could be produced with only a minor impact on North Slope oil production. All Alaska North Slope natural gas production in the EIA forecast is limited to this 26 Tcf of stranded gas reserves. EIA estimates that this already discovered gas requires a return of at least $0.80 per thousand cubic feet at the wellhead before these reserves would be developed.

Foreign Natural Gas Supply Submodule

This section describes the structure for the Foreign Natural Gas Supply Submodule (FNGSS) within the Oil and Gas Supply Module (OGSM). FNGSS includes U.S. trade in foreign natural gas via either the North American pipeline network or ocean-going tankers.[19] Gas is traded with Canada and Mexico via pipelines. The border crossing locations are identified in Figure 7. Gas trade with other, nonadjacent, countries is in the form of liquefied natural gas (LNG) and involves liquefaction, transportation by tanker and subsequent regasification. To date, the United States has imported LNG from Algeria, Australia, Indonesia, Malaysia, Nigeria, Oman, Qatar, Trinidad and Tobago, and the United Arab Emirates.

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

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

[17]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.

[18]*Alaska Gas: Clean Energy for the Future,* British Petroleum, 2001.

[19]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.

Figure 7. Foreign Natural Gas Trade via Pipeline

size of available import capacity. Natural gas LNG and Canadian exports are included in the National Energy Modeling System (NEMS) as exogenous assumptions. Exports to Mexico are determined endogenously. This section presents descriptions of the separate methodological approaches for Canadian, Mexican, and LNG natural gas trade.

Canadian Gas Trade

This submodule determines the components and the subsequent parameters needed to define the Western Canadian conventional natural gas price/supply curve used by the NGTDM to help determine Canadian import levels. Canadian production is represented for three regions in the NEMS -- the Western Canadian Sedimentary Basin (WCSB, including Alberta, British Columbia, and Saskatchewan), the Northern Frontier (Arctic Islands and MacKenzie Delta), and Eastern Canada. Production from the WCSB is further disaggregated into conventional and unconventional (coalbed methane) production. Eastern Canadian production is set exogenously in the NGTDM. Baseline production levels for unconventional production are effectively set exogenously in the NGTDM as well, but are allowed to vary in the NGTDM in response to variations in the realized price. Gas production from the MacKenzie Delta is dependent on the construction of a pipeline to Alberta, which is also determined by the NGTDM and documented separately.

The approach taken to determine WCSB gas supplies differs from that used in the domestic submodules of the OGSM. Drilling activity, measured as the number of successful wells drilled, is estimated directly as a function of the Western Canadian natural gas wellhead price and production in the previous year, rather than as a function of expected profitability proxied by the expected DCF. No distinction is made between exploration and development. Next, an exponentially declining finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves); and an estimated extraction rate determines production potential [production to reserves ratio (PRR)]. The general methodology employed for estimating potential conventional Canadian gas production from the WCSB is depicted in Figure 8. Production from unconventional sources (i.e., coalbed methane, largely in Western Canada) is handled within the NGTDM as an assumed production function dependent on price.

The determination of the import volumes into the United States occurs in the equilibration process of the NGTDM, utilizing the WCSB supply curve parameters, unconventional and eastern Canadian production, gas from the MacKenzie Delta, as well as Canadian demand estimates. Forecasts of Canadian consumption are set at levels published in EIA's *International Energy Outlook 2002*.

Conventional Gas from the Western Canadian Sedimentary Basin

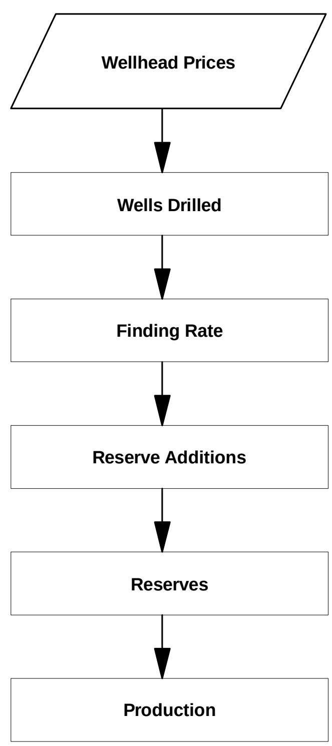
Wells Determination

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

$$SUCWELL_t = e^{\beta 0} * GPRICE_t^{\beta 1} * OGPRDCAN_{t-1}^{\beta 2} \tag{39}$$

where,

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



$SUCWELL_t$ = total conventional successful gas wells completed in Western Canada in year t
$GPRICE_t$ = price per Mcf of natural gas in 1987 US dollars in year t
$OGPRDCAN_{t-1}$ = conventional gas production in the previous forecast year (million cubic feet)
β_0 = econometrically estimated parameter (-3.91064, Appendix E)
β_1 = econometrically estimated parameter (0.499703, Appendix E)
β_2 = econometrically estimated parameter (0.791501, Appendix E)

Reserve Additions

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

Gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to wells or feet drilled in such a way that the rate of reserve additions declines as more wells are drilled. The reason for this is, all else being constant, the larger prospects typically are drilled first. Consequently, the finding rate can be expected to decline as a region matures, although the rate of decline and the functional forms are a subject of considerable debate. In previous versions of the model an attempt was made to estimate this equation; while the latest version is assumption based. Canadian gas reserve additions are a function of the cumulative number of successful wells drilled, the recoverable resource base (including inferred resources), and the rate of technological progress. The finding rate for gas is defined by:

$$FRCAN_t = FRCAN_{t-1} * e^{(-deltacan_t * SUCWELL_t)} * (1 + FRTECH) \tag{40}$$

where,
FRCAN = finding rate
$SUCWELL_t$ = successful gas wells drilled in year t
$deltacan_t$ = finding rate decline parameter in year t (>0)
FRTECH = finding rate technology factor (=0.07)

In this specification, the yield from successful drilling begins at the initial finding rate for each period ($FRCAN_{t-1}$) and declines exponentially as drilling continues. However, technological progress can reduce or even reverse this decline. The decline parameter (deltacan) is set as follows:

$$deltacan_t = \frac{(FRCAN_{t-1} - FRMIN) * RSVGR}{RR - CUMRES_{t-1}} \tag{41}$$

where,
$deltacan_t$ = finding rate decline parameter in year t (>0)
t = forecast year
FRCAN = finding rate (billion cubic feet per well)
FRMIN = minimum finding rate (0.15)
RSVGR = reserves growth factor (4.4)
RR = initial recoverable resource estimate (including inferred resources) at beginning of projection period

CUMRES = cumulative reserve discoveries (RESADCAN) from beginning of projection period to the current projection year t

The denominator represents the remaining recoverable resource estimate in a given period. The minimum finding rate (FRMIN) is incorporated in the equation so that the cumulative reserve discoveries match the recoverable resource estimate when the yield from wells drilled falls to the minimum. The changing recoverable volume necessitates recomputing the decline parameter (deltacan) in each period.

Total reserve additions in period t is given by:

$$RESADCAN_t = \int_0^{sucwell_t} FRCAN_t \; d(SUCWELL) \tag{42}$$

-or-

$$RESADCAN_t = \frac{FRCAN_{t-1}}{deltacan_t} * e^{(-deltacan \, * \, SUCWELL_t)} \tag{43}$$

where,

$RESADCAN_t$	=	Reserve additions in year t, in BCF
$FRCAN_{t-1}$	=	Finding rate in the previous year, in BCF per well
$SUCWELL_t$	=	Successful gas wells drilled in year t
$deltacan_t$	=	finding rate decline parameter in year t

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

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \tag{44}$$

where,

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

When rapid and slow technological progress cases are run, the forecasted values for the number of successful wells and for the finding rate decline are adjusted accordingly.

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.

Conventional gas production in the WCSB in year t is processed in the NGTDM and is represented by the following equation:

$$Q_t = R_{t-1} * PR_t * (1 + \beta * \frac{\Delta P_t}{P_{t-1}}) \tag{45}$$

where,

Q_t	=	Gas production in year t, BCF
R_{t-1}	=	End-of-year gas reserves in previous year, BCF
PR_t	=	gas extraction rate in previous year (measured as the production to reserves ratio at the end of the previous year)
P_t	=	gas price at the wellhead in year t, 1987$/Mcf
β	=	assumed short run price elasticity of extraction
ΔP_t	=	(P_t-P_0), the difference in the price in year t from a reference price (P_0, set in the NGTDM) associated with the reference quantity (R_{t-1} * PR_t), 1987$/Mcf

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

$$PRRATCAN_{t+1} = \frac{OGPRDCAN_t * (1 - PR_t) + PRRATNEW * RESADCAN_t}{RESBOYCAN_t} \tag{46}$$

where,

$PRRATCAN_{t+1}$	=	gas extraction rate in previous year (measured as the production to reserves ratio at the end of year t)
$PRRATCAN_t$	=	gas extraction rate in year t (measured as the production to reserves ratio at the end of the previous year: PR_t = $OGPRDCAN_t$ / $RESBOYCAN_{t-1}$)
$RESBOYCAN_t$	=	end-of-year gas reserves in year t, BCF
$OGPRDCAN_t$	=	Canadian gas production in year t, BCF
$RESADCAN_t$	=	reserve additions in year t, BCF
PRRATNEW	=	new production to reserves ratio for new reserve additions

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

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

Mexican Gas Trade

Mexican gas trade is a highly complex issue. A range of noneconomic factors will influence, if not determine, future flows of gas between the United States and Mexico. Uncertainty surrounding Mexican/U.S. trade is great enough 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.[20]

Despite the uncertainty and the significant influence of noneconomic factors that influence Mexican gas trade with the United States, a methodology to anticipate the path of future Mexican imports and exports has been incorporated into FNGSS. This outlook is generated using assumptions regarding regional supply and regional/sectoral demand growth for natural gas in Mexico that have 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. Excess supply is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States.

Liquefied Natural Gas

Liquefaction is a process whereby natural gas is cooled to minus 260 degrees Fahrenheit, causing it to be converted from a gas to a liquid. This also reduces its volume significantly, making it possible to transport to distant markets. This allows stranded gas, or gas that would otherwise be inaccessible due either to lack of nearby markets or lack of pipeline infrastructure to deliver it to local markets, to be monetized. LNG imports into the United States have grown steadily over the past five years, and prospects for continued growth are good. Various factors have contributed to the recent re-emergence of LNG as an economically viable source of energy, including contracts with pricing and delivery flexibility, the emergence of a spot market for LNG, a growing preference toward natural gas due to the lesser environmental consequences for burning it versus other fossil fuels, a desire for diversification and security of energy supply, and lower costs throughout the LNG supply chain. High natural gas prices during the winter of 2000/2001 provided further impetus.

Determining U.S. Imports and Exports of LNG

Costs of producing, liquefying, transporting, and re-gasifying the gas for delivery via pipeline to end-users are input to the FNGSS. The summations of these values for each location serve as economic thresholds that must be achieved before investment in expansion at an existing, or construction of a new, LNG project occurs.

Costs of imported LNG do not compete with wellhead prices 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 higher transportation costs incurred in getting these more distant domestic supplies to market.

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

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

A key assumption for any LNG outlook from FNGSS is that all major operational or institutional difficulties have been incorporated into the recognized allowable schedule for capacity operation and expansion. No other difficulties arise that are not assumed to be 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 (Figure 7). All but Cove Point are currently open, and it is assumed that Cove Point will open in 2003.

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 less than 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 specified exogenously .

New Construction

The algorithm for representing LNG regasification capacity expansion in the United States compares estimated costs for bringing LNG into various regions in the United States with the average market price in the region over the previous three years of the forecast. If the market price has been sustained above the estimated cost, construction of additional regasification capacity is expected to occur. The regions represented are: New England Census Division, Middle Atlantic Census Division, South Atlantic Census Division (excluding Florida), Florida, East South Central Census Division, West South Central Census Division, California, and Washington/Oregon. The incremental expansion volumes are specified exogenously, along with the expected utilization of the capacity across time. Under special circumstances (e.g., rapid consumption growth) these utilization rates are adjusted endogenously. The assumed costs for bringing LNG into the United States reflect the least cost aggregation of cost estimates for production, liquefaction, transportation, and regasification from potential supply sources to each of the coastal regions of the United States. Build decisions occur under various restrictions, such as the limitation that new capacity can not be added in a region until existing capacity has been expanded to a specified limit and all of this capacity is fully utilized within the region. In deciding upon capacity expansion, the model does not attempt to anticipate future market situations, factor in regional demand for LNG (except through its indirect impact on prices), nor select between potential regasification sites.

Increases in LNG deliveries beyond expanded capacity at existing sites require the construction of new facilities. 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,
- Lag time between decision to build or expand and start of construction,
- Length of construction period,
- Design capacity and utilization rates for the newly constructed capacity,
- Regional locations for new construction sites,[21]
- Regional prices (trigger prices) that would bring forth additional LNG import capacity, and
- Period over which regional prices must be sustained to trigger decision to build or expand.

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

Appendix 4-A. Discounted Cash Flow Algorithm

Introduction

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

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

where,

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

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

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

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

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

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

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

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

where,

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.

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:

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

where,

PRODTAX = production tax rate.

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

Present Value of Expected Costs

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

Present Value of Expected Drilling Costs

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

The present value of expected drilling costs is given by:

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

where,

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

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

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

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

Present Value of Expected Lease Equipment Costs

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

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

where,

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:

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

where,

KAP = other major capital expenditures, exclusive of lease equipment.

Present Value of Expected Operating Costs

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

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

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

where,

OPCOST = operating costs per well.

Present Value of Expected Abandonment Costs

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

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

where,

COSTABN = abandonment costs.

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

Present Value of Expected Income Taxes

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

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

- Windfall Profits Tax on oil was repealed,
- Investment Tax Credits were eliminated, and
- Depreciation schedules shifted to a Modified Accelerated Cost Recovery System.

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

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

Table 4A-1. Tax Treatment in Oil and Gas Production by Category of Company Under Current Tax Legislation

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

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

$$PVTAXBASE_T = \sum_{t=T}^{T+n} \Bigg[(TREV_t - ROY_t - PRODTAX_t - OPCOST_t - ABANDON_t - XIDC_t - AIDC_t - DEPREC_t - DHC_t) * \left(\frac{1}{1+disc}\right)^{t-T} \Bigg] \tag{11}$$

where,

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

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

disc = expected discount rate.

$TREV_t$, ROY_t, $PRODTAX_t$, $OPCOST_t$, and $ABANDON_t$ are the nondiscounted individual year values. The following sections describe the treatment of expensed and amortized costs for purpose of determining corporate income tax liability at the State and Federal level.

Expected Expensed Costs

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

Expected Intangible Drilling Costs

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

$$\begin{aligned} XIDC_t = {} & COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t + \\ & COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t \end{aligned} \tag{12}$$

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:

[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.

$$AIDC_t = \sum_{j=\beta}^{t} \Big[\big(COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j +$$

$$COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j \big) *$$

$$DEPIDC_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \tag{13}$$

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

where,

j	=	year of recovery
β	=	index for write-off schedule
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

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

where,

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

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

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

Amortization of depreciable costs, excluding capitalized IDC's, conforms to the Modified Accelerated Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in Table 2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If

[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 4A-2. MACRS Schedules
(Percent)

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

Source: U.S. Master Tax Guide.

depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

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

$$\begin{aligned} DEPREC_t = \sum_{j=\beta}^{t} \Big[\big[& (COSTEXP_T * EXKAP + EQUIP_T) * SR_1 * NUMEXP_j + \\ & (COSTDEV_T * DVKAP + EQUIP_T) * SR_2 * NUMDEV_j + KAP_j \big] * \\ & DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \end{aligned} \tag{15}$$

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

where,

j	=	year of recovery
β	=	index for write-off schedule
m	=	number of years in standard recovery period
COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
EQUIP	=	lease equipment costs per well
SR	=	success rate (1=exploratory, 2=developmental)

NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells drilled in a given period
KAP	=	major capital expenditures such as gravel pads in Alaska or offshore platforms, exclusive of lease equipment
DEP	=	for $t \leq n+T-m$, 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

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

where,

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

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

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

where,

FDRT	=	federal corporate income tax rate.

Summary

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

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

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

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

Appendix 4-B. LNG Cost Determination Methodology

Introduction

The expected LNG import volumes will respond to the projected gas prices at the point of delivery into the U.S. pipeline network. That is, the unit cost of imported LNG[1] will be compared to the cost of other gas available to the pipeline network at that location. Unit LNG costs include a reasonable rate-of-return for each step in the LNG supply chain and 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 comprises four components distinguished by separate operational phases: production, liquefaction, shipping, and regasification. Each cost component is expressed as the cost incurred at each phase to supply a unit of LNG.

The methodology 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.

Unit LNG costs are represented as follows:

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

where,

t	=	forecast year
$DCST_t$	=	delivered cost per unit of LNG
$SUPCST_t$	=	supply 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.

Supply

The stranded natural gas[2] production costs for different supply sources range between $0.25 (in 2001 dollars) per thousand cubic feet (Mcf) to $0.60 per Mcf and are based on expert judgments drawn from the 2001 World LNG/GTL Review and the *Oil & Gas Journal's* March 5, 2001, article titled "Asian Gas Prospects-1," which has a cost breakdown for liquefied natural gas delivered to Japan from various sources.

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

[2]Gas reserves that have been located but are isolated from potential markets, commonly referred to as "stranded" gas, are likely to provide most of the natural gas for LNG in the future. Reserves that can be linked to sources of demand via pipeline are unlikely candidates to be developed for LNG.

Liquefaction

LNG liquefaction cost data for different supply sources for 2001 are based on the average liquefaction capital cost for one train (3 million metric tons of LNG or 143 billion cubic feet (Bcf) per year) of $1 billion, which is assumed to be amortized over a 20-year period. It is assumed that the construction of a one-train liquefaction plant will take 3 years to complete. Assuming a 50 percent debt-to-equity ratio and a 12-percent discount rate, the overall project capital cost is $1.130 billion. Hence, the depreciation cost for this liquefaction plant is $0.39/Mcf, to which the return on investment capital and other overhead costs for operations including fuel costs (7 percent of average supply cost of $0.5/Mcf is assumed), taxes ($0.20/Mcf is assumed), and administrative and general ($0.14/Mcf is assumed) are added. The rate of return on capital is assumed to be 12 percent, and costs are adjusted to account for the plant's age, the location, and an escalation cost. In general, these liquefaction costs fall in the $1.32-1.72/Mcf range.

Shipping

LNG per-mile transportation costs are based on the distance-weighted average of two per-mile shipment costs: from Australia to Japan and from Indonesia to Japan. The shipment costs per mile from these two supply areas are respectively $0.000244, and $0.000238 (MMBtu/mile), and are based on shipment costs drawn from the Oil and Gas Journal's March 5, 2001, article referenced above. This per unit average cost to Japan is $0.0002413/MMBtu/mile and is applied to the different distances from the supply sources to the different LNG receiving terminals in the United States to arrive at the transportation costs.

Adjustments to these shipping costs are made by adding a differential cost to the above shipping costs across the board. This differential cost is computed as the average of the differences between two transportation costs, which are computed from two different methods for the same route (from a supply source to a receiving LNG terminal). The first method is already described above. The second method assumes an LNG carrier with the following characteristics:

- -Average capital cost = $186 million (including interest charges during the 3 year construction)
- -Ship capacity = 143,000 cubic meters of LNG or 3 Bcf of natural gas
- -Rate of return on capital= 12 percent
- -Amortization period = 20 years
- -Fuel costs = 7 percent to 42 percent of supply costs, depending on distance
- -Administrative and general = 20 percent of capital and depreciation costs

The differential cost is computed equal to $0.52/Mcf (2001 dollars) for a rate of return on capital of 12 percent. This differential is added to the shipping costs across the board, which are computed using the first method. The final shipping costs obtained are in the $0.89-3.72/Mcf range. The cheapest is from Trinidad to North Carolina ($0.89/Mcf) and the highest shipping cost is from Qatar to Southern California ($3.72/Mcf).

Regasification

Regasification costs are based on capital and operating expenses developed by PTL Associates for a generic 183 Bcf per year, two storage tank LNG import terminal at a non-seismically active site with no requirement for dredging or piling. The provided costs were adjusted to account for land purchase; rate of return; and site-specific permitting, special land and waterway preparation and/or acquisitions, and regulatory costs. Because an LNG facility has not been built in the last 20 years in the United States and because the site-specific permitting and regulatory costs vary so much by location, experience in other countries is not applicable to the difficulties and costs that would apply in the United States. Consequently, anecdotal evidence and analyst judgement was used to develop estimates of the site-specific costs on a regional basis for both construction of new, and expansion of existing, facilities. To account for other general construction and operating cost differences across the United States, multipliers (provided by PTL and ranging from .77 to 1.50) were applied to the costs for each coastal Natural Gas Transmission and Distribution Model (NGTDM) region.

NG facilities are developed with an initial design capacity along with a capability for future expansion. For existing terminals, original capital expenditures are considered sunk costs. Costs were additionally determined for expansion beyond documented expansion capability at existing facilities under the assumption that if prices reached sustained levels at which new facilities would be constructed, additional expansion at existing facilities would likely be considered. The costs of expansion at existing facilities within a region are in general lower that those for the construction of new facilities.

Appendix 4-C. Unconventional Gas Recovery Supply Submodule

INTRODUCTION

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

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

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

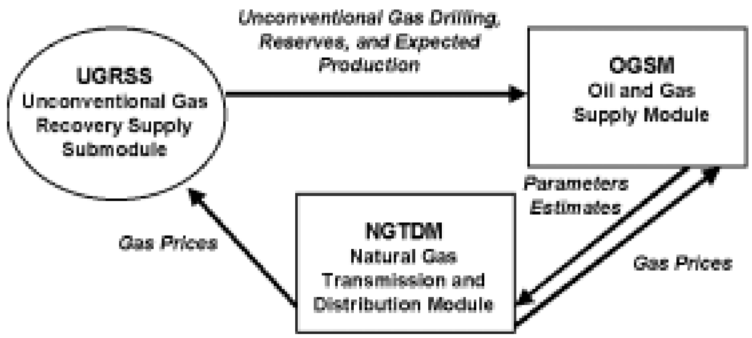
MODEL PURPOSE

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

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

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

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



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

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

Table 4C-1. USGS 1995 National Assessment

Background

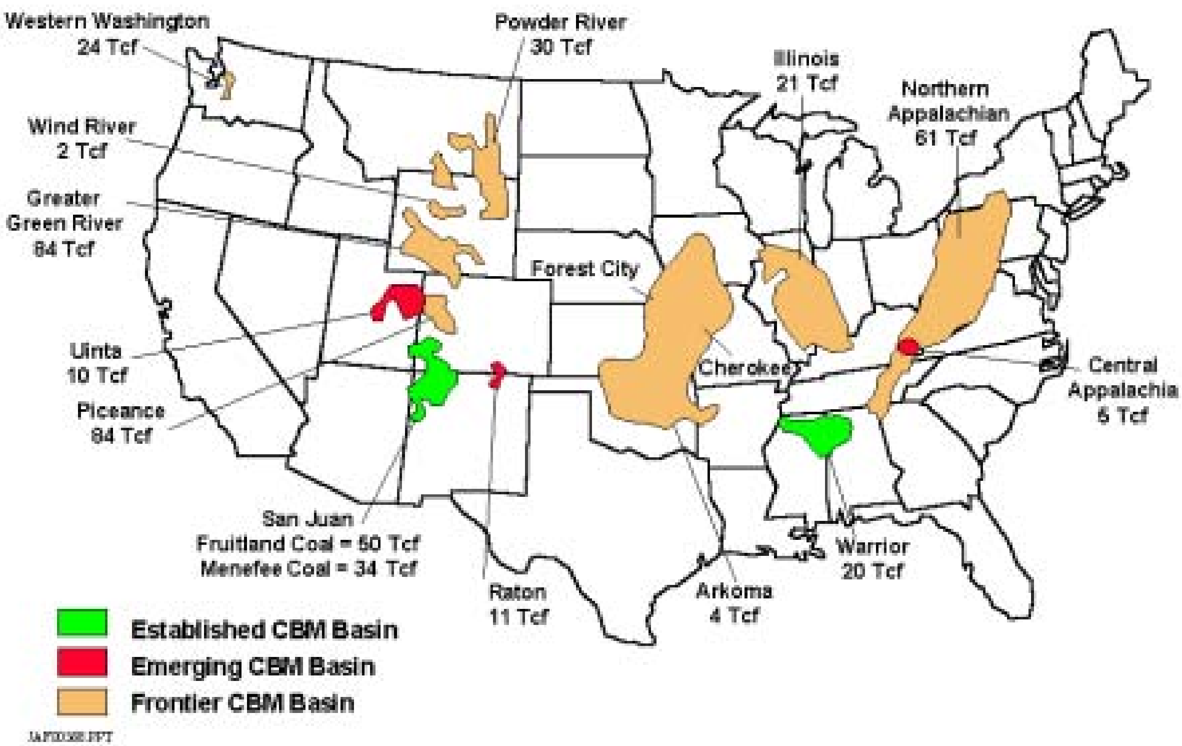
- **The 1995 National Assessment of U.S. Oil and Gas Resources by the USGS established unconventional gas (continuous-type deposits) as the largest undiscovered onshore technically recoverable natural gas resource:**

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

*Includes low permeability chalks

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

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



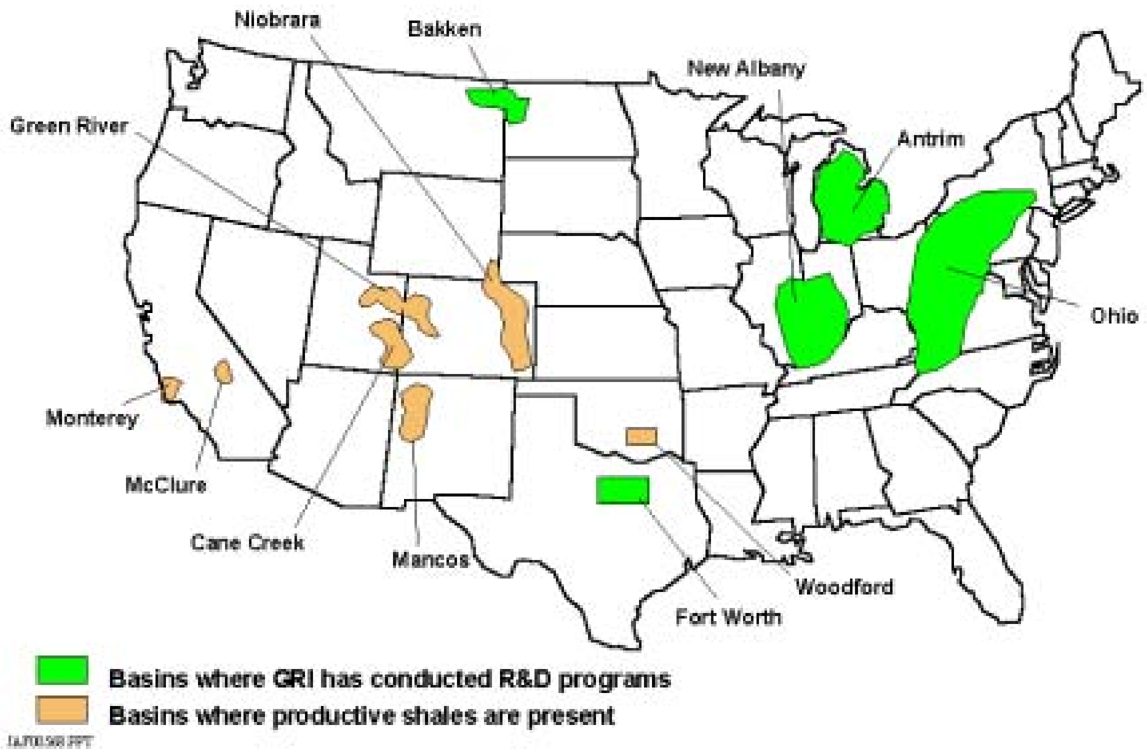
Source: Advanced Resources, International

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

JAF01368.PPT

Source: Advanced Resources, International

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



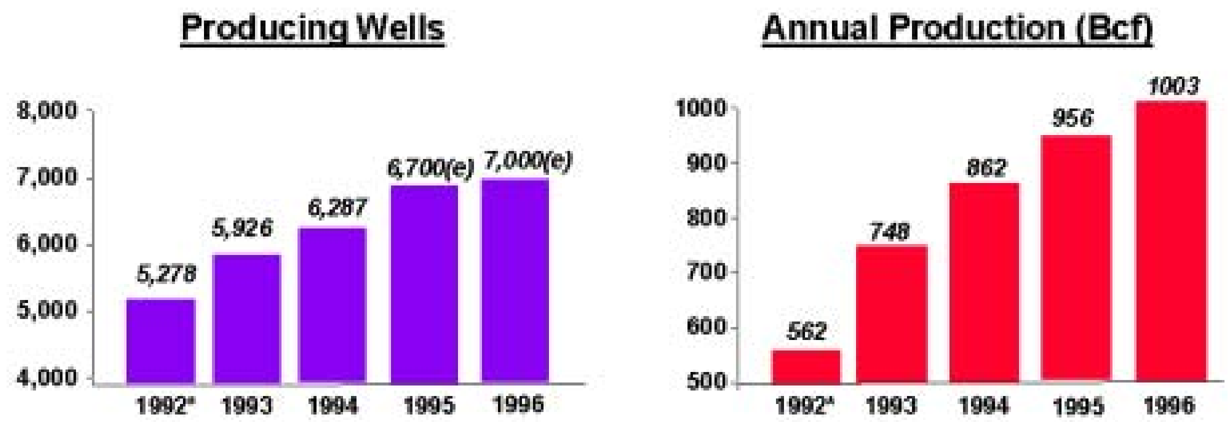
Source: Advanced Resources, International

MODEL OVERVIEW & RATIONALE

The growth of unconventional gas activities in the recent past has been so significant that DOE/EIA needed a better understanding of the quantity of unconventional resources and the technologies associated with its production. Figures 4C-5 and 4C-6 and Table 4C-2 illustrate growth in coalbed methane, tight gas and gas shales production. By 1996, unconventional gas made up 20 percent of US natural gas production and 30 percent of US natural gas reserves. Much of this growth can be attributed to technological advances from R&D in unconventional gas supported by the DOE, the Gas Research Institute (GRI), and industry in the late 1980's and early 1990's.

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

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



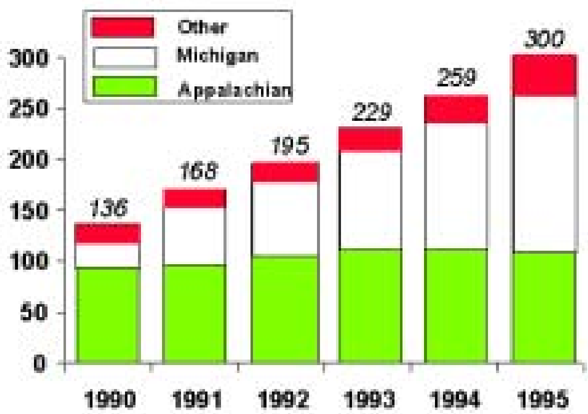
*1992 was the end of the Sec. 29 tax credit.

Source: Advanced Resources, International

Figure 4C-6

Gas Shales Production and Well Completions

Annual Production



Well Completions

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

*Illinois (New Albany) and Denver (Niobrara).

Source: Advanced Resources, International

Table 4C-2

Tight Gas Production -- 1992-1996

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

Source: Advanced Resources, International

DATA SOURCES

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

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

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

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

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

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

Table 4C-3

Tight Sand Resource Base
(as of 1/1/96)

Tight Sand Basins	Undeveloped Recoverable Resources (Tcf)			Comments
	No. Plays	USGS	ARI	
Appalachian Basin	6	43.9	16.2	Reduced Area
Arkoma	1	N/A	0.5	New Assessment
Columbia	1	12.6	6.3	Reduced Area; Success Rates
Louisiana-Miss Salt	1	6.2	17.6	Improved Performance
Mid-Continent (Anadarko)	3	N/A	19.6	New Assessment
Northern Great Plains	3	39.9	21.3	Reduced Performance
Rocky Mountain Basins				
- *Denver*	*1*	*0.8*	*2.5*	*Increased Well Density*
- *San Juan*	*3*	*21.7*	*19.4*	*Comparable Assessment*
- *Uinta*	*4*	*7.9*	*12.8*	*Improved Performance*
- *Green River*	*7*	*86.7*	*140.7*	*Added Deep Gas/Improved Performance*
- *Piceance*	*3*	*12.8*	*24.2*	*Improved S. Basin Assessment*
- *Wind River*	*4*	*N/A*	*35.4*	*New Assessment*
Permian	2	N/A	9.0	New Assessment
Texas Gulf	3	N/A	21.5	New Assessment
TOTAL		**232.5**	**347.2**	

Source: Advanced Resources, International

Table 4C-4

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

Gas Shales Basins	Undeveloped Recoverable Resources (Tcf)			Comments
	No. Plays	USGS	ARI	
Appalachian Basin	4	24.4	23.9	Comparable Assessment
- *Big Sandy Central*	*1*	*9.1*	*8.6*	
- *Big Sandy Extension*	*1*	*9.1*	*9.0*	
- *Greater Siltsone Area*	*1*	*2.8*	*2.8*	
- *Low Thermal Maturity*	*1*	*3.4*	*3.5*	
Michigan Basin	2	18.9	18.9	Comparable Assessment
Illinois Basin	1	1.9	2.0	Comparable Assessment
Cincinnatti Arch	1	1.4	1.4	Comparable Assessment
Williston Basin	1	1.9	1.6	Comparable Assessment
Fort Worth Basin	1	-	6.9	USGS Did Not Assess
TOTAL	**10**	**48.5**	**54.7**	

Source: Advanced Resources, International

Table 4C-5

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

CBM Basins	Undeveloped Recoverable Resources (Tcf)			Comments
	No. Plays	USGS	ARI	
Appalachian Basin	3	14.9	12.3	Comparable Assessment
- *Central*	*(1)*		*(3.7)*	
- *Northern*	*(2)*		*(7.6)*	
- *Cahaba*	*(1)*		*(1.0)*	
Black Warrior Basin	2	2.3	2.2	Comparable Assessment
Illinois Basin	1	1.6	0.6	Reduced Area
Mid-Continent	2	5.0	3.2	Reduced Well EUR's
Rocky Mountain Basins				
- *San Juan*	*5*	*7.5*	*18.1*	*Infill Development, Improved Well EURs*
- *Raton*	*3*	*1.8*	*7.2*	*Expanded Area*
- *Uinta*	*3*	*3.2*	*7.8*	*New Plays; Expanded Area*
- *Powder River*	*2*	*1.1*	*11.5*	*Improved Well EURs, Success Rates, Play Probabilities; Expanded Area*
- *Green River*	*2*	*3.9*	*11.0*	*Added Deep Coals, Improved Well EURs*
- *Piceance*	*4*	*7.5*	*8.4*	*Comparable Assessment*
Others (Wind River, etc.)	2	1.1	-	Small Resources, Little Data
TOTAL	**28**	**49.9**	**82.3**	

Source: Advanced Resources, International

UGRSS MODEL STRUCTURE

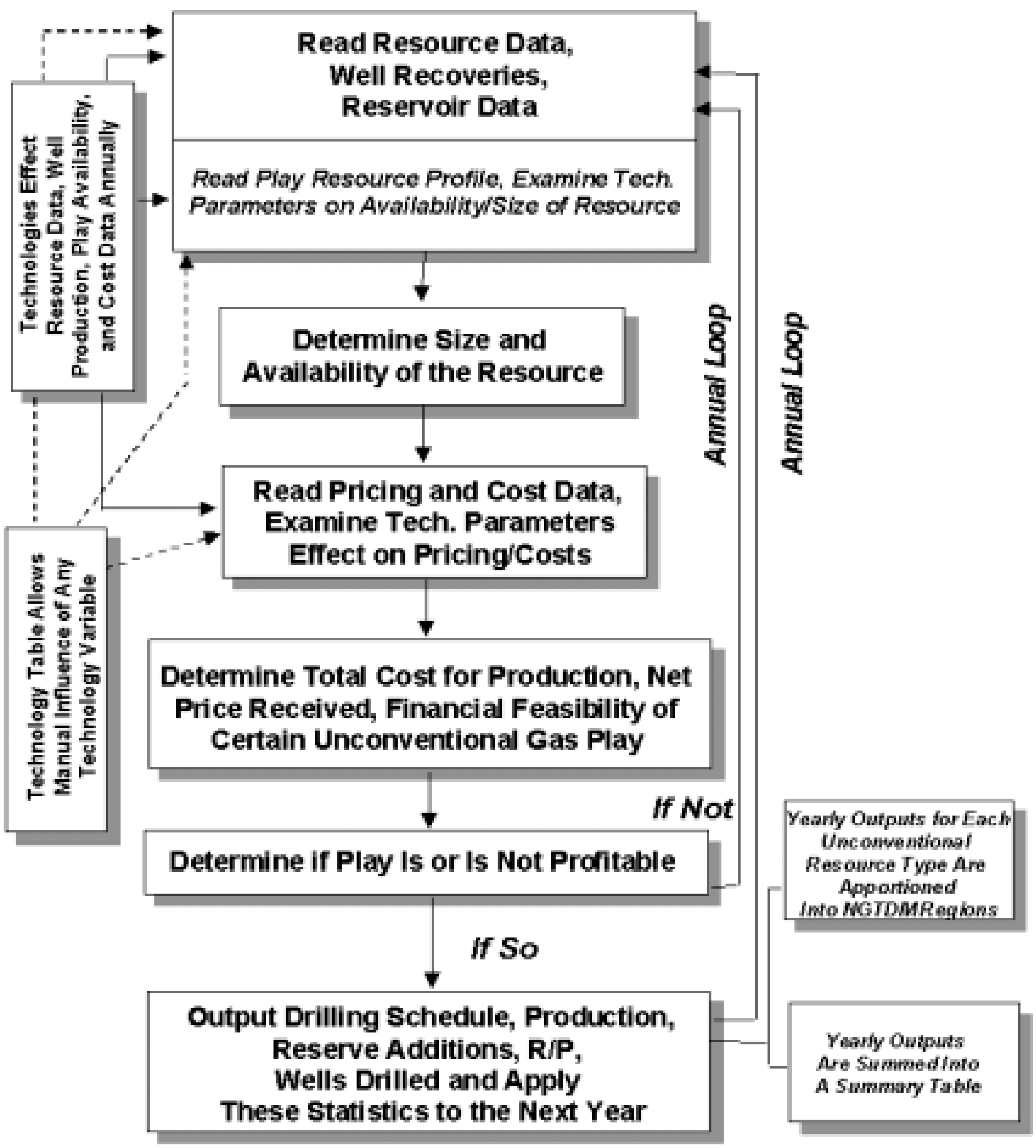
The UGRSS is a FORTRAN-based modeling system developed in a spreadsheet format. The UGRSS projects future unconventional natural gas production for the U. S. onshore lower 48 States. This section discusses in detail the programming structure, design, model inputs and technology variables that allow the UGRSS to function. The first section provides a brief introduction of the UGRSS and a description of the interface between the UGRSS, NEMS, and OGSM. The resource base is categorized in detail in the next section. The justification is detailed for the modifications made by ARI to the existing USGS data, and some background is provided for the new plays that are introduced in the new model. An explanation of how the total resource is derived through equations is summarized and described more fully in the section dealing with technologies. The third section deals with the price and cost components of the UGRSS. Justifications are provided for each price and cost variable that effects the model output. The fourth section describes the output of the model and how the model's output in the base year is built upon and either grows or shrinks over time. Further description of how the equations of the model change from the base case year to subsequent years is provided in this section. The final section describes the technology variables. This section illustrates how different technologies apply to different plays and unconventional gas resource types and how adjustments to these technologies affect the output of the model.

INTRODUCTION

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

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

Figure 4C-7. UGRSS General Process Flow Diagram



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

Advanced Resources International (ARI) incorporated much of the resource information used in the UGRSS from the 1995 USGS United States Oil and Gas Resource Assessment. ARI also used the NPC and it own studies as reference data to track historical unconventional resource data and to illustrate how the outlook concerning unconventional gas has changed over the last 10 years. After analyzing these studies, ARI chose the specific basins and plays it viewed as important producing or potential unconventional gas areas. Some of these plays included in the UGRSS were not quantitatively assessed in the USGS study. These plays include the deep coalbed methane in the Green River Basin, the Barnett Shale of the Fort Worth Basin, and the Tertiary-age and Upper Cretaceous-age tight sands of the Wind River Basin. For these resource estimates, ARI gathered basin and play information from expert sources and added these specific plays to the resource base.

RESOURCE BASE

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

PNUM	=	Play Number: The play number established by ARI
BASLOC	=	Basin Location: The basin and play name
BASAR	=	Basin Area: Area in square miles
DEV_CEL	=	Developed Cells: Number of locations already drilled
WSPAC_CT	=	Well Spacing - Current Technology: Current spacing in acres
WSPAC_AT	=	Well Spacing - Advanced Technology: Spacing in acres under Advanced Technology
SZONE	=	Stimulation Zones: Number of times a single well is stimulated in the play
AVGDPTH	=	Average Depth: Average depth of the play
NOACCESS	=	Percentage of the undrilled locations that are legally inaccessible

CTUL = Legally accessible undrilled Locations - Current Technology: Current number of locations legally accessible and available to drill

$$\boxed{CTUL = ((BASAR*WSPAC\_CT) - (DEV\_CEL)) * (1-NOACCESS)} \qquad (1)$$

ATUL = Legally accessible undrilled Locations - Advanced Technology: Number of locations legally accessible and available to drill under advanced technology

$$\boxed{ATUL = ((BASAR*WSPAC\_AT) - (DEV\_CEL)) * (1-NOACCESS)} \qquad (2)$$

WELL PRODUCTIVITY

This section of the unconventional gas model concerns well productivity. The Estimated Ultimate Recovery (EUR) numbers were taken directly (with some modifications) from the USGS 1995 Assessment. ARI placed the base case year estimates in as hard-wire figures and then extrapolated these figures throughout the model as formulas. For future years, much of the input resource and production numbers in the UGRSS are derived from equations. Year 1 includes many actual measured values because they offer a base of historic information from which to forecast. Each is noted in this documentation and the actual number and forecast equation are described.

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

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

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

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

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

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

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

For Year 1:

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

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

$MEUR1_{1,2}$ = A weighted average for the best 30 percent of the potential wells in the basin

$MEUR1_{1,2} = (0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$

$MEUR1_{1,3}$ = A weighted average for the middle 30 percent of the potential wells in the basin

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

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

Where,

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

As mentioned above, the equations change for MEUR after the first year. After Year 1, experience and technology enable the basin to be better understood geologically and from a potential productive aspect. Accordingly, the model gradually high grades each basin into a best, average, and worst area. As the understanding of the basin develops over time and technology advances, the area thought to be the best 30 percent from a drilling prospective moves toward an EUR representative of the best 10 percent and 20 percent of the basin, the average area stays consistent with the middle 30 percent basin EUR value and the area figured to constitute the worst 40 percent of the potential drilling prospects slowly downgrades to the bottom 40 percent basin EUR value. The EUR for the entire basin is also increasing over time due to the effect of technological progress in reducing damage from drilling and stimulation, increasing fracture length and conductivity, and improving pay contact. This process uses the following equations:

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

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

Where,

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

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

$$MEUR1_{iyr,3} = RW30_{iyr} * (1+TECHYRS*(REDAM\%/20)+TECHYRS*(FRCLEN\%/20)+TECHYRS*(PAYCON\%/20))) \tag{5}$$

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

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

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

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

MEUR2 = For Coalbed Methane, "MEUR1" adjusted for technological progress in the development of New Cavity Fairways (explained in more detail in the Technology Section - Appendix 4-D)

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

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

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

MEUR3 = For Enhanced Coalbed Methane, "MEUR2" adjusted for technological progress in the commercialization of Enhanced Coalbed Methane (explained in more detail in the Technology Section - Appendix 4-D)

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

S C
$SSRT_1$ = Success Rate : The ratio of successful wells over total wells drilled (This can also be called the dry hole rate if you use the equation 1 - SCSSRT). Though each of

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

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

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

TRW = The amount of technically recoverable wells available regardless of economic feasibility. Though each of these TRW values is an input value in Year 1, future forecasting turns these inputs into formulas that capture the effects of technology on the resource base. These equations will be explained in the technology section.

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

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

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

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

$$\boxed{RESNPROD_{iyr} = RESNPROD_{iyr-1}+RESADD_{iyr-1}} \tag{11}$$

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

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

<u>ECONOMICS AND PRICING</u>

The next section of the unconventional gas model focuses on economic and pricing of the different types of unconventional gas. The pricing section involves many variables and is impacted by technology.

DIS_FAC = Discount Factor: This is the discount factor[2] that is applied to the EUR for each well. The discount factor is based on the Present Value of a production stream from a typical coalbed methane, tight sands, or gas shales well over a 20 year period. The stream is discounted at a rate of 15 percent. Both the production stream and the discount rate are variables that are easily modified.

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

DISCRES	=	(DIS_FAC*MEUR3)	(13)

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

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

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

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

DACC = Drilling and completion costs

DACC = IF AVGDPTH less than 2000 feet:
DACC = AVGDPTH*DCC_L2K+DCC_G&G
IF AVGDPTH equal to or greater than 2000 feet:
DACC = 2000*DCC_L2K+(AVGDEPTH-2000)*DCC_G2K)+DCC_G&G (15)

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

The following table represents drilling costs for Coalbed Methane:

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

Table 4C-6. Drilling Costs for Coalbed Methane

Well Depth	Well Cost	Land / G&G Costs
< 2000 feet	$50.00 / foot	$10,000
> 2000 feet	$80.00 / foot	$10,000

Source: Advanced Resources, International

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

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

Table 4C-7. Drilling Costs for Tight Sands

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

Table 4C-7. Drilling Costs for Tight Sands

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

Table 4C-7. Drilling Costs for Tight Sands

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

Table 4C-7. Drilling Costs for Tight Sands

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

Table 4C-7. Drilling Costs for Tight Sands

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

Source: Advanced Resources, International

Table 4C- 8. Drilling Costs for Gas Shales

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

Source: Advanced Resources, International

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

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

STIMC = (SZONE*STM_CST)	(16)

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

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

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

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

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

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

WOML_WTR = Water Producing Well Lease Equipment Costs

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

Table 4C-9. Lease Equipment Costs Matrix

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

Source: Advanced Resources, International

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

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

RST = Variable G&A Cost - Currently 10 percent

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

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

DHC = Dry Hole Costs: Calculates the dry hole costs

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

CCWDH = Capital Costs & Dry Hole Costs with Access Adjustment: Combines these two costs, converts into $/Mcf, and adjusts costs to reflect higher costs in portion of play where lease stipulations occur

CCWDH =	If ACCESS equals 0 or YEAR is less than ACCESS_YR: CCWDH = (LEASSTIP/(1.0-NOACCESS))*1.06 *((TCC+DHC)/DISCRES*1,000,000)) + ((1.0-LEASSTIP-NOACCESS)/ (1.0-NOACCESS))*((TCC+DHC)/DISCRES* 1,000,000) If ACCESS is not equal to 0 and YEAR is greater than or equal to ACCESS_YR: CCWDH = (TCC+DHC)/(DISCRES*1,000,000)	(22)

LEASSTIP = Lease Stipulated Share: The percentage of the play that is subject to Federal lease stipulations

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

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

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

VOC2 = Variable Operating Costs: Establishes an extra operating cost for plays that will incorporate the technology of Enhanced CBM in the future

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

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

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

(25)

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

Table 4C-10. Operation and Maintenance Costs Matrix

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

Source: Advanced Resources, International

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

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

$$\boxed{TOTL\_CST = CCWDH+FOMC/(DISCRES*1{,}000{,}000)} \quad (26)$$

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

$$\boxed{NET\_PRC = (1-RST)*(WHGP+BASNDIF)} \quad (27)$$

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

NET PROFITABILITY

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

MIN_ROI = Risk premium ($/Mcf): A minimum rate of return on investment

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

NET_PROF	=	NET_PRC - TOTL_CST - MIN_ROI	(28)

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

NET_PROF2	=	If NET_PROF is greater than 0: NET_PROF2 = NET_PROF If NET_PROF is less than or equal to 0: NET_PROF2 = 0	(29)

MODEL OUTPUTS

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

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

```
UNDV_WELLS   =   If NET_PROF is greater than 0:
                     IF ENPRGS     =    1:
                     UNDV_WELLS        =    TRW*(ENV%+
                                            LOW%/LOWYRS
                                            *TECHYRS)
                     IF ENPRGS     =    0:
                     UNDV_WELLS        =    TRW
                 If NET_PROF is less than or equal to 0:
                 UNDV_WELLS     =    0
```
(30)

ENPRGS = Establishes if the play is pipeline or environmentally regulated.

ENV% = The percentage of the play that is not restricted from development due to environmental or pipeline regulations

LOW% = The percentage of the play that is restricted from development due to environmental or pipeline regulations

LOWYRS = The number of years the environmental and or pipeline regulation will last.

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

```
MEUR4   =   If NET_PROF is greater than 0:
            MEUR4     =     MEUR3
            If NET_PROF is less than or equal to 0:
            MEUR4     =     0
```
(31)

PROV_RES = Proved Reserves: This variable is a plugged number in the first year to equate with the EIA published figure

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

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

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

```
DRL_SCHED  =  If HYP% is equal to 0:
                    If NET_PROF2 is less than or equal to 0:
                    DRL_SCHED   =        0
                    If NET_PROF2 is greater than 0:
                          If NET_PROF2 is less than LOW$:
                          DRL_SCHED   =        USLOW
                          If NET_PROF2 is greater than or equal to LOW$:
                                If NET_PROF2 is less than SMAL$:                 (32)
                                DRL_SCHED   =        SLOW
                                If NET_PROF2 is greater than or equal to SMAL$:
                                      If NET_PROF2 is less than MED$:
                                      DRS_SCHED   =MED
                                      If NET_PROF2 is greater than or equal
                                      to MED$:
                                            If NET_PROF2 is less than LAR$:
                                            DRL_SCHED=FAST
                                            If NET_PROF2 is greater than or
                                            equal to LAR$:
                                            DRL_SCHED=UFAST
               If HYP% is not equal to 0:
               DRL_SCHED          =        0
```

HYP% = Establishes whether or not the play is hypothetical

Table 4C-11. Drilling Rules Matrix

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

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

DRL_SCHED2 =	If DRL_SCHED is greater than 0:
	    If EMRG is equal to 1:
	    DRL_SCHED2 = (DRL_SCHED+EMERG%) -EMERG#
	    If EMRG is not equal to 1:
	    DRL_SCHED2 = DRL_SCHED
	If DRL_SCHED is less than or equal to 0:
	DRL_SCHED2 = 0
		(33)

EMRG = The parameter that determines if the play is an emerging basin. This designation was made by ARI.

EMERG% = The number of years added onto the drilling schedule because of the hindrance of the play being an emerging basin.

EMERG# = The number of years taken off the drilling schedule for an advancement in technology.

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

DRL_SCHED3 =	If DRL_SCHED2 is less than DRL_SCHED:
	    DRL_SCHED3 = DRL_SCHED
	    If DRL_SCHED2 is greater than or equal to DRL_SCHED:
	    DRL_SCHED3 = DRL_SCHED2
		(34)

DRL_SCHED4 = Drilling Schedule: This variable adjusts the drilling schedule for the play to reflect the effect of access-limiting lease stipulations

DRL_SCHED4 =	If ACCESS equals 0 or YEAR is less than ACCESS_YR: DRIL_SCHED4 = (LEASSTIP/(1.0-NOACCESS))*1.10 *DRIL_SCHED3 +((1.0-LEASSTIP-NOACCESS)/(1.0-NOACCESS))* DRIL_SCHED3 If ACCESS is not equal to 0 and YEAR is greater than or equal to ACCESS_YR: DRIL_SCHED4 = DRIL_SCHED3	(35)

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

NW_WELLS =	If DRL_SCHED4 is greater than 0: If Year is greater than 1 and NW_WELLS_LAG is greater than 0: If UNDV_WELLS/DRL_SCHED4 is greater than 1.3*NW_WELLS_LAG: NW_WELLS = 1.3*NW_WELLS_LAG Else if UNDV_WELLS/DRL_SCHED4 is less than .7*NW_WELLS_LAG: NW_WELLS = .7*NW_WELLS_LAG Else: NW_WELLS = UNDV_WELLS/ DRL_SCHED4 If Year is equal to 1 or NW_WELLS_LAG is equal to 0: NW_WELLS = UNDV_WELLS/DRL_SCHED4 If DRL_SCHED4 is equal to 0: NW_WELLS = 0	(36)

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

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

NW_WELLS2	=	If UNDV_WELLS is less than NW_WELLS: NW_WELLS2 = UNDV_WELLS If UNDV_WELLS is greater than or equal to NW_WELLS: NW_WELLS2 = NW_WELLS	(37)

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

DRA	=	NW_WELLS2*MEUR4	(38)

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

RGA	=	If RES_GR is equal to 1: If ENCBM is equal to 1: RGA = RGR*PROV_RES + .025*((MEUR3-MEUR2)*DEV_CEL) If ENCBM is not equal to 1: RGA = RGR*PROV_RES: If RES_GR is not equal to 1: RGA = 0	(39)

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

RGR = Reserve Growth Rate

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

R_ADD	=	DRA+RGA	(40)

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

PROV_RES2 =	If (PROV_RES+R_ADD-PROD) is greater than 0:
	PROV_RES2 = PROV_RES+R_ADD-PROD
	If (PROV_RES+R_ADD-PROD) is less than or equal to 0:
	PROV_RES2 = 0
			(41)

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

RP_RAT2 =	If R/P is greater than 10: RP_RAT2 = RP_RAT-1 If R/P is less than or equal to 10: RP_RAT2 = RP_RAT	(42)

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

PROD2 =	If R/P2 is equal to 0: PROD2 = 0 If R/P2 is not equal to 0: PROD2 = PROV_RES2/(RP_RAT2)	(43)

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

UNDV_WELLS2 =	If ENPRGS is equal to 1:
	UNDV_WELLS2 = TRW-NW_WELLS2
	If ENPRGS is not equal to 1:
	If UNDV_WELLS is equal to 0:
	UNDV_WELLS2 = 0
	If UNDV_WELLS is not equal to 0:
	If (UNDV_WELLS-NW_WELLS2) is equal to 0:
	UNDV_WELLS2 = 0.1
	If (UNDV_WELLS-NW_WELLS2) is not equal to 0:
	UNDV_WELLS2 = UNDV_WELLS -NW_WELLS2
		(44)

Appendix 4-D. Unconventional Gas Recovery Supply Technologies

I. INTRODUCTION

The Unconventional Gas Recovery Supply Submodule (UGRSS), shown in **Figure 4D-1**, relies on the Technology Impacts and Timing functions to capture the effects of technology progress on the costs and rates of gas production from coalbed methane, gas shales, and tight sands. The numerous research and technology initiatives are grouped into 11 specific "technology packages," that encompass the full spectrum of key disciplines -- geology, engineering, operations, and the environment. The enclosed materials define these 11 technology packages for unconventional gas exploration and production (E&P).

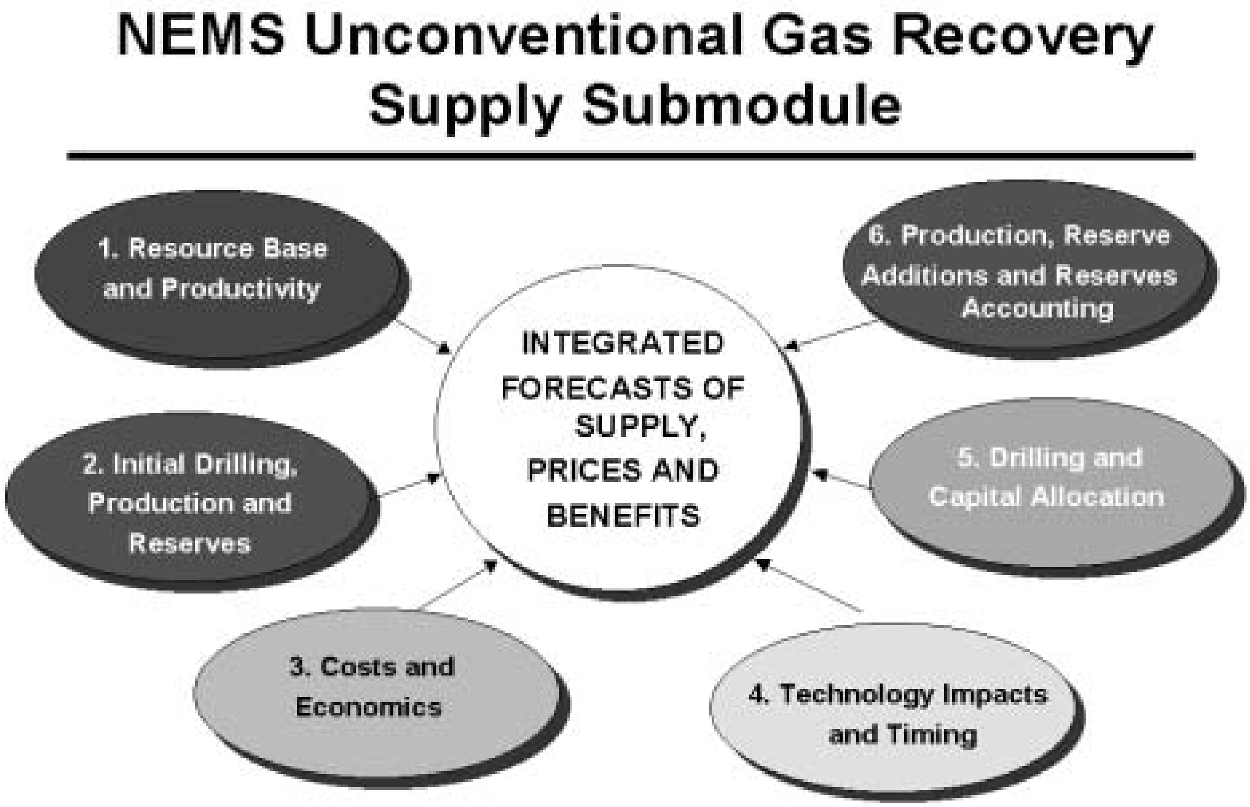
The technology packages are grouped into four distinct technology cases -- Reference Case, Low Technology, High Technology, and Reference Case without Department of Energy (DOE) research and development (R&D)-- that capture four different futures for technology progress, as further described below:

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

- The **Low Technology** case developed by ARI for the UGRSS captured the pace of technology progress assuming only industry supported R&D and continuing reductions in corporate R&D budgets. With the scale-back in major company R&D outlays and the dominance of independent producers, who fund little R&D in unconventional gas, the pace of technology progress under Low Technology was expected to be modest. For the Annual Energy Outlook 2003 (AEO2003), the Low Technology case represents an R&D outlook where the effects of the various technologies are generally about 15 percent less than in the Reference Case.

- The **High Technology** case developed by ARI for the UGRSS defined strong, focused and integrated industry, DOE and GRI R&D programs in unconventional gas. It reflected the levels of investment and progress achieved during the late 1980's and early 1990's when DOE and GRI R&D programs and industry's own commitment to unconventional gas were high and highly productive. For the AEO2003, the High Technology case represents an R&D outlook where the effects of the various technologies are generally about 15 percent greater than in the Reference Case.

Figure 4D-1



NEMS Unconventional Gas Recovery Supply Submodule
1. Resource Base and Productivity
2. Initial Drilling, Production and Reserves
3. Costs and Economics
4. Technology Impacts and Timing
5. Drilling and Capital Allocation
6. Production, Reserve Additions and Reserves Accounting
INTEGRATED FORECASTS OF SUPPLY, PRICES AND BENEFITS

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

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

1. Increasing the Resource Base with Basin Assessments.

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

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

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

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

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

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

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

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

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

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

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

Table 4D-1

Summary of Technological Progress

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

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

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

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

Table 4D-2
Details of Coalbed Methane Technological Progress

R&D Program	CBM Resource Impacted	Technology Lever	Current Situation	Technology Cases: Reference Case	Technology Cases: Low Technology	Technology Cases: High Technology
1. Basin Assessment	Hypothetical Plays	Date Available	Not Available	Year 2025	Not Available	Year 2021
2. Extended Resource Characterization	Emerging Basins	Pace of Development	30 to 60 years (+20 years over Developing Basins)	-.7 yr/year (Max -20 years)	-.6 yrs/year (Max -20 years)	-.8 yrs/year (Max -20 years)
3. Well Performance Diagnostics & Remediation	Proved Reserves	Reserve Growth	All Basins with Proved Reserves @ 3%/yr., declining	All Basins @ 2%/yr., declining (30 years)	All Basins @ 1.7%/yr., declining (20 years)	All Basins 2.3%./yr, declining (40 years)
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	25% to 95%	+.25%/year from 2000 (max 95%)	+.21%/year from 2000 (max 95%)	+.29%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify "Best" 30% by Year 2017	Identify "Best" 30% by year 2021	Identify "Best" 30% by year 2014
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+.17%/year (30 years)	+.14% (30 years)	+.19% (30 years)

Table 4D-2
Details of Coalbed Methane Technological Progress

R&D Program	CBM Resource Impacted			Technology Cases		
		Technology Lever	Current Situation	Reference Case	Low Technology	High Technology
6. Improved Drilling and Stimulation	All Plays	EUR/Well	As Calculated	+.33%/year (30 years)	+.28%/year (30 years)	+.38%/year (30 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	+.33%/year (30 years)	+.28%/year (30 years)	+.38%/year (30 years)
8. Water and GasTreating R&D	Wet CBM Plays	Water & Gas Treating O&M Costs/Mcf	$0.30/Mcf	-.67%/year (30 years)	-.57%/year (30 years)	-.77%/year (30 years)
9. Advanced CBM Cavitation	Cavity Fairway Plays	EUR/Well	As Calculated	+20% (year 2016)	+17% (year 2020)	+23% (year 2013)
10. Enhanced CBM Recovery	ECBM Eligible Plays	a. Recovery/ Efficiency	As Calculated	Not Available	Not Available	+34.5% (year 2022)
		b. O&M Costs/Mcf	As Calculated	Not Available	Not Available	+$0.75/Mcf, Incremental
11. Environmental Mitigation	EV Sensitive Plays	Acreage Available	35% of Play Restricted	Removed in 35 years (1%/yr from year 2000)	Removed in 41 years (.85%/ yr from year 2000)	Removed in 30 years (1.15%/yr from year 2000)

Table 4D-3
Details of Gas Shales Technological Progress

R&D Program	Gas Shales Resource Impacted	Technology Lever	Current Situation	Technology Cases: Reference Case	Technology Cases: Low Technology	Technology Cases: High Technology
1. Basin Assessment	Hypothet-ical Plays	Date Available	Not Available	Year 2025	Not Available	Year 2021
2. Extended Resource Characterization	Emerging Basins	Pace of Development	30 to 60 years (+20 years over Developing Basins)	-.7 yrs/year (Max -20 years)	-.6 yrs/year (Max -20 years)	-.8 yrs/year (Max -20 years)
3. Well Performance Diagnostics and Remediation	Proved Reserves	Reserve Growth	All Basins with Proved Reserves @ 3%/yr., declining	All Basins @ 3%/yr., declining (30 years)	All Basins @ 2.55%/yr., declining (20 years)	All Basins 3.45%./yr, declining (40 years)
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	25% to 95%	+.25%/year from 2000 (max 95%)	+.21%/year from 2000 (max 95%)	+.29%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify "Best" 30% by Year 2017	Identify "Best" 30% by year 2021	Identify "Best" 30% by year 2014
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+.17%/year (30 years)	+.14% (30 years)	+.19% (30 years)

Table 4D-3
Details of Gas Shales Technological Progress

R&D Program	Gas Shales Resource Impacted			Technology Cases		
		Technology Lever	Current Situation	Reference Case	Low Technology	High Technology
6. Improved Drilling and Stimulation	All Plays	EUR/Well	As Calculated	+.33%/year (30 years)	+.28%/year (30 years)	+.38%/year (30 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	+.33%/year (30 years)	+.28%/year (30 years)	+.38%/year (30 years)
8. Water and Gas Treating R&D	All Plays	Water & Gas Treating O&M Costs/Mcf	$0.30/Mcf	-.67%/year (30 years)	-.57%/year (30 years)	-.77%/year (30 years)
9. Multi-Lateral Completions	Eligible Plays	Recovery Efficiency	As Calculated	Not Available	Not Available	Not Available
10. Other Gas Shales Technology	Eligible Plays	a. EUR/Well	As Calculated	Not Available	Not Available	Not Available
		b. O&M Costs/Mcf	As Calculated	Not Available	Not Available	Not Available
11.Environ-mental Mitigation	EV Sensitive Plays	Acreage Available	35% of Play Restricted	Removed in 35 years (1%/yr from year 2000)	Removed in 41 years (.85%/ yr from year 2000)	Removed in 30 years (1.15%/yr from year 2000)

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

R&D Program	Tight Sands Resource Impacted	Technology Lever	Current Situation	Technology Cases: Reference Case	Low Technology	High Technology
1. Basin Assessment	Hypothetical Plays	a. Date Available	Not Available	Year 2025	Not Available	Year 2021
2. Extended Resource Characterization	Emerging Basins	Pace of Development	30 to 60 years (+20 years over Developing Plays)	-1.2 yrs/year (Max -20 years)	-1.1 yrs/year (Max -20 years)	-1.4 yrs/year (Max -20 years)
3. Well Performance Diagnostics and Remediation	Proved Reserves	Reserve Growth	San Juan Basin @ 3%/yr., declining	All Basins @ 2%/yr., declining (30 years)	All Basins @ 1.7%/yr., declining (20 years)	All Basins 2.3%./yr, declining (40 years)
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	30% to 95%	+.25%/year from 2000 (max 95%)	+.21%/year from 2000 (max 95%)	+.29%/year from 2000 (max 95%)
		b. Exploration Efficiency	Random	Identify “Best” 30% by Year 2017	Identify “Best” 30% by year 2021	Identify “Best” 30% by year 2014
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+.17%/year (30 years)	+.14% (30 years)	+.19% (30 years)

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

R&D Program	Tight Sands Resource Impacted			Technology Cases		
		Technology Lever	Current Situation	Reference Case	Low Technology	High Technology
6. Improved Drilling and Stimulation	All Plays	a. EUR/Well	As Calculated	+.33%/year (30 years)	+.28%/year (30 years)	+.38%/year (30 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-.33%/year (30 years)	-.28%/year (30 years)	-.38%/year (30 years)
8. Water and Gas Treating R&D	All Plays	Water & Gas Treating O&M Costs/Mcf	$0.15/Mcf	-.67%/year (30 years)	-.57%/year (30 years)	-.77%/year (30 years)
9. Horizontal Wells	Continuous Sands	Recovery Efficiency	As Calculated	+10% (year 2016)	+8.5% (year 2020)	+11.5% (year 2013)
10. Other Tight Gas Technology	Other Sands	EUR/Well	As Calculated	Not Available	Not Available	+11.5% (year 2022)
11. Environmental Mitigation	EV Sensitive Plays	Acreage Available	35% of Play Restricted	Removed in 35 years (1%/yr from year 2000)	Removed in 41 years (.85%/ yr from year 2000)	Removed in 30 years (1.15%/yr from year 2000)

II. Technology Packages

1. Increasing the Resource Base with Basin Assessments

Background and Problem

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

Technology Lever

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

Impacts and Benefits

The CBM basins and plays listed on **Table 4D-6** are categorized as hypothetical and thus are currently not available for CBM development. **Tables 4D-7** and **4D-8** provide similar information on the hypothetical gas shale and Tight Gas Plays. (The data and information in the 1995 USGS National Assessment provide the foundation for the CBM, gas shales, and tight sands resource estimates on these tables). Selected high potential basin and plays not evaluated by the USGS, such as the Wind River Basin tight sands and the Deep Green River Basin CBM, were added from special studies by Advanced Resources International, Inc.

Reference Case Technology enables these plays to become available for industry consideration in the year 2025. Low Technology keeps the situation as is, leaving the hypothetical plays unavailable for development. High Technology makes these gas plays available for industry consideration 4 years earlier, in year 2021.

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

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

Table 4D-5

Parameter Values for Basin Assessment Technologies

Technology Case	**Year Hypothetical Plays Become Available**
Current Situation	Not Available
Reference Case	Year 2025
Low Technology	Not Available
High Technology	Year 2021

Table 4D-6

Hypothetical CBM Plays and Resources

Basins	Gas Plays	Undeveloped Resource (Bcf)
Appalachia	N. Basin -- Syncline	3,300
Mid-Continent	Forest City/Arkoma Syncline	1,152
San Juan	Southern (Menefee)	420
Uinta	Sego	726
Piceance	Deep Basin	2,304*
Green River	Deep Basin	3,600*
Black Warrior	Central Basin	224

Source: Advanced Resources, International

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

Table 4D-7

Hypothetical Gas Shale Plays and Resources

Basin	Gas Play	Undeveloped Resources (Bcf)
Appalachia	Devonian Shale - Low Thermal Maturity	3,528
Michigan	Antrim Shale - Undeveloped Area	13,937
Illinois	New Albany Shale - Developing Area	1,985
Cincinnati Arch	Devonian Shale	1,426
Williston	Shallow Niobrara, Biogenic Gas	1,575

Source: Advanced Resources, International

Table 4D-8

Hypothetical Tight Sands Plays and Resources

Basin	Gas Plays	Undeveloped Resources (Bcf)
Appalachia	Clinton/Medina Moderate	5,474
	Clinton/Medina Low	2,400
	Upper Devonian Moderate	743
	Upper Devonian Low	1,260
Columbia	Basin Center	6,300
Uinta	Tertiary West	1,666
	Basin Flank MV	5,004
	Deep Synclinal MV	1,274
Piceance	N. Basin WF/MV	4,200
Green River	Fort Union	1,686
	Lewis	28,256
	Deep MV	21,168
	Deep Frontier	34,875
Wind River	Fort Union/ Lance Deep	16,000*
	MV/Frontier Deep	1250*
N. Great Plains	Moderate Potential	12,784
	Low Potential	6,745

Source: Advanced Resources, International

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

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

Background and Problem

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

Technology Lever

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

Impacts and Benefits

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

Reference Case Technology removes the initial 20 year "stretch-out" in development time for the emerging plays in 29 years, at a rate of .7 year of reduced time delay per year for CBM and gas shales. The reference case removes this stretch out time in 17 years, at a rate of 1.2 years of reduced time delay per year for tight sands. Low Technology removes the "stretch-out" period in 33 years at 0.6 years per year for coalbed methane and gas shales and 18 years at 1.1 years per year for tight sands. High Technology overcomes the 20 year development "stretch-out" time faster, in 25 years, at a rate of .8 years of reduced time delay per year for CBM and gas shales and in 14 years, at a rate of 1.4 years of reduced time delay per year for tight sands.

The specific parameter values for the technology cases for all three of the unconventional gas resources (CBM, gas shales, and tight sands) are set forth in **Table 4D-9** below:

Table 4D-9

Parameter Values for Reservoir Characterization Technologies

Technology Case	Development Constraints on Emerging Plays	Rate of Constraint Removal
Current Situation	+20 years to development time	Not removed
Reference Case	a. Removed in 29 years, starting in 1997 for CBM and Gas Shales	a. .7 year reduction/year
	b. Removed in 17 years, starting in 1997 for Tight Sands	b. 1.2 years reduction/year
Low Technology	a. Removed in 33 years, starting in 1997 for CBM and Gas Shales	a. .6 years reduction/year for CBM and Gas Shales
	b. Removed in 18 years, starting in 1997 for Tight Sands	b. 1.1 years reduction/year for Tight Sands
High Technology	a. Removed in 25 years, starting in 1997 for CBM and Gas Shales	a. .8 years reduction/year for CBM and Gas Shales
	b. Removed in 14 years, starting in 1997 for Tight Sands	b. 1.4 years reduction/year for Tight Sands

Table 4D-10

Emerging CBM Plays and Resources

Basin	Gas Play	Undeveloped Resources (Bcf)
Appalachia	N. Basin Anticline	4,971
Illinois	Central Basin	582
Mid-Continent	Cherokee/Arkoma Basin	1,718
Uinta	Blackhawk Formation	1,290
	Sego	726
Piceance	Shallow Basin Margins	3,334
Raton	North Area	1,792
	South Area	1,176
Powder River	Central Basin	4,474
Green River	Shallow Areas	3,835
	Deep Areas	3,600

Source: Advanced Resources, International

Table 4D-11

Emerging Gas Shale Plays and Resources

Basin	Gas Plays	Undeveloped Resources (Bcf)
Appalachia	Devonian Shale - Big Sandy Extension Area	9,000
	Devonian Shale - Greater Siltstone Area	2,832
Fort Worth	Barnett Shale - Main Area	6,885*

Source: Advanced Resources, International

**New Gas Shale play added by Advanced Resources International, Inc.*

Table 4D-12

Emerging Tight Sands Plays and Resources

Basins	Gas Plays	Undeveloped Resources (Bcf)
Texas Gulf Coast	Vicksburg	4,343*
	Olmos	2,871*
Permian	Abo	1,152*
Wind River	Ft. Union/Lance Shallow	16,517*
	MV/Frontier Shallow	1,663*
Green River	Fox Hills/Lance	27,633
	Shallow MV	19,553
	Lewis	28,256
Piceance	S. BasinWF/MV	16,800*
	N. BasinWF/MV	4,200
	Iles/MV	3,246
Arkoma	Atoka	520*
N. Great Plains	Biogenic Gas, High Potential	1,796

Source: Advanced Resources, International

**New Tight Gas plays added by Advanced Resources International, Inc.*

3. Extending Reserve Growth in Existing Unconventional Gas Fields with Advanced Well Performance Diagnostics and Remediation

Background and Problem

A review of the historical data shows that proved reserves in existing unconventional gas fields grow by 2 to 4 percent per year due to adjustments and revisions stemming from uphole well recompletions, restimulation and more effective production practices. However, the pace of this non-drilling based reserve growth has been declining steadily as operators face increasing difficulties in identifying and diagnosing the problems of low recovery efficiencies and underperforming unconventional gas wells.

Technology Lever

A rigorous unconventional gas well diagnostics and remediation R&D program would provide the appropriate set of tools for evaluating and targeting problem gas wells. It would also provide a basis for designing and selecting the appropriate cost-effective well remediation technologies, helping support continued reserve growth.

Impact and Benefits

Currently, the plays listed on **Tables 4D-14, 4D-15, and 4D-16** have proved resources of CBM, gas shales, and tight sands. Based on the available data, improved well remediation and production practices provide approximately 2 to 3 percent annual growth in proved reserves, with a noticeable decline in growth since the early 1990's.

Reference Case Technology starts with a 3 percent annual reserve growth for gas shales plays with existing proved reserves and declines the level of reserve growth over 30 years. Reference Case Technology for tight sands and coalbed methane start with a 2 percent annual reserve growth (for plays with existing proved reserves) and decline the level of reserve growth over 20 years. Low Technology provides lower and declining reserve growth, starting at 2.55 percent per year for gas shales and 1.7 percent per year for tight sands. Growth in the low technology case declines over 20 years for gas shales and over 15 years for tight sands and coalbed methane. High Technology starts with a higher 3.45 percent annual growth in proved reserves for gas shales and a 2.3 percent growth for tight sands and coalbed methane. This growth declines over 35 years for CBM and gas shales and over 25 years for tight sands.

The specific parameter values for the technology cases are set forth **Table 4D-13** below.

Table 4D-13

Parameter Values for Advanced Well Performance Diagnostics and Remediation Technologies

Technology Case	Applicable Basins	Reserve Growth Factor
Current Situation	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	2% - 4% with Recent Declines
Reference Case	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	a. 3%, Declining for Gas Shales
		b. 2%, Declining for Tight Gas and Coalbed Methane
Low Technology	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	a. 2.55%, Declining for Gas Shales
		b. 1.7% Declining for Tight Gas
High Technology	Basins/Plays on Tables 4D-14, 4D-15, and 4D-16	a. 3.45%, Declining for Gas Shales
		b. 2.3% Declining for Tight Gas and Coalbed Methane

Table 4D-14

CBM Plays With Proved Reserves

Basin	Gas Play	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
San Juan	North Basin (CO)	696	700
	Cavity Fairway (NM/CO)	6,170	6,157
	West Basin (NM)	586	550
	East Basin (NM)	152	150
Warrior	Shallow Basin Area	972	823
Unita	Ferron Formation	400	400
Raton	North Basin Area	0	31
	Purgatory River Area	100	249
Powder River	Shallow Basin Margin	100	150
Piceance	Divide Creek	56	52
Appalachia	Central App. Basin	1,137	1,172
Mid Continent	Cherokee & Arkoma	130	130
TOTALS		**10,499**	**10,564**

Source: Advanced Resources, International

Table 4D-15

Gas Shale Plays With Proved Reserves

Basins	Gas Plays	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
Appalachia	Devonian Shale - Big Sandy Central Area	1,360	1,470
	Devonian Shale - Big Sandy Extension Area	340	330
Michigan	Antrim Shale - Developing Area	1,500	1,680
Fort Worth*	Barnett Shale - Main Area	208	270
TOTALS		**3,408**	**3,750**

Source: Advanced Resources, International

**New Gas Shale plays added by Advanced Resources International, Inc.*

Table 4D-16

Tight Sands Plays With Proved Reserves

Basin	Gas Plays	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
Appalachia	Clinton/Medina High	900	1,020
	Upper Devonian High	3,600	3,700
San Juan	Picture Cliffs	900	960
	Central Basin/MV	5,200	5,300
	Central Basin/Dakota	2,700	2,600
Uinta	Tertiary East	500	527
	Basin Flask MV	10	9
Piceance	S. Basin WF/MV	600	700
	N. Basin WF/MV	150	140
	Iles/MV	150	140
Green River	Fox Hills/Lance	100	200
	Lewis	100	95
	Shallow MV	1,800	1,805
	Frontier (Moxa Arch)	3,400	3,406
Wind River	Ft. Union/Lance Shallow	150	210
	MV/Frontier Shallow	300	300
Denver	Deep J Sandstone	1,000	1,050
Louisiana/Mississippi Salt	Cotton Valley	4,200	4,500
Texas Gulf Coast	Vicksburg	200	170
	Wilcox/Lobo	2,400	2,580
	Olmos	650	700
Permian	Canyon	2,000	2,160
	Abo	600	640
Anadarko	Cleveland	400	496
	Cherokee/Redfork	1,500	1,420
	Granite Wash/ Atoka	380	364
N. Great Plains	Biogenic Gas, High Potential	300	300
Arkoma	Atoka	500	600
TOTALS		**34,690**	**36,221**

Source: Advanced Resources, International

4. Improving Exploration Efficiency with Advanced Exploration and Natural Fracture Detection Technology

Background and Problem

In settings where the unconventional gas resource has sufficiently high gas concentration and is intensely naturally fractured, this resource can be produced at commercial rates. Finding these settings of high natural fracture intensity and diversity of orientation is a major technical challenge and greatly influences the economics of unconventional gas development. Currently, the USGS assumes that the development of unconventional gas or continuous-type basins and plays will be based on a uniform, basin wide development plan rather than selective exploration for higher permeability areas. The R&D goal is to develop and introduce improved exploration technology to enable producers to find the best, "sweet-spot" portions of these gas basins.

Technology Lever

A significant portion of DOE/NETL's current R&D on low permeability gas reservoirs is directed at technologies and field projects on natural fracture detection and improved exploration technology. These methods will help operators to identify, before drilling, the "sweet spots" in otherwise tight reservoirs, resulting in a larger initial portion of high productivity wells.

Impacts and Benefits

Currently, unconventional gas plays are generally assessed based on the performance and economics of the "average well" in the play. This assumes that large numbers of low productivity wells need to be drilled to develop the higher productivity areas, increasing the threshold costs for the gas play.

Reference Case Technology addresses the question of exploration efficiency, the "c" factor in the exploration efficiency equation, and enables the industry to find the "best 30 percent" of the basin in 20 years, by the year 2017. Reference Case Technology also improves the success rate of the play by .25 percent per year, starting in the year 2000. For all recovery types, Low Technology improves the success rate of the play by .21 percent per year and enables industry to find the "best 30 percent" of the basin in 24 years. High Technology enables industry to reliably find the "best 30 percent" of a basin by the year 2014 for all recovery types. For this case the drilling success rate increases by .29 percent per year, all increases starting in the year 2000.

The specific parameter values for the technology cases, for all three of the unconventional gas resources (CBM, gas shales, and tight sands), are set forth in **Table 4D-17** below:

Table 4D-17

Parameter Values for Advanced Exploration and Natural Fracture Detection Technologies

Technology Case	Level of Exploration Efficiency	Change in Drilling Success Rate
Current Status	Random	50% to 90% Success Rates
Reference Case	Identify "Best" 30% of Play by Year 2017	Improves by .25%/year from Year 2000
Low Technology	Identify "Best" 30% of Play by Year 2021	Improves by .21%year from Year 2000
High Technology	Identify "Best" 30% of Play by Year 2014	Improves by .29%/year from Year 2000

5. Increasing Recovery Efficiency With Geology/Technology Modeling and Matching

Background and Problem

Field development plans and operations are challenging to design for unconventional gas plays, given the complex, difficult to measure and widely varying reservoir properties. As a result, the selection and application of “best available” technology and production practices to optimize gas recovery has proven to be difficult.

Technology Lever

The key task is improved understanding of unconventional gas reservoir conditions and appraisals of “best available” technology. For this, new research data on multi-phase relative permeability, stress sensitive formations, and natural fracture patterns are essential. Also needed are advanced reservoir simulators that can properly model these complex settings and behaviors, and thus provide more reliable projections of gas recovery. These data and tools would allow more optimum selection of appropriate technology for efficient field development.

Impacts and Benefits

Currently, fields are designed with a variety of assumptions and “rules of thumb” about reservoir properties and technology performance, without consideration of the complex interaction of the reservoir and the chosen technology. This leads to much lower than optimum gas recoveries per well.

Reference Case Technology increases recovery from new wells by 5.1 percent in 30 years, at a rate of .17% percent per years for all recovery types. Low Technology increases recovery from new wells by 4.2 percent in 30 years at a rate of .14 percent per years. High Technology increases recovery per well by 5.7 percent, at a rate of .19 percent per year.

The specific parameter values for technology cases are summarized in **Table 4D-18** below:

Table 4D-18

Parameter Values for Geology/Technology
Modeling and Matching Technologies

Technology Case	Improved Recovery After 20 Years	Rate of Change
Current Status	As Calculated	-
Reference Case	5.1%	.17%/year
Low Technology	4.2%	.14%/year
High Technology	5.7%	.19%/year

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

Background and Problem

The permeability in CBM, gas shale and tight sand formations is easily damaged by use of chemicals, gels, drilling muds and heavy cement, leading to underperforming wells. Improving well drilling, completion and stimulation fluids and procedures would help improve recoveries from such wells, particularly in multi-zone, vertically heterogeneous formations.

Technology Lever

R&D on formation and fluid compatibility, low damage fluids such as CO_2 or N_2, improved rock mechanics and stimulation models, underbalanced drilling, and improved proppant carrying fluids, particularly for multi-zone reservoirs, could reduce formation damage, increase fracture length and placement, and increase fracture conductivity, thus improving reserves per well.

Impacts and Benefits

Currently, hydraulic stimulations are short, poorly propped, and often ineffective. Also, overbalanced drilling through the reservoir causes formation damage, leading to lower than optimum recoveries per well and much less effective reserves to production (R/P) ratios, particularly in the economically crucial first 5 years.

Reference Case Technology increases recovery per well by 10 percent in 30 years (at a rate of .33 percent per year) for all recovery types. Low Technology increases recovery by $7^1/_2$ percent in 30 years (at a rate of .28% percent per year). High Technology increases recovery by $12^1/_2$ percent in 30 years (at a rate of .38% percent per year).

The specific parameter values for the technology cases are summarized in **Table 4D-19** below.

Table 4D-19

Parameter Values for Lower Damage, More Effective Well Completions and Stimulations Technologies

Technology Case	Improved Well Recovery After 30 Years	Rate of Change
Current Status	As Calculated	-
Reference Case	10% (30 years)	.33% year
Low Technology	7½% (30 years)	.28%/year
High Technology	12½% (30 years)	.38%/year

7. Lowering Well Drilling and Completion Costs with Unconventional Gas Specific Drilling and Hydraulic Fracturing R&D

Background and Problem

Well drilling and completion represent the primary capital cost items in unconventional gas development and place a high economic hurdle on these resources, particularly when these costs are assessed using discounted cash flow analysis. Lowering well drilling and stimulation costs would significantly improve the overall economics, particularly for the deeper, low permeability gas plays.

Technology Lever

R&D on advanced drilling and completion methods, particularly the use of downhole motors and modified stimulation practices, will lead to faster formation penetration rates, simpler frac fluids, and thus lower costs.

Impacts and Benefits

Currently, drilling costs for unconventional gas range from $30 to $100 per foot. However, tightness in the rig market is putting pressure on drilling day-rates and pushing up costs. Stimulation costs add $30,000 to $300,000 per well. These costs have declined over past years, but are now stabilizing. The decline in D&C costs has slowed appreciably as many of the easier cost cutting efforts have been accomplished and the industry is returning to full capacity.

Reference Case Technology reduces drilling and stimulation costs by 10 percent, at a rate of .33 percent per year for 30 years. Low Technology reduces drilling costs by 7.5 percent, at a rate of .28 percent per year for 30 years. High Technology reduces drilling costs by 12.5 percent, at a rate of .38 percent per year for 30 years.

The specific parameter values for the technology cases are summarized in **Table 4D-20** below.

Table 4D-20

Parameter Values for Unconventional Gas Specific Drilling and Hydraulic Fracturing R&D

Technology Case	Reduction in Well D&C Costs After 20 Years	Rate of Change
Current Status	As Calculated	-
Reference Case	-10%	.33 %/year
Low Technology	-7.5%	.28%/year
High Technology	-12.5%	.38%/year

8. Lowering Water Disposal and Gas Treating Costs Through New Practices and Technologies

Background and Problem

Disposing the produced water and treating the produced methane for CO_2 and N_2 contaminants add significant costs to unconventional gas operations. Lowering these costs would improve the overall economics of the gas plays, particularly those with high water production and CO_2 content.

Technology Lever

R&D on water treatment, such as the use of electrodialysis and reverse osmosis, and improved water disposal practices, may lead to lower produced water disposal costs. R&D on gas treating, such as the use of advanced membranes, may help lower the costs of CO_2 and N_2 removal.

Impacts and Benefits

As of 1998 (the year the UGRSS was developed), the O&M costs for water disposal in a high water producing gas play were about $0.05/Mcf. The O&M costs for CO_2 and N_2 removal were on the order of $0.10/Mcf. Gas dehydration, lease fuel and gas compression cost $0.15/Mcf. The combined costs were $0.30/Mcf for wet CBM and gas shale plays, $0.25/Mcf for dry CBM and Gas Shale plays, and $0.15/Mcf for tight sand plays.

Reference Case Technology lowers the O&M costs for water disposal and gas treating by 20 percent, equal to $0.06/Mcf for CBM and wet gas shales and $0.03 for tight sands, at a rate of .67 percent per year for 30 years. Low Technology lowers these cost by 17 percent or $0.05/Mcf for CBM and Gas Shale and about $0.02/Mcf for tight sands, at a rate of .57 percent per year for 30 years. High Technology lowers these cost by 23 percent, or $0.07/Mcf, at a rate of .77 percent per year for 30 years, for CBM and wet gas shales and $0.04/Mcf for tight sands, at the same rate.

The specific parameter values for the technology cases are summarized **Table 4D-21** below.

Table 4D-21

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

Technology Case	Water Disposal/Gas Treating O&M Costs		Rate of Change
	CBM and Wet Gas Shales	Tight Sands	
Current Status	$0.30/Mcf	$0.15/Mcf	-
Reference Case	-20% ($0.06/Mcf) (30 years)	-20% ($0.03/Mcf) (30 years)	.67%/year
Low Technology	-17% ($0.04/Mcf) (30 years)	-17% ($0.02/Mcf) (30 years)	.57%/year
High Technology	-23% ($0.08/Mcf) (30 years)	-23% ($0.04/Mcf) (30 years)	.77%/year

9. Improving Recovery Efficiency With Advanced Well Drilling and Completion Technology

A. Coalbed Methane

Background and Problem

Cavitation of CBM wells in geologically favorable "cavity fairways" provides gas production rates, reserves, and recovery efficiencies far in excess of traditionally drilled, cased and hydraulically stimulated wells. However, little is known as to what combination of reservoir properties is essential or favorable for cavitation, and little has been invested in cavitation science, design or operating procedures. As a result, only one "cavity fairway" has been established in the United States to date -- in the central San Juan Basin.

Technology Lever

A limited R&D program, sponsored by DOE's SBIR program, is working to identify other potential "CBM cavity fairways." The SBIR program has also supported the development of the first publicly available CBM cavitation model, CAVITYPC. Expansion of R&D in CBM well cavitation could help identify additional high productivity "cavity fairways" and strengthen the scientific knowledge base on the rock mechanics and flow equations that are at the heart of improving cavitation technology.

Impact and Benefits

Currently, one existing CBM play is being developed with cavitation, the central San Juan Basin. Based on preliminary data, four additional CBM plays are candidates for cavitation, as shown on **Table 4D-23**.

Reference Case Technology would improve recovery efficiency (and reserves per well) in the four potential "cavitation plays" by 20 percent over current well completion and stimulation methods and would make this technology available in the year 2016.

Low Technology would improve recovery efficiency (and reserves per well) in the four potential "cavitation plays" by 17 percent over current well completion and stimulation methods but would not make this technology available until the year 2020. High Technology would make an advanced version of cavitation technology available by the year 2013, providing a total improvement of 23 percent in recovery efficiency and reserves per well in the four potential "cavitation plays" listed on Table 4D-24.

The specific parameter values for the technology cases for CBM are set forth in **Table 4D-22** below.

Table 4D-22

Parameter Values for Advanced Well Drilling and Completion Technology: Coalbed Methane

Technology Case	Applicable CBM Plays	Year Available	Improvement in Recovery/Efficiency
Current Status	San Juan Basin Fairway	Now	(Already Included)
Reference Case	Four New Cavity Fairways	2016	20%
Low Technology	Four New Cavity Fairways	2020	17%
High Technology	Four New Cavity Fairways	2013	23%

Table 4D-23

CBM Plays That Are Candidates for Advanced Well Cavitation

Basin	Applicable CBM Plays	Status	Undeveloped Resources (Bcf)
San Juan	Cavity Fairway	Existing	7,932
Uinta	Ferron Fairway	Potential	5,580
Raton	Purgatory River	Potential	4,271
Piceance	Deep Basin Coals	Potential	2,304
Green River	Deep Basin Coals	Potential	3,600

Source: Advanced Resources, International

* *Much of the San Juan cavity fairway has been developed accounting for 6.2 Tcf of proved reserves. Development of the remainder of the fairway and closer spaced infill development along the western portion of the fairway account for the undeveloped resources.*

B. Gas Shales

Background and Problem

Because gas shales generally have a thick pay section, multiple productive horizons, and low vertical permeability, horizontal wells have not been successful and, most likely, will not be a technology of choice. However, the use of multiple laterals may enable a single vertical wellbore to contact and efficiently drain a vertically thick, heterogeneous gas shale formation. While multi-lateral wells are in use in oil reservoirs, no application of this technology to gas shales is reported.

Technology Lever

A new program of using multi-lateral drilling in gas shale plays would need to be introduced to have this technology available during the forecast period.

Impact and Benefit

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

Table 4D-24

Parameter Values for Advanced Well Drilling and Completion Technology: Shale Gas

Technology Case	Year Available	Improvement in Recovery/Efficiency
Current Status	Not Available	Not Applicable
Reference Case	Not Available	Not Applicable
Low Technology	Not Available	Not Applicable
High Technology	Not Available	Not Applicable

Table 4D-25

Gas Shale Plays That Are Candidates for Multi-Lateral Drillings

Basin	Gas Play	Current Status	Undeveloped Resource (Bcf)
Michigan	Antrim, Developing Area	Not Available	4,944
	Antrim, Undeveloped Area	Not Available	13,937
Illinois	New Albany, Developing Area	Not Available	1,985
Williston	Shallow Niobrara	Not Available	1,575

Source: Advanced Resources, International

C. Tight Sands

Background and Problem

Horizontal wells in geologically appropriate "blanket" type tight sand formations provide improved reservoir contact and, theoretically, considerably improved recovery efficiencies and reserves per well. However, the performance of horizontal wells in tight sand has been disappointing to date, raising questions on appropriate reservoir settings, efficient placement and drilling damage. The DOE supported horizontal well at the MWX site, drilled into the Corcoran Formation (Iles/Mesaverde) in the Southern Piceance Basin quickly turned to water after high initial gas rates and was abandoned. Meanwhile, horizontal wells in conventional oil and gas formations, such as the Austin Chalk, and the offshore Gulf of Mexico, have shown good performance.

Technology Lever

The DOE horizontal well project in the Green River Basin may help define the appropriate geologic settings for using horizontal wells in tight sand formations and advance the essential low damage drilling and stimulation technologies for successful application of horizontal wells in these damage sensitive, low permeability formations.

Impact and Benefits

Reference Case Technology would help define the appropriate settings for using horizontal wells by the year 2016, providing a 10 percent improvement in recovery efficiency from selected tight sand reservoirs and plays at costs comparable to current practices. **Table 4D-27** list the tight sands gas plays that could be applicable for horizontal wells.

Low Technology would introduce a $8^1/_2$ percent improvement in recovery efficiency in 2020 and High Technology would provide a $11^1/_2$ percent improvement in recovery efficiency starting in 2013.

The specific parameter values for the technology cases for tight sands are set forth in **Table 4D-26** below.

Table 4D-26

Parameter Values for Advanced Well Drilling and Completion Technology: Tight Sands

Technology Case	Applicable Tight Sand Plays	Year Available	Improvement in Recovery/Efficiency
Current Status	None	Not Available	Not Applicable
Reference Case	See Table 4D-27	2016	10%
Low Technology	See Table 4D-27	2020	$8^1/_2$%
High Technology	See Table 4D-27	2013	$11^1/_2$%

Table 4D-27
Tight Gas Plays Applicable for Horizontal Well Technology, Reference Case

Basin	Gas Play	Status	Undeveloped Resource (Bcf)
Appalachia	Clinton/Medina High	Potential	3,324
Denver	Deep J Sandstone	Potential	2,534
Greater Green River	Shallow Mesaverde	Potential	19,553
	Frontier (Deep)	Potential	34,875
Piceance	Iles/Mesaverde	Potential	3,246
San Juan	Central Basin/Dakota	Potential	9,563

10. Improving and Accelerating Gas Production With Other Unconventional Gas Technologies

A. Coalbed Methane

Background and Problem

Laboratory tests demonstrate that injection of adsorbing gases such as CO_2 and N_2 into coal seams can improve and accelerate the desorption of methane from the coal. However, major questions remain as to how the injected gases will flow in the reservoir, how effectively these injected gases will contact and displace the methane adsorbed on the coals, and how to cost-efficiently treat the produced methane/injected gas mixtures. As a result, only a few field pilots in the San Juan Basin have been conducted using this high potential CBM recovery process.

Technology Lever

A fundamental and comprehensive R&D program involving geologic, laboratory, and field studies of enhanced CBM recovery (similar to those underway for enhanced oil recovery) would provide industry the basic information on the feasibility of and appropriate settings for conducting enhanced CBM (ECBM).

Impacts and Benefits

Based on potential access to low cost CO_2 and favorable geologic properties, the basins and gas plays listed on **Table 4D-29** are considered candidates for enhanced CBM. However, since only limited pilot testing of enhanced CBM is underway, commercial scale enhanced CBM is not currently available.

Reference Case Technology introduces new ECBM recovery technology that improves CBM recovery efficiency by 30 percent, and makes this technology commercially available in the year 2026. Low Technology introduces new ECBM recovery technology that improves CBM recovery efficiency by $25^1/_2$ percent but does not introduce this technology until year 2031. High Technology introduces a more efficient ECBM technology in 2022 that improves efficiency by $34^1/_2$ percent. Enhanced CBM also entails higher investment and operating costs for the injected gases of $1.00 per Mcf of incremental CBM produced in the Reference Case, $0.75 per Mcf of incremental CBM produced in the high technology case, and $1.25 per Mcf of incremental CBM produced in the Low Technology Case.

The specific parameter values for the enhanced technology cases are set forth in **Table 4D-28** below.

Table 4D-28

Parameter Values for Other Unconventional Gas Technologies Improving & Accelerating Gas Production

Technology Case	Year Available	RecoveryEfficiency	Costs
Current Status	Under R&D	As Calculated	As Calculated
Reference Case	2026	Improves Recovery Per Well by 30%	$1.00/Mcf of Incremental CBM
Low Technology	2031	Improves Recovery Per Well by $25^1/_2$%	$1.25/Mcf of Incremental CBM
High Technology	2022	Improves Recovery Per Well by $34^1/_2$%	$0.75/Mcf of Incremental CBM

B. Gas Shales

At this time no Other Gas Shales recovery technology has been defined. This technology lever is available for future use.

C. Tight Sands

Only the high technology case has any effect from Other Tight Sands recovery technology. Recovery efficiency is increased by $11^1/_2$% in the year 2022.

Table 4D-29

CBM Plays That Are Candidates for Enhanced CBM

Basins	Plays	Undeveloped Resources (Bcf)
San Juan	North Basin Western Eastern	4,446 2,333 1,154
Raton	North Basin South Basin	1,792 1,176
Uinta	Ferron Blackhawk Sego	5,580 1,290 908
Piceance	Divide Creek White River Dome Basin Margin	1,457 746 3,334
Appalachian	Central Northern - Shallow Northern - Deep	3,739 1,641 3,300
Black Warrior	Central Shallow	224 1,710
Green River	Basin Margin	3,899

11. Mitigating Environmental and Other Constraints on Development

Background and Problem

Development of unconventional gas particularly in the Rocky Mountain basins, is constrained by concerns over air quality, land disturbance, and water disposal and is restricted by wilderness set-asides. These environmental constraints significantly slow the pace of drilling and exclude high potential areas from access and development.

Technology Lever

The environmental constraints may be mitigated or overcome by in-depth environmental assessments of the major constraints, the introduction of environmentally enhanced E&P technology such as low NO_x compressors, improved water treatment and environmentally neutral disposal methods, and the drilling of multiple, directional wells from a single well pad.

Impacts and Benefits

Currently, the basins and gas plays listed on **Tables 4D-31, 4D-32, and 4D-33** experience development constraints (in addition to constraints from Federal lease restrictions) that exclude a significant portion, up to 35 percent, of the productive acreage from development.

Reference Case Technology removes these environmental constraints in 35 years, starting in the year 2000. Low Technology removes these environmental constraints in 41 years. High Technology removes these constraints in 30 years, starting in the year 2000.

The specific parameter value for the technology cases for all three of the unconventional gas resources(CBM, gas shales and tight sands) are summarized in **Table 4D-30** below.

Table 4D-30

Technology Parameters for Technologies
Mitigating Environmental & Other Constraints on Development

Technology Situation	Environmental (EV) and Other Constraints
Current Status	35% of Area Excluded in EV Sensitive Basins
Reference Case	Constraints Removed in 35 years @ 1%/year
Low Technology	Constraints removed in 41 years @ .85%/year
High Technology	Constraints Removed in 30 years @ 1.15%/year

Table 4D-31

CBM Plays/Basins With Environmental Constraints on Development

Basin	Play	Undeveloped Resource (Bcf)
Uinta	Ferron*	5,580

Source: Advanced Resources, International

** Constraint removed in 1998 with approval of EIS.*

Table 4D-32

Gas Shale Play/Basins With Environmental Constraints on Development

Basin	Play	Undeveloped Resource (Bcf)
Appalachia	Devonian Shale - Big Sandy Central	8,568
	Devonian Shale - Big Sandy Extension	9,000
	Devonian Shale - Greater Siltstone Area	2,832
	Devonian Shale - Low Thermal Maturity Area	3,528
Michigan	Antrium Shale - Undeveloped Area	13,937
Illinois	New Albany Shale - Developing Area	1,985
Willston	Shallow Niobrara	1,575

Source: Advanced Resources, International

Table 4D-33

Tight Sands Plays/Basins With Environmental Constraints on Development

Basin	Play	Undeveloped Resource (Bcf)
Uinta	Tertiary East	4,891
	Tertiary West	1,666
	Basin Flank MV	5,004
	Deep Synclinal MV	1,274
Wind River	Fort Union/Lance Shallow	16,517
	MV/Frontier Shallow	1,663
	Fort Union/ Lance Deep	16,000
	MV/Frontier Deep	12,500
Appalachian	Upper Devonian High	3,408
	Upper Devonian Moderate	743
	Upper Devonian Low	1,260
Greater Green River	Fort Union	1,686
	Fox Hills/ Lance	27,633
	Lewis	28,256
	Shallow MV	19,553
	Deep MV	21,168
	Frontier (Moxa Arch)	7,484
	Frontier Deep	34,875
Piceance	North Basin - WF/MV	16,800
	South Basin - WF/MV	4,200
	Iles/MV	3,246
Northern Great Plains	High Potential	1,796
	Moderate Potential	12,768
	Low Potential	6,745
Colombia	Basin Centered Gas	6,300

Source: Advanced Resources, International

Appendix 4-E. Offshore Supply Submodule

The Offshore Supply Submodule (OSS) is a PC-based modeling system for projecting the reserve additions and production from undiscovered resources in the offshore Gulf of Mexico Outer Continental Shelf (OCS) region.

This chapter discusses in detail the programming structure, design implementation, costing algorithms, and input databases for resource description, technology options, and other key performance parameters that were used to develop the OSS modeling system. In the first section, the model components are introduced. This is followed by the process flow diagrams highlighting the major steps involved in each of the components. The chapter includes a characterization of the undiscovered resource base in the Gulf of Mexico OCS classified by region and resource type (crude oil and natural gas). In the same section, the input database of resource characteristics developed for OSS are described. The subsequent section deals with the rationale behind the various technology options for shallow and deepwater exploration, development and production practices incorporated in OSS. This is followed by a discussion of the typical exploration, development, and production scheduling assumed in the model. It covers the well productivity and production profile parameters assumed in OSS. The next section describes the unit cost equations utilized in the OSS to estimate the various costs associated with exploration, development, and production operations in the Gulf of Mexico OCS. This is followed by a discussion of the financial analysis approach and the discounted cash-flow methodology used in OSS to determine the profitability of crude oil and natural gas prospects, and to generate price-supply data. The final section in this chapter deals with the endogenous component of OSS that involves calculation of reserves and production for the total Gulf of Mexico offshore region.

INTRODUCTION

The OSS was developed offline from EIA's Oil and Gas Supply Module (OGSM). A methodology was developed within OGSM to enable it to readily import and manipulate the OSS output, which consists essentially of detailed price/supply tables disaggregated by the Minerals Management Services (MMS) Gulf of Mexico planning regions (Eastern, Central, and Western) and fuel type (oil or natural gas). Maps of the three Gulf of Mexico planning regions are presented in Figures 4E-1 through 4E-3.

At the most fundamental level, therefore, it is useful to identify the two structural components that make up the OSS, as defined by their relationship (exogenous vs. endogenous) to the OGSM:

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

Figure 4E - 1. Map of Western Gulf of Mexico Planning Area

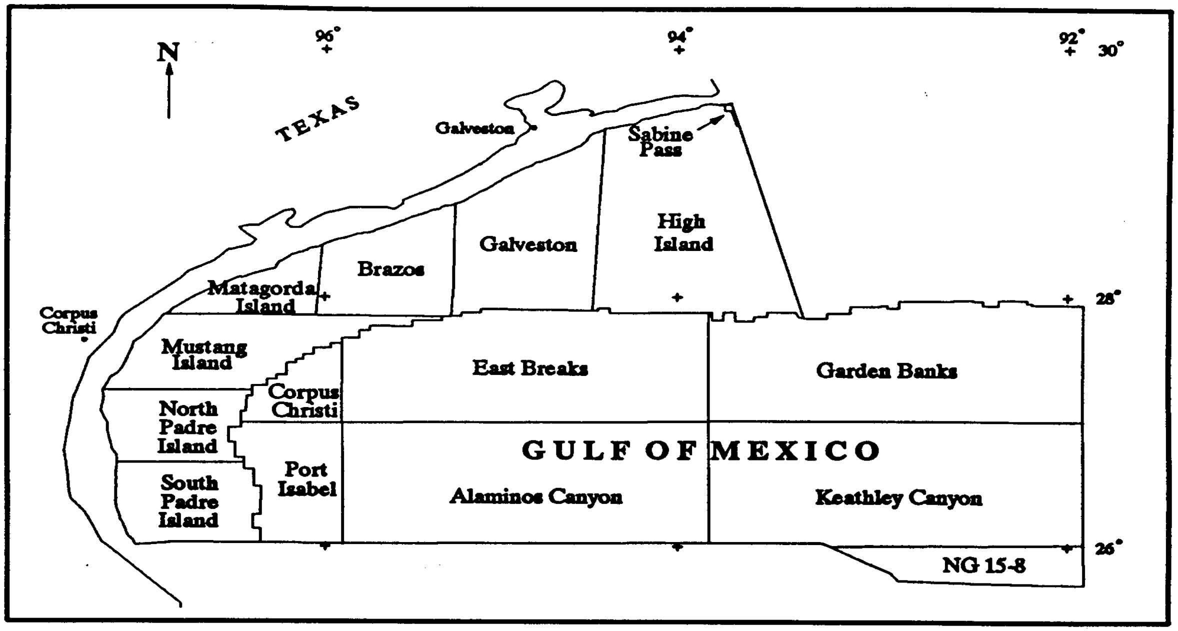


Figure 4E - 2. Map of Central Gulf of Mexico Planning Area

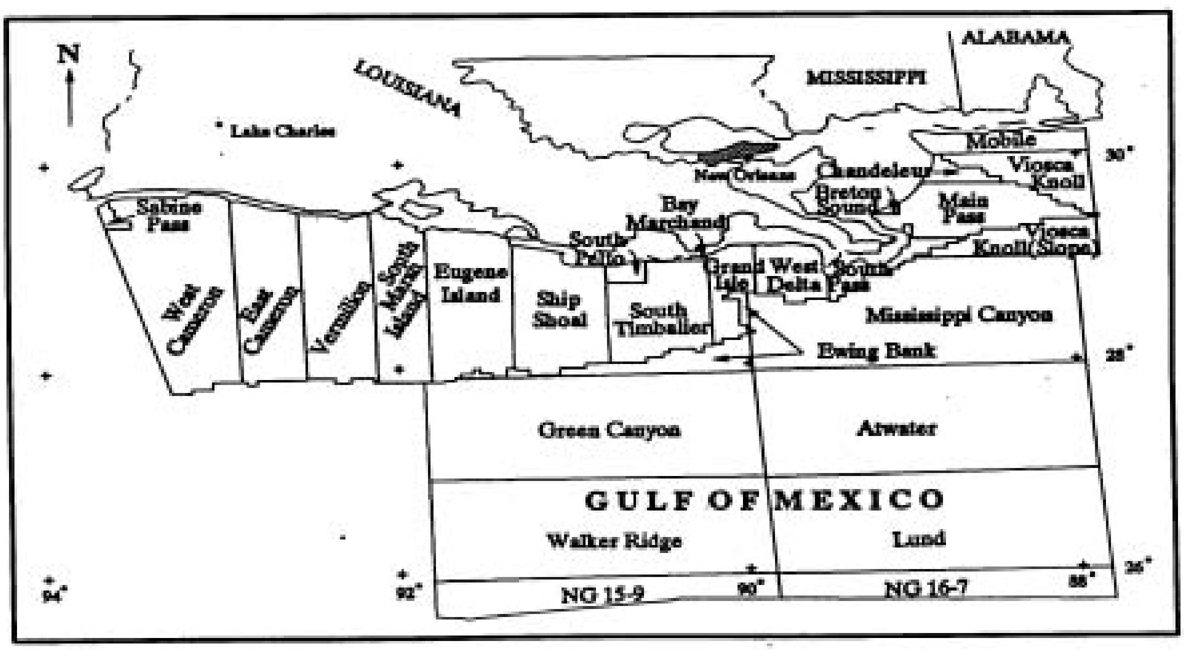
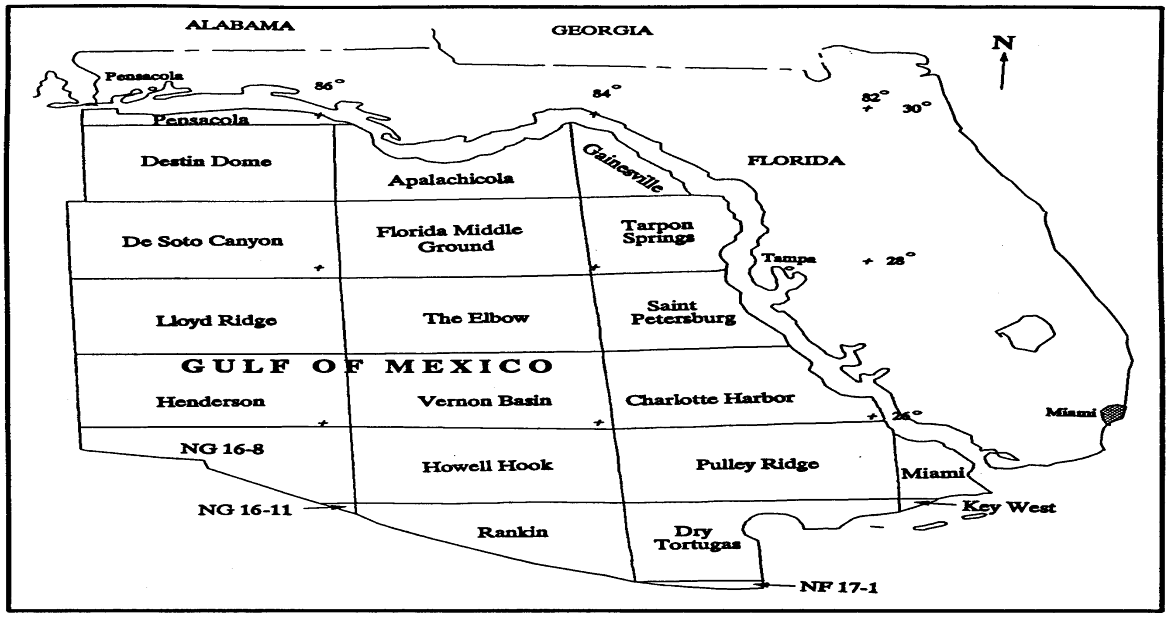


Figure 4E - 3. Map of Eastern Gulf of Mexico Planning Area



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

PROCESS FLOW DIAGRAMS

The general process flow diagram for the exogenous component of OSS model is provided in Figure 4E-4. This component of the model is used to generate price-supply curves for use in the endogenous component of the model. The general process flow diagram for the endogenous component of OSS model is provided in Figure 4D-5. This component utilizes price information received endogenously from NEMS to generate reserve additions and production response based on the supply potential made available by the price-supply model.

CHARACTERIZATION OF GULF OF MEXICO UNDISCOVERED RESOURCES

The great bulk of undiscovered oil and gas resources are estimated to be in deeper waters of the Gulf of Mexico OCS. Based on estimates developed in MMS's latest resource assessment, *2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf, as of January 1, 1999*, approximately 56 billion of 71 billion barrels of oil-equivalent crude oil and natural gas resources are in deepwater areas of the Gulf of Mexico OCS, as shown below in Table 4E-1.

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

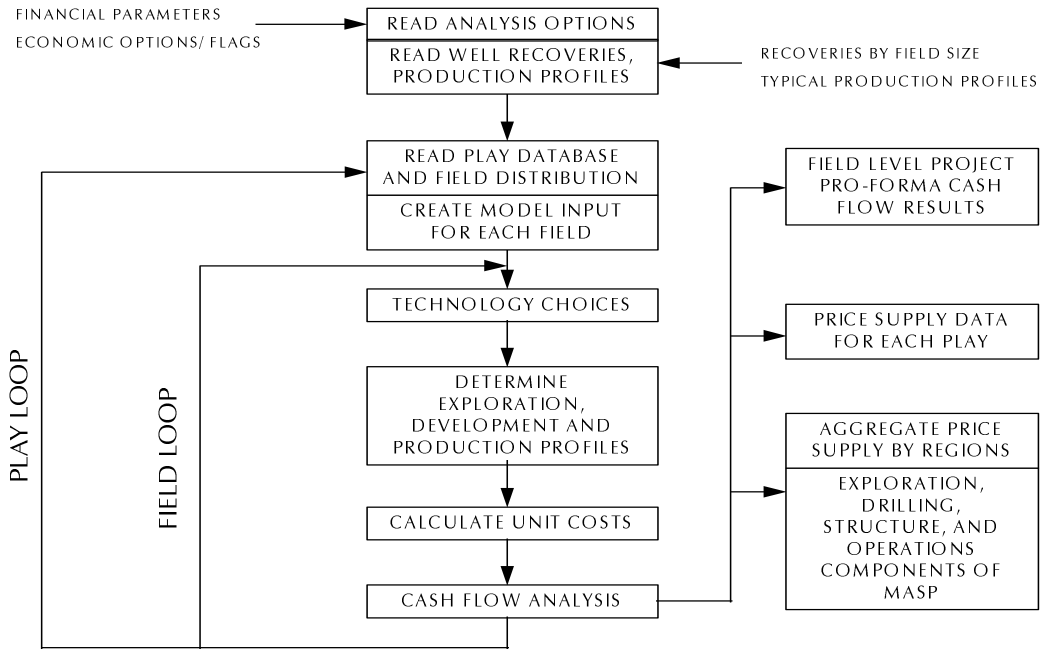


Figure 4E - 5. Programming Structure of the Endogenous Component of the OSS

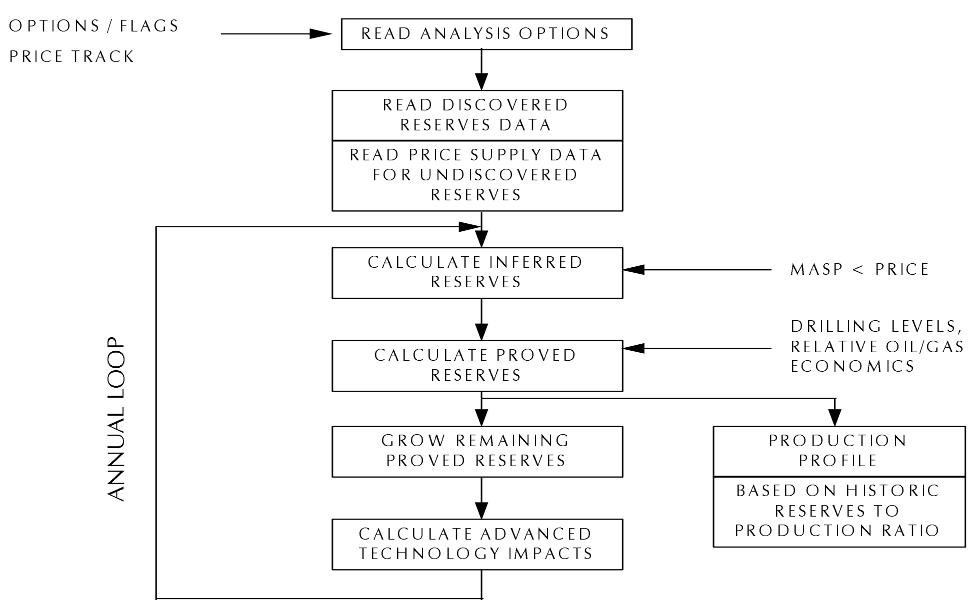


Table 4E-1. Recoverable Undiscovered Resources in the Gulf of Mexico (Billions of Barrels of Oil Equivalent)

Water Depth Category	Western	Central	Eastern	Total
0-200 meters	4.783	7.434	2.780	15.005
200-800 meters	3.888	3.734	0.253	7.889
800-1600 meters	8.314	11.310	0.172	19.796
1600-2400 meters	7.273	12.742	0.535	20.551
> 2400 meters	2.022	4.017	2.143	8.166
All Depths	26.281	39.180	5.766	71.223

Source: Minerals Management Survey, *2000 Assessment of Conventional Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1999*, OCS report 2001-087.

Database of Undiscovered Oil and Gas Prospects

The resource distribution information received from MMS consisted of two sets of databases. The first listed typical recoveries for crude oil and natural gas, typical gas-oil-ratio for oil fields and typical condensate yield for gas fields, and the proportion of oil and gas bearing fields. The other database listed a rank-ordered field size distribution (in acre-ft) in each play. The parameters listed in the first database are:

1. Proportion gas bearing fields, fraction,
2. Oil recovery factor, Bbl/Acre-ft,
3. Gas-oil ratio for oil bearing fields, Scf/Bbl,
4. Gas recovery factor, Mcf/Acre-ft, and
5. Condensate yield for gas bearing fields, Bbl/MMcf.

However no information was available from these databases on the distribution between oil and gas fields. Therefore, using spreadsheet analyses, different combinations of oil and gas fields in each play were assumed until close matches were obtained for the following with the corresponding MMS values:

- Proportion gas bearing fields (number of gas fields / total number of fields in the given play); and
- Total oil and gas resource for each water depth range in each region

Once the distribution of oil and gas bearing fields for each play was established, the resource database comprising of the field rank, field type (oil or gas), field size (oil and associated gas, or gas and associated condensate) was combined with other field properties and parameters necessary for generating the required inputs for the OSS to generate play-specific input database sets.

Additional Required Input Data

Additional information that is needed to perform the economic evaluation of offshore crude oil and natural gas fields include the following:

- The Average API Gravity is used to compute a price penalty based on the quality of crude oil. These data have been obtained from published averages in the Gulf of Mexico, as well as MMS estimates.
- The Average Gas-Oil Ratio is used to determine the total amount of associated/dissolved (A/D) gas in the oil field.
- The Average Condensate Yield is used to determine the total amount of associated condensate in the gas field.
- The Average Water Depth is used for platform and well cost calculations. Average water depth for each water depth class was determined from actual field data in different water depth categories of the Gulf of Mexico.
- The Total Exploration and Development Well Drilled Depths are critical factors in drilling costing algorithms. The depths reflect the most likely future exploration and development well depths in each play and were based on actual well completion data.
- Exploration and Development Drilling Success Rates are critical in determining the number of well required to explore for and develop a field.

TECHNOLOGY OPTIONS

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

The technology employed in the deepwater offshore areas to find and develop hydrocarbons can be significantly different than that used in shallower waters, and represents significant challenges for the companies and individuals involved in the deepwater development projects. Some of the reasons behind this are that the deepwater prospects:

- Are in a predominantly frontier exploration area;
- Are in locations that are more remote;
- Have wells that produce at much higher rates; and
- Are explored for and developed in significantly more extreme environmental conditions.

In many situations in the deepwater OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed. For purposes of specifying technology choices in OSS, a standard classification system for categorizing fields by size class was required.

The table below shows the distribution of field sizes by classes defined by US Geological Survey (USGS), which are used for specifying many of the technology assumptions in OSS.

USGS Class	**Field Size Range (MMBOE)**
7	0.190 - 0.380
8	0.380 - 0.760
9	0.760 - 1.520
10	1.520 - 3.040
11	3.040 - 6.070
12	6.070 - 12.140
13	12.140 - 24.300
14	24.300 - 48.600
15	48.600 - 97.200
16	97.200 - 194.300
17	194.300 - 388.600
18	388.600 - 777.200
19	777.200 - 1554.500
20	< 1554.500

Technology Choices for Exploration Drilling

During the exploration phase of an offshore project, the type of drilling rig used depends on both economic and technical criteria. Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. For deepwater exploratory drilling, two types of drilling rigs are most commonly employed.

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This extends the maximum operating depth greatly, and some of these rigs can be used in water depths up to and beyond 3,000 feet. The shape of a semisubmersible rig tends to dampen wave motion greatly regardless of wave direction. This allows its use in areas where wave action is severe.

Dynamically positioned drill ships are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3000 feet where the semi-submersible type of drilling rigs can not be deployed. Some of the drillships are designed with the rig equipment and anchoring system mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This helps to dampen wave motion.

Water depth is the primary criterion for selecting a drilling rig. Therefore, OSS assumes the selection of drilling rig type to be a function of water depth, as follows:

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

Technology Options for Development/Production Structure

Six different options for development/production of offshore prospects are currently assumed in OSS, based on those currently considered and/or employed by operators in Gulf of Mexico OCS. These are the conventional fixed platforms, the compliant towers, tension leg platforms, Spar platforms, floating production systems and subsea satellite well systems. Choice of platform tends to be a function of the size of field and water depth, though in reality other operational, environmental, and/or economic decisions influence the choice.

1. **Conventional Fixed Platform (FP).** A fixed platform consists of a jacket with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The jacket is a tall vertical section made of tubular steel members supported by piles driven into the seabed. The fixed platform is economical for installation in water depths up to 1,200 feet. Although advances in engineering design and materials have been made, these structures are not economically feasible in deeper waters.

2. **Compliant Towers (CT).** The compliant tower is a narrow, flexible tower type of platform which is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the tower and terminating on pile or gravity anchors on the sea floor. The compliant tower can withstand significant forces while sustaining lateral deflections, and is suitable for use in water depths of 1,200 to 3,000 feet. A single tower can accommodate up to 60 wells, however, the compliant tower is constrained by limited deck loading capacity and no oil storage capacity.

3. **Tension Leg Platform (TLP).** The tension leg platform is a type of semi-submersible structure which is attached to the sea bed by tubular steel mooring lines. The natural buoyancy of the platform creates an upward force which keeps the mooring lines under tension and helps maintain vertical stability. This type of platform becomes a viable alternative at water depths of 1,500 feet and is considered to be the dominant system at water depths greater than 2,000 feet. Further, the costs of the TLP are relatively insensitive to water depth. The primary advantages of the TLP are its applicability in ultra-deepwaters, an adequate deck loading capacity, and some oil storage capacity. In addition, the field production time lag for this system is only about 3 years.

4. **Floating Production System (FPS).** The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10 percent. These structures can only accommodate a maximum of approximately 25 wells. The wells are completed subsea on the ocean floor and are connected to the production deck through a riser system designed to accommodate platform motion. This system is suitable for marginally economic fields in water depths up to 4,000 feet.

5. **Spar Platform (SPAR).** Spar Platform consists of a large diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull which is moored using a taut caternary system of 6 to 20 lines anchored into the seafloor. Spar platforms are presently used in water depths up to 3,000 feet, although existing technology is believed to be able to extend this to about 10,000 feet.

6. **Subsea Wells System.** Subseas system ranges from single subsea well tied back to a nearby production platform (such as FPS or TLP) to a set of multiple wells producing through a common sub-sea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet.

The typical water depth and field size class ranges for selection of a given platform in the model is given below:

Production Structure	Water Depth (meters)	Field Size Class Range
Fixed Platform	<400	> 12
Compliant Tower	400 - 600	> 15
Tension Leg Platform	600 - 1500	> 15
Floating Production System	400 - 1500	12 - 15
Spar Platform	>1500	> 12
Subsea Wells System	All Depth Ranges	< 12

Technology Choices For Development Drilling

Pre-drilling of development wells during the platform construction phase is done using the drilling rig employed for exploration drilling. Development wells drilled after installation of the platform which also serves as the development structure is done using the platform itself. Hence, the choice of drilling rig for development drilling is tied to the choice of the production platform.

Technology Choices for Product Transportation

It is assumed in the model that existing trunk pipelines will be used, and that the prospect economics must support only the gathering system design and installation. However, in case of small fields tied back to some existing neighboring production platform, a pipeline is assumed to be required to transport the crude oil and natural gas to the neighboring platform.

Exploration, Development, and Production Scheduling

This section sets forth the descriptions, assumptions, methodology, and sources used for determining the exploration, development, and production schedules assumed for various types of potential prospects that remain to be discovered in the offshore Gulf of Mexico.

The typical project development in the offshore consists of the following phases. The pre-development activities, including early field evaluation using conventional geological and geophysical methods and the acquisition of the right to explore the field, are assumed to be completed before initiation of the development of the prospect:

- Exploration phase
  - Exploration drilling program
  - Delineation drilling program
- Development phase
  - Fabrication and installation of the development/production platform

- Development drilling program
    - Pre-drilling during construction of platform
    - Drilling from platform
- Construction of gathering system

■ Production operations

■ Field abandonment.

The timing of each activity, relative to the overall project life and to other activities, affects the potential economic viability of the undiscovered prospect. The modeling objective is to develop an exploration, development, and production plan which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

Exploration Phase

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

Exploration drilling. Drilling of all exploration wells (i.e., the wildcat and all corresponding exploratory dry holes) is assumed to begin in the first year of the field development project, and that exploration drilling takes one year to complete. The exploration success rate (ratio of the number of field discovery wells to total wildcat wells) is used to establish the number of exploration wells required to discover the field. For all Gulf of Mexico OCS prospects, OSS assumes that the exploration success rate is 1:4, i.e., for each successful well, a total of four wells need to be drilled.

Delineation drilling. The delineation well drilling program is assumed to begin the year after initiation of exploration drilling, i.e., year 2 of the project. The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. In the engineering costing model and for production operations, the delineation wells are treated as dry holes. The number of delineation wells required to define each field is calculated using the ***combined extension and development success rate*** (ratio of successful extension and development wells to total extension and development wells). The duration of the delineation well drilling program is determined as a function of the number of delineation drilling wells, the average total drilled depth, and the average drilling rate. The equations for drilling rates used in the model are shown below for various depth categories:

Total Drilled Depth (feet)	Average Drilling Rate (feet/day)
< 10,000	800 - 0.058 * Drilling Depth
>= 10,000	200

These relationships were developed based on an examination of drilling rates currently occurring in the Gulf of Mexico.

Development Phase

During this phase of an offshore project, the development structures are designed, fabricated, and installed; the development wells (successful and dry) are drilled and completed; and the product transportation/gathering system is installed.

Development structures. The model assumes that the design and construction of any development structure begins in the year following completion of the exploration and delineation drilling program. However, the length of time required to complete the construction and installation of these structures depends upon the type of system used. The table below lists the required time for construction and installation of the various development structures used in the model. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

Large fields (Field Size Class > 15)

Water Depth	**Construction and Installation Time (Years)**			
(meters)	**Fixed Platforms**	**Compliant Towers**	**Tension Leg Platforms**	**Spar Platforms**
0 - 400	2	-	-	-
400 - 900	-	3	3	-
> 900	-	-	4	3

Mid-size fields (Field Size Class 12 - 15)

	Fixed Platforms	**Floating Production Systems**
0 - 400	2	-
> 400	-	2

Small fields (Field Size Class < 12)

Tied back to existing production facilities through subsea manifold and pipelines.

1 year

The importance of reducing the time lag is addressed by assuming the use of early production techniques, such as:

- Using simultaneous drilling and production operations, or
- Pre-drilling some of the development wells during the time in which the development structure is being constructed and installed.

Development drilling program. The timing of the development drilling program is also determined by the type of development system assumed. When conventional fixed platforms are used, the following development schedule is assumed.

- No pre-drilling program is utilized. Use of a fixed platform would delay initial production by 2 to 4 years, which is consistent with current offshore practices.
- The development drilling program begins the year after the platforms are installed. All wells are drilled from the platform.

For all other types of development structures, including compliant towers, tension leg platforms, Spar platforms, and floating production systems, the following development schedule is assumed:

- The subsea drilling templates are fabricated and installed the first year of structure construction;
- Pre-drilling of some development wells begins from a mobile rig during the first year of structure construction, and continues through the construction time;
- The remaining wells are drilled from the structure beginning the year after installation; and
- The pre-drilled wells begin producing during the first year after installation of the structure.

Regardless of the type of development system used, the number of development wells required to completely develop the field is determined by the field size and estimated ultimate recovery per well. The ***Development Success Rate*** (ratio of successful to total developmental wells) is used to establish the number of unsuccessful wells that can be expected while drilling within the boundary of a known field. These development drilling success rates are based on historical drilling data.

The time required to drill all wells, both successful and dry, depends on the number of wells to be drilled, the average drilled depth and a corresponding average drilling rate:

Total Drilled Depth (feet)	Average Drilling Rate (feet/day)
< 10,000	1000 - 0.0725 * Drilling Depth
>= 10,000	250

These relationships are based on examination of drilling rates currently occurring in the Gulf of Mexico. It is assumed that 15 days are required to complete each well, after drilling is complete. Further, an equal number of wells are assumed to be drilled each year.

Production transportation/gathering system. It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within 1 year.

Production Operations

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. The well productivities and production profiles over the productive life are discussed below.

Typical production profiles. Typical oil and gas production profiles for offshore development wells are based upon typical recovery profiles generated by using standard reservoir performance models. The Primary Recovery Predictive Model (PRPM) for crude oil and Gas Systems Analysis Model (GSAM) for natural gas, developed for Department of Energy's Office of Fossil Energy, were used for this purpose. These models can predict the deliverability of the reservoir and year-wise production performance as a function of reservoir properties (area, thickness, porosity, permeability, lithology, depth, saturation, etc.) and technology, using standard stream tube (for crude oil) and type curve (for natural gas) performance prediction techniques. The associated gas recovery in case of an oil well and the associated NGL (natural gas liquids) in case of a gas well are calculated using a regional average gas-oil ratios. The production profiles generated using the reservoir performance models were modified to reflect the platform capacity constraints, as well as wellbore productivity constraints not considered in the performance models. In order to generate the revised per well production profiles, the producing life of each well is assumed to be 5 years for a small field, 10 years for a mid-size field, and 15 years for a large field. The revised per well production profiles assumed in OSS are given below:

Year in Production	Percent of Total Ultimate Recovery FIELD SIZE CLASS RANGE		
	4 - 9	10 - 14	15 - 20
1	40.0	30.0	27.0
2	26.0	22.0	21.0
3	17.0	16.0	16.0
4	11.0	12.0	11.0
5	7.0	9.0	8.0
6		7.0	6.0
7		5.0	4.0
8			3.0
9			3.0
10			2.0

Productivity and number of wells. The number of producing oil / gas wells per field is a key input required by OSS. For a particular field, the number of required wells is determined by using an average well productivity (arrived at by summation of the annual production figures generated by the reservoir performance models, PRPM and GSAM) as a function of field size class, divided into the field size to give the required number of wells for the particular size field. The data used for estimating recovery per well as a function of field size in OSS are shown in Table 4E-2.

Table 4E-2. Average Size of a USGS Field Size Class, and Per Well Recovery

USGS Class	Average Size (MMBOE)	Per Well Recovery (MBOE)
7	0.273	250.0
8	0.547	500.0
9	1.094	1000.0
10	2.189	1500.0
11	4.378	2000.0
12	8.741	2600.0
13	17.480	3300.0
14	34.990	4300.0
15	69.980	5500.0
16	139.960	6800.0
17	279.790	8500.0
18	559.580	10500.0
19	1119.160	13500.0

Notes:

1. Geometric means of USGS Field Size Classes (= 1.44 * minimum of the range).
2. 1 BOE = 5.8 Mcf

Abandonment Phase

The year when the project production reaches economic limit (operating costs exceed the revenues), defines the last year of production. The development structures and production facilities are abandoned in the year following the cessation of production.

ENGINEERING COSTING ALGORITHMS

This section sets forth descriptions, assumptions, methodology, and reference sources used for determining the engineering cost algorithms for key cost factors for developing and producing crude oil from the Gulf of Mexico. The assumptions underlying the selection of technologies for field exploration, development, and production represent the best industry practices subject to the ultimate project economics, and are based on review of a number of sources including a database of existing/proposed projects, past analytical works and reports of ICF, MMS costing assumptions, and various other sources. The cost equations represent the functional relationships between the cost components of the financial analysis model and the parameters affecting them.

Capital Costs

Geological and Geophysical Activities. The cost to conduct the geological and geophysical (G&G) assessment of the field is based on surveys of oil and gas industry expenditures. The cost of these activities tends to be roughly 15 percent of the cost to drill and complete all exploration wells, including the field delineation wells. In financial analyses, the portion of these costs associated with drilling the unsuccessful wells (dry holes) is expensed in the year incurred (the first year of analysis), while the portion of the costs associated with drilling successful wells is depleted using unit-of-production depreciation. However, since most offshore exploration and delineation wells are plugged after drilling, all costs of all such wells are assume to be expensed in OSS.

Exploration and Delineation Well Drilling. The costs to drill an offshore exploration well can be divided into the following three categories:

1. Fixed cost items - including wellhead and downhole equipment, and rig setup;
2. Time dependent items - including rigs, barges, labor, service equipment rentals, and other support services; and
3. Well depth dependent items - including casing, tubing, cementing, and other equipment associated with drilling the well.

Exploration drilling costs estimated in the model for the two classes of drilling rigs are presented below:

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

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

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

Exploration Drilling Cost = 2,000,000 + 1,825*WD + (0.01*WD + 0.045*ED - 415)*ED

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

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

where,

WD	=	Water Depth (feet)
ED	=	Exploration Drilling Depth (feet)

The engineering costing equations used for estimating exploration well drilling costs are also used to estimate the cost to drill field delineation wells (i.e., the wells drilled to define the extent of the field). The delineation wells are treated as dry exploration wells.

Delineation Drilling Cost = 0.85*Exploration Drilling Cost

All costs associated with drilling the exploration wells are treated as intangible capital investments and are expensed in the year in which they occur.

Production and Development Structure. The type of development structure depends primarily upon the conditions of water depth, environmental hostility, and reservoir size. In some cases, the development structures used for drilling production and injection wells also serve as the production facility.

The total cost of the development structures is distributed evenly over the time period between the initiation of construction and the installation of the structures. In each year during this development period, 90 percent of these costs are treated as capitalized tangible investments and are depreciated beginning the following year. The remaining 10 percent of these costs are expensed in the year incurred. The costs associated with each type of development and production structure considered in OSS are described in the paragraphs below. In all the equations for the various platforms shown in the paragraphs below:

NSLT	=	Number of Slots per Structure
WD	=	Water depth (feet)
NTMP	=	Number of Templates

1. **Conventional Fixed Platform (FP).** The following engineering costing equations are used to estimate conventional fixed platform costs, which include design, fabrication, and installation of the jacket, pilings, and the deck sections, as shown below:

   Cost ($) = 2,000,000 + 9,000*NSLT + 1,500*WD*NSLT + 40*WD*WD

2. **Compliant Tower (CT).** The costing equation developed for compliant towers is expressed as a function of water depth and is valid for water depths greater than 1,000 feet. Costs include those for the design, fabrication, and installation of the jacket, pilings, deck sections, and mooring system (including guy lines), as shown below:

   Cost ($) = (NSLT + 30)*(1,500,000 + 2,000*(WD-1,000))

3. **Tension Leg Platform (TLP).** Tension leg platforms are designed primarily for use in deeper waters; however, the costs are relatively insensitive to water depths greater than 1,000 feet. The following costing equation includes the design, fabrication, and installation of the deck sections, mooring system, and related foundations, as shown below:

   Cost ($) = (NSLT + 30)*(3,000,000 + 750*(WD-1,000))

4. **Spar Platform (SPAR).** Spar platforms are a recent development. It is estimated that these types of platforms would be dominant in the deepwater, and that they would be applicable in water depths upto 10,000 feet. The costs are shown below:

   Cost ($) = (NSLT + 20)*(5,000,000 + 500*(WD-1,000))

5. **Floating Production System (FPS).** The costs to construct a FPS include not only the rig purchase, fabrication, and installation costs, but also the cost to fabricate and install a flexible production riser system, and are expressed by the following equation. Since flexible production risers are generally easier to install and maintain than rigid risers, OSS assumes that production to a converted semi-submersible or tanker is accomplished with flexible risers. The costs are shown below:

   Cost ($) = (NSLT + 20)*(1,500,000 + 250*(WD-1,000))

6. **Subsea Wells System.** Since the cost to complete a well are included in the development well drilling and completion costs, OSS assumes no cost for a subsea wells system. Typically subsea wells are tied back to neighboring structures, and the only cost is the cost of the pipeline to connect the wells from the subsea system to the platform.

Subsea Template Installation. The engineering costing model also assumes that a subsea template is required for all development wells producing to any structure other than a fixed platform.

Cost of Subsea Template ($/well) = 2,500,000 * NTMP

These costs are also applicable to the subsea well systems tied back to neighboring platforms.

Development Well Drilling. During the field development phase of an offshore project, the type of structure used to drill the development wells also depends on both economic and technical criteria. The most important factors affecting the selection of a drilling structure are the timing of the field development and the type of production facility employed.

In all cases except a field where a fixed platform is assumed to be installed, OSS assumes that pre-drilling of development wells will be carried out using the exploration drilling rig. It is assumed that wells will be drilled from either a semi-submersible rig or a dynamically-positioned drill-ship. OSS assumes that the cost to pre-drill a dry development well would be equal to the cost of drilling a delineation well using one of the rigs listed above. For a successful development well, the costs for completing and equipping the well are added to the cost of drilling a dry development well.

OSS further assumes that once the production structure is ready, the remaining development wells will be drilled from the platform. The components of the engineering costing equations for development drilling are similar to those presented earlier for exploration drilling, except for the following differences:

- The average time required to drill and complete a development well is much less than for an exploration well.
- The drilling rig rates are much less for wells drilled from a platform or tower.

The dry development well drilling costs do not include costs to complete and equip the well (production casing or production facility costs, i.e., flowlines, valves, etc.). OSS is set up to compute the dry development drilling well costs and well completion and equipment costs. The cost of successful development drilling is calculated by summing the dry development well drilling costs and the well completion and equipment costs.

Dry Development Drilling Cost

For water depths less than or equal to 900 meters,

Cost ($/well) = 1,500,000 + (1,500 +0.04*DD)*WD + (0.035*DD - 300)*DD

For water depths greater than 900 meters,

Cost ($/well) = 5,500,000 + (150 + 0.004*DD)*WD + (0.035*DD - 250)*DD

where,

WD	=	Water Depth, feet
DD	=	Development Drilling Depth, feet

Well Completion and Equipment Cost ($/well)

Water Depth (feet)	**Development Drilling Depth (feet)** < 10,000	**10,001-20,000**	**> 20,000**
0 - 3000	800,000	2,100,000	3,300,000
> 3000	1,900,000	2,700,000	3,300,000

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

Production Facility System. The cost to install production equipment on the development structure is a function of the anticipated peak oil / gas production capacity for the structure. The following equations for estimating facility costs include primary separation facilities, treating equipment, pumps, compressors, storage systems, and associated piping and control systems:

For Oil Production

Oil Production Capacity: 0 - 10,000 bbl/day

Production Equipment Cost ($/well) = (540,000 +52.5*QMXOIL) / NSTRUC

Oil Production capacity: > 10,000 bbl/day

Production Equipment Cost ($/well) = (900,000 + 7.8*QMXOIL) / NSTRUC

For Gas Production

Gas Production Capacity, 0 - 20 MMcf/day

PRCEQP = (0.675 * QMXGAS) * 1,000,000 / NSTRUC
TOPEQP = (0.950 * QMXGAS) * 1,000,000 / NSTRUC

Gas Production Capacity, 20 - 40 MMcf/day

PRCEQP = (13.5 + (0.275 * (QMXGAS-20)) * 1,000,000 / NSTRUC
TOPEQP = (19.0 + (0.225 * (QMXGAS-20)) * 1,000,000 / NSTRUC

<u>Gas Production Capacity, 40 - 120 MMcf/day</u>

PRCEQP = (19.0 + (0.181 * (QMXGAS-40)) * 1,000,000 / NSTRUC
TOPEQP = (23.5 + (0.100 * (QMXGAS-40)) * 1,000,000 / NSTRUC

<u>Gas Production Capacity, > 120 MMcf/day</u>

PRCEQP = (33.5 + (0.156 * (QMXGAS-20)) * 1,000,000 / NSTRUC
TOPEQP = (31.5) * 1,000,000 / NSTRUC
where,

NSTRUC	=	Number of Structures
PRCEQP	=	Processing Equipment Cost
TOPEQP	=	Topside Equipment Cost
QMXOIL	=	Peak Oil Production Capacity, bbl/day
QMXGAS	=	Peak Gas Production Capacity, Mmcf/day

For platforms producing primarily gas, the top total costs of the topside facility is represented by the sum of the processing equipment costs (PRC EQP) and the topisde equipment cost (TOPEQP).

The production facility costs are assumed to occur in the same year in which the development structure is constructed. All of the production and injection equipment costs are treated as tangible investments and are depreciated beginning the following year after costs are incurred.

Production Gathering System. All fields are assumed to utilize existing trunk lines in the vicinity of the field. Each development structure requires a gathering system. The average length of each gathering system in the different fields are assumed to be a function of the size of the field. The following approximations for pipeline costs were developed.

For all small fields (Field Size Class < 10), GATDIS = 1 mile

For all large fields (Field Size Class > 15), GATDIS = Data from Input Database

For all mid-size fields (Field Size Class Range 10-15), GATDIS is determined by interpolating between the values for the small and large fields.

OSS estimates the cost of constructing gathering system as follows:

Gathering Line Costs ($) = 250,000 * GATDIS * NSTRUC

where,

GATDIS = Average length of gathering system
NSTRUC = Number of structures in the field

These costs are considered to be tangible capital investments and are capitalized the year following the installation costs are incurred.

Structure and Facility Abandonment. The costs to abandon the development structure and production facilities depend upon the type of production technology used. The abandonment costs for fixed platforms and compliant towers assume the structure is abandoned. The costs for tension leg platforms, converted semi-submersibles, and converted tankers assume that the structures are removed for transport to another location for reinstallation. These costs are treated as intangible capital investments and are expensed in the year following cessation of production. Based upon historical data, these costs are estimated as a fraction of the initial structure costs, as follow:

	Fraction of Initial Platform Cost
Fixed Platform	0.45
Compliant Tower	0.45
Tension Leg Platform	0.45
Floating Production Systems	0.15
Spar Platform	0.15

There is a provision in the model to not include the abandonment costs in the economic evaluation of the Gulf of Mexico OCS prospects. It is a user-defined analysis option.

Annual Operating Costs

Platform Operating Costs. In general, platform operating costs for all types of structures are a function of water depth and the number of slots on the structure. These costs include the following items:

- primary oil and gas production costs,
- labor,
- communications and safety equipment,
- supplies and catering services,
- routine process and structural maintenance,
- well service and workovers,
- insurance on facilities, and
- transportation of personnel and supplies.

The equation used for estimating annual structure operating costs is as follows:

Cost ($/structure/year) = 1,265,000 +135,000*NSLT + 0.0588*NSLT*WD*WD

If water depth is less than or equal to 1500 feet, WD = WDEP
If water depth is greater than 1500 feet, WD = 1500

where,

WDEP	=	Water depth, feet
NSLT	=	Number of Slots per Structure
QGAS	=	Gas Production Capacity
NSTRUC	=	Number of Structures

Operating Costs of Pipeline Operating System. Pipeline operating costs are estimated to be a function of the amount of oil and gas produced. The input database file for each of the water depth aggregated plays contains the typical transportation tariffs (in $/bbl of crude oil or $/Mcf of gas produced) for these regions and is used in the calculation of pipeline operating costs. These costs represent a share of the operation of the existing trunk line that is proportional to the volume of oil and gas transported through the trunk line by the prospect under consideration.

FINANCIAL ANALYSIS AND PRICE-SUPPLY MODELING

The financial analysis and price-supply model is the off-line exogenous component of OSS. It consists of a set of algorithms that have been designed to systematically evaluate the relative economic potential of the undiscovered crude oil and natural gas prospects in the Gulf of Mexico OCS. Key reasons for the necessity of a systematic financial analysis approach are:

- To represent all standard industry accounting practices in determining the after-tax cash flow for each year of a potential project, including depreciation and expensing;
- To systematically represent all issues associated with prospect-specific resource characteristics, technology choices, project scheduling, and costing;
- To represent all components that are dependent on price, such as transportation tariff deductions and API gravity adjustments;
- To represent all transfer payments, such as taxes and royalties, including government incentives
- To represent the time value of money; and
- To solve for the replacement cost, or that value which yields a zero net present value of the combined yearly after-cash flow streams.

The financial analysis algorithms in OSS is a minimum supply price calculation routine that uses the method of bisection to solve for the minimum required crude oil or natural gas price for a crude oil or natural gas prospect, respectively, to be economic at a specified rate of return. A discounted cash flow (DCF) calculation is used to estimate the present net worth of the net inflow or outflow of money that occurs during a specified period, as represented below:

Gross Revenue or Savings
less **Operating Expenses**
less **Tax Costs**
less **Capital Costs**

____

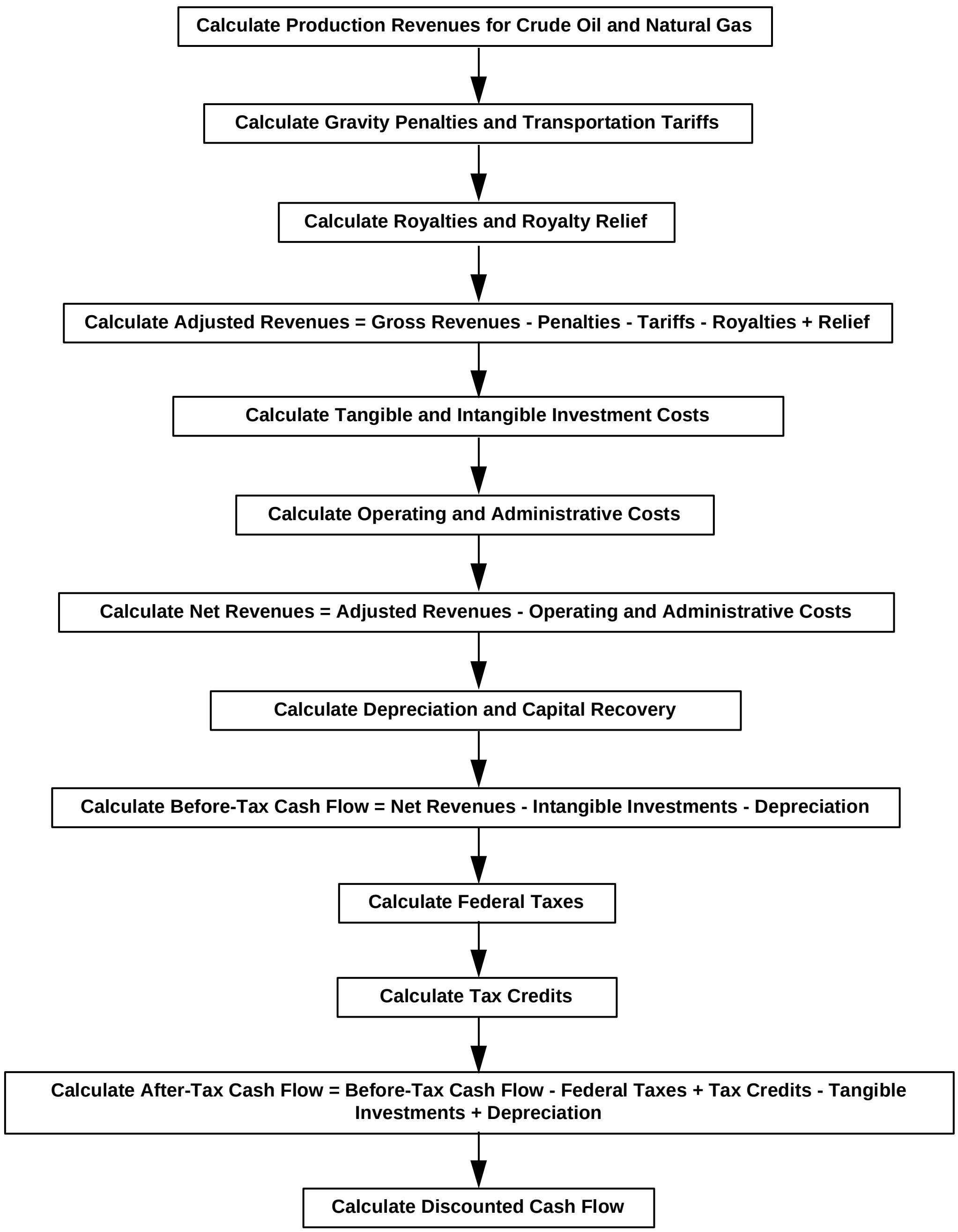
= **Cash Flow**

Figure 4E-6 represents the process-flow diagram of the financial analysis routines in OSS. In the following sections, the key components and their methodologies are described in more detail.

Gravity Adjusted Revenues

The 1984 National Petroleum Council (NPC) assessment of the potential of enhanced oil recovery (EOR) devoted considerable attention to the value of crude oils of various composition. In general, low API gravity oils (10-26^{o} API) have less value because of a preponderance of heavy hydrocarbons (and perhaps sulfur) which reduces the volume of higher value refined products. In addition, special facilities (and higher costs) are required to transport and refine heavier crudes. Although the pricing of crude oil is a complex and intricate process,

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



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

- The reference standard for crude oil is 40^o API.
- If the typical crude gravity for a field is at or above 32^o API, the price penalty is $0.10 per degree below 40^o API.
- If the typical crude gravity for a field is between 20^o and 31^o API, the price penalty is $0.20 per degree below 40^o API.
- If the typical crude gravity for a field is below 20^o API, the price penalty is $0.40 per degree below 40^o API.

These penalties are calculated from a nominal price of $26.50 and are escalated for prices above or below this price.

Co-product Valuation

In order to determine the value of associated/dissolved gas produced from oil-bearing fields, and the value of condensate yield from gas-bearing fields in the Gulf of Mexico OCS, a co-product valuation methodology was incorporated into the OSS. This assumes that the value of natural gas would be 68 percent of the energy-equivalent value of crude oil at the nominal oil price established from recent trends in valuations of crude oil and natural gas in the market. This value is used for all calculations of revenues from associated/dissolved gas in oil-bearing fields and condensate yield in gas-bearing fields.

Capitalized and Expensed Costs

Capital investments in the OSS include expenditures for geological and geophysical evaluations, exploration drilling, delineation drilling, development drilling including pre-drilling, production structure, and gathering pipeline system.

For tax purposes, the fastest method of deducting costs is to “expense” them in the year incurred, which means to deduct them in full amount in the year incurred. However, tax law does not permit “expensing” all costs, but instead permits these costs to be “capitalized” and deducted for tax purposes over a period of time greater than a year.

Pre-Development Costs which include geological and geophysical costs are depleted using “unit of production” depreciation method described in the following section.

Exploration and Delineation Drilling Costs are treated as “intangible” investments and are expensed in the year incurred.

Development Drilling Costs are split into tangible and intangible investment costs. In the OSS, 30 percent of the costs are considered tangible investment costs. Intangible drilling costs are defined as the cost of drilling oil and gas wells to the point of completion. The model assumes that only 70 percent of the intangible drilling costs may be expensed in the year incurred with the remaining 30 percent of the intangible drilling costs “capitalized”.

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

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

Capitalized items are depleted by depreciation in the OSS. This permits the recovery of these expenditures over a specified period of time, as described in the following section.

Depreciation Schedules Assumed

Annual taxable income is reduced by an annual depreciation deduction or allowance that reduces the annual amount of income tax payable to justify "a reasonable allowance for the exhaustion, wear and tear, and obsolescence of property held by a tax payer for the production of income." A property is depreciable if it meets these requirements:

- It must be used in business or held for the production of income;
- It must have a determinable life and that life must be longer than 1 year;
- It must be something that wears out, decays, gets used up, becomes obsolete, or loses values from natural causes; and
- It is placed in service or is in a condition or state of readiness and available to be placed in service.

Depreciation of tangible property placed in service after 1986 is based on using modified accelerated cost recovery system (ACRS) depreciation for: (1) the applicable depreciation method, (2) the applicable recovery period (depreciation life), and (3) the applicable first year depreciation convention. Modified ACRS depreciation calculations relate to two of the following three depreciation methods modeled in OSS, 'straight line depreciation' and 'double declining balance'. The third method, 'unit of production' depreciation, is used to a lesser extent for tax deduction purposes but to a greater extent for shareholder reporting purposes.

1. ***Straight Line Depreciation***. Straight line depreciation is the simplest method of computing depreciation. With the straight line method, depreciation per year is determined by multiplying the cost basis of a property times a straight line depreciation rate which is one divided by the allowable depreciation life, "n" years. In equation form:

Straight Line Depreciation Per Year = (Cost) * (1/n)

2. ***Double Declining Balance.*** Double declining balance depreciation applies a depreciation rate to a declining balance each year. Using a standard approach, factors for each year in the depreciation life have been developed, as shown in equation below:

Double Declining Balance Depreciation Per Year = (Cost) * (Adjusted Factor)

The adjusted factors for two depreciation lives in the OSS, 5 years and 7 years, are given below:

Year	1	2	3	4	5	6	7
Life = 7 years	0.14	0.25	0.20	0.16	0.13	0.08	0.04
Life = 5 years	0.15	0.22	0.21	0.21	0.21		

3. ***Units of Production.*** Units of production depreciation deducts the asset cost over the estimated producing life of the asset by taking annual depreciation deductions equal to the product of the "asset cost" times the ratio of the "units produced" in a depreciation year, divided by "expected asset lifetime unit of production".

Units of Production Depreciation Per Year = (Cost) * (Production in the Year)/ Total Recoverable Reserves in the Year

Federal Tax, Royalties, and Incentives

A rigorous methodology for computing federal taxes and producer royalties has been included in the OSS. No provision has been kept for State taxes as these are not applicable in Gulf of Mexico OCS, which are exclusively Federal properties. Provision has, however, been kept for calculation of severance taxes and tax incentives/credits, and have been set equal to zero for this analysis.

A federal tax rate of 34 percent on taxable income is assumed in the model. Royalty rates are set at 12.5 percent of the adjusted gross revenues. Royalty relief, as applicable under the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, have been incorporated as follows:

Water Depth Range	Relief Volume Applicable (MMBOE)
200 - 400 meters	17.5
400 - 900 meters	52.5
> 900 meters	87.5

These figures set the limit on cumulative production of crude oil or natural gas that is not subject to royalty from a given field in each of the water depth classes. All production volumes in excess of these amounts are subject to royalty deductions.

Discounted Net Present Value

The term discount refers to the "present worth" in economic evaluation work. Compound interest is the generally accepted approach for calculating return on investment in time value of money calculations. The future value that is projected to be accrued from the investment of dollars today at a specified compound interest rate is equal to the sum of the accrued interest and the initial principal invested. The concept of "present worth" is just the opposite of compounding. The terms "discounting" implies reducing the value of something and is equivalent to determining the present worth of a future value. A discount rate of 10 percent is the default value assumed for all investment decisions in the OSS, though this is a parameter that can be specified by the user.

Net Present Value of After-Tax Cash Flow in year "IYR"

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

The previous sections covered the structure, methodology, and key components of the exogenous portion of the OSS which is used to generate the price-supply curves for the offshore Gulf of Mexico OCS, i.e. the potential supply from undiscovered resources at different nominal prices for crude oil and natural gas. These price-supply data can be generated under a variety of economic scenarios and analysis options due to the modular construction of the OSS. Having a separate exogenous component that can be used to study the impacts of various policy, regulatory, and economic scenarios outside of the Oil and Gas Supply Module (OGSM) and National Energy Modeling System (NEMS) helps to speed the computational process. Besides supply price and reserves data, the exogenous component of OSS also transfers key cost data (exploration, drilling, structure installation, and operations) and well counts required to develop the reserves in a field.

DEVELOPMENT OF RESERVES AND PRODUCTION TIMING

The endogenous component of the OSS is an integral part of OGSM. The primary purpose of this endogenous component is to make a realistic forecast of offshore Gulf of Mexico OCS reserves development and production performance over a study period of 15-20 years based on the information supplied to it, i.e., the price-supply and other supply-side information generated in the exogenous module, and price information for crude oil and natural gas generated from the other demand-side components of NEMS, the Petroleum Market Module (PMM) and Natural Gas Transmission and Distribution Module (NGTDM), respectively. The model has been designed to make investment and field development decisions from the perspective of a field operator, and to incorporate real-life exploration and development constraints faced by the operator.

The basic process-flow diagram of the endogenous component has already been shown in Figure 4E-5. The following sections are devoted to a more detailed discussion of the modeling approach.

Inferred Reserves

The first task of the endogenous component of the OSS is to calculate the inferred reserves for a given year in the study. Based on the regional wellhead prices supplied by PMM and NGTDM, the crude oil and natural gas supply information generated in the exogenous component is skimmed to determine the total crude oil and natural gas resources that are economic at those prices. It is basically the amount of crude oil and natural gas resources that are economic to explore, develop, and produce from the remaining undiscovered prospects in the Gulf of Mexico.

$$\text{INFERRED RESERVES}_{iyr,\, fuel} = \text{INFERRED RESERVES}_{iyr-1,\, fuel} + \text{FIELD RESERVES}_{fuel,\, nfield}$$

where,

iyr	=	Year under consideration
fuel	=	Fuel type, crude oil or natural gas
nfield	=	Fields remaining to be discovered

Inferred reserves that do not get developed in the year they become economic get carried over to the next year and are added to the inferred reserves that come onstream at the crude oil and natural gas wellhead supply prices in the next year.

The routine also determines an average supply price for crude oil and natural gas for the total inferred reserves based on a weighted average of the individual prospect supply price. The weighting basis is the amount of technically recoverable reserves in those prospects. The total number of exploration, development and dry development wells, and the total number of production structures needed to develop the different prospects that sum up to the inferred reserves are also accounted for and carried along with the inferred reserves.

Proved Reserves

Due to physical and monetary constraints, only a portion of the inferred reserves are assumed to be developed in any given year. These are based on capital investment constraints, infrastructure, and rig availability constraints. OSS has been designed to develop the inferred reserves and generate proved reserves in a given year based on the number of development wells that can be drilled in that particular year. Historic drilling activity levels in the offshore Gulf of Mexico were used to characterize the current drilling level constraints. The governing equations for calculating rig and drilling capacities are:

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

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

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

where,

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

The ratio of development drilling wells available to be drilled based on the drilling constraints to the total number of development wells needed to develop the total inferred reserves in a given year is multiplied by the total reserves for both crude oil and natural gas to project the proved reserves.

However, the model still has to decide between how much of the crude oil and how much of the natural gas reserves will be developed. Historically, the development of a particular fuel type has been driven by the "relative price-economics" of the development prospect for each of the two fuel types, crude oil and natural gas. Relative price economics is defined as the ratio of the price spread (difference between the average minimum acceptable supply price of the resource remaining to be discovered and the wellhead fuel price) and the fuel price (oil or gas wellhead prices). The higher the spread, the more economic it is to develop that category of resource that remains to be discovered. The proportion of development wells to be drilled for crude oil and natural gas prospects is determined by these ratios.

Production

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

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

$$PRODUCTION_{k,\ iyr} = PROVED\text{-}RESERVES_{k,iyr} / RESERVES\text{-}TO\text{-}PRODUCTION\text{-}RATIO_{iyr}$$

where,

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

Reserves Growth

Reserves growth includes those resources that are expected to be added to proved reserves in a field as a consequence of extension of proved fields, through revisions of reserve estimates, and/or by addition of new payzones in these fields. Also included in this category are resources expected to be added to reserves through application of improved recovery technologies. OSS has been designed to allow the remaining proved reserves at the end of the year to be adjusted by a certain multiplier to estimate additional reserves growth attributable to these activities.

$$RESERVES\ GROWTH_{k,\ iyr} = (PROVED\ RESERVES_{k,\ iyr} - PRODUCTION_{k,\ iyr}) * GROWTH\ RATE\ MULTIPLIER$$

where,

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

Advanced Technology Impacts

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities and hence on the profitability of the undiscovered crude oil and natural gas prospects. The OSS has been designed to give due consideration to the effect of future advances in technology that may occur in the future. Since the exogenous component of the OSS that generates price-supply information evaluates the various offshore Gulf of Mexico prospects on the basis of existing technology choices, some way of translating the impact of future advances in technology needs to be incorporated into the analytical approach.

The endogenous component of the OSS has been designed to modify the exploration, drilling, structure installation, and operational costs associated with undiscovered prospects that have not been added to the inferred reserves category. At the end of each year, exploration, drilling, structure installation, and operations costs for all the crude oil and natural gas prospects that remain uneconomic investments can individually reduced using unique factors for each of the cost components.

$$MASP_{nfield,\ iyr,\ fuel,\ component} = DRILLING\ MASP_{nfield,\ iyr,\ fuel,\ component} * ADV\ TECH\ FACTOR$$

where,

nfield	=	A crude oil or natural gas field
iyr	=	Year under consideration
fuel	=	Crude oil or natural gas
component	=	Key cost components: Exploration, Drilling, Structure, Operations

The minimum acceptable supply price (MASP) for each of the undiscovered remaining uneconomic prospect is also adjusted accordingly.