DOE/EIA-M063(2009)

# Documentation of the Oil and Gas Supply Module (OGSM)

**June 2009**

**Office of Integrated Analysis and Forecasting**
**Energy Information Administration**
**U.S. Department of Energy**
**Washington, DC 20585**

# Update Information

This edition of the *Documentation of the Oil and Gas Supply Module* reflects changes made to the oil and gas supply module over the past year for the *Annual Energy Outlook 2009*. These changes include:

- Re-estimation of lower 48 onshore drilling, lease equipment, and operating costs
- Revision to oil shale facility capital costs
- Moving most of the Foreign Natural Gas Supply Submodule to the Natural Gas Transmission and Distribution Module
- Re-estimation of lower 48 onshore conventional natural gas drilling equations
- Revision to onshore conventional oil and natural gas reserve revisions
- Addition of two gas shale plays, Marcellus and Haynesville
- Addition of three Alaska oil fields, Nikaitchuq, Liberty, and Qannik
- Opening of access to resources in the Pacific, Atlantic, and Eastern/Central OCS areas, which were formerly under leasing moratoria
- Updates to the assumptions used for the announced/nonproducing offshore discoveries
- Updates to historical reserves and production.

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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 both conventional and unconventional natural gas supply. Unconventional gas recovery (UGR) includes supply from tight gas formations, gas shales, 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 natural gas trade via pipeline from Canada. Liquefied natural gas (LNG) trade and natural gas trade with Mexico are determined in the Natural Gas Transmission and Distribution Module (NGTDM). 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 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. To equilibrate supply and demand in the given year, the NGTDM employs short-term supply functions (the parameters for which are provided by OGSM) to determine nonassociated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. These 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 passed to the Integrating Module for reporting purposes. Forecasts of oil and gas production are also provided 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 NEMS2009. The NEMS version documented is that used to produce the *Annual Energy Outlook 2009 (AEO2009)*. 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.

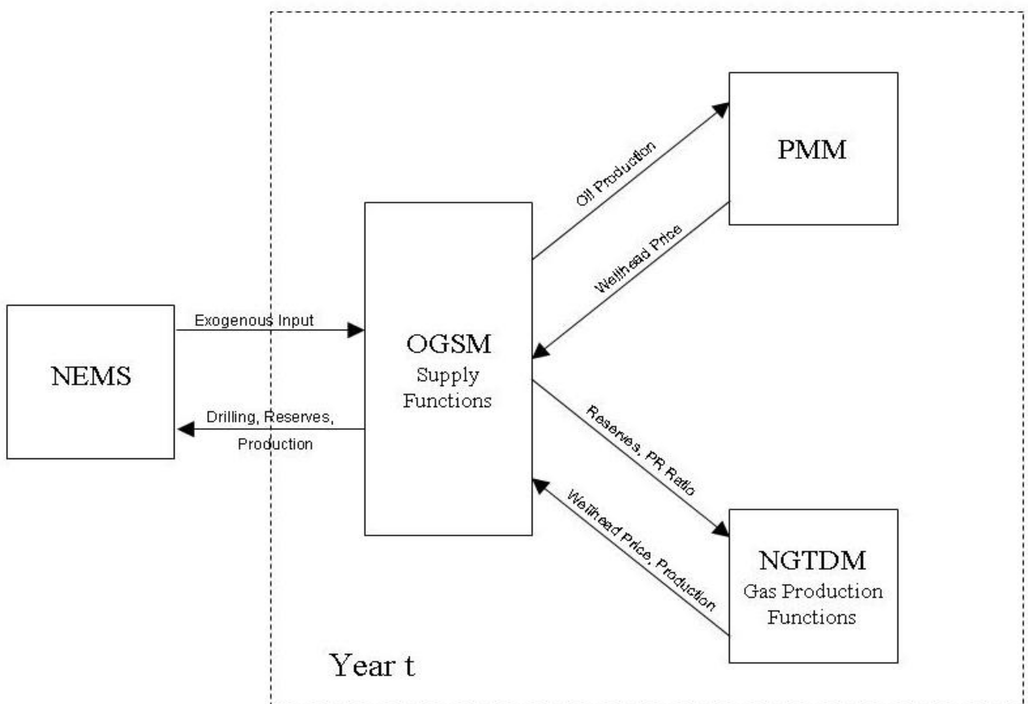
- Model purpose
- Module structure
- Inventory of input data, parameter estimates, and model output

# 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 domestic projections 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). Projected natural gas and crude oil wellhead prices are determined within the NGTDM and PMM, respectively. As the supply component only, OGSM cannot project prices, which are the outcome of the equilibration of both demand and supply.

The basic interaction between OGSM and the other oil and gas modules is represented in Figure 1. The OGSM provides to the NGTDM beginning-of-year reserves and production-to-reserves ratio for use in the short-term domestic nonassociated gas production functions that reside in the NGTDM, associated-dissolved natural gas production, and pipeline imports from Mexico. The interaction of supply and demand in NGTDM determines nonassociated gas production. The OGSM provides domestic crude oil production to the PMM. The interaction of supply and demand in the PMM determines the level of imports. System control information (e.g., forecast year) and expectations (e.g., expect price paths) come from the Integrating 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 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, gas shales, and coalbed methane formations.

OGSM provides mid-term (through year 2030) projections and serves as an analytical tool for the assessment of alternative supply policies. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues that 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.

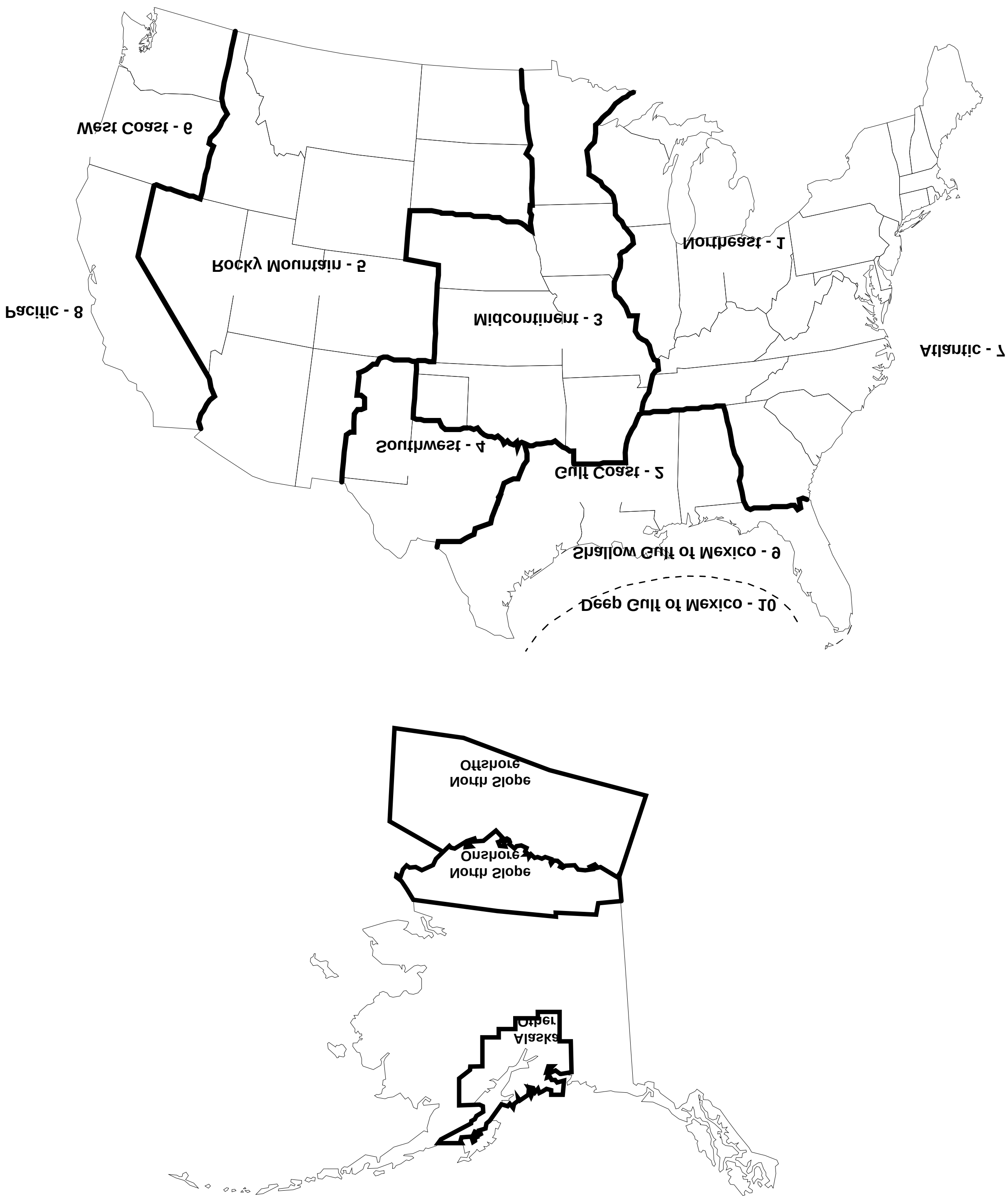
OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). With some modification, this feature could allow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



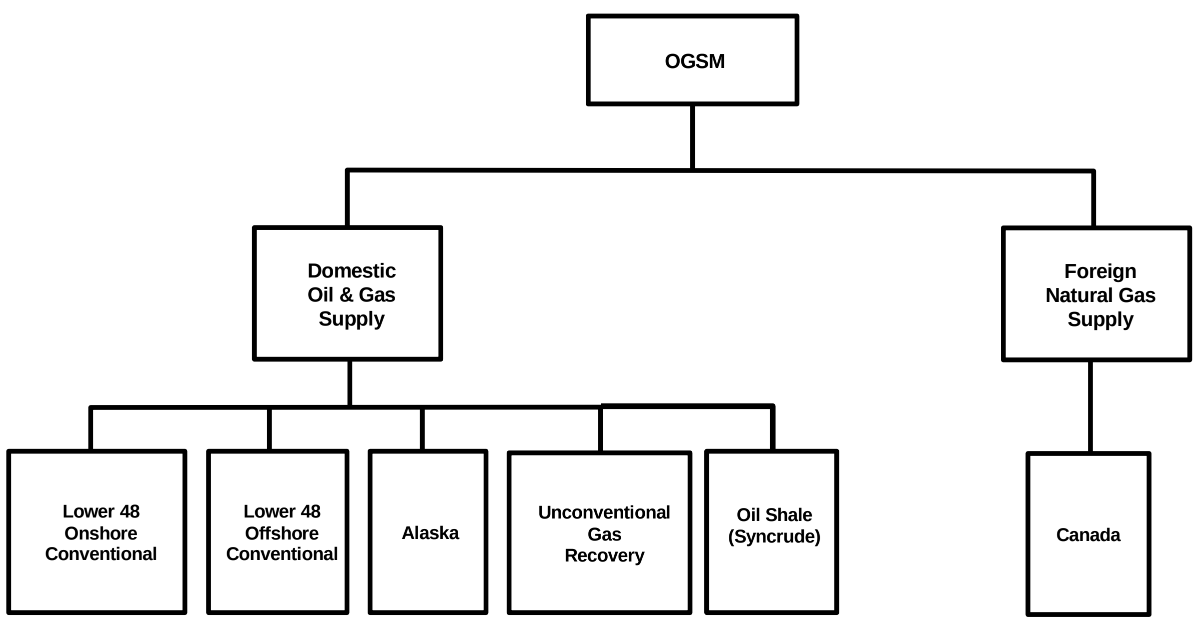
# 3. Model Structure

## Introduction

This chapter describes the Oil and Gas Supply Module (OGSM) of the National Energy Modeling System (NEMS), 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 Canada via pipeline. 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 NEMS. The oil and gas supplies in each period are balanced against the regionally-derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the wellhead and end-use 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 represents the activities of firms that produce oil and natural gas from domestic fields throughout the United States, or acquire natural gas from Canadian 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. Unconventional oil includes production of synthetic crude from oil shale (syncrude). Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM represents Canadian trade in natural gas as pipeline imports and exports by entry region of the United States. Liquefied natural gas (LNG) imports and Mexico natural gas imports/exports are determined in the NGTDM.

**Figure 3. Submodules within the Oil and Gas Supply Module**



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.

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 OGSM distinguishes between drilling for new fields (new field wildcats) and that for additional deposits within old fields (other exploratory and developmental wells). 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 the literature regarding resource recovery.[5]

The breadth of supply processes that are encompassed within OGSM results in different methodological approaches for determining crude oil and natural 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 five 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 shale formations, and coalbeds. The Offshore Oil and Gas Supply Submodule (OOGSS) represents oil and gas exploration and development in the offshore Gulf of Mexico, Pacific, and Atlantic 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 Canada. These distinctions are reflected in the presentation of the methodology in this chapter.

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

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[1]*Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically 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.

[2]*Proved reserves* are the estimated quantities that analyses 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.

methodology of the Unconventional Gas Recovery Supply Submodule, the Offshore Oil and Gas 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 four 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, unconventional gas recovery, technologies for unconventional gas recovery, offshore oil and gas supply, and shale oil synthetic crude (syncrude) 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.

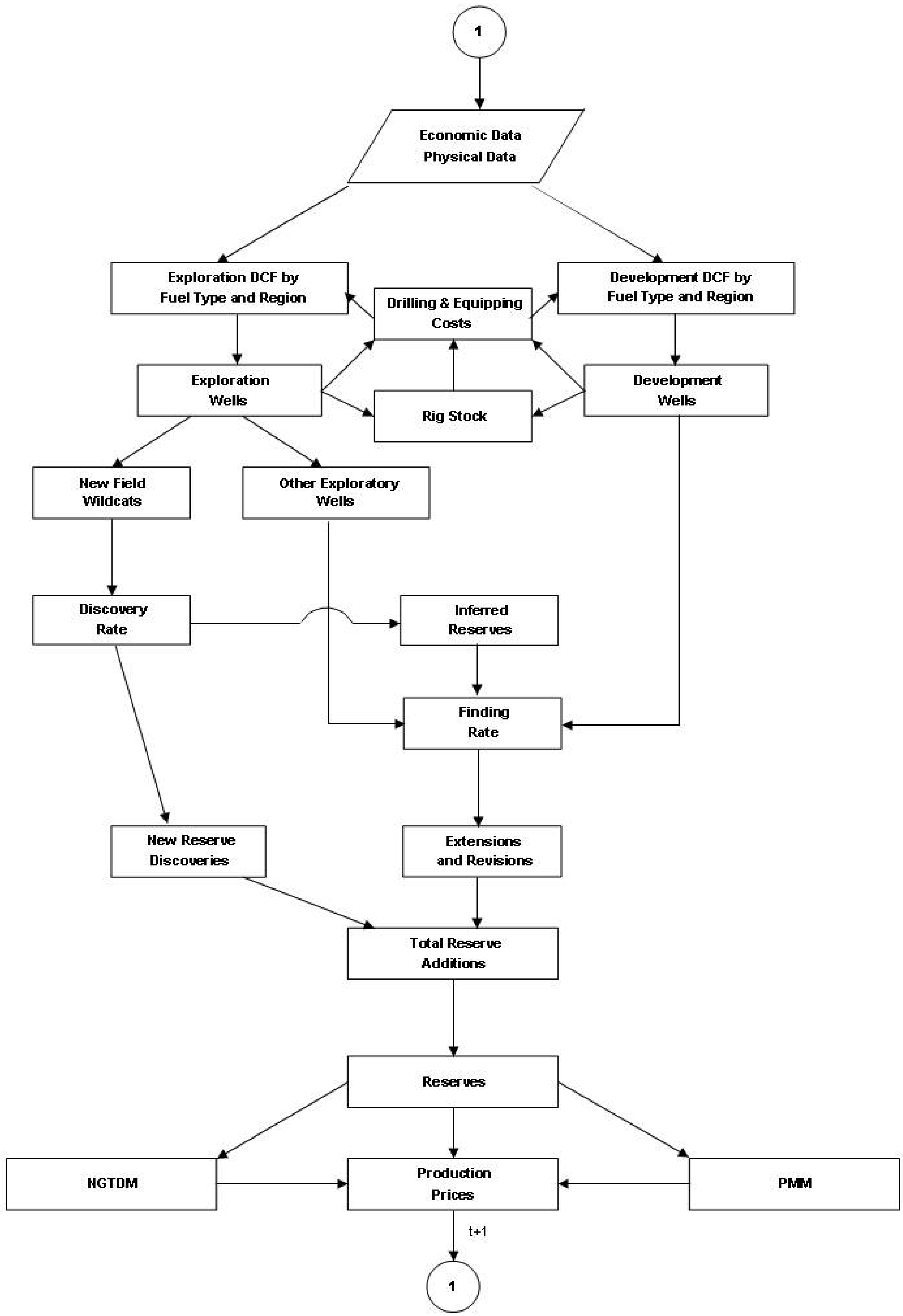
A discounted cash flow (DCF) algorithm is used to calculate the expected profitability of a representative well in each region. Inputs to this algorithm include oil and gas prices (from the PMM and NGTDM), production profiles, co-product ratios, drilling costs, lease equipment costs, operating costs, severance tax rates, ad valorem tax rates, royalty rates, State tax rates, Federal tax rates, tax credits, depreciation schedules, and success rates. Expected DCF values are calculated for each well type (exploratory, developmental), and for each 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 profitability 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.

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 the short-run natural gas supply functions.

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



## 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 (SR); the probability of failure is given by one minus the success rate (1-SR). 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 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:

$$\begin{aligned} \mathrm{NCFON}_{i,r,k,s} = & \left(\mathrm{REV} - (\mathrm{ROY} + \mathrm{PRODTAX} + \mathrm{STATETAX} + \mathrm{FEDTAX})\right)_{i,r,k,s} \\ & -\left(\mathrm{DRILLCOST} + \mathrm{EQUIPCOST} + \mathrm{OPCOST} + \mathrm{DRYCOST}\right)_{i,r,k,s} \end{aligned} \tag{1}$$

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) |
| 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 2 for OGSM region codes) |
| k | = | subscript indicating fuel type |
| s | = | subscript indicating year of project life.[6] |

[6]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.

The calculation of REV depends on expected production and prices. Expected production is calculated on the basis of individual wells. Flow from each successful well begins at a level equal to the historical average for production over the first 12 months. Production subsequently declines at a rate equal to the historical average production to reserves ratio. The default price expectation is that real prices will remain constant over the project's expected lifetime. The OGSM also can utilize an expected price vector provided from the NEMS system that reflects a user-specified assumption regarding price expectations. The calculations of STATETAX and FEDTAX account for the tax treatment of tangible and intangible drilling expenses, lease equipment expenses, operating expenses, and dry hole expenses. The algorithm also incorporates the impact of unconventional fuel tax credits and has the capability of handling other forms of investment tax credits. For a detailed discussion of the discounted cash flow methodology, the reader is referred to Appendix 3-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:

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

where,

| | | |
|---|---|---|
| PROJDCFON | = | the discounted cash flow for a representative developmental project |
| 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:

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

it is easily calculated as:

$$DCFON_{i,r,k,t} = PRJDCFON_{i,r,k,t} * SR_{i,r,k} \quad (4)$$

where,

| | | |
|---|---|---|
| DCFON | = | expected discounted cash flow for a representative onshore developmental well. |
| SR | = | drilling success rate |

### *Onshore Lower 48 Exploration*

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

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

$$\begin{aligned}\mathrm{PROJDCFON}_{1,r,k,t} &= \mathrm{SUCDCFON}_{1,r,k,t} + \left(\frac{1}{\mathrm{SR}_{1,r,k}} - 1\right) * \mathrm{DRYDCFON}_{1,r,k,t} \\ &+ m_k * \left[\mathrm{SUCDCFON}_{2,r,k,t} + \left(\frac{1}{\mathrm{SR}_{2,r,k}} - 1\right) * \mathrm{DRYDCFON}_{2,r,k,t}\right]\end{aligned} \tag{5}$$

where,

$m_k$ = number of successful developmental wells in a representative project.

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

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

$$\mathrm{DCFON}_{1,r,k,t} = \mathrm{PRJDCFON}_{1,r,k,t} * \mathrm{SR}_{1,r,k} \tag{6}$$

### *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,

$$w1_{i,r,k,t} = \frac{\mathrm{WELLS}_{i,r,k,t-1}}{\sum_{i=1}^{2} \mathrm{WELLS}_{i,r,k,t-1}} \tag{7}$$

and

$$\mathrm{ODC\ FON}_{r,t} = \sum_{i=1}^{2} w1_{i,r,k,t} * \mathrm{DCFON}_{i,r,k,t}, \text{ for } k = 1 \tag{8}$$

$$\mathrm{SGDC\ FON}_{r,t} = \sum_{i=1}^{2} w1_{i,r,k,t} * \mathrm{DCFON}_{i,r,k,t}, \text{ for } k = 3 \tag{9}$$

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 Exploration and Development Budget for Wells Determination*

Expected U.S. budget for exploration and development is estimated as,

$$US\_ED_t = b0 * ROI\_FOREIGN_t^{b1} * RPCGAS_t^{b2} * RPCOIL_t^{b3} * PRDGAS_t^{b4} \tag{10}$$

where RPCGAS (RPCOIL) is the ratio of the price of natural gas (crude oil) in 1997 dollars to the national natural gas (crude oil) well operating cost index in 1997 dollars and PRDGAS is U.S. natural gas production.

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 D. These equations can be expressed in the following generalized form.

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & e^{m0_{i,r,k} + m1_{i,k} * DCFON_{i,r,k,t} * US\_ED_t} * REMAINRES_{r,k,t}^{m2_{i,k}} * WELLSON_{i,r,k,t-1}^{\rho_{i,k}} \\ & * e^{-\rho_{i,k} * (m0_{i,r,k} + m1_{i,k} * DCFON_{i,r,k,t-1} * US\_ED_{t-1})} * REMAINRES_{r,k,t-1}^{-\rho_{i,k} * m2_{i,k}} \end{aligned} \tag{11}$$

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 |
| US_ED | = | U.S. budget for exploration and development in year t |
| REMAINRES | = | remaining unproved resources |
| m'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,

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k} \tag{12}$$

where,

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

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

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t} \tag{13}$$

where,

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

## Drilling, Lease Equipment, and Operating Cost Calculations

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

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

$$ESTOWELLS_t = \exp(b00) * POIL_t^{b1} * ESTOWELLS_{t-1}^{\rho} * \exp(-\rho * b00) * POIL_{t-1}^{-\rho * b1} \tag{14}$$

$$ESTGWELLS_t = \exp(b01) * PGAS_t^{b2} * ESTGWELLS_{t-1}^{\rho} * \exp(-\rho * b01) * PGAS_{t-1}^{-\rho * b2} \tag{15}$$

where,

| | | |
|---|---|---|
| ESTOWELLS | = | estimated total onshore lower 48 oil wells drilled |
| ESTGWELLS | = | estimated total onshore lower48 gas wells drilled |
| POIL | = | average wellhead price of crude oil |
| PGAS | = | average wellhead price of natural gas |
| b00, b01, b1, b2 | = | 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:

$$RIGSL48_t = e^{b0} * RIGSL48_{t-1}^{b1} * REVRIG_{t-1}^{b2} * RIGSL48_{t-1}^{\rho} * e^{-\rho * b0} * RIGSL48_{t-2}^{-\rho * b1} * REVRIG_{t-2}^{-\rho * b2} \tag{16}$$

where,

| | | |
|---|---|---|
| RIGSL48 | = | onshore lower 48 rigs |
| REVRIG | = | total drilling expenditures per rig |
| b0, b1, b2 | = | estimated parameters |
| ρ | = | estimated serial correlation parameter |
| t | = | year. |

### *Drilling Costs*

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

$$\mathrm{DRILLCOST}_{r,k,t} = e^{b0+b1_k*\mathrm{DEPTH}_{r,k,t}} * \mathrm{ESTWELLS}_t^{b2} * e^{b3*\mathrm{TIME}_t} * e^{\mathrm{CAPCOST}} * \mathrm{DRILLCOST}_{r,k,t-1}^{\rho} * e^{-\rho*(b0+b1_k*\mathrm{DEPTH}_{r,k,t-1})} * \mathrm{ESTWELLS}_{t-1}^{-\rho*b2} * e^{-\rho*b3*\mathrm{TIME}_{t-1}} * e^{-\rho*CAPCOST} \tag{17}$$

$$\mathrm{DRYCOST}_{r,k,t} = e^{b0+b1_k*\mathrm{DEPTH}_{r,k,t}} * \mathrm{ESTWELLS}_t^{b2} * e^{b3*\mathrm{TIME}_t} * e^{\mathrm{CAPCOST}} * \mathrm{DRYCOST}_{r,k,t-1}^{\rho} * e^{-\rho*(b0+b1_k*\mathrm{DEPTH}_{r,k,t-1})} * \mathrm{ESTWELLS}_{t-1}^{-\rho*b2} * e^{-\rho*b3*\mathrm{TIME}_{t-1}} * e^{-\rho*CAPCOST} \tag{18}$$

where,

| | | |
|---|---|---|
| DRILLCOST | = | drilling cost per successful well |
| DRYCOST | = | drilling cost per dry hole |
| ESTWELLS | = | estimated total onshore lower 48 oil and gas wells drilled |
| RIGSL48 | = | onshore lower 48 rigs |
| TIME | = | time trend - proxy for technology |
| CAPCOST | = | estimated capital cost escalation factor |
| r | = | OGSM lower 48 onshore region |
| k | = | fuel type (1 = shallow oil, 2 = deep oil, 3 = shallow gas, 4 = deep gas) |
| b0, b1, b2, b3, b4 | = | estimated parameters |
| ρ | = | estimated serial correlation parameter |
| t | = | year. |

### *Lease Equipment Costs*

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

$$\mathrm{LEQC}_{r,k,t} = e^{b0_{r,k}} * \mathrm{DEPTH}_{r,k,t}^{b1_k} * \mathrm{ESTSUCWELLS}_t^{b2_k} * e^{b3_k*\mathrm{TIME}_t} * \mathrm{LEQC}_{r,k,t-1}^{\rho_k} * e^{-\rho_k*b0_{r,k}} * \mathrm{DEPTH}_{r,k,t-1}^{-\rho_k*b1_k} * \mathrm{ESTSUCWELLS}_{t-1}^{-\rho_k*b2_k} * e^{-\rho_k*b3_k*\mathrm{TIME}_{t-1}} \tag{19}$$

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 |
| b0, b1, b2, b3 | = | estimated parameters |
| ρ | = | estimated serial correlation parameter |
| 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:

$$\begin{aligned} OPC_{r,k,t} = {} & e^{b0_{r,k}} * DEPTH_{r,k,t}^{b1_k} * ESTSUCWELLS_{k,t}^{b2_k} * e^{b3_k * TIME_t} * e^{b4_k * PGAS} * OPC_{r,k,t-1}^{\rho_k} \\ & * e^{-\rho_k * b0_{r,k}} * DEPTH_{r,k,t-1}^{-\rho_k * b1_k} * ESTSUCWELLS_{k,t-1}^{-\rho_k * b2_k} * e^{-\rho_k * b3_k * TIME_{t-1}} * e^{-\rho * b4_k * PGAS} \end{aligned} \tag{20}$$

where,

| | | |
|---|---|---|
| OPC | = | oil and gas well operating costs |
| ESTSUCWELLS | = | estimated lower 48 successful onshore wells |
| DEPTH | = | average well depth |
| PGAS | = | regional average natural gas wellhead price (for oil only) |
| TIME | = | time trend - proxy for technology |
| b0, b1, b2, b3, b4 | = | estimated parameters |
| ρ | = | estimated serial correlation parameter |
| 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 D.

## 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. Other exploratory drilling account for proved reserves added through new pools or extensions. The determinants of revisions and adjustments are not well understood and thus projecting net revisions and adjustments is somewhat problematic, particularly for natural gas. For example, a negative adjustment or revision can be recorded because of a change in ownership and, thus, not linked directly to drilling. Over the last 25 years, net natural gas revisions and adjustments have varied from a low of -2.2 trillion cubic feet to as much as 3.1 trillion cubic feet.

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.[7]

### *Functional Forms*

Wells are divided into three categories: (1) new field wildcats, (2) other exploratory wells, and (3) development wells. 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.

New reserve discoveries per successful new field wildcat are a function of drilling activity, average depth, and the estimated volume of remaining undiscovered resources. Specifically, the finding rate equation for new field wildcats is:

$$FR1_{r,k,t} = e^{\beta 0_k} * RESOURCE_{r,k,t-1}^{\beta 1_{r,k}} * SW1_{r,k,t}^{\beta 2_k} * DEPTH_{r,k,t}^{\beta 3_k} \tag{21}$$

where,

| | | |
|---|---|---|
| FR1 | = | new field wildcats finding rate |
| RESOURCE | = | remaining undiscovered resources |
| SW1 | = | number of successful new field wildcats |
| DEPTH | = | average well depth |
| β0, β1, β2, β3 | = | estimated parameters |
| 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

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

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 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 equations.

[7]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*.

$$\mathrm{FR2}_{r,k,t} = e^{\beta 0_{r,k}} * \mathrm{INFR}_{r,k,t}^{\beta 1_{r,k}} * \mathrm{SW2}_{r,k,t}^{\beta 2_k} * \mathrm{WHP}_{r,k,t}^{\beta 3_{r,k}} * e^{\beta 4_k * \mathrm{year}_t} * \mathrm{FR2}_{r,k,t-1}^{\rho_k}$$
$$* e^{-\rho_k * \beta 0_{r,k}} * \mathrm{INFR}_{r,k,t-1}^{-\rho_k * \beta 1_{r,k}} * \mathrm{SW2}_{r,k,t-1}^{-\rho_k * \beta 2_k} * \mathrm{WHP}_{r,k,t-1}^{-\rho_k * \beta 3_{r,k}} * e^{-\rho_k * \beta 4_k * \mathrm{year}_{t-1}} \quad (23)$$

where,

| | | |
|---|---|---|
| FR2 | = | other exploratory well finding rate |
| INFR | = | remaining inferred reserves |
| SW2 | = | successful other exploratory wells |
| WHP | = | wellhead price |
| β0, β1, β2, β3, β4 | = | estimated parameters |
| ρ | = | estimated serial correlation parameter |
| r | = | region |
| k | = | fuel type (oil or gas) |
| t | = | year. |

The total volume of proved reserves added in any year through other exploratory drilling in the form of new pools and extensions is given by

$$\mathrm{EXTENSIONS}_{r,k,t} = \mathrm{FR2}_{r,k,t} * \mathrm{SW2}_{r,k,t} \quad (24)$$

The final reserve category is revisions. As noted earlier, revisions vary widely historically can not be estimated econometrically as a function of developmental drilling. Revisions are determine by

$$\mathrm{REVISIONS}_{r,k,t} = m0_{r,k} + m1_k * WHP_{r,k,t} * INFR_{r,k,t} + m2_k * SW3_{r,k,t}\text{, for oil} \quad (25)$$

$$\mathrm{REVISIONS}_{r,k,t} = m0_{r,k} + m1_k * WHP_{r,k,t} + m2_k * RESBOY_{r,k,t} + m3_k * SW3_{r,k,t}\text{, for natural gas} \quad (26)$$

where,

| | | |
|---|---|---|
| WHP | = | wellhead price |
| INFR | = | remaining inferred reserves |
| SW3 | = | successful development wells |
| RESBOY | = | beginning-of-year reserves |
| m0, m1, m2, m3 | = | assumed parameters |
| r | = | region |
| k | = | fuel type (oil or gas) |
| t | = | year. |

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

$$\mathrm{RA}_{r,k,t} = \mathrm{NRD}_{r,k,t} + \mathrm{EXTENSIONS}_{r,k,t} + \mathrm{REVISIONS}_{r,k,t} \quad (27)$$

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

$$\mathrm{R}_{r,k,t} = \mathrm{R}_{r,k,t-1} - \mathrm{Q}_{r,k,t} + \mathrm{RA}_{r,k,t} \quad (28)$$

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[8] 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:

$$PR_{r,k,t} = \frac{Q_{r,k,t}}{R_{r,k,t-1}} \tag{29}$$

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.

$PR_{r,k,t}$ represents the rate of extraction from all wells drilled up to year t (through year t-1). Because the production to reserves ratio is between zero and one, there is merit to estimating the logistical transformation of the PR ratio rather than estimate the ratio itself. In this case the dependent variable is $LOGISTIC_{r,k,t}$ which is defined as

$$LOGISTIC_{r,k,t} = \ln\left(\frac{PR_{r,k,t}}{1 - PR_{r,k,t}}\right) \tag{30}$$

The variable LOGISTIC is estimated using the calculation

$$\begin{aligned} LOGISTIC_{r,k,t} = {} & a_{r,k} * (1 - \rho_k) + b0 * \frac{REVISIONS_{r,k,t}}{SW3_{r,k,t}} + b1 * \frac{NRD_{r,k,t} + EXTENSIONS_{r,k,t}}{SW3_{r,k,t}} \\ & + b2_{r,k} * \ln(SW3_{r,k,t}) + \rho_k * LOGISTIC_{r,k,t-1} \\ & - \rho_k * [b0 * \frac{REVISIONS_{r,k,t-1}}{SW3_{r,k,t-1}} + b1 * \frac{NRD_{r,k,t-1} + EXTENSIONS_{r,k,t-1}}{SW3_{r,k,t-1}} + b2_{r,k} * \ln(SW3_{r,k,t-1})] \end{aligned} \tag{31}$$

where RA_RATIO is the ratio of total reserve additions to beginning of year reserves in year t. The PR ratio is then determined by

$$PR_{r,k,t} = \frac{\exp(LOGISTIC_{r,k,t})}{1 + \exp(LOGISTIC_{r,k,t})} \tag{32}$$

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

The values for $R_{r,k,t}$ and $PR_{r,k,t+1}$ 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:

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

$$Q_{r,k,t+1} = R_{r,k,t} * PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1}) \quad (33)$$

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 |
| $\Delta P_{t+1}$ | = | $(P_{t+1}-P_t)/P_t$, 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 D.

## Associated-dissolved Gas

The production of associated-dissolved gas (AD gas) was assumed to be a function of end-of-year reserves and AD gas production for the previous year and oil production in the current year. The P/R ratio for AD gas is then calculated as the ratio of AD gas production in the current year to the end-of-year reserves in the previous year.

$$Q\_ADGAS_{r,t} = e^{\alpha 0} * Q\_ADGAS_{r,t-1}^{\alpha 1} * R\_ADGAS_{r,t-1}^{\alpha 2} * OILPRD_{r,t}^{\alpha 3} \quad (34)$$

where,

| | | |
|---|---|---|
| Q_ADGAS | = | associated-dissolved gas production |
| R_ADGAS | = | associated-dissolved gas reserves measured as of the end-of-year |
| OILPRD | = | crude oil production |
| r | = | OGSM region |
| t | = | year |
| α0, α1, α2, α3 | = | estimated parameters |

The PR ratio is then determined by

$$PR\_ADGAS_{r,t} = \frac{Q\_ADGAS_{r,t}}{R\_ADGAS_{r,t-1}} \quad (35)$$

Associated-dissolved gas reserve additions are given by

$$RA\_ADGAS_{r,t} = \beta 0 + \beta 1 * NRD_{r,t} + \beta 2 * EXTENSIONS_{r,t} + \beta 3 * REVISIONS_{r,t} \quad (36)$$

Finally, end-of-year associated-dissolved gas reserves equals:

$$R\_ADGAS_{r,t} = R\_ADGAS_{r,t-1} - Q\_ADGAS_{r,t} + RA\_ADGAS_{r,t} \quad (37)$$

## 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 3-B and an in depth view of the treatment of technology in the UGRSS is provided in Appendix 3-C.

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. Other drilling is "infill" in nature and does not result in reserve additions. This latter drilling is based on projected production for the year and is essentially the additional wells required to meet that production level. Given the projected 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 Oil and Gas Supply Submodule (OOGSS). The OOGSS is designed to project the exploration and development of U.S. offshore oil and natural gas resources. As described in previous sections, annual production is not determined within the OOGSS but rather the parameters for the short-term supply functions that are used in the market equilibration routine within the NGTDM and PMM. This section provides an overview of the basic approach. A more detailed description of the methodology is presented in Appendix 3-D as well as a discussion of the characterization of the undiscovered resource base and the various technology options for offshore exploration, development, and production practices incorporated in the OOGSS.

The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories: (1) undiscovered fields, (2) discovered, undeveloped fields, and (3) producing fields. Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are five water depth categories: 0-200 meters, 200-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters.

Supply curves for crude oil and natural gas are generated for four offshore regions: Pacific, Atlantic, shallow GOM (water depth less than 200 meters), and deep GOM (water depth greater than 200 meters). Crude oil production includes oil condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

# 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 5).Transportation costs are used in conjunction with the relevant market price of oil or natural 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 Alaskan drilling and production activities. Oil and gas investments decisions 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 s profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, and historical production patterns and announced plans for currently producing fields.

## Calculation of Costs

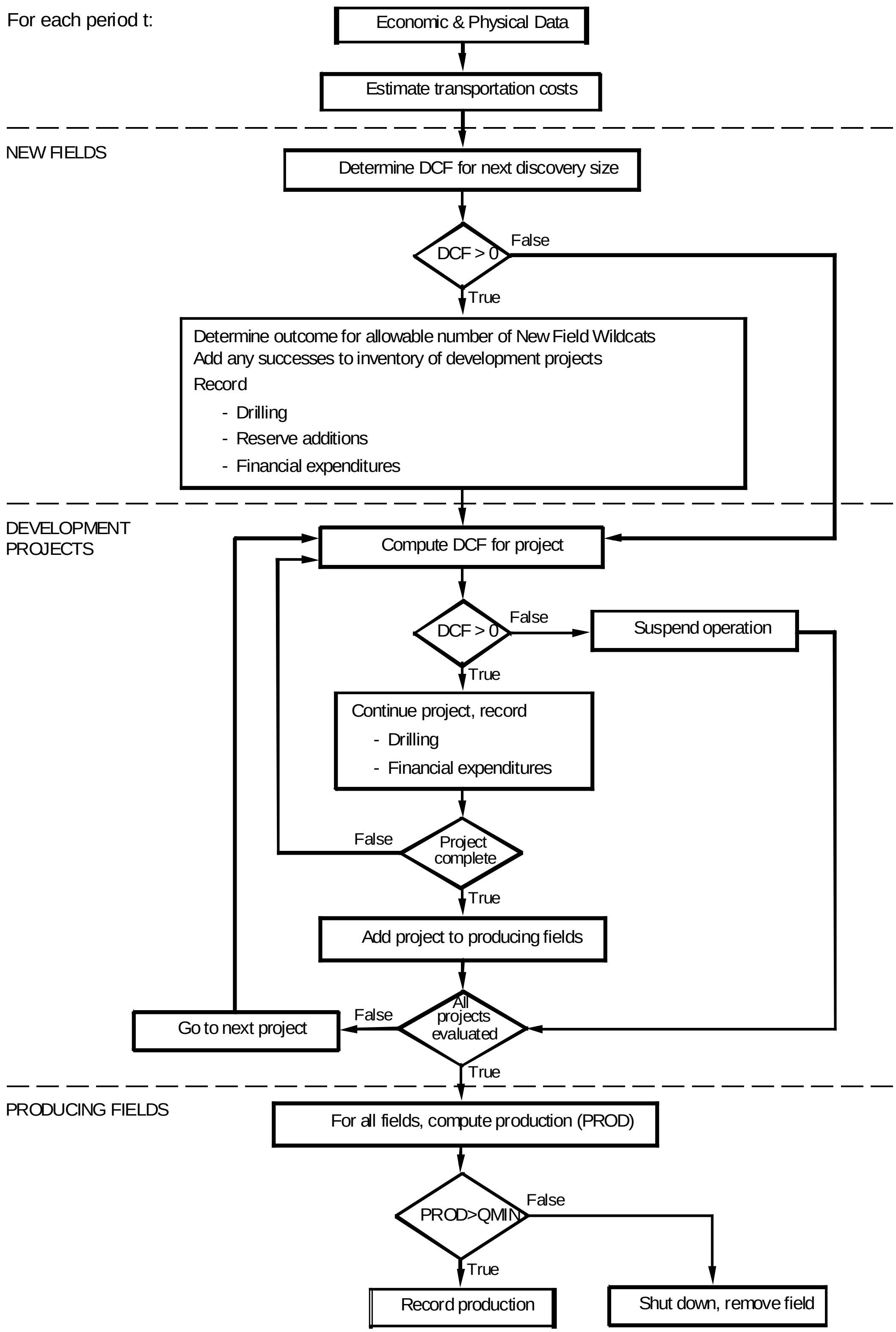
Costs differ within the model for successful wells and dry holes. Costs are categorized functionally within the model as:

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

All costs in the model incorporate the estimated impact of environmental compliance. Environmental regulations that preclude a supply activity outright are 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

**Figure 5. Flowchart of the Alaska Oil and Gas Supply Submodule**



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:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1) ** (t - T_b) \tag{38}$$

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:

$$EQUIP_{r,k,t} = EQUIP_{r,k,t} * (1 - TECH2)^{r - T_b} \tag{39}$$

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:

$$\mathrm{OPCOST}_{r,k,t} = \mathrm{OPCOST}_{r,k,t} * (1 - \mathrm{TECH2})^{r - T_b} \tag{40}$$

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 is 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.[9] 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:[10]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_t) \tag{41}$$

where,

| | | |
|---|---|---|
| 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:

$$\begin{aligned} DCF_{f,t} = (&PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP \\ &- PVOPCOST - PVPRODTAX - PVSIT - PVFIT - PVWPT)_{f,t} \end{aligned} \tag{42}$$

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 |

[9]See Appendix 3.A at the end of this chapter for a detailed discussion of the DCF methodology.

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

PVWPT = present value of expected windfall profits tax[11]

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

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \tag{43}$$

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:

$$PROF_{f,t} = \frac{DCF_{f,t}}{COST_{f,t}} \tag{44}$$

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

## New Field Discovery

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

- 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.
- technically recoverable oil and gas resource estimates by region,
- distribution of technically recoverable field sizes within each region,

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.

[11]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.

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.[12] 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 conforms to the characteristics of the input distribution. Thus, this estimated set of fields is consistent with the expected geology with respect to expected aggregate recovery and the relative frequency of field sizes.

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

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil deposits. 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.[13] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to peak rate,

[12]*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).

[13]*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).

- 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.)

## 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.

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.[14] In addition, the re-injection 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.[15]

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.[16] 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 $1.14 (2006 dollars per thousand cubic feet) at the wellhead in Alaska before these reserves would be developed.

---

[14]Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction. Details of how this decision is made in NEMS are included in the Natural Gas Transmission and Distribution Module documentation.

[15]The current version of AOGSS does not include r 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, but that the netback from the Lower-48 States is likely higher than for LNG and therefore preferred.

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

# 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). Most of what was once contained in this submodule has now been transferred to the Natural Gas Transmission and Distribution Module (NGTDM) and is documented as such. The only piece that remains in OGSM is the representation of conventional natural gas, including from tight formations, in Western Canada. The model consists of estimated equations for new gas wells drilled, the amount found per well, and the expected production rate from the established proved reserves. This expected production rate is used as a basis for developing a supply curve for Western Canada for use in the market equilibration process in the NGTDM. For *AEO2010*, this remaining component of the FNGSS will be moved to the NGTDM.

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 natural gas wells drilled, is estimated directly as a function of various market drivers rather than as a function of expected profitability proxied by the expected DCF. No distinction is made between exploration and development. Next, an econometrically specified finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves). Finally an estimated extraction rate determines production potential [production to reserves ratio (PRR)]. The ultimate determination of the import volumes into the United States occurs in the equilibration process of the NGTDM.

## *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, remaining undiscovered resources, last year's production-to-reserve ratio, and proxy term for the drilling cost per well, as follows:

$$\begin{aligned} SUCWELL_t &= \exp(\beta 0) * CN\_PRC00^{\beta 1} * URRCAN^{\beta 2} \\ &\quad * CST\_PRXYLAG^{\beta 3} * \exp(\beta 4 * CURPRRCAN) \end{aligned} \tag{45}$$

where,

$$CURPRRCAN_t = OGPRDCAN_{t-1} / CURRESCAN \tag{46}$$

where,

| | | |
|---|---|---|
| $SUCWELL_t$ | = | total conventional successful gas wells completed in Western Canada in year t |
| $CN\_PRC00_t$ | = | price per Mcf of natural gas[17] in 2000 US dollars in year t |

[17] In the fall of 2007 legislation was passed to increase the royalty rate in Alberta from 25 percent to 30 percent. Since royalty rates are not explicitly modeled for Canada, the effect of this was modeled by decreasing the price that would be seen in Alberta for the purposes of making drilling decisions by 0.9 (ROYADJ), which is equivalent to (1-.3)/(1-.25), starting in 2009 when the legislation takes affect.

| | | |
|---|---|---|
| $URRCAN_t$ | = | remaining conventional gas recoverable resources in year t in western Canada in (Bcf) |
| CST_PRXYLAG | = | proxy term to reflect the change in drilling costs per well, projected into the future based on projections for the average lower 48 drilling costs |
| CURPRRCAN | = | production-to-reserve ratio from last year |
| $OGPRDCAN_{t-1}$ | = | conventional gas production in the previous forecast year (million cubic feet) |
| CURRESCAN | = | proved reserves of conventional gas at the beginning of the previous forecast year (million cubic feet) |
| $\beta_0$ | = | econometrically estimated parameter (-1.24038, Appendix D) |
| $\beta_1$ | = | econometrically estimated parameter (-1.10382, Appendix D) |
| $\beta_2$ | = | econometrically estimated parameter (1.52862, Appendix D) |
| $\beta_3$ | = | econometrically estimated parameter (-0.863675, Appendix D) |
| $\beta_4$ | = | econometrically estimated parameter (33.6137, Appendix D) |

The number of wells is restricted to increase by no more than 30 percent annually.

## 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 1) wells or feet drilled in such a way that reserve additions per well decline as more wells are drilled, and/or 2) remaining resources in such a way that reserve additions per well decline as remaining resources deplete. 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 the finding rate (reserves added per well) was assumption based, while the current version was econometrically estimated using the following:

$$\mathrm{FRCAN}_t = \exp\{(1-\rho) * \beta 0 + \beta 1 * \ln \mathrm{URRCAN}_t + \rho * \ln \mathrm{FRLAG} - \rho * \beta 1 * \mathrm{URRCAN}_{t-1}] \qquad (47)$$

where,

| | | |
|---|---|---|
| $\mathrm{FRCAN}_t$ | = | finding rate in year t (Bcf per well) |
| FRLAG | = | finding rate in year t-1 (Bcf per well) |
| $\mathrm{URRCAN}_t$ | = | remaining conventional gas recoverable resources in year t in Western Canada in (Bcf) |
| $\beta_0$ | = | econometrically estimated parameter (-27.3542, Appendix D) |
| $\beta_1$ | = | econometrically estimated parameter (2.31124, Appendix D) |
| $\rho$ | = | serial correlation parameter (0.417206, Appendix D) |

Remaining conventional plus tight gas recoverable resources are initialized in 2004 and set each year thereafter as follows:

$$\mathrm{URRCAN}_t = \mathrm{RESBASE} * (1 + \mathrm{RESTECH})^{\mathrm{T}} - \mathrm{CUMRCAN}_t \qquad (48)$$

where,

RESBASE = initial recoverable resources in 2004 (set at 92,000 Bcf)[18]
RESTECH = assumed rate of increase, primarily due to the contribution from tight gas formations, but also attributable to technological improvement (1.5 percent or 0.0015)
$CUMRCAN_t$ = cumulative reserves added since initial year of 2004 in Bcf

Total reserve additions in period t are given by:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \tag{49}$$

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

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

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \tag{50}$$

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 expected production-to-reserve ratio for new wells 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 determined in the NGTDM through a market equilibrium mechanism using a supply curve based on an expected production level provided by the OGSM. The realized extraction is likely to be different. The expected or normal operating level of production is set as the product of the beginning-of-year reserves (RESBOYCAN) and an expected extraction rate under normal operating conditions. This expected production-to-reserve ratio is estimated as follows:

[18]Source: National Energy Board, "Canada's Conventional Natural Gas Resources: A Status Report," Table 1.1A, April 2004. Adjusted downward slightly so as not to double count the potential tight gas contribution in the early years.

$$PRRATCAN_t = \frac{e^{C+\beta1*\ln SUCWELL_t+\beta2*\ln FRCAN_t+\beta3*RLYR}}{1+e^{C+\beta1*onSUCWEL_t+\beta2*onFRCAN_t+\beta3*(RLYR-1)}} * \left(\frac{PRRATCAN_{t-1}}{1-PRRATCAN_{t-1}}\right)^{\rho} * e^{-\rho*(C+\beta1*\ln SUCWELL_{t-1}+\beta2*\ln FRCAN_{t-1})} \tag{51}$$

where,

| | | |
|---|---|---|
| $PRRATCAN_t$ | = | expected production-to-reserve natural gas ratio in Western Canada for conventional and tight gas |
| $FRCAN_t$ | = | finding rate in year t, in BCF per well |
| $SUCWELL_t$ | = | successful gas wells drilled in year t |
| RLYR | = | calendar year |
| C | = | econometrically estimated constant term (-74.5150, Appendix D) |
| $\beta_1$ | = | econometrically estimated parameter (0.115314, Appendix D) |
| $\beta_2$ | = | econometrically estimated parameter (0.41412, Appendix D) |
| $\beta_3$ | = | econometrically estimated parameter (0.035578, Appendix D) |
| $\rho$ | = | serial correlation parameter (0.912281, Appendix D) |

The resulting production-to-reserve ratio is limited, so as not to increase or decrease more than 5 percent from one year to the next and to stay within the range of 0.7 to 0.12.

# Appendix 3-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 (e.g., 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 3A-1).

$$DCF_T = (PVTREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP - PVKAP - PVOPCOST - PVABANDON - PVSIT - PVFIT)_T \tag{3A-1}$$

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 3A-1 is discussed starting with the expected revenue and royalty payments, followed by the expected costs, and lastly the expected tax payments.

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

Revenues from an oil or gas project are generated from the production and sale of both the primary fuel as well as any co-products. The present value of expected revenues measured at the wellhead from the production of a representative project is defined as the summation of yearly expected net wellhead price[1] times expected production[2] discounted at an assumed rate. The discount rate used to evaluate private

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

[2]Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 3.

investment projects typically represents a weighted average cost of capital (WACC), i.e., a weighted average of both the cost of debt and the cost of equity.

Fundamentally, the formula for the WACC is straightforward.

$$WACC = \frac{D}{D+E} * R_D * (1-t) + \frac{E}{D+E} * R_E \tag{3A-2}$$

where D = market value of debt, E = market value of equity, t = corporate tax rate, $R_D$ = cost of debt, and $R_E$ = cost of equity. Because the drilling projects being evaluated are long term in nature, the values for all variables in the WACC formula are long run averages.

The WACC calculated using the formula given above is a nominal one. The real value can be calculated by:

$$disc = \frac{(1+WACC)}{(1+\pi_e)} - 1 \tag{3A-3}$$

where $\pi_e$ = expected inflation rate. The expected rate of inflation over the forecasting period is measured as the average annual rate of change in the U.S. GDP deflator over the forecasting period using the forecasts of the GDP deflator from the Macro Module (MC_JPGDP).

The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$PVREV_{T,k} = \sum_{t=T}^{T+n} \left[ Q_{t,k} * \lambda * P_{t,k} * \left[ \frac{1}{1+disc} \right]^{t-T} \right], \lambda = \begin{cases} 1 \text{ if primary fuel} \\ COPRD \text{ if secondary fuel} \end{cases} \tag{3A-4}$$

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:

$$PVTREV_T = PVREV_{T,1} + PVREV_{T,2} \tag{3A-5}$$

where,

| | | |
|---|---|---|
| $PVREV_{T,1}$ | = | present value of expected revenues generated from the primary fuel |

[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.

$PVREV_{T,2}$ = 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:

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{3A-6}$$

where,

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

### 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:

$$\begin{aligned} PVPRODTAX_T = {} & PRREV_{T,1} * (1 - ROYRT_1) * PRDTAX_1 + PVREV_{T,2} \\ & *(1 - ROYRT_2) * PRODTAX_2 \end{aligned} \tag{3A-7}$$

where,

PRODTAX = production tax rate.

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

## Present Value of Expected Costs

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

### Present Value of Expected Drilling Costs

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

The present value of expected drilling costs is given by:

---

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

$$\text{PVDRILLCOST}_T = \sum_{t=T}^{T+n} \Bigg[ \Big[ \text{COSTEXP}_T * \text{SR}_1 * \text{NUMEXP}_t + \text{COSTDEV}_T * \text{SR}_2 * \text{NUMDEV}_t$$

$$+ \text{COSTDRY}_{T,1} * (1 - \text{SR}_1) * \text{NUMEXP}_t \qquad (3A\text{-}8)$$

$$+ \text{COSTDRY}_{T,2} * (1 - \text{SR}_2) * \text{NUMDEV}_t \Big] * \left(\frac{1}{1+\text{disc}}\right)^{t-T} \Bigg]$$

where,

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

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

## Present Value of Expected Lease Equipment Costs

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

$$\text{PVEQUIP}_T = \sum_{t=T}^{T+n} \left[ \text{EQUIP}_T * (\text{SR}_1 * \text{NUMEXP}_t + \text{SR}_2 * \text{NUMDEV}_t) * \left[\frac{1}{1+\text{disc}}\right]^{t-T} \right] \qquad (3A\text{-}9)$$

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:

$$\text{PVKAP}_T = \sum_{t=T}^{T+n} \left[ \text{KAP}_t * \left[\frac{1}{1+\text{disc}}\right]^{t-T} \right] \qquad (3A\text{-}10)$$

where,

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

### Present Value of Expected Operating Costs

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

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

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[ OPCOST_T * \sum_{k=1}^{t} \left[ SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left( \frac{1}{1+disc} \right)^{t-T} \right] \qquad (3A\text{-}11)$$

where,

OPCOST = operating costs per well.

### Present Value of Expected Abandonment Costs

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

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[ COSTABN_T * \left[ \frac{1}{1+disc} \right]^{t-T} \right] \qquad (3A\text{-}12)$$

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,

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

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 3A-1. A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users. An independent is any oil and gas producer or owner of an interest in oil and gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and gas equivalent). The present DCF methodology reflects the tax treatment provided by current tax laws for large independent producers.

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

$$\begin{aligned} \mathrm{PVTAXBASE}_T = \sum_{t=T}^{T+n} \Big[ \big(&\mathrm{TREV}_t - \mathrm{ROY}_t - \mathrm{PRODTAX}_t - \mathrm{OPCOST}_t - \mathrm{ABANDON}_t - \mathrm{XIDC}_t \\ &- \mathrm{AIDC}_t - \mathrm{DEPREC}_t - \mathrm{DHC}_t\big) * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-T} \Big] \end{aligned} \tag{3A-13}$$

where,

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

$\mathrm{TREV}_t$, $\mathrm{ROY}_t$, $\mathrm{PRODTAX}_t$, $\mathrm{OPCOST}_t$, and $\mathrm{ABANDON}_t$ are the undiscounted 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.

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

## 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 3A-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:

$$\begin{aligned} \mathrm{XIDC}_t = {} & \mathrm{COSTEXP}_T * (1 - \mathrm{EXKAP}) * (1 - \mathrm{XDCKAP}) * \mathrm{SR}_1 * \mathrm{NUMEXP}_t \\ & + \mathrm{COSTDEV}_T * (1 - \mathrm{DVKAP}) * (1 - \mathrm{XDCKAP}) * \mathrm{SR}_2 * \mathrm{NUMDEV}_t \end{aligned} \quad (3A\text{-}14)$$

where,

COSTEXP = drilling cost for a successful exploratory well
EXKAP = fraction of exploratory drilling costs that are tangible and must be depreciated

**Table 3A-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**<br>G&G[a]<br>Lease Acquisition | **Cost Depletion**[b]<br>G&G<br>Lease Acquisition | **Maximum of Percentage or Cost Depletion**<br>G&G<br>Lease Acquisition |
| Depreciable Costs | **MACRS**[c]<br>Lease Acquisition<br>Other Capital Expenditures<br>Successful Well Drilling Costs Other than IDC's<br>**5-year SLM**[d]<br>20 percent of IDC's | **MACRS**<br>Lease Acquisition<br>Other Capital Expenditures<br>Successful Well Drilling Costs Other than IDC's | **MACRS**<br>Lease Acquisition<br>Other Capital Expenditures<br>Successful Well Drilling Costs Other than IDC's |
| Expensed Costs | Dry Hole Costs<br>80 percent of IDC's<br>Operating Costs | Dry Hole Costs<br>80 percent of IDC's<br>Operating Costs | Dry Hole Costs<br>80 percent of IDC's<br>Operating Costs |

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

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

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

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

$$\begin{aligned} AIDC_t = \sum_{j=\beta}^{t} \Big[ & \big(COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j \\ & + COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j\big) \\ & * DEPIDC_t * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \end{aligned} \tag{3A-15}$$

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

where,

| | | |
|---|---|---|
| j | = | year of recovery |
| β | = | index for write-off schedule |
| DEPIDC | = | for t ≤ n+T-m, 5-year SLM recovery schedule with half year convention; otherwise, 1/(n+T-t) in each period |

[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.

| | | |
|---|---|---|
| infl | = | expected inflation rate[8] |
| disc | = | expected discount rate |
| m | = | number of years in standard recovery period. |

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

***Expected Dry Hole Costs***

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

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \qquad (3A\text{-}16)$$

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 3A-2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

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

[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 3A-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.

$$\begin{aligned}\mathrm{DEPREC}_t = \sum_{j=\beta}^{t} \Big[ \big[ & (\mathrm{COSTEXP}_T * \mathrm{EXKAP} + \mathrm{EQUIP}_T) * \mathrm{SR}_1 * \mathrm{NUMEXP}_j \\ & + (\mathrm{COSTDEV}_T * \mathrm{DVKAP} + \mathrm{EQUIP}_T) * \mathrm{SR}_2 * \mathrm{NUMDEV}_j + \mathrm{KAP}_j \big] \\ & * \mathrm{DEP}_{t-j+1} * \left(\frac{1}{1+\mathrm{infl}}\right)^{t-j} * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-j} \Big],\end{aligned} \tag{3A-17}$$

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

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

$$PVSIT_T = PVTAXBASE_T * STRT \tag{3A-18}$$

where,

| | | |
|---|---|---|
| PVTAXBASE | = | present value of expected taxable income (Equation 3A-14) |
| STRT | = | state income tax rate. |

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

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \tag{3A-19}$$

where,

| | | |
|---|---|---|
| FDRT | = | federal corporate income tax rate. |

## Summary

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

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

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

[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.

# Appendix 3B. 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:

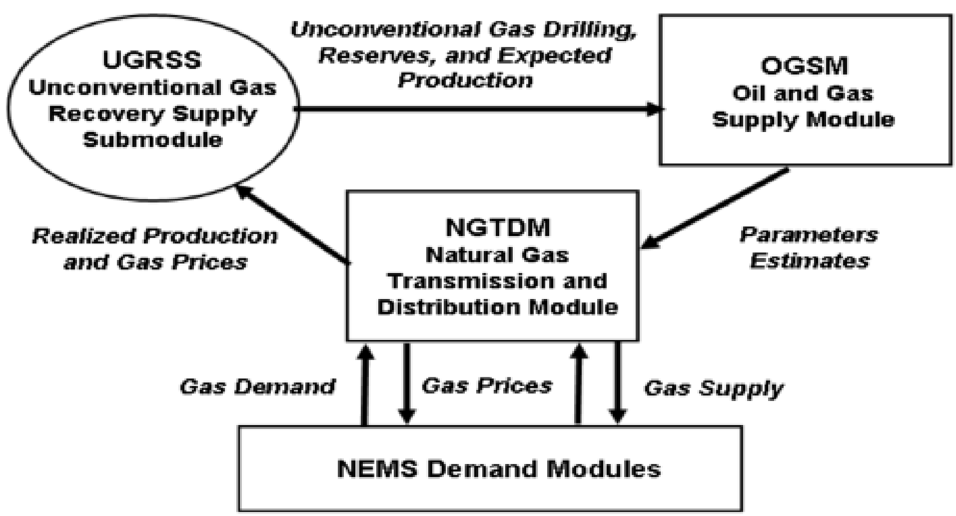
- Model purpose
- Model overview and rationale
- Model structure
- Data sources

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 fourth section discusses the data sources for the model. In this section the unconventional gas resource base is presented in detail with the underlying assumptions. All dollars ($) are in are in 1996 constant dollars unless stated otherwise.

## MODEL PURPOSE

The Unconventional Gas Recovery Supply Submodule (UGRSS) offers EIA the ability to analyze the unconventional gas resource base and its potential for future economic production under differing technological circumstances. The UGRSS was built exogenously from the National Energy Modeling System (NEMS) but now functions as a submodule within the NEMS Oil and Gas Supply Module (OGSM).

Figure 3B-1



The UGRSS uses pricing data from EIA's NGTDM, resource data from the USGS[1] (as modified by Advanced Resources, International), 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 3B-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.

In the 1995 USGS National Assessment, unconventional gas represented the largest onshore technically recoverable natural gas resource. These resource estimates have since been updated and augmented with additional plays not assessed by USGS. Table 3B-1 shows the undiscovered technically recovered resource base for each type of unconventional natural gas formation. Figures 3B-2 through 3B-4 illustrates the major unconventional formations in which each type of resource exists. Since 1992, production in each unconventional gas resource has increased and by 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.

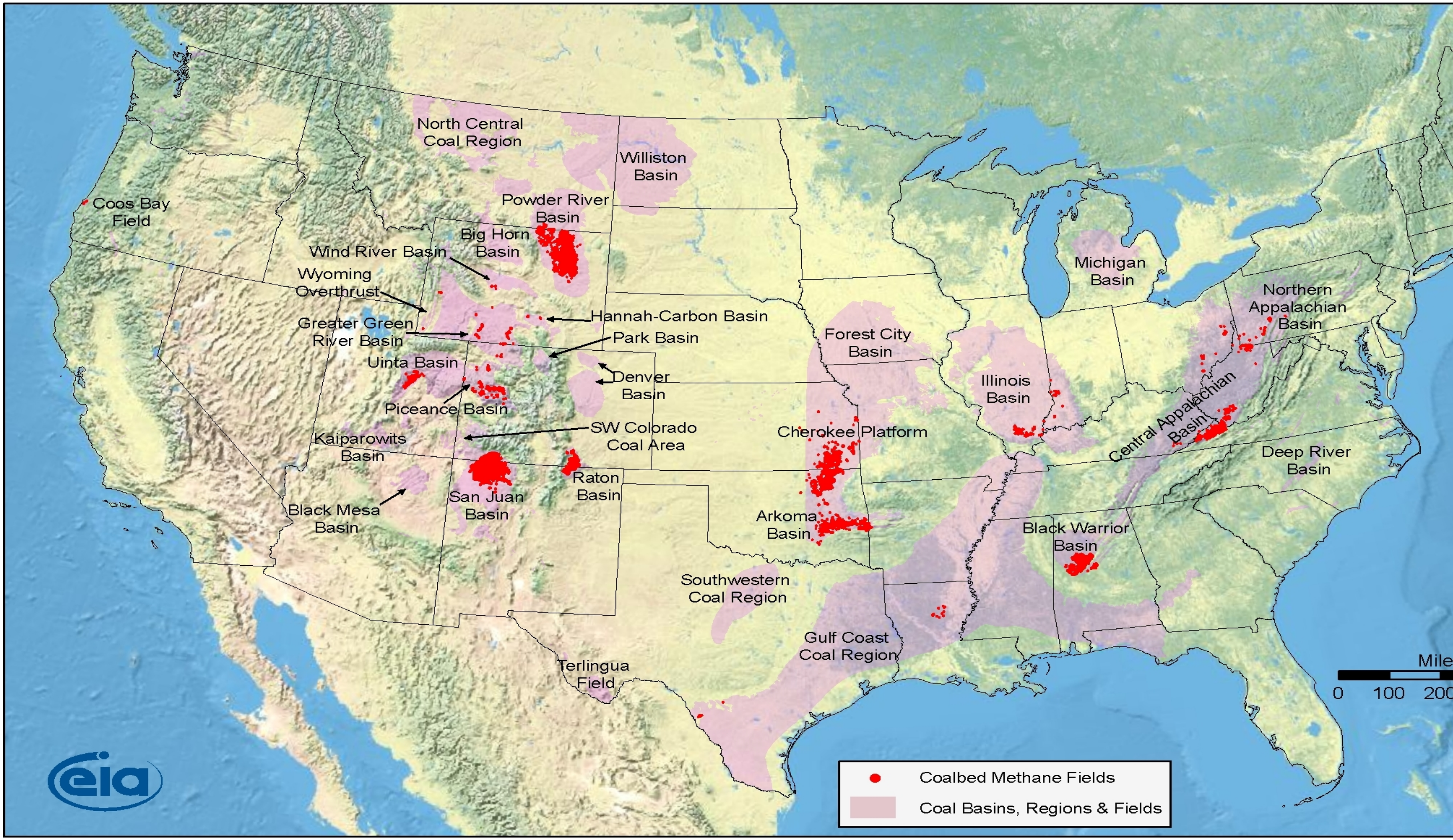
Prior to the development of the current UGRSS, the estimates of unconventional gas production in the Annual Energy Outlook (AEO) were based on the results of econometric equations. OGSM forecasted representative drilling costs and drilling activities (wells) by region and resource type, including unconventional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

[1] "1995 National Assessment of United States Oil and Gas Resources," U.S. Geological Survey (USGS), National Oil and Gas Resource Assessment Team, U.S. Geological Survey Circular 1118, (1995); Basin-by-basin Resource Assessment updates through 2003, USGS - http://energy.cr.usgs.gov/oilgas/noga/assessment/bybasin.htm .

**Table 3B-1 Undiscovered Technically Recoverable Resources (as of January 1, 2007)**

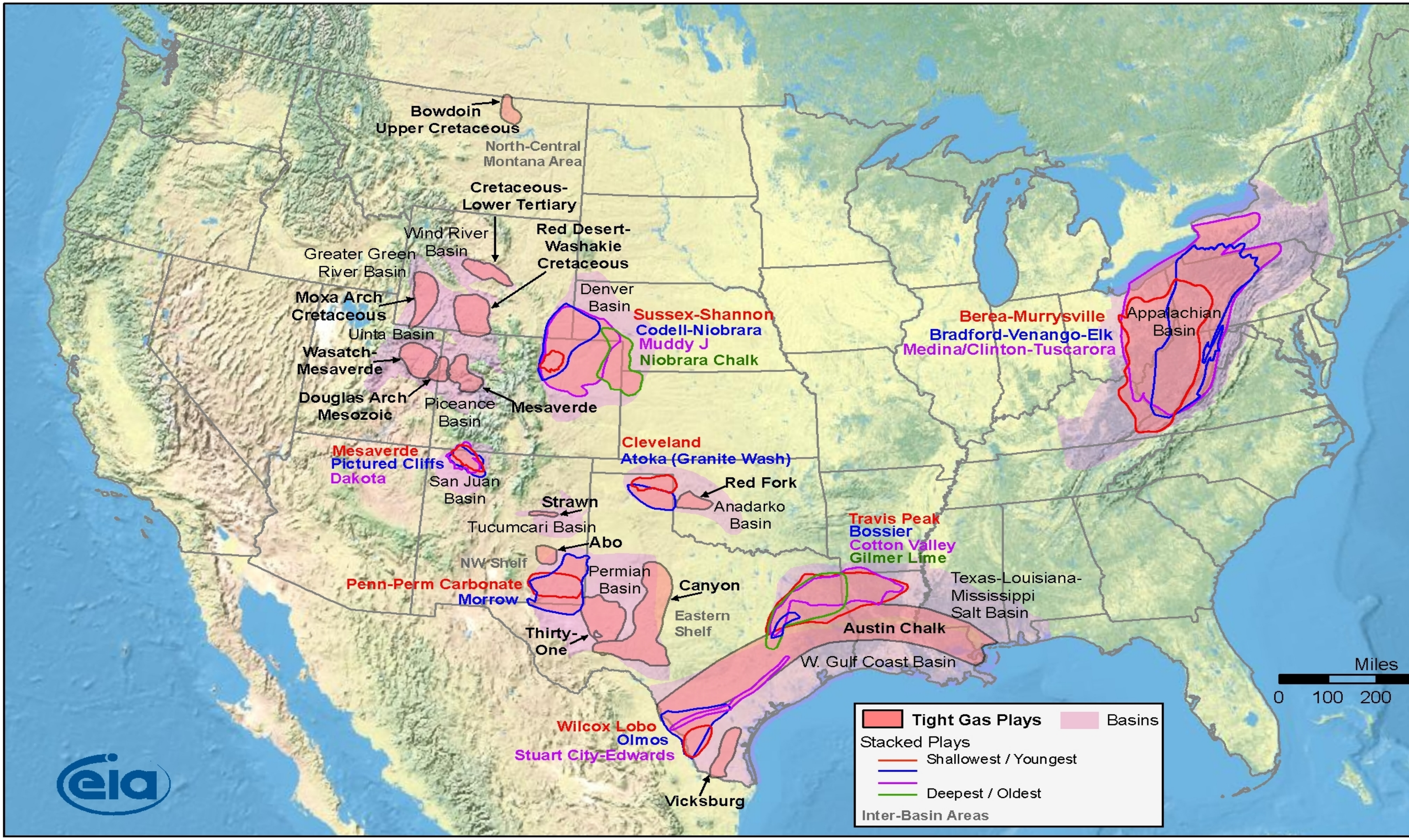
| | | |
|---|---|---|
| **Continuous-Type Deposits** | | **645 Tcf** |
| Coalbed Methane | 68 Tcf | |
| Gas Shales | 267 Tcf | |
| Tight sands | 310 Tcf | |
| **Reserve Growth** | | **569 Tcf** |
| **Undiscovered Conventional Resources** | | **349 Tcf** |

# Coalbed Methane Fields, Lower 48 States



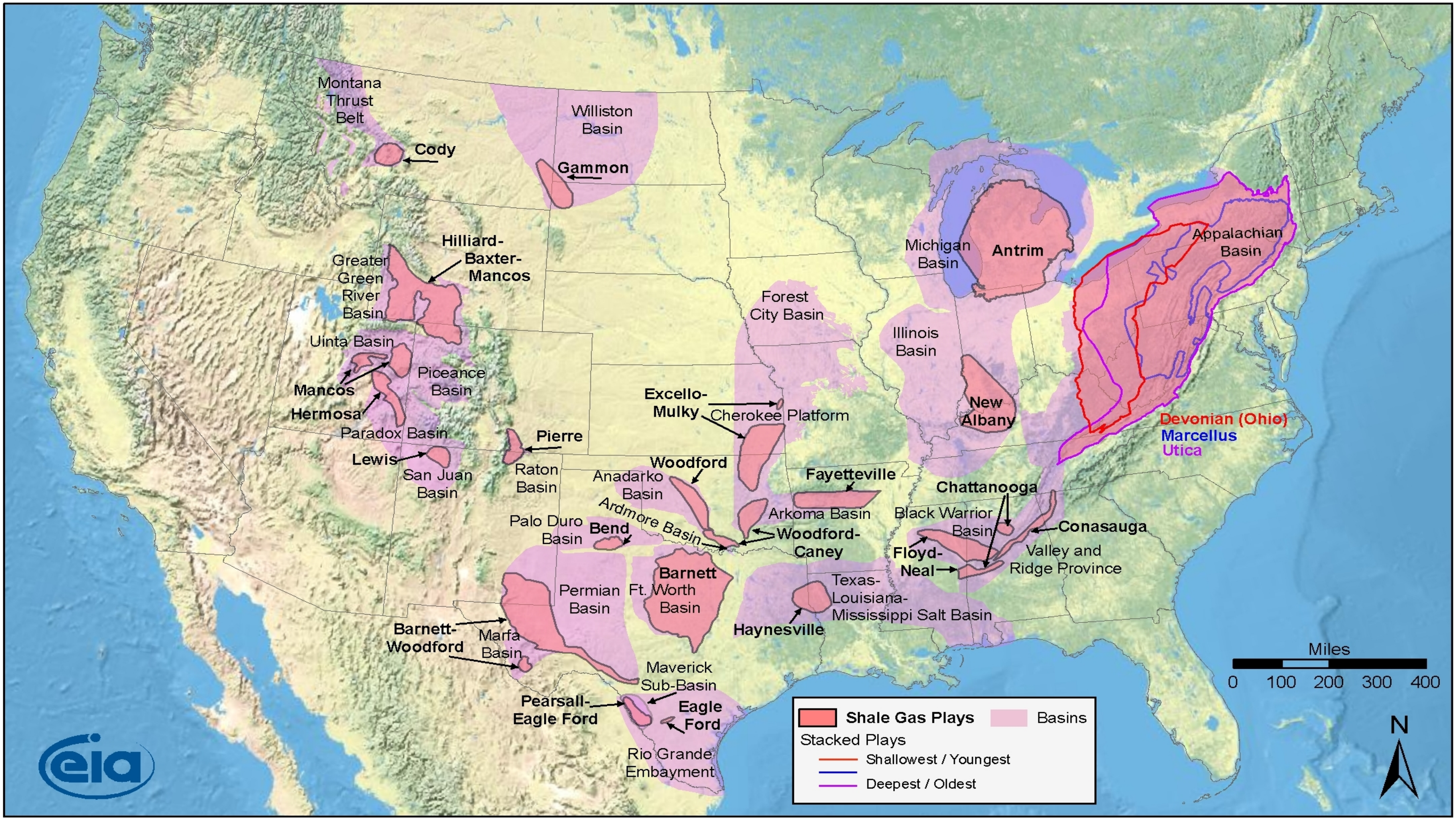

Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

# Major Tight Gas Plays, Lower 48 States




Source: Energy Information Administration based on data from various published studies
Updated: April 8, 2009

# Shale Gas Plays, Lower 48 States




Source: Energy Information Administration based on data from various published studies
Updated: May 28, 2009

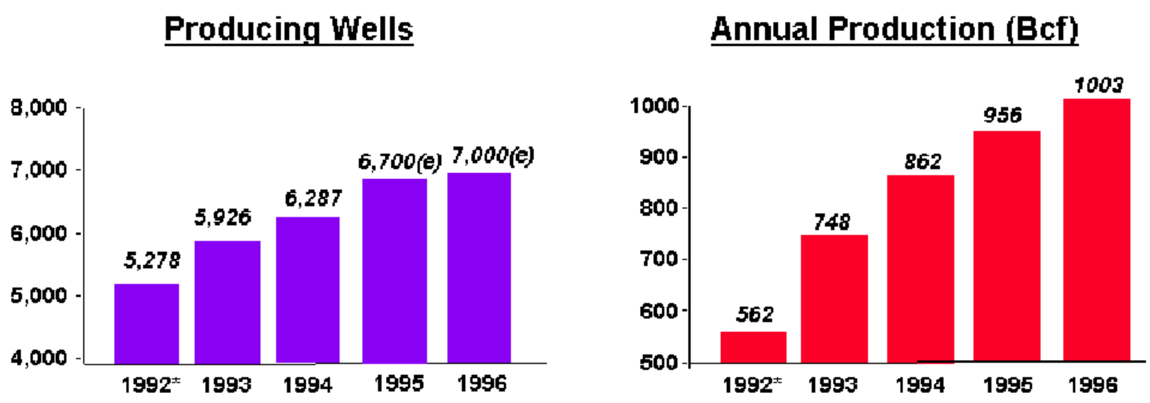
## MODEL OVERVIEW & RATIONALE

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 3B-5 and 3B-6 and Table 3B-7 illustrate growth in coalbed methane, tight gas and gas shales production. By 1996, unconventional gas made up 20 percent of US natural gas production and 30 percent of US natural gas reserves. Much of this growth could 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 3B-5

## Growth in Coalbed Methane Wells and Production



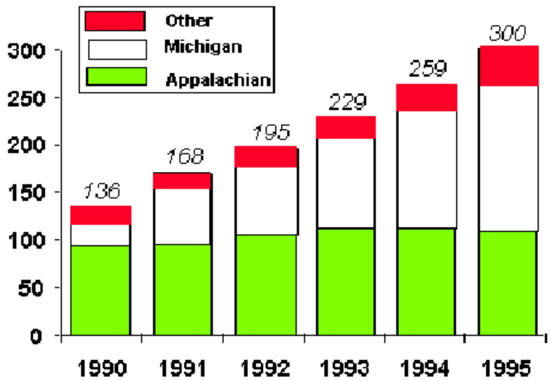

*1992 was the end of the Sec. 29 tax credit.

Source: Advanced Resources, International

# Figure 3B-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 3B-2

## Tight Gas Production -- 1992-1996

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

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). Another source for unconventional gas resource data was 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 model's structure, many ARI internal basin and play level evaluations, reservoir simulations and history-matching based well performances were included to modify the existing data. Further refinements to some of the estimated ultimate recoveries (EUR's) per well, a key component in deriving resource estimates, were provided by an independent expert reviewer, Harry Vidas of Energy and Environmental Analysis, Inc . These modifications provide the UGRSS with up-to-date and expert resource evaluation to base its future projections upon. Detailed UGRSS resource tables with resources broken down by component are provided in Tables 3B-3 to 3B-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. They also reflect some recommended modifications by an independent expert reviewer, Leo Giangiacomo of Extreme Petroleum Technology, Inc.

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, GTI and industry that lead to significant technology progress. These variables will each be explained in detail in Appendix 3-c.

Drilling allocations establish a pace of well drilling for economically feasible gas plays based on play profitability, play maturity, and aggregate U.S. oil and gas upstream expenditures. The baseline data and these determinations are linked to the other drilling projections within OGSM.

The major model outputs are drilling, reserve additions, reserves, and expected production (productive capacity) by OGSM regions. These outputs are linked to directly to OGSM and, through OGSM, indirectly to NGTDM, the natural gas price/supply component of the NEMS integrating framework.

# Table 3B-3. Tight Sands Resource Base: Detailed Breakdown

| | Basin | Play | A<br>Basin Area (Square Miles) | B<br>Developed Cells (1/1/1996) | C<br>Wells per Square Mile | D<br>Estimated Ultimate Recovery (Bcf/Well) | E<br>Success Rate | F<br>Play Probability | G<br>Official No Access | H<br>Undev'd. Resources 1/1/1996 (Bcf) | I<br>USGS 30-Year Factor | J<br>30-Year Undev'd. Resources 1/1/1996 (Bcf) | K<br>Expected Reserve Growth 1/1/1996 (Bcf) | L<br>Unproved Resources 1/1/1996 (Bcf) | M<br>Adj.'s for Tech. & Dev. (Bcf) | N<br>Unproved Resources 1/1/2007 (Bcf) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Uinta Basin** | Tertiary East | 1600 | 928 | 16 | 0.69 | 95% | 100% | 16.34% | 13530 | 29% | 3924 | 28 | 3952 | -887 | 3065 |
| 2 | | Tertiary West | 1603 | 0 | 8 | 4.85 | 95% | 100% | 57.39% | 25177 | 21% | 5287 | 0 | 5287 | 226 | 5513 |
| 3 | | Basin Flank Mesaverde | 1708 | 22 | 8 | 1.18 | 87% | 100% | 33.38% | 9330 | 50% | 4665 | 3 | 4668 | -337 | 4331 |
| 4 | | Deep Synclinal Mesaverde | 2893 | 3 | 8 | 1.18 | 67% | 50% | 2.11% | 8955 | 29% | 2597 | 0 | 2597 | 108 | 2705 |
| 5 | **Wind River Basin** | Fort Union/Lance Shallow | 1500 | 59 | 8 | 1.39 | 86% | 100% | 0.00% | 14274 | 100% | 14274 | 6 | 14280 | -317 | 13963 |
| 6 | | Mesaverde/Frontier Shallow | 250 | 94 | 4 | 1.51 | 56% | 100% | 0.00% | 766 | 100% | 766 | 18 | 784 | -96 | 688 |
| 7 | | Fort Union/Lance Deep | 2500 | 11 | 4 | 0.64 | 86% | 80% | 9.42% | 3984 | 100% | 3984 | 0 | 3984 | 171 | 4155 |
| 8 | | Mesaverde/Frontier Deep | 250 | 23 | 4 | 2.34 | 75% | 50% | 9.45% | 776 | 100% | 776 | 2 | 778 | 19 | 797 |
| 9 | **Appalacian Basin** | Clinton/Medina High | 14773 | 22545 | 8 | 0.30 | 90% | 100% | 0.00% | 25823 | 50% | 12911 | -1 | 12910 | -2261 | 10649 |
| 10 | | Clinton/Medina Moderate/Low | 27281 | 55500 | 15 | 0.09 | 86% | 100% | 0.00% | 27378 | 52% | 14236 | 0 | 14236 | 1656 | 15892 |
| 11 | | Clinton/Medina Berea Sandstone | 51863 | 60000 | 8 | 0.21 | 90% | 75% | 0.00% | 50308 | 23% | 11571 | 0 | 11571 | 313 | 11884 |
| 12 | | Upper Devonian High | 12775 | 53940 | 10 | 0.25 | 85% | 100% | 0.00% | 15685 | 46% | 7215 | 310 | 7525 | -904 | 6621 |
| 13 | | Upper Devonian Moderate/Low | 29808 | 55000 | 10 | 0.07 | 85% | 100% | 0.00% | 14463 | 32% | 4628 | 0 | 4628 | 2015 | 6643 |
| 14 | | Upper Devonian Tuscarora Sandstone | 42495 | 83 | 8 | 0.82 | 75% | 75% | 0.00% | 156768 | 2% | 2665 | 0 | 2665 | -97 | 2568 |
| 15 | **Denver Basin** | Deep J Sandstone | 3500 | 8809 | 16 | 0.29 | 85% | 100% | 1.04% | 11512 | 90% | 10361 | 134 | 10495 | -1446 | 9049 |
| 16 | **Greater Green River Basin** | Fort Union/Fox Hills | 3858 | 45 | 8 | 0.84 | 72% | 81% | 12.11% | 13270 | 8% | 995 | 2 | 997 | -95 | 902 |
| 17 | | Lance | 5500 | 25 | 8 | 7.89 | 95% | 100% | 10.96% | 293484 | 12% | 35218 | 3 | 35221 | -10927 | 24294 |
| 18 | | Lewis | 5172 | 512 | 8 | 1.57 | 92% | 100% | 6.28% | 55318 | 25% | 13830 | 33 | 13863 | -153 | 13710 |
| 19 | | Shallow Mesaverde (1) | 5239 | 1056 | 4 | 1.49 | 90% | 100% | 7.80% | 24605 | 53% | 13041 | 185 | 13226 | -1975 | 11251 |
| 20 | | Shallow Mesaverde (2) | 6814 | 0 | 8 | 0.80 | 35% | 100% | 8.28% | 14000 | 49% | 6860 | 0 | 6860 | 341 | 7201 |
| 21 | | Deep Mesaverde | 16416 | 153 | 4 | 0.49 | 60% | 75% | 8.14% | 13269 | 15% | 1990 | 3 | 1993 | 77 | 2070 |
| 22 | | Frontier (Moxa Arch) | 2334 | 2144 | 8 | 1.43 | 94% | 100% | 14.83% | 18923 | 25% | 4731 | 190 | 4921 | -1379 | 3542 |
| 23 | | Frontier (Deep) | 15619 | 14 | 4 | 3.08 | 75% | 75% | 9.19% | 98273 | 9% | 8845 | 0 | 8845 | 386 | 9231 |
| 24 | **Piceance Basin** | South Basin Williams Fork/Mesaverde | 1008 | 414 | 32 | 1.30 | 95% | 100% | 8.56% | 35958 | 87% | 31283 | 2 | 31285 | -2403 | 28882 |
| 25 | | North Basin Williams Fork/Mesaverde | 1008 | 0 | 8 | 1.85 | 87% | 100% | 1.98% | 12722 | 87% | 11068 | -23 | 11045 | -175 | 10870 |
| 26 | | Iles/Mesaverde | 972 | 189 | 8 | 0.64 | 80% | 100% | 4.81% | 3698 | 40% | 1479 | 2 | 1481 | -196 | 1285 |
| 27 | **LA/MS Salt Basin** | East Texas Cotton Valley/Bossier | 2730 | 6812 | 12 | 1.66 | 95% | 100% | 0.00% | 40920 | 100% | 40920 | 339 | 41259 | -12212 | 29047 |
| 28 | **Arkoma Basin** | Arkoma - Atoka | 1000 | 2455 | 8 | 1.55 | 90% | 100% | 0.00% | 7735 | 75% | 5801 | 233 | 6034 | -2357 | 3677 |
| 29 | **San Juan Basin** | Picture Cliffs | 6558 | 5821 | 4 | 0.51 | 90% | 100% | 1.83% | 9197 | 25% | 2299 | 91 | 2390 | -337 | 2053 |
| 30 | | Central Basin/Mesaverde | 3689 | 5118 | 8 | 0.86 | 95% | 100% | 1.76% | 19580 | 50% | 9790 | 305 | 10095 | -2551 | 7544 |
| 31 | | Central Basin/Dakota | 3918 | 4880 | 6 | 0.58 | 95% | 100% | 0.82% | 10179 | 56% | 5700 | 192 | 5892 | -986 | 4906 |
| 32 | **Northern Great Plains Basin** | High Potential | 2000 | 1838 | 4 | 0.73 | 88% | 100% | 4.29% | 3789 | 100% | 3789 | -69 | 3720 | -984 | 2736 |
| 33 | | Moderate Potential | 2000 | 200 | 4 | 0.40 | 50% | 80% | 4.24% | 1195 | 100% | 1195 | 0 | 1195 | 54 | 1249 |
| 34 | | Low Potential | 3000 | 83 | 4 | 0.25 | 30% | 75% | 1.05% | 663 | 100% | 663 | 0 | 663 | 41 | 704 |
| 35 | **Columbia Basin** | Basin Centered. | 1500 | 0 | 8 | 1.50 | 70% | 50% | 0.00% | 6300 | 100% | 6300 | 0 | 6300 | 225 | 6525 |
| 36 | **Anadarko Basin** | Cleveland | 1500 | 1207 | 4 | 1.09 | 84% | 100% | 0.00% | 4388 | 100% | 4388 | -15 | 4373 | -608 | 3765 |
| 37 | | Cherokee/Redfork | 1500 | 3350 | 4 | 1.07 | 90% | 100% | 0.00% | 2552 | 100% | 2552 | 154 | 2706 | -1546 | 1160 |
| 38 | | Granite Wash/Atoka | 1500 | 641 | 4 | 2.06 | 91% | 100% | 0.00% | 10046 | 100% | 10046 | 9 | 10055 | -2308 | 7747 |
| 39 | **Texas Gulf Basin** | Vicksburg | 600 | 2011 | 8 | 2.83 | 94% | 100% | 0.00% | 7419 | 100% | 7419 | 284 | 7703 | -4464 | 3239 |
| 40 | | Wilcox/Lobo | 1500 | 5103 | 8 | 1.91 | 92% | 100% | 0.00% | 12119 | 100% | 12119 | 430 | 12549 | -5689 | 6860 |
| 41 | | Olmos | 2500 | 1038 | 4 | 0.52 | 83% | 100% | 0.00% | 3868 | 100% | 3868 | -62 | 3806 | -629 | 3177 |
| 42 | **Permian Basin** | Canyon | 6000 | 6651 | 8 | 0.26 | 75% | 100% | 0.00% | 8063 | 100% | 8063 | 136 | 8199 | -1058 | 7141 |
| 43 | | Abo | 1500 | 2091 | 8 | 1.19 | 75% | 100% | 0.00% | 8844 | 100% | 8844 | -203 | 8641 | -2352 | 6289 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

## Table 3B-4. Gas Shales Resource Base: Detailed Breakdown

| | | | A | B | C | D | E | F | F | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Play # | Basin | Play | Basin Area (Square Miles) | Developed Cells 1/1/1996 | Wells per Square Mile | Estimated Ultimate Recovery 1/1/1996 (Bcf/Well) | Success Rate 1/1/1996 | Play Probability | Official No Access | Undev'd. Resources 1/1/1996 (Bcf) | USGS 30-Year Factor | 30-Year Undev'd. Resources 1/1/1996 (Bcf) | Expected Reserve Growth 1/1/1996 (Bcf) | Unproved Resources 1/1/1996 (Bcf) | Adj.'s for Tech. (+) & Dev.(-) (Bcf) | Unproved Resources 1/1/2007 (Bcf) |
| 1 | Appalachian Basin | Big Sandy Central | 8800 | 8344 | 6 | 0.30 | 86% | 100% | 0.00% | 11470 | 52% | 5964 | 825 | 6789 | -2804 | 3985 |
| 2 | | Big Sandy Extension | 7000 | 10658 | 6 | 0.25 | 86% | 100% | 0.00% | 6739 | 52% | 3504 | 210 | 3714 | -529 | 3185 |
| 3 | | Greater Siltstone Area | 22899 | 4600 | 7 | 0.10 | 59% | 100% | 0.00% | 9186 | 19% | 1745 | 0 | 1745 | 109 | 1854 |
| 4 | | Low Thermal Maturity | 45844 | 3500 | 8 | 0.06 | 74% | 80% | 0.00% | 12903 | 19% | 2452 | 0 | 2452 | 1656 | 4108 |
| 5 | | Marcellus | 10619 | 0 | 5 | 3.30 | 70% | 100% | 0.00% | 122649 | 30% | 36795 | 0 | 36795 | 1480 | 38275 |
| 6 | Michigan Basin | Antrim - Developing Area | 2000 | 7197 | 8 | 0.32 | 95% | 100% | 0.00% | 2676 | 100% | 2676 | 826 | 3502 | -1548 | 1954 |
| 7 | | Antrim - Undeveloped Area | 8000 | 0 | 8 | 0.30 | 50% | 80% | 0.00% | 7680 | 100% | 7680 | 0 | 7680 | 380 | 8060 |
| 8 | Illinois Basin | New Albany | 5000 | 134 | 4 | 0.25 | 50% | 80% | 0.00% | 1987 | 100% | 1987 | 0 | 1987 | 1111 | 3098 |
| 9 | | Cincinatti Arch - Devonian Shales | 6000 | 0 | 4 | 0.12 | 50% | 50% | 0.00% | 720 | 100% | 720 | 0 | 720 | 406 | 1126 |
| 10 | Williston Basin | Shallow Niobrara | 10000 | 0 | 2 | 0.45 | 58% | 75% | 4.01% | 3758 | 100% | 3758 | 0 | 3758 | 102 | 3860 |
| 11 | Fort Worth Basin | Barnett - Core Area | 1555 | 411 | 8 | 4.30 | 95% | 100% | 0.00% | 49138 | 100% | 49138 | 61 | 49199 | -73 | 30890 |
| 12 | | Barnett - Extension 1 | 2450 | 0 | 4 | 2.40 | 75% | 100% | 0.00% | 17640 | 100% | 17640 | 0 | 17640 | -1138 | 14827 |
| 13 | | Barnett - Extension 2 | 2450 | 0 | 8 | 1.39 | 50% | 100% | 0.00% | 13622 | 100% | 13622 | 0 | 13622 | 336 | 13958 |
| 14 | San Juan Basin | Lewis Shale | 7506 | 0 | 6 | 0.59 | 95% | 100% | 0.00% | 25243 | 34% | 8583 | 0 | 8583 | 1902 | 10485 |
| 15 | Midcontinent | Fayetteville - Central | 5300 | 0 | 8 | 1.60 | 94% | 100% | 0.00% | 63770 | 39% | 24870 | 0 | 24870 | 1111 | 25981 |
| 16 | | Fayetteville - West | 5400 | 0 | 8 | 0.80 | 88% | 100% | 0.00% | 30413 | 10% | 3041 | 0 | 3041 | 173 | 3214 |
| 17 | | Woodford - Western Arkoma | 2900 | 0 | 4 | 2.80 | 90% | 100% | 0.00% | 29232 | 43% | 12570 | 0 | 12570 | 7130 | 19700 |
| 18 | | Woodford - Central OK Fold Belt | 1800 | 0 | 4 | 2.00 | 86% | 100% | 0.00% | 12384 | 41% | 5077 | 8 | 5085 | 2020 | 7105 |
| 19 | Gulf Coast | Haynesville Shale | 5467 | 0 | 12 | 4.67 | 70% | 100% | 0.00% | 214459 | 30% | 64338 | 0 | 64338 | 7255 | 71593 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

## Table 3B-5. Coalbed Methane Resource Base: Detailed Breakdown

| Play # | Basin | Play | A<br>Basin Area (Square Miles) | B<br>Developed Cells (1/1/1996) | C<br>Wells per Square Mile | D<br>Estimated Ultimate Recovery (Bcf/Well) | E<br>Success Rate | F<br>Play Probability | G<br>Official No Access | H<br>Undev'd. Resources 1/1/1996 (Bcf) | I<br>USGS 30-Year Factor | J<br>30-Year Undev'd. Resources 1/1/1996 (Bcf) | K<br>Expected Reserve Growth 1/1/1996 (Bcf) | L<br>Unproved Resources 1/1/1996 (Bcf) | M<br>Adj.'s for Tech. (+) & Dev.(-) (Bcf) | N<br>Unproved Resources 1/1/2007 (Bcf) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | H = (A*C-B)*D*E*F*(1-G) | | J=I*H | | L=J+K | | N=L+M |
| 1 | Uinta Basin | Ferron | 400 | 100 | 8 | 1.56 | 93% | 100% | 11% | 4003 | 80% | 3202 | 271 | 3473 | -932 | 2541 |
| 2 | | Blackhawk | 586 | 40 | 8 | 0.31 | 58% | 100% | 5% | 794 | 74% | 588 | 0 | 588 | -129 | 459 |
| 3 | | Sego | 534 | 0 | 4 | 0.61 | 50% | 80% | 10% | 469 | 80% | 375 | 0 | 375 | -58 | 317 |
| 4 | Raton Basin | Northern Basin | 470 | 13 | 8 | 0.70 | 10% | 75% | 0% | 197 | 100% | 197 | 0 | 197 | -24 | 173 |
| 5 | | Purgatory River | 360 | 82 | 8 | 0.62 | 75% | 100% | 0% | 1301 | 100% | 1301 | 77 | 1378 | 642 | 2020 |
| 6 | | Southern Basin | 386 | 36 | 8 | 0.75 | 75% | 100% | 2% | 1682 | 100% | 1682 | 0 | 1682 | 1588 | 3270 |
| 7 | Powder River Basin | Wyodak/Upper Fort Union | 3600 | 1498 | 20 | 0.27 | 80% | 100% | 1% | 15076 | 97% | 14624 | 84 | 14708 | -4186 | 10522 |
| 8 | | Big George/Lower Fort Union | 2880 | 11 | 16 | 0.52 | 77% | 100% | 1% | 18262 | 61% | 11140 | 0 | 11140 | -2126 | 9014 |
| 9 | | Wasatch | 216 | 0 | 8 | 0.11 | 31% | 100% | 1% | 58 | 99% | 58 | 0 | 58 | -2 | 56 |
| 10 | | Central Basin | 3870 | 675 | 8 | 0.35 | 79% | 100% | 0% | 8374 | 46% | 3852 | 870 | 4722 | -1952 | 2770 |
| 11 | | NAB - High | 3817 | 34 | 12 | 0.25 | 70% | 100% | 0% | 8010 | 10% | 801 | 0 | 801 | -2 | 799 |
| 12 | | NAB - Mod/Low | 8906 | 0 | 12 | 0.16 | 70% | 55% | 0% | 6583 | 10% | 658 | 0 | 658 | 44 | 702 |
| 13 | Black Warrior Basin | Extention Area | 700 | 0 | 8 | 0.16 | 50% | 50% | 0% | 224 | 26% | 58 | 0 | 58 | 3 | 61 |
| 14 | | Main Area | 1000 | 3500 | 12 | 0.41 | 70% | 100% | 0% | 2440 | 100% | 2440 | 744 | 3184 | -310 | 2874 |
| 15 | Green River Basin | Shallow | 720 | 17 | 8 | 0.41 | 80% | 100% | 20% | 1507 | 92% | 1386 | 0 | 1386 | 230 | 1616 |
| 16 | | Deep | 3600 | 0 | 4 | 1.20 | 30% | 50% | 15% | 2203 | 90% | 1983 | 0 | 1983 | 84 | 2067 |
| 17 | Piceance Basin | Divide Creek | 144 | 11 | 8 | 0.36 | 50% | 100% | 13% | 179 | 99% | 177 | 0 | 177 | 18 | 195 |
| 18 | | White River Dome | 216 | 23 | 8 | 0.82 | 88% | 100% | 8% | 1132 | 99% | 1121 | 0 | 1121 | 78 | 1199 |
| 19 | | Shallow | 2000 | 62 | 4 | 0.60 | 70% | 100% | 9% | 3034 | 94% | 2852 | 0 | 2852 | -104 | 2748 |
| 20 | | Deep | 2000 | 0 | 4 | 1.20 | 30% | 80% | 3% | 2235 | 96% | 2145 | 0 | 2145 | -29 | 2116 |
| 21 | Midcontinent Basin | Arkoma | 2998 | 520 | 8 | 0.43 | 66% | 100% | 0% | 6659 | 70% | 4661 | 0 | 4661 | -615 | 4046 |
| 22 | | Cherokee & Forest City | 2750 | 0 | 8 | 0.13 | 71% | 100% | 0% | 2031 | 100% | 2031 | 10 | 2041 | -151 | 1890 |
| 23 | Cahaba Basin | Cahaba Basin | 387 | 204 | 8 | 0.36 | 76% | 100% | 0% | 791 | 100% | 791 | 0 | 791 | -215 | 576 |
| 24 | Illinois Basin | Central Basin | 1214 | 4 | 8 | 0.24 | 25% | 100% | 0% | 582 | 100% | 582 | 0 | 582 | 30 | 612 |
| 25 | San Juan Basin | Northern Basin - CO | 780 | 1091 | 4 | 3.04 | 95% | 100% | 7% | 5450 | 100% | 5450 | 2871 | 8321 | -4323 | 3998 |
| 26 | | Fairway- NM | 670 | 434 | 4 | 2.32 | 95% | 100% | 7% | 4604 | 97% | 4466 | 2568 | 7034 | -2787 | 4247 |
| 27 | | North Basin - NM | 2060 | 1333 | 4 | 0.56 | 75% | 100% | 7% | 2698 | 98% | 2644 | 453 | 3097 | 2586 | 5683 |
| 28 | | South Basin - NM | 1190 | 293 | 4 | 0.40 | 75% | 100% | 7% | 1246 | 100% | 1246 | 117 | 1363 | -91 | 1272 |
| 29 | | Menefee-NM | 7454 | 0 | 5 | 0.19 | 70% | 50% | 7% | 2305 | 10% | 230 | 0 | 230 | 12 | 242 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

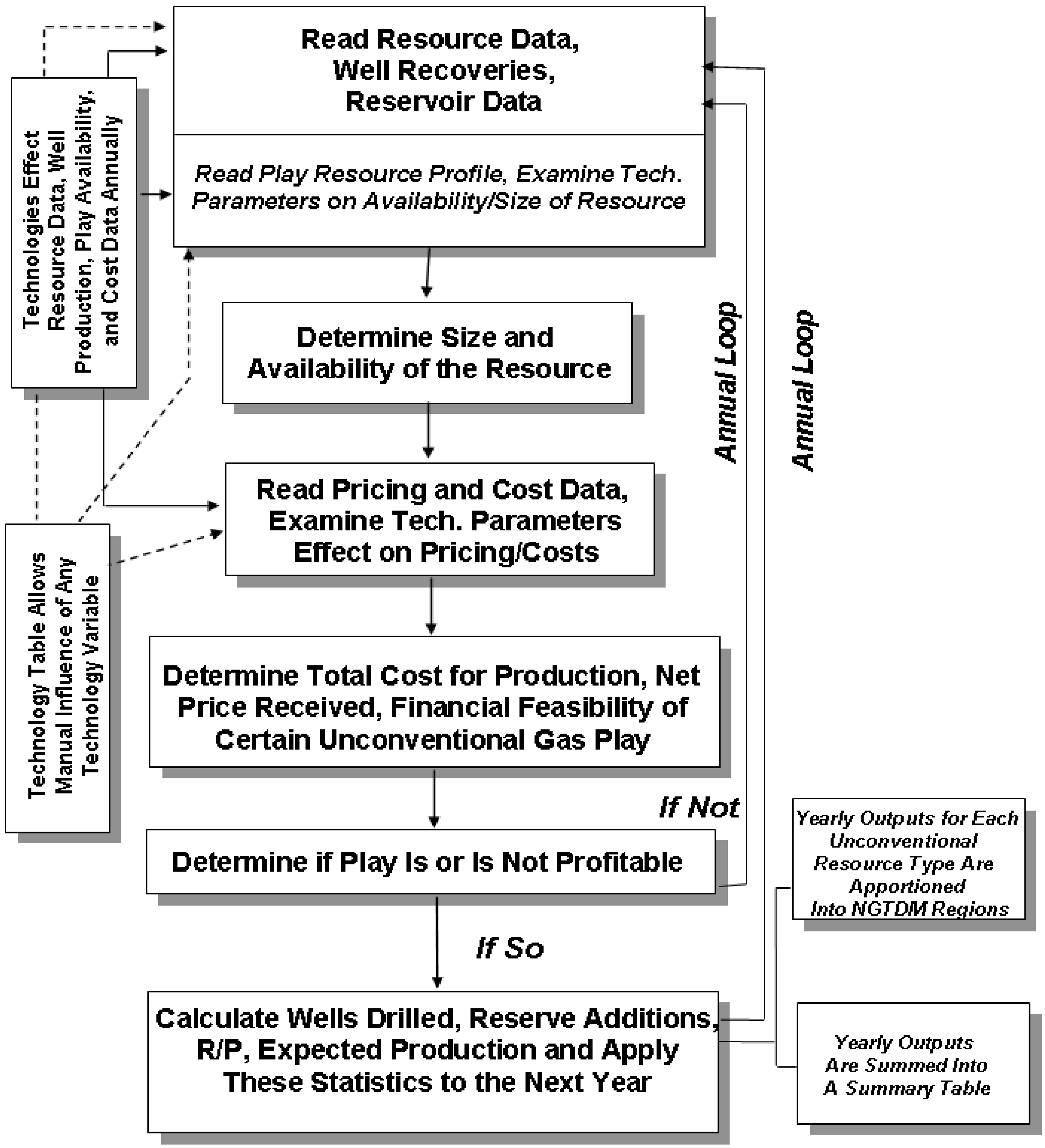
**UGRSS MODEL STRUCTURE**

## 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 3B-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 3B-7. UGRSS General Process Flow Diagram



TREATMENT OF ACCESS RESTRICTIONS

A current issue with respect to natural gas development concerns the ability of producers to access natural gas resources on Federal lands. Most of the unconventional gas resources are in the Rocky Mountains, and these resources are subject to a variety of access restrictions. For 5 major basins in the Rocky Mountains an inter-agency assessment of access restrictions was conducted in 2002 by the Federal government under the authority of the Energy Policy and Conservation Act (EPCA)[2]. The access assumptions for the Rocky Mountains in the *Annual Energy Outlook 2007* (AEO2006) reflect the results of the EPCA assessment. In this regard 7 percent of the undeveloped unconventional gas resources are officially off limits to either drilling or surface occupancy. Included in this category are those areas where drilling is precluded by statute (e.g., national parks and wilderness areas) and by administrative decree (e.g., "Wilderness Re-inventoried Areas", "Roadless Areas"). Also included are those areas of a lease where surface occupancy is prohibited by stipulation to protect identified resources such as the habitats of endangered species of plants and animals. An additional 28 percent of the resources are judged to be currently developmentally constrained because of the prohibitive effect of compliance with environmental and pipeline regulations created to affect such laws as the National Historic Preservation Act, the National Environmental Policy Act, the Endangered Species Act, the Air Quality Act, and the Clean Water Act. Approximately 19 percent of the resources are accessible, but located in areas where lease stipulations, which affect accessibility, are set by a federal land management agency, either the U.S. Bureau of Land Management or the U.S. Forest Service. The remaining 46 percent of undeveloped Rocky Mountain unconventional gas resources are located either on Federal land without lease stipulations or on private land and are accessible subject to standard lease terms (i.e., no lease stipulations).

The treatment of access restrictions varies by restriction category. Resources that are located on land that is officially inaccessible are removed from the model's operative resource base. Resources located in areas that are developmentally constrained because of environmental and pipeline regulations are initially removed from the model's resource base but are made available gradually over the forecast period to reflect the tendency of technological progress to enhance industry's ability to overcome difficulties in complying with these types of restrictions. Resources that are accessible but located in areas that are subject to lease stipulated access limitations are accounted for by two adjustments. Exploration and development costs are increased by a given amount to reflect the increased costs that these access restrictions generally add to a project. Additionally, time is added to complete a project in these areas to simulate the delay usually incurred as a result of efforts to comply with the access restrictions.

[2] The following basins (study areas) were reassessed by the USGS as part of a Federal interagency study of access restrictions in the Rocky Mountains: the Paradox/San Juan, the Uinta/Piceance, the Greater Green River, the Powder River, and the Montana Thrust Belt. The study, Scientific Inventory of Onshore Federal Land's Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development (January 2003), was conducted under the authority of the Energy Policy and Conservation Act (EPCA).

RESOURCE BASE

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, the Fayetteville and Woodford Shales of the Midcontinent 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.

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 | = | Play 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 officially inaccessible due to Federal statute or administrative decree (Note: For EPCA plays, plays in basins studied in the EPCA assessment[3], this variable represents only those areas off limits due to Federal statute) |

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

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

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

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

[3]Ibid.

WELL PRODUCTIVITY

This section of the unconventional gas model concerns well productivity. The Estimated Ultimate Recovery (EUR) numbers represent ARI modifications of base-level USGS assessments. 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 play 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 play. The weights reflect the degree to which the driller is able to ascertain a complete understanding of the play's structure.

The actual EUR's for the play in year 1 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

These EUR's increase over time for all potential wells in all plays as technology progresses in 2 major areas: lower damage completion and stimulation; and improved geology/technology modeling and matching,

$$RW10_{iyr} = RW10_{iyr-1} * (1 + MINIMUM\ (REDAM\%, (1+REDAM\% / DEVPER)) + MINIMUM\ (FRCLEN\%,(1+FRCLEN\%/DEVPER)))$$
$$RW10_{iyr} = RW10_{iyr-1} * (1 + MINIMUM\ (REDAM\%, (1+REDAM\% / DEVPER)) + MINIMUM\ (FRCLEN\%,(1+FRCLEN\%/DEVPER)))$$
$$RW10_{iyr} = RW10_{iyr-1} * (1 + MINIMUM\ (REDAM\%, (1+REDAM\% / DEVPER)) + MINIMUM\ (FRCLEN\%,(1+FRCLEN\%/DEVPER)))$$
$$RW10_{iyr} = RW10_{iyr-1} * (1 + MINIMUM\ (REDAM\%, (1+REDAM\% / DEVPER)) + MINIMUM\ (FRCLEN\%,(1+FRCLEN\%/DEVPER)))$$

Where,

REDAM% = Total percentage increase over development period due to advances in reduced-damage drilling and stimulation technology
FRCLEN% = Total percentage increase over development period due to increase in fracture length from advances in geology/technology modeling matching
DEVPER = Total number of years (from base year) over which incremental advances in indicated technology occur

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 perceived productivity 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 play'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 play.

For Year 1:

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

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

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

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

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

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

$MEUR1_{1,4}$ = A weighted average for the perceived worst 40 percent of the potential wells in the play

$MEUR1_{1,4} = (0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$

Where,

Subscript 1 = year count, with 1996=1
Subscript 2 = play area
1 = total area of play
2 = perceived "best area" of the play
3 = perceived "average area" of the play
4 = perceived "worst area" of the play

As mentioned above, the equations change for MEUR after the first year. After Year 1, experience and technology enable the play to be better understood geologically and from a potential productive aspect. Accordingly, the model gradually high grades each play into a best, average, and worst area. As the understanding of the play develops over time and technology advances, the area thought to contain the best 30 percent of potential wells from an EUR perspective moves toward an area representative of the actual best 10 percent and 20 percent of wells in the play, the expected average area stays consistent with the middle 30 percent, and the area figured to constitute the worst 40 percent of the potential drilling prospects slowly downgrades to the actual bottom 40 percent

To begin this process, the number of potential wells is first established in year 1 for each perceived productivity category for a given play.

$SCSSRT_1$ = Success Rate : The ratio of successful wells over total wells drilled (This can also be called the dry hole rate if you use the equation 1 - SCSSRT). Though each of these SCSSRT values is an input value in Year 1, future forecasting turns these inputs into formulas that capture the effects of technology on the resource base. These equations will be explained in the technology section.

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

FAC30YR = The proportion of the technically recoverable resources that can likely be recovered in the next 30 years - from the USGS

**TRW** = The amount of potential 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.

| | | |
|---|---|---|
| **TRW** | = | (ATUL*SCSSRT*PLPROB2*FAC30YR) |

Because of the relatively random nature of drilling decisions early in the life of a play, the mix of potential wells by true EUR's in year 1 is the same in each of the 3 perceived productivity categories (areas thought to represent the best 30%, the middle 30%, and the worst 40%, respectively) for a given play. For each perceived productivity category in a given play,

$$RW10\_WELLS_1 = .1 * TRW$$
$$RW20\_WELLS_1 = .2 * TRW$$
$$RW30\_WELLS_1 = .3 * TRW$$
$$RW40\_WELLS_1 = .4 * TRW$$

Where,

RW10_WELLS= The number of available wells in a perceived productivity category that have an EUR equal to the average EUR for the actual top 10 percent (by EUR) of the wells in the play

RW20_WELLS= The number of available wells in a perceived productivity category that have an EUR equal to the average EUR for the actual next highest 20 percent of the wells in the play

RW30_WELLS= The number of available wells in a perceived productivity category that have an EUR equal to the average EUR for the actual next highest ("middle") 30 percent of the wells in the play

RW40_WELLS= The number of available wells in a perceived productivity category that have an EUR equal to the average EUR for the actual lowest 40 percent of the wells in the play

Each successive projection year the mix of potential wells by true EUR (top 10% and 20%, middle 30%, bottom 40%) in each category of perceived EUR (top 30%, middle 30%, and bottom 40%) is adjusted to reflect the increasing ability of producers to better understand the play and also to reflect the removal of wells drilled in the previous year. The actual average EUR for each of the perceived productivity categories is then determined as a well-weighted average of the true EUR's of the wells in the category.

For year greater than 1:

$$\mathbf{MEUR1_{iyr}} = (RW10\_WELLS_{iyr,}*RW10_{iyr} + RW20\_WELLS_{iyr}*RW20_{iyr} + RW30\_WELLS_{iyr}*RW30_{iyr} + RW40\_WELLS_{iyr}*RW40_{ute}) / TRW$$

NEWCAVFRWY = For Coalbed Methane, establishes whether or not cavitation technology is advanced to the point that "New Cavity Fairways" are developed for the plays 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 3-c)

**MEUR2** = IF NEWCAVFRWY equal to 1:
MEUR2 = MEUR1 * (1 + CAVFRWY%)
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 plays 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 3-c)

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

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

| | |
|---|---|
| **UNDEV_RES** = | (MEUR3*TRW) |

$R\_ADD_{iyr-1}$ = Total Reserve Additions in the previous year.

**$RESNPROD_{iyr}$** = Beginning-of-year cumulative proved reserves: This is an input number for Year 1 but changes into the following formula for subsequent years.

| | |
|---|---|
| **$RESNPROD_{iyr}$** = | $RESNPROD_{iyr-1}+R\_ADD_{iyr-1}$ |

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

| | |
|---|---|
| **URR** = | (RESNPROD+UNDEV_RES) |

ECONOMICS AND PRICING

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

DIS_FAC = Discount Factor: This is the discount factor[4] 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) |

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

| | | |
|---|---|---|
| WHGP | = | Wellhead Gas Price ($/Mcf): The wellhead gas price is received from the NEMS Natural Gas Supply and Disposition Module (NGTDM). It is a market-simulated price solution based on integration of NEMS supply and demand modules. |
| 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

| | | |
|---|---|---|
| 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 |
| DACC_ADJ | = | Adjustment to calculated drilling costs to reflect proportionate variation in Joint Association Survey (JAS) Drilling Costs in years other than the data year (2002) of the data upon which the equation is based. |

**DACC** = Drilling and completion costs

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

The following table represents drilling costs for Coalbed Methane:

**Table 3B-6.** Drilling Costs ($2002) for Coalbed Methane

| Well Depth | Well Cost $2002 | Land / G&G Costs $2002 |
|---|---|---|
| < 2000 feet | $60.00 / foot | $10,000 |
| > 2000 feet | $75.00 / 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 3B-7.** Drilling Costs ($2002) for Tight Sands

| UTAH - Uinta Basin | | | |
|---|---|---|---|
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 20 |
| | 2500-5000 | 15000 | 25 |
| | 5000-7500 | 15000 | 32 |
| | 7500-10000 | 15000 | 59 |
| | 10000-12500 | 15000 | 85 |
| | 12500-15000 | 15000 | 125 |
| | 15000-20000 | 15000 | 240 |
| WYOMING - Wind River, Greater Green River Basins | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 50 |
| | 2500-5000 | 15000 | 60 |
| | 5000-7500 | 15000 | 80 |
| | 7500-10000 | 15000 | 80 |
| | 10000-12500 | 15000 | 80 |
| | 12500-15000 | 15000 | 106 |
| | 15000-20000 | 15000 | 450 |
| COLORADO - Piceance, Denver Basins | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 20 |
| | 2500-5000 | 15000 | 25 |
| | 5000-7500 | 15000 | 32 |
| | 7500-10000 | 15000 | 59 |
| | 10000-12500 | 15000 | 85 |
| | 12500-15000 | 15000 | 125 |
| | 15000-20000 | 15000 | 200 |
| | | | |
| NEW MEXICO - WEST (Rockies) - San Juan Basin | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 47 |

**Table 3B-7.** Drilling Costs ($2002) for Tight Sands

| | | | |
|---|---|---|---|
| | 2500-5000 | 15000 | 60 |
| | 5000-7500 | 15000 | 69 |
| | 7500-10000 | 15000 | 75 |
| | 10000-12500 | 15000 | - |
| | 12500-15000 | 15000 | - |
| | 15000-20000 | 15000 | - |
| NEW MEXICO - East - AZ, SW | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | - |
| | 2500-5000 | 15000 | 45 |
| | 5000-7500 | 15000 | 65 |
| | 7500-10000 | 15000 | 67 |
| | 10000-12500 | 15000 | 70 |
| | 12500-15000 | 15000 | 89 |
| | 15000-20000 | 15000 | 117 |
| | | | |
| APPALACHIA - Appalachian Basin | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 25 |
| | 2500-5000 | 15000 | 33 |
| | 5000-7500 | 15000 | 33 |
| | 7500-10000 | 15000 | 50 |
| | 10000-12500 | 15000 | - |
| | 12500-15000 | 15000 | - |
| | 15000-20000 | 15000 | - |
| | | | |
| LA/MS/TX Salt Basins - Cotton Valley / Travis Peak | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 25 |
| | 2500-5000 | 15000 | 32 |
| | 5000-7500 | 15000 | 59 |
| | 7500-10000 | 15000 | 85 |
| | 10000-12500 | 15000 | 125 |
| | 12500-15000 | 15000 | 200 |
| | 15000-20000 | 15000 | - |
| | | | |
| ARKANSAS/OKLAHOMA/TEXAS - Arkoma / Anadarko Basins | | | |
| | Depth | fixed cost | variable cost $/ft |

**Table 3B-7.** Drilling Costs ($2002) for Tight Sands

| | | | |
|---|---|---|---|
| | 0-2500 | 15000 | 63 |
| | 2500-5000 | 15000 | 65 |
| | 5000-7500 | 15000 | 70 |
| | 7500-10000 | 15000 | 83 |
| | 10000-12500 | 15000 | 112 |
| | 12500-15000 | 15000 | 150 |
| | 15000-20000 | 15000 | 200 |
| | | | |
| MONTANA - Northern Great Plains Basins | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 34 |
| | 2500-5000 | 15000 | 34 |
| | 5000-7500 | 15000 | - |
| | 7500-10000 | 15000 | - |
| | 10000-12500 | 15000 | - |
| | 12500-15000 | 15000 | - |
| | 15000-20000 | 15000 | - |
| | | | |
| TX - Texas Gulf Basins -- Wilcox/Lobo, Vicksburg, Olmos | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 25 |
| | 2500-5000 | 15000 | 50 |
| | 5000-7500 | 15000 | 74 |
| | 7500-10000 | 15000 | 105 |
| | 10000-12500 | 15000 | 160 |
| | 12500-15000 | 15000 | 217 |
| | 15000-20000 | 15000 | 300 |
| | | | |
| TX / NM - Permian Basin -- Canyon Sands | | | |
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 0 |
| | 2500-5000 | 15000 | 45 |
| | 5000-7500 | 15000 | 65 |
| | 7500-10000 | 15000 | 67 |
| | 10000-12500 | 15000 | 70 |
| | 12500-15000 | 15000 | 89 |
| | 15000-20000 | 15000 | 117 |
| | | | |

**Table 3B-7.** Drilling Costs ($2002) for Tight Sands

| TX / NM - Permian Basin -- Abo | | | |
|---|---|---|---|
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 0 |
| | 2500-5000 | 15000 | 78 |
| | 5000-7500 | 15000 | 90 |
| | 7500-10000 | 15000 | 100 |
| | 10000-12500 | 15000 | 115 |
| | 12500-15000 | 15000 | 150 |
| | 15000-20000 | 15000 | 200 |

Source: Advanced Resources, International

**Table 3B- 8.** Drilling Costs ($2002) for Gas Shales

| MI - Antrim Shale Wells | | | |
|---|---|---|---|
| | Depth | fixed cost | variable cost $/ft |
| | 0-2500 | 15000 | 80 |
| | 2500-5000 | 15000 | 100 |
| | 5000-7500 | 15000 | 120 |
| | 7500-10000 | 15000 | 130 |
| | 10000-12500 | 15000 | 130 |
| | 12500-15000 | 15000 | 130 |
| | 15000-20000 | 15000 | 130 |

Source: Advanced Resources, International

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

**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.

| | | |
|---|---|---|
| **STIMC** | = | (SZONE*STM_CST) |

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

WATR_DISP = Establishes whether or not (and degree to which) water disposal is required (No Disposal=0; Maximum Disposal=1)

**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 $1 / foot. If not, a flat variable is added.

**PASE** = IF WATR_DISP is equal to 1:
PASE = BASET + AVGDPTH
IF WATR_DISP is not equal to 1:
PASE = 10000.

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
LSE_EQ_ADJ = Adjustment to calculated lease equipment costs to reflect proportionate variation in Energy Information Administration lease equipment costs in years other than the data year (2002) of the data upon which the equation is based.

**LSE_EQ** = Lease Equipment Costs: For tight gas and gas shale it is first established whether H2O disposal is needed and, if so, a fee is added to the variable Lease Equipment costs depending on MEUR. For coalbed methane a base level lease equipment costs is used, which cost varies by play. These input values are multiplied by LSE_EQ_ADJ.

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

**Table 3B-9.** Lease Equipment Costs ($2002) Matrix

| Well Size (EUR) | Reservoir Type | Lease Equipment | Water |
|---|---|---|---|
| Well Size O&M Small Well - <0.5 Bcf | Tight Sands – Rocky Mountain | $ 155,274 | $ - |
| | Tight Sands – Non Rocky Mountain | $ 77,637 | $ - |
| | Gas Shales | $ 38,819 | $ 11,091 |
| Well O&M Medium Well - <2.0 Bcf | Tight Sands – Rocky Mountain | $ 199,638 | $ - |
| | Tight Sands – Non Rocky Mountain | $ 99,819 | $ - |
| | Gas Shales | $ 49,910 | $ 22,182 |
| Well O&M Large Well - >2.0 Bcf | Tight Sands – Rocky Mountain | $ 288,366 | $ - |
| | Tight Sands – Non Rocky Mountain | $ 144,183 | $ - |
| | Gas Shales | $ 72,092 | $ 33,273 |

Source: Non Rocky Mountain: Advanced Resources, International; Rocky Mountain: Leo Giangiacomo

**LSE_EQ** = LSE_EQ * LSE_EQ_ADJ

RST = Percent variable G&A Cost - Currently 10 percent

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

**GAA10**= RST*(LSE_EQ+ PASE+ STIMC+ DACC)

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

**TCC** = DACC+STIMC+PASE+LSE_EQ+GAA10

**DHC** = Dry Hole Costs: Calculates the dry hole costs

| | | |
|---|---|---|
| **DHC** | = | (DACC+STIMC) * ((1/SCSSRT)-1) |

| | | |
|---|---|---|
| LEASSTIP | = | Lease Stipulated Share: The percentage of the play that is subject to Federal lease stipulations |
| ACC_COST | = | The extra cost in Federal restricted areas (areas subject to Federal lease stipulations) |
| | | |
| **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))* (1.0+ACC_COST) *((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 |

| | | |
|---|---|---|
| **GASTR** | = | Gas treatment costs ($/Mcf) |

| | | | | |
|---|---|---|---|---|
| **GASTR** | = | If Tight Sands: | | |
| | | GASTR | = | .125 + WHGP/32.0 |
| | | If Gas Shales: | | |
| | | GASTR | = | .125 + WHGP/32.0 |
| | | If Coalbed Methane: | | |
| | | GASTR | = | .25 + WHGP/16.0 |

| | | |
|---|---|---|
| WTR_DSPT | = | Water Disposal Fee: $0.05 per Mcf |
| 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 |

GTF% = Total percentage decrease in gas treatment and fuel costs over the development period due to technological advances

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

**VOC** = IF WATR_DISP is equal to 1:
VOC = (WTR_DSPT*(TECHYRS)*(WDT%/30))
+((WOMS)*(TECHYRS)*(PUMP%/30))
+((GASTR)*(TECHYRS)*(GTF%/30))
+(WTR_DSPT+WOMS+GASTR)
IF WATR_DISP is equal to 0:
VOC = (WTR_DSPT*(TECHYRS)*(WDT%/30))
+((WOMS)*(TECHYRS)*(PUMP%/30))
+((GASTR)*(TECHYRS)*(GTF%/30))
+(WOMS+GASTR)

ECBM_OC = Enhanced CBM Operating Costs Variable - $2.00 ($2002) per Mcf
ENH_CBM% = Enhanced CBM EUR Percentage gain

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

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

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
FOMC_ADJ = Adjustment to calculated fixed operating and maintenance costs to reflect proportionate variation in Energy Information Administration operating costs in years other than the data year (2002) of the data upon which the equation is based.

**FOMC** = Fixed Operating and Maintenance Costs. For Tight Sands and Gas Shales: (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. For coalbed methane a base level fixed operating and maintenance cost is used, which cost varies by play. These input values are multiplied by FOMC_ADJ.

**Table 3B-10.** Operation and Maintenance Costs ($2002) Matrix: Tight Sands and Gas Shales

| OGSM Region | Well Size (EUR) | Well O&M $H_2O$ | Well O&M No $H_2O$ |
|---|---|---|---|
| Northeast | <0.5 Bcf | $ 226560 | $ 147264 |
| | <2.0 Bcf | $ 283680 | $ 184392 |
| | >2.0 Bcf | $ 434880 | $ 282672 |
| Gulf Coast | <0.5 Bcf | $ 179328 | $ 119612 |
| | <2.0 Bcf | $ 279360 | $ 186333 |
| | >2.0 Bcf | $ 371520 | $ 247804 |
| Mid-continent | <0.5 Bcf | $ 226560 | $ 151116 |
| | <2.0 Bcf | $ 283680 | $ 189215 |
| | >2.0 Bcf | $ 434880 | $ 290065 |
| Southwest | <0.5 Bcf | $ 195017 | $ 130076 |
| | <2.0 Bcf | $ 272320 | $ 181637 |
| | >2.0 Bcf | $ 378720 | $ 252606 |
| Rocky Mountain | <0.5 Bcf | $ 231040 | $ 154104 |
| | <2.0 Bcf | $ 268160 | $ 178863 |
| | >2.0 Bcf | $ 401280 | $ 267654 |
| West Coast | <0.5 Bcf | $ 231040 | $ 154104 |
| | <2.0 Bcf | $ 268160 | $ 178863 |
| | >2.0 Bcf | $ 401280 | $ 267654 |

Source: Advanced Resources, International

Tight Sands and Gas Shales

**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
+VOC2*(DISCRES*1,000,000))
*FOMC_ADJ

If MEUR3 is greater than .5 and less than or equal to 2:

FOMC = (DIS_FACT*WOMM_OMW
+VOC2*(DISCRES*1,000,000))
*FOMC_ADJ

If MEUR3 is greater than 2:

FOMC = (DIS_FACT*WOML_OMS
+VOC2*(DISCRES*1,000,000))
*FOMC_ADJ

If WATR_DISP is less than 0.5:

If MEUR3 is less than or equal to .5:

FOMC = (.6*DIS_FACT*WOMS_OMW
+VOC2*(DISCRES*1,000,000))
*FOMC_ADJ

If MEUR3 is greater than .5 and less than or equal to 2:

FOMC = (.6*DIS_FACT*WOMM_OMW
+VOC2*(DISCRES*1,000,000))
*FOMC_ADJ

If MEUR3 is greater than 2:

FOMC = (.6*DIS_FACT*WOML_OMS
+VOC2*(DISCRES*1,000,000))
*FOMC_ADJ

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

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

ROYALTY = Royalty (14.6% for Rocky Mountain plays, 12.5% for all other plays)
SEVTAX = Severance Tax (play-level input)

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

**NET_PRC** = (1-ROYALTY-SEVTAX)*(WHGP+BASNDIF)

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 |

$$\boxed{\mathbf{NET\_PROF} = NET\_PRC - TOTL\_CST - MIN\_ROI}$$

MODEL OUTPUTS

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

| | | |
|---|---|---|
| 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 that it will take for technology improvements to offset the prohibitive effect of the environmental and or pipeline regulations. |

**UNDV_WELLS** = Undeveloped Wells: (1) establish whether or not prohibitive environmental or pipeline regulations exist for the play (Note: For EPCA plays this step applies only to environmental regulation.) (3) If such regulations exist, restrict a certain percentage of the play from development; (4) If such regulations do not exist, allow the entire play to be accessible for development.

| | | | | | |
|---|---|---|---|---|---|
| **UNDV_WELLS** | = | If ENPRGS | = | 1: | |
| | | UNDV_WELLS | | = | TRW*(ENV%+ (LOW%/LOWYRS) *TECHYRS) |
| | | If ENPRGS | = | 0: | |
| | | UNDV_WELLS | | = | TRW |

| | | |
|---|---|---|
| EPCA | = | Establishes if a play is in a basin that was studied in the EPCA assessment (in studied basin = 1, not in studied basin = 0) |
| NACC_FA | = | For EPCA plays - the percentage of the play that is off limits due to Federal administrative decree. |

**UNDV_WELLS2** = For EPCA plays - available wells adjusted to account for well locations that are off limits due to Federal administrative decree.

| | | | | |
|---|---|---|---|---|
| **UNDV_WELLS2** | = | If EPCA is equal to 1: | | |
| | | UNDV_WELLS2 | = | (1. - NACC_FA) * UNDV_WELLS |
| | | If EPCA is equal to 0: | | |
| | | UNDV_WELLS2 | = | UNDV_WELLS |

NACC_PIPE = For EPCA plays - the percentage of the play that is initially off limits due to pipeline regulations.

LIFRT_PIPE = For EPCA plays - the percentage of the play that is initially off limits due to pipeline regulations, the amount in percentage that will become accessible each year due to technological progress (e.g., if 23 percent is initially off limits and LIFRT_PIPE = 1 percent, then 1 of this 23 percent will become accessible each year due to technological progress).

**UNDV_WELLS3** = For EPCA plays - available wells adjusted to account for well locations that are off limits due to pipeline regulations.

| | |
|---|---|
| **UNDV_WELLS3** = | If EPCA is equal to 1:<br>UNDV_WELLS3 = minimum (1., (1.-NACC_PIPE+LIFRT_PIPE*TECHYRS)) * UNDV_WELLS2<br>If EPCA is equal to 0::<br>UNDV_WELLS3 = UNDV_WELLS2 |

NORM = The Standard Normal Density Function
NORM($X$) = ((1./((2.*3.14159265)**.5))*exp(-.5*$X$**2)

CNORM = The Standard Normal Cumulative Distribution Function
CNORM($X$ ) = 1. – NORM($X$) * (.31938*(1./(1.+.23164*$X$))
 - .35656*((1/(1+.23164*$X$))**2.) + 1.78147*((1./(1.+.23164*$X$))**3.)
 - 1.82125*((1./(1.+.23164*$X$))**4.) + 1.33027*((1./(1.+.23164*$X$))**5.)
e.g,, CNORM(1.96) =.975.

C1 = Common (to all plays) constant in estimated function for FOR_WELLS_RATIO

B1 = Binary constant (specific to a given play) in estimated function for FOR_WELLS_RATIO

B2, B3, B4 = Coefficients on explanatory variables in estimated function for FOR_WELLS_RATIO

SIGMA = Parameter in estimated function for FOR_WELLS_RATIO

**FOR_WELLS_RATIO** = The share of total accessible wells (UNDEV_WELLS3) drilled in a given year

| | |
|---|---|
| **FOR_WELLS_RATIO**= | NORM( (MAX(0.0,C1+B1+B2*CUM_RAT +B3*NET_PROF+B4*US_ED)/ SIGMA) )<br>* SIGMA<br>+<br>CNORM( (MAX(0.0,C1+B1+B2*CUM_RAT +B3*NET_PROF+B4*US_ED)/ SIGMA) ) *<br>(MAX(0.0,C1+B1+B2*CUM_RAT+B3*NET_PROF+B4* US_ED) |

**NW_WELLS** = New Wells: The number of discovery wells drilled in the current year

**NW_WELLS** = If HYPPLAYS equals 0:
If NET_PROF is greater than or equal to 0.0:
NW_WELLS = FOR_WELLS_RATIO*UNDEV_WELLS3
If NET_PROF is less than 0:
If NET_PROF is greater than or equal to -1.0:
NW_WELLS=.75*FOR_WELLS_RATIO*
UNDEV_WELLS3
If NET_PROF is less than -1.0 and greater than or
Equal to -2.0:
NW_WELLS =.5*FOR_WELLS_RATIO*
UNDEV_WELLS3
If NET_PROF is less than -2.0:
NW_WELLS = 0.0
If HYPPLAYS equal 1:
NW_WELLS=0.0

EMERGBAS = The parameter that determines if the play is an emerging play. 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 play.

EMERG# = The number of emerging plays " additional years taken off the drilling schedule by advancements in technology.

**NW_WELLS2** = New Wells: This variable adjusts the new wells in a play to reflect that the play is an emerging play

**NW_WELLS2** = If EMERGBAS is equal to 1:
NW_WELLS2 = NW_WELLS*
((UNDEV_WELLS3/NW_WELLS2)/
((UNDEV_WELLS3/NW_WELLS2)+
EMERG%-EMERG#)
If EMERGBAS is equal to 0:
NW_WELLS2 = NW_WELLS

ACC_XYRS% = The percentage increase in the number of years it takes to develop a play in Federal restricted areas (areas subject to Federal lease stipulations)

**NW_WELLS3** = New wells: This variable adjusts the new wells for the play to reflect the effect of access-limiting lease stipulations

| | | |
|---|---|---|
| **NW_WELLS3** | = | If ACCESS equals 0 or YEAR is less than ACCESS_YR:<br>NW_WELLS3 = NW_WELLS2 *<br>1 / ((1.0+LEASSTIP*ACC_XYRS%)/<br>(1.0-NOACCESS))<br>If ACCESS is not equal to 0 and year is greater than or equal to ACCESS_YR:<br>NW_WELLS3 = NW_WELLS2 |

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

**NW_WELLS4** = New wells: This variable constricts the new discovery wells to be within a reasonable range of variation from year-to-year

| | |
|---|---|
| **NW_WELLS4** = | If UNDEV_WELLS3 is greater than NW_WELLS3:<br>If NW_WELLS_LAG is greater than 0.0:<br>If NW_WELLS3 is greater than<br>1.3*NW_WELLS_LAG:<br>NW_WELLS4 = 1.3*NW_WELLS_LAG<br>If NW_WELLS3 is less than<br>.7*NW_WELLS_LAG:<br>NW_WELLS4 =.7*NW_WELLS_LAG<br>If NW_WELLS_LAG equals 0.0:<br>NW_WELLS4 = .5*NW_WELLS3<br>If UNDEV_WELLS3 is less than or equal to NW_WELLS3:<br>NW_WELLS4 = UNDEV_WELLS3 |

NW_RGA% = For new well, as a share of ultimate reserve additions, that portion not booked in the current year but appearing in future years as reserve growth additions resulting from workovers, re-fracturing, technological enhancements, etc.

**DRA** = Drilled Reserve Additions: Reserve additions booked in the current year and resulting directly from new wells drilled in the current year.

| | | |
|---|---|---|
| **DRA** | = | NW_WELLS4*MEUR4*(1-NW_RGA%) |

**NW_INFRES** = For new wells, the total amount of reserve additions that will be booked after the current year as reserve growth additions resulting from workovers, re-fracturing, technological enhancements, etc.

| | | |
|---|---|---|
| **NW_INFRES** = | NEWWELLS4*MEUR4*NW_RGA% | |

**PROV_RES** = Beginning-of-Year Proved Reserves for the current year: This variable is a plugged number in the first year to equate with the EIA published figure

RES_GR = Establishes for a given play whether or not initial reserves (reserves existing in year 1) will have reserve growth. These parameters are explained in the technology section.

RGR_IR = Reserve Growth Rate of initial reserves.

**RGRADD_IR** = Reserve Growth Additions from initial reserves: This variable establishes if the play will have reserve growth for reserves existing in Year 1 and then allocates an appropriate amount for the play

**RGRADD_IR** = If RES_GR is equal to 1:

If ENCBM is equal to 1:

RGA_IR= $RGR*PROV\_RES_1 + .025*((MEUR3-MEUR2)*DEV\_CEL)$

If ENCBM is not equal to 1:

RGA_IR= $RGR*PROV\_RES_1$:

If RES_GR is not equal to 1:

RGA_IR= 0

**NW_INFRES** = For a new well, the total amount of reserve additions that will be booked in future years as reserve growth additions resulting from workovers, re-fracturing, technological enhancements, etc.

**NW_INFRES** = NEWWELLS4*MEUR4*NW_RGA%

RGR_NR = Reserve Growth Rate of reserves added in Year 1 through the Preceding year.

**RGADD_NR** = Reserve Growth Additions from reserves added after Year 1.

RGRADD_NR = $RGR\_NR*(DRA_1.......DRA_{iyr-1})$

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

| | | |
|---|---|---|
| **R_ADD** | = | DRA+RGRADD_IR+RGRADD_NR |

**PROD** = Current (realized) Production: This variable is a plugged number in historical years. In projection years it is received from the NEMS NGTDM.

**PROV_RES2** = Beginning-of-Year Proved Reserves for the next year: This variable calculates the reserves for the coming year from the calculation of occurrences during the year.

| | | |
|---|---|---|
| **PROV_RES2** | = | If (PROV_RES+R_ADD-PROD) is greater than 0:<br>PROV_RES2 = PROV_RES+R_ADD-PROD<br>If (PROV_RES+R_ADD-PROD) is less than or equal to 0:<br>PROV_RES2 = 0 |

**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.

| | | |
|---|---|---|
| C_PR | = | Constant in auto-regressive estimation of the logistical transformation of the production-to-reserve (P/R) ratio |
| RHO | = | Autoregressive parameter in auto-regressive estimation of the logistical transformation of the P/R ratio |
| B1_PR, B2_PR,B3_PR | = | Estimated coefficients on explanatory variables in auto-regressive estimation of the logistical transformation of the P/R ratio |
| RA_RATIO | = | Ratio of reserve additions (R_ADD) in current year to beginning-of-year Reserves (PROV_RES) in current year |
| RA_RATIO_LAG | = | Ratio of reserve additions in previous year to beginning-of-year reserves in previous year |
| LOGISTIC_PR_LAG | = | The previous year's value for the logistical transformation of the P/R ratio |

**LOGISTIC_PR** = The estimated logistical transformation of the P/R ratio.

| | | |
|---|---|---|
| **LOGISTIC_PR** | = | If R_ADD and PROV_RES are not equal to 0:<br>LOGISTIC_PR = C_RP*(1.-RHO)+B1_RP*RA_RATIO<br>+B2_RP*RA_RATIO_LAG<br>+B3_RP*NW_WELLS4<br>+ RHO*LOGISTIC_PR_LAG<br>+ RHO*(B1_RP*RA_RATIO_LAG<br>+B2_RP*RA_RATIO_LAG2<br>+B3_RP*NW_WELLS_LAG) |

MIN_RP = Minimum achievable R/P ratio

**RP_RAT2** = R/P Ratio for the next year: This variable establishes the expected play-level R/P ratio for the next projection year.

**RP_RAT2** = If R_ADD and PROV_RES are not equal to 0:
RP_RAT2 = 1./(exponential(LOGISTIC_PR)/
(1.+exponential(LOGISTIC_PR))
If R_ADD or PROV_RES is equal to 0:
If RP_RAT is greater than MIN_RP:
RP_RAT2 = RP_RAT –
(1.0-Minimum (1.0,R_ADD/PROD))
If RP_RAT is less than or equal to MIN_RP:
If (MIN_RP-RP_RAT) is less than 1.0:
RP_RAT2 = RP_RAT+1.0
If (MIN_RP-RP_RAT) is equal to or less than 1.0:
RP_RAT2 = MIN_RP

**PROD2** = Expected (not realized) production for the following year: This variable is combined with other OGSM expected production values to obtain expected NGTDM regional-level Production-to-Reserve ratios for the following year.

**PROD2** = If RP_RAT2 is equal to 0:
PROD2 = 0
If RP_RAT2 is not equal to 0:
PROD2 = PROV_RES2/(RP_RAT2)

**UNDV_WELLS4** = Remaining potential discovery wells available for drilling in following years.

**UNDV_WELLS4** = If ENPRGS is equal to 1:
UNDV_WELLS4 = TRW-NW_WELLS4
If ENPRGS is not equal to 1:
If UNDV_WELLS3 is equal to 0:
UNDV_WELLS4 = 0.0
If UNDV_WELLS3 is not equal to 0:
If(UNDV_WELLS3-NW_WELLS4) is equal to 0.0:
UNDV_WELLS4 = 0.1
If (UNDV_WELLS3-NW_WELLS4) is not equal to 0.0:
UNDV_WELLS4 = maximum (0.0, UNDV_WELLS3 - NW_WELLS4)

In the following section the mix of potential discovery wells by true EUR (top 10% and 20%, middle 30%, bottom 40%) in each category of perceived EUR (top 30%, middle 30%, and bottom 40%) for the following year is adjusted to reflect the increasing ability of producers to better understand the play and to reflect the removal of wells drilled in the current year.

For each perceived productivity category:

| | | |
|---|---|---|
| **RW10_NEWWELLS** | = | The number of new wells drilled that have an EUR equal to the average EUR for the actual top 10 percent (by EUR) of the wells in the play |
| **RW20_NEWWELLS** | = | The number of new wells drilled that have an EUR equal to the average EUR for the actual next highest 20 percent of the wells in the play |
| **RW30_NEWWELLS** | = | The number of new wells drilled that have an EUR equal to the average EUR for the actual next highest ("middle") 30 percent of the wells in the play |
| **RW40_NEWWELLS** | = | The number of new wells drilled that have an EUR equal to the average EUR for the actual lowest 40 percent of the wells in the play |

**RW10_NEWWELLS** = NW_WELLS4 *(RW10_WELLS/(RW10_WELLS + RW20_WELLS+RW30_WELLS+RW40_WELLS)

**RW20_NEWWELLS** = NW_WELLS4 * (RW20_WELLS/(RW10_WELLS + RW20_WELLS+RW30_WELLS+RW40_WELLS)

**RW30_NEWWELLS** = NW_WELLS4 * (RW30_WELLS/(RW10_WELLS + RW20_WELLS+RW30_WELLS+RW40_WELLS)

**RW40_NEWWELLS** = NW_WELLS4 * (RW40_WELLS/(RW10_WELLS + RW20_WELLS+RW30_WELLS+RW40_WELLS)

| | | |
|---|---|---|
| TOT_RW10_WELLS | = | The total number of remaining wells (adjusted for new wells drilled)in the play that have an EUR equal to the average EUR for the original top10 percent (in Year 1) of the wells in the play |
| TOT_RW20_WELLS | = | The total number of remaining wells in the play that have an EUR equal to the average EUR for the original next highest 20 percent of the wells in the play |
| TOT_RW30_WELLS | = | The total number of remaining wells in the play that have an EUR equal to the average EUR for the original next highest 30 percent of the |

wells in the play

TOT_RW40_WELLS = The total number of remaining wells in the play that have an EUR equal to the average EUR for the original lowest 40 percent of the wells in the play

SHIFT% = A factor representing the effect of accumulated information and advancing technology that enables drillers to more effectively locate the best prospective areas of the play.

$\mathbf{RW10\_WELLS_{iyr+1}}$ = For the following year, the number of available wells that have an EUR equal to the average EUR for the actual top10 percent of the wells in the play

$\mathbf{RW20\_WELLS_{iry+1}}$ = For the following year, the number of available wells that have an EUR equal to the average EUR for the actual next highest 20 percent of the wells in the play

$\mathbf{RW30\_WELLS_{iyr+1}}$ = For the following year, the number of available wells that have an EUR equal to the average EUR for the actual next highest ("middle") 30 percent of the wells in the play

$\mathbf{RW40\_WELLS_{iyr+1}}$ = For the following year, the number of available wells that have an EUR equal to the average EUR for the actual lowest 40 percent of the wells in the play

For play area thought to be the top 30 percent with respect to productivity:

$$\mathbf{RW10\_WELLS_{iyr+1}} = TOT\_RW10\_WELLS * minimum\ (.3+SHIFT\%,1.0)$$

$$\mathbf{RW20\_WELLS_{iyr+1}} = TOT\_RW20\_WELLS_{iyr} * minimum\ (.3+SHIFT\%,1.0)$$

$$\mathbf{RW30\_WELLS_{iyr+1}} = TOT\_RW30\_WELLS_{iyr} * maximum\ (.3-(3/7)*SHIFT\%,0.0)$$

$$\mathbf{RW40\_WELLS_{iyr+1}} = TOT\_RW40\_WELLS_{iyr} * maximum\ (.3-(1/2)*SHIFT\%,0.0)$$

For play area thought to be the middle 30 percent with respect to productivity:

$$\mathbf{RW10\_WELLS_{iyr+1}} = TOT\_RW10\_WELLS * maximum\ (.3-(3/7)*SHIFT\%,0.0)$$

$$\mathbf{RW20\_WELLS_{iyr+1}} = TOT\_RW20\_WELLS * maximum\ (.3-(3/7)*SHIFT\%,0.0)$$

$$\textbf{RW30\_WELLS}_{iyr+1} = \text{TOT\_RW30\_WELLS*minimum (.3+SHIFT\%),1.0)}$$

$$\textbf{RW40\_WELLS}_{iyr+1} = \text{TOT\_RW40\_WELLS*maximum (.3-((1/2)*SHIFT\%),0.0)}$$

For play area thought to be the lowest 40 percent with respect to productivity:

$$\textbf{RW10\_WELLS}_{iyr+1} = \text{TOT\_RW10\_WELLS*maximum (.4-(4/7)*SHIFT\%,0.0)}$$

$$\textbf{RW20\_WELLS}_{iyr+1} = \text{TOT\_RW20\_WELLS*maximum (.4-(4/7)*SHIFT\%,0.0)}$$

$$\textbf{RW30\_WELLS}_{iyr+1} = \text{TOT\_RW30\_WELLS*maximum (.4-(4/7)*SHIFT\%,0.0)}$$

$$\textbf{RW40\_WELLS}_{iyr+1} = \text{TOT\_RW40\_WELLS*minimum (.4-(1/2)*SHIFT\%,0.0)}$$

WELLON% = The proportion of the year that a well drilled in the current year is in production

PROD1STYR%= The proportion of a well's total production stream that occurs in the first full year of production

**INFILL_WELLS** = The number of infill wells drilled as implied by the expected production for the following year

$$\textbf{INFILL\_WELLS} = \text{Max (0, (PROD2-(1-(1/RP\_RAT))*PROD) /(WELLON\%*PROD1STYR\%*MEUR4) - NW\_WELLS2)}$$

TOT_WELLS_LAG = The total successful wells drilled in the previous year

**TOT_WELLS** = The total successful wells drilled in the current year

| | |
|---|---|
| **TOT_WELLS** = | If(NW_WELLS4+INFILL_WELLS) is greater than 1.3*TOT_WELLS_LAG:<br>TOT_WELLS = 1.3*(NW_WELLS4+INFILL_WELLS)<br>Else if TOT_WELLS is less than .7*(NW_WELLS4 +INFILL_WELLS)<br>TOT_WELLS = .7*(NW_WELLS4+INFILL_WELLS)<br>Else:<br>TOT_WELLS = NW_WELLS4+INFILL_WELLS |

# Appendix 3C. Unconventional Gas Recovery Supply Technologies

## INTRODUCTION

The Unconventional Gas Recovery Supply Submodule (UGRSS), shown in **Figure 3C-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 types of research and technologies 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).

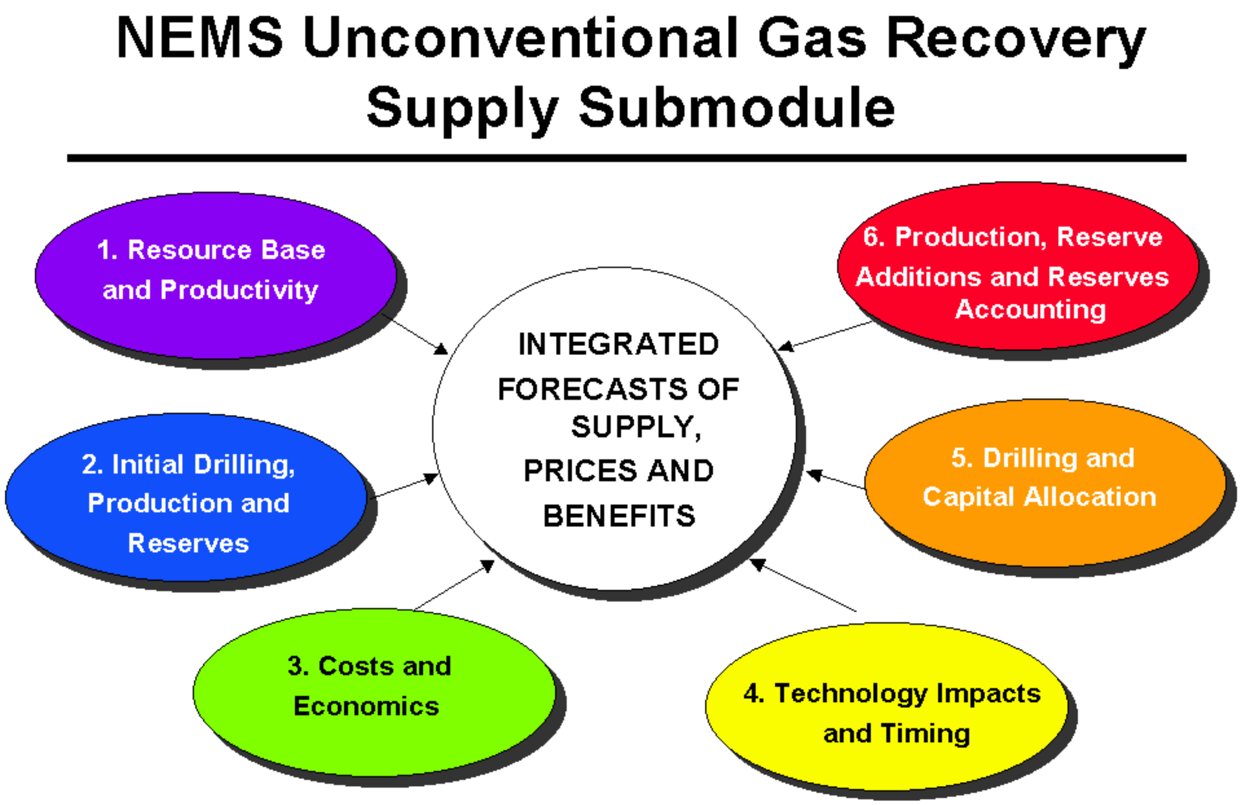
The technology packages are grouped into three distinct technology cases -- Reference Case, Slow Technology, and Rapid Technology -- that capture three different futures for technology progress, as further described below:

1. **Reference Case** captures the current status and trends in the E&P technology for unconventional gas. In addition to industry funded R&D, a limited amount of R&D on tight sand reservoirs is directly supported by the U.S. Department of Energy (DOE), particularly on advanced macro-exploration, seismic technologies, and matching of technology to reservoir settings. The Gas Technology Institute (GTI) R&D program funds valuable studies of emerging and future gas plays and supports advanced well stimulation technology. Also, direct R&D on coalbed methane (CBM) has been funded by the DOE Small Business Innovative Research (SBIR) program for CBM cavitation technology. In addition to the directly funded R&D, considerable indirect R&D by DOE, GTI and industry 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 GTI and the United States Geological Survey (USGS).

2. For the Annual Energy Outlook 2009 (AEO2009), the **Slow Technology** case represents an R&D outlook where the effects of the various technologies are generally about 50 percent less than in the Reference Case.

3. For the AEO2009, the **Rapid Technology** case represents an R&D outlook where the effects of the various technologies are generally about 50 percent greater than in the Reference Case.

# Figure 3C-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

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

1. Increasing the Resource Base with Basin Assessments.

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

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

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

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

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

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

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

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

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

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

The impact each of these 11 R&D packages has on unconventional gas development and the specific technology lever used to model these impacts in the Supply and Technology Model is shown on **Table 3C-1**.

# Table 3C-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 Operation and Maintenance (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 3C-2** for Coalbed Methane (CBM), on **Table 3C-3** for gas shales, and **Table 3C-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.

# Table 3C-2
# Details of Coalbed Methane Technological Progress

| R&D Program | CBM Resource Impacted | Technology Lever | Current Situation | Technology Cases | | |
|---|---|---|---|---|---|---|
| | | | | Reference Case | Slow Technology | Rapid Technology |
| 1. Basin Assessment | Hypothetical Plays | Date Available | Not Available | Not Available | Not Available | Not Available |
| 2. Extended Resource Characterization | Emerging Plays | Pace of Development | 30 to 60 years (+30 years over Developing Plays) | 1.0 yr/year (Max - 30 years) | 0.5 yr/year (Max - 30 years) | 1.5 yr/year (Max - 30 years) |
| 3. Well Performance Diagnostics & Remediation | Proved Reserves | Reserve Growth | All Plays with Proved Reserves @ 3%/yr., declining | All Plays @ 2%/yr., declining .1% over 40 years | All Plays @ 1%/yr., declining .1% over 20 years | All Plays @ 3%/yr., declining .1% over 60 years |
| 4. Exploration & Natural Fracture Detection R&D | All Plays | a. E/D Success Rate | 25% to 95% | +.2%/year from 2005 (max 95%) | +.1%/year from 2005 (max 95%) | +.3%/year from 2005 (max 95%) |
| | | b. Exploration Efficiency | Random | Identify "Best" 30% by Year 2045 | Identify "Best" 30% by year 2100 | Identify "Best" 30% by year 2031 |
| 5. Geology/ Technology Modeling and Matching | All Plays | EUR/Well | As Calculated | +.2%/year (30 years) | +.1%/year (30 years) | +.3%/year (30 years) |
| 6. Improved Drilling and Stimulation | All Plays | EUR/Well | As Calculated | +.36%/year (30 years) | +.18%/year (30 years) | +.45%/year (30 years) |
| 7. Lower Cost Drilling & Stimulation | All Plays | D&S Costs/Well | As Calculated | -.25%/year (30 years) | -.13%/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 | Not Available | Not Available | Not Available |
| 9. Advanced CBM Cavitation | Cavity Fairway Plays | EUR/Well | As Calculated | Not Available | Not Available | 2016 |
| 10. Enhanced CBM Recovery | ECBM Eligible Plays | a. Recovery/ Efficiency | As Calculated | +20% | Not Available | +30% |
| | | b. O&M Costs/Mcf | As Calculated | +$1.00($1996)/ Mcf, Incremental | Not Available | +$0.75($1996)/ Mcf, Incremental |

# Table 3C-2
## Details of Coalbed Methane Technological Progress

| R&D Program | CBM Resource Impacted | Technology Lever | Current Situation | Technology Cases | | |
|---|---|---|---|---|---|---|
| | | | | Reference Case | Slow Technology | Rapid Technology |
| | | c. Year Available | Not Available | 2025 | Not Available | 2015 |
| 11. Environmental Mitigation | EV Sensitive Plays | Acreage Available | Non- EPCA[1]: 35% of Play Restricted | Non-EPCA Plays: Removed in 35 years (0.7%/year) | Non-EPCA Plays: Removed in 70 years (0.35%/year) | Non-EPCA Plays: Removed in 23 years (1.05%/year) |
| | | | EPCA Plays: Variable | EPCA Plays: Variable | EPCA Plays: Variable (.5*Reference Case Values) | EPCA Plays: Variable (1.5*Reference Case Values) |

[1] The following basins (study areas) were reassessed by the USGS as part of a Federal interagency study of access restrictions in the Rocky Mountains: the Paradox/San Juan, the Uinta/Piceance, the Greater Green River, the Powder River, and the Montana Thrust Belt. The study , *Scientific Inventory of Onshore Federal Land's Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development* (January 2003) , was conducted under the authority of the Energy Policy and Conservation Act (EPCA).

## Table 3C-3
## Details of Gas Shales Technological Progress

| R&D Program | Gas Shales Resource Impacted | Technology Lever | Current Situation | Technology Cases | | |
|---|---|---|---|---|---|---|
| | | | | Reference Case | Slow Technology | Rapid Technology |
| 1. Basin Assessment | Hypothet-ical Plays | Date Available | Not Available | Not Available | Not Available | Not Available |
| 2. Extended Resource Characterization | Emerging Plays | Pace of Development | 30 to 60 years (+30 years over Developing Plays) | 1.0 yr/year (Max - 30 years) | 0.5 yr/year (Max - 30 years) | 1.5 yrs/year (Max -30 years) |
| 3. Well Performance Diagnostics and Remediation | Proved Reserves | Reserve Growth | All Plays with Proved Reserves @ 3%/yr., declining | All Plays @ 4%/yr., declining .1% over 40 years | All Plays @ 2%/yr., declining .1% over 20 years | All Plays 6%/yr, declining .1% over 60 years |
| 4. Exploration & Natural Fracture Detection R&D | All Plays | a. E/D Success Rate | 25% to 95% | +.2%/year from 2005 (max 95%) | +.1%/year from 2005 (max 95%) | +.3%/year from 2005 (max 95%) |
| | | b. Exploration Efficiency | Random | Identify "Best" 30% by Year 2045 | Identify "Best" 30% by year 2100 | Identify "Best" 30% by year 2031 |
| 5. Geology/ Technology Modeling and Matching | All Plays | EUR/Well | As Calculated | +.25%/year (30 years) | +.13%/year (30 years) | +.38%/year (30 years) |
| 6. Improved Drilling and Stimulation | All Plays | EUR/Well | As Calculated | +.25%/year (30 years) | +.13%/year (30 years) | +.38%/year (30 years) |
| 7. Lower Cost Drilling & Stimulation | All Plays | D&S Costs/Well | As Calculated | Not Available | Not Available | Not Available |
| 8. Water and Gas Treating R&D | All Plays | Water & Gas Treating O&M Costs/Mcf | $0.30/Mcf | Not Available | Not Available | Not Available |
| 9. Multi-Lateral Completions | Eligible Plays | Recovery Efficiency | As Calculated | 20% (Year 2016) | Not Available | 30% (Year 2009) |
| 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 |
| | | c. Year Available | Not Available | Not Available | Not Available | Not Available |
| 11.Environ-mental Mitigation | EV Sensitive Plays | Acreage Available | 35% of Play Restricted | Removed in 35 years (1%/year) | Removed in 70 years (.5%/ year) | Removed in 23 years (1.5%/year) |

# Table 3C-4
# Details of Tight Gas Sands Technological Progress

| R&D Program | Tight Sands Resource Impacted | Technology Lever | Current Situation | Technology Cases | | |
|---|---|---|---|---|---|---|
| | | | | Reference Case | Slow Technology | Rapid Technology |
| 1. Basin Assessment | Hypothetical Plays | a. Date Available | Not Available | 2021 | 2021 | 2021 |
| 2. Extended Resource Characterization | Emerging Plays | Pace of Development | 30 to 60 years (+20 years over Developing Plays) | -.75 yr/year (Max - 30 years) | -.38 yr/year (Max - 30 years) | -1.13 yr/year (Max -30 years) |
| 3. Well Performance Diagnostics and Remediation | Proved Reserves | Reserve Growth | San Juan Basin @ 3%/yr., declining | All Plays @ 1%/yr., declining (20 years) | All Plays @ 0.5%/yr., declining (10 years) | All Plays 1.5%/yr, declining (30 years) |
| 4. Exploration & Natural Fracture Detection R&D | All Plays | a. E/D Success Rate | 30% to 95% | +.2%/year from 2005 (max 95%) | +.1%/year from 2005 (max 95%) | +.3%/year from 2005 (max 95%) |
| | | b. Exploration Efficiency | Random | Identify "Best" 30% by Year 2045 | Identify "Best" 30% by year 2100 | Identify "Best" 30% by year 2031 |
| 5. Geology/ Technology Modeling and Matching | All Plays | EUR/Well | As Calculated | +.20%/year (30 years) | +.10% (30 years) | +.30% (30 years) |
| 6. Improved Drilling and Stimulation | All Plays | a. EUR/Well | As Calculated | +.36%/year (30 years) | +.18%/year (30 years) | +.45%/year (30 years) |
| 7. Lower Cost Drilling & Stimulation | All Plays | D&S Costs/Well | As Calculated | -0.13%/year (30 years) | -0.25%/year (30 years) | -0.38%/year (30 years) |
| 8. Water and Gas Treating R&D | All Plays | Water & Gas Treating O&M Costs/Mcf | $0.15/Mcf | Not Available | Not Available | Not Available |

# Table 3C-4
# Details of Tight Gas Sands Technological Progress

| R&D Program | Tight Sands Resource Impacted | Technology Lever | Current Situation | Technology Cases | | |
|---|---|---|---|---|---|---|
| | | | | Reference Case | Slow Technology | Rapid Technology |
| 9. Horizontal Wells | Continuous Sands | Recovery Efficiency | As Calculated | +20% (year 2025) | Not Available | +30% (year 2015) |
| 10. Other Tight Sands 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 |
| | | c. Year Available | Not Available | Not Available | Not Available | Not Available |
| 11. Environmental Mitigation | EV Sensitive Plays | Acreage Available | Non-EPCA Plays: 35% of Play Restricted | Non-EPCA Plays: Removed in 35 years (0.7%/year) | Non-EPCA Plays: Removed in 70 years (.35%/ year) | Non-EPCA Plays: Removed in 23 years (1.05%/year) |
| | | | EPCA Plays: Variable | EPCA Plays: Variable | EPCA Plays: Variable: .5*Reference Case Values | EPCA Plays: Variable: 1.5*Reference Case Values |

**Technology Packages**

**1. Increasing the Resource Base with Basin Assessments**

**Background and Problem**

A significant portion of the unconventional gas resource base (54 Tcf) and many of the high potential gas settings are hypothetical plays. Because basic information is lacking on these plays, industry is constrained in exploring or developing them in a timely fashion. The hypothetical plays listed on **Tables 3C-5**, **3C-6**, and **3C-7** are currently not available for development. The 1995 USGS National Assessment was used as the basis for the play categorization and for guidance on resource estimates in these tables. In addition, the resource estimates for certain of the plays have been updated and expanded by special studies by Advanced Resources International, Inc.

**Technology Lever**

Fundamental studies of the geology and hydrocarbon potential of these new gas plays will be required to initiate their development. These studies would provide the essential foundation for exploring and developing natural gas from hypothetical plays and would improve their probabilities for success.

**Foundation for Technology Lever**

The foundation for the "Basin Studies and Assessments" technology lever is expert judgment. The input data for this expert judgment stems from the observed industry responses to a variety of major basin level studies of unconventional gas prepared in the past 25 years:

- Initial ERDA/DOE basin and play level resource and recoverable estimates for tight gas basins (1980).
- Subsequent Gas Resource Institute (GRI) series of basin studies and assessments for eight major coalbed methane basins (1990-1997), prepared by ARI and the Bureau of Economic Geology (BEG), Texas.
- Joint USGS/ARI basin study and assessment for the Barnett Shale in the Fort Worth Basin, Texas (1998).
- "Portfolio of Emerging Natural Gas Resources" (1999) for the three major Rocky Mountain tight gas basins, sponsored by GRI and prepared by ARI.
- Gas Atlas series for major natural gas producing states or regions, sponsored by GRI and prepared by BEG, Barlow and Haun and various state geological surveys.

**Table 3C-5**

**Hypothetical CBM Plays and Resources**

| Basins | Gas Plays | Undeveloped Resource (Bcf) |
|---|---|---|
| **Appalachia** | N. Basin – Moderate/Low | 702 |
| **San Juan** | Southern (Menefee) | 242 |
| **Uinta** | Sego | 317 |
| **Piceance** | Deep Basin | 2,116 |
| **Green River** | Deep Basin | 2,067 |
| **Black Warrior** | Extension Area | 61 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

**Table 3C-6**

**Hypothetical Gas Shale Plays and Resources**

| Basin | Gas Play | Undeveloped Resources (Bcf) |
|---|---|---|
| **Appalachia** | Appalachia – Low Thermal Maturity | 4,108 |
| **Michigan** | Antrim Shale -Undeveloped Area | 8,060 |
| **Illinois** | New Albany Shale - Developing Area | 3,098 |
| **Cincinnati Arch** | Devonian Shale | 1,126 |
| **Williston** | Shallow Niobrara - Biogenic Gas | 3,860 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

**Table 3C-7**

**Hypothetical Tight Sand Plays and Resources**

| Basin | Gas Plays | Undeveloped Resources (Bcf) |
|---|---|---|
| **Columbia** | Basin Center | 6,525 |
| **Uinta** | Deep Synclinal MV | 2,705 |
| **Greater Green River** | Deep Mesaverde | 2,070 |
| | Deep Frontier | 9,231 |
| **Wind River** | Fort Union/Lance Deep | 4,155 |
| **Williston** | Moderate Potential | 1,249 |
| | Low Potential | 704 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

## Gas Plays With Reservoir Characterization

**Background and Problem**

Much of the unconventional gas resource is in new, emerging plays in the Rocky Mountain 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 3C-8, 3C-9 and 3C-10** 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 30 year stretch-out in field development time.

**Foundation for Technology Lever**

The foundation for the "Play-Specific Resource Characterization" technology lever is based on the observed industry response to a series of DOE and GRI sponsored field R&D and reservoir characterization studies in unconventional gas plays:

- DOE's MWX field laboratory at Rulison Field, Piceance Basin, Colorado provided detailed information on the deposition continuity and properties of the lenticular Williams Fork/Mesaverde tight gas sands. Before R&D, lenticular sands were considered undevelopable. Today, the Rulison Field and the Williams Fork Formation is a multi-Tcf natural gas play.
- GRI's reservoir characterization of the Barnett Shale at Newark Field provided essential information that has led to nearly 2,000 wells being drilled in this new very active gas shale play.
- Extensive resource characterization of Warrior Basin coalbed methane, at GRI's Rock Creek Field Laboratory, assisted this basin to provide the first active CBM play in the country.

**Table 3C-8**

**Emerging CBM Plays and Resources**

| Basin | Gas Play | Undeveloped Resources (Bcf) |
|---|---|---|
| **Appalachia** | Northern Basin-High Thermal Maturity | 799 |
| **Illinois** | Central Basin | 612 |
| **Uinta** | Blackhawk Formation | 459 |
| **Piceance** | White River Dome | 1,199 |
| | Shallow | 2,748 |
| **Raton** | Northern Basin | 173 |
| **Greater Green River** | Washakie | 1,616 |
| **Powder River** | Central Basin | 2,770 |
| | Wasatch | 56 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

**Table 3C-9**

**Emerging Gas Shale Plays and Resources**

| Basin | Gas Plays | Undeveloped Resources (Bcf) |
|---|---|---|
| **Appalachia** | Devonian Shale - Big Sandy Extension Area | 3,185 |
| | Devonian Shale - Greater Siltstone Area | 1,854 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

**Table 3C-10**

**Emerging Tight Sand Plays and Resources**

| Basins | Gas Plays | Undeveloped Resources (Bcf) |
|---|---|---|
| **Texas Gulf Coast** | Olmos | 3,177 |
| **Wind River** | Ft. Union/Lance Shallow | 13,963 |
| | Mesaverde/Frontier Shallow | 688 |
| | Mesaverde/Frontier Deep | 797 |
| **Greater Green River** | Ft. Union/Fox Hills/Lance | 25,196 |
| | Lewis | 13,710 |
| | Shallow Mesaverde (2) | 18,452 |
| **Piceance** | N. Basin Williams Fork /Mesaverde | 10,870 |
| | Iles/Mesaverde | 1,285 |
| **Uinta** | Basin Flank Mesaverde | 4,331 |
| | Tertiary West | 5,513 |
| **Williston** | High Potential | 2,736 |
| **Midcontinent** | Anadarko – Granite Wash/Atoka | 7,747 |
| **Appalachia** | Berea Sandstone | 11,884 |
| | Upper Devonian High | 6,621 |
| | Upper Devonian Moderate-Low | 6,643 |
| | Tuscarora Sandstone | 2,568 |
| | Clinton/Medina Moderate-Low | 15,892 |

Source: Advanced Resources, International (1996 through 2006 estimates), EIA (2007 estimate)

## 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**

The gas plays listed on **Tables 3C-11, 3C-12 and 3C-13** are existing unconventional plays with advanced well performance diagnostics and remediation.

**Foundation for Technology Lever**

The foundation for the "Reserve Growth" technology lever is data from a select number of basins and areas where unconventional gas dominates natural gas production, such as W. New Mexico (with its extensive tight gas and CBM plays), Utah (also with tight gas and CBM plays), and Michigan (with its Antrim Shale gas play). These data series show that proved reserves grow at annual rate of 2% to 4% due to non-drilling based activities such as adjustments and revisions, depending on the basin and gas play, as discussed below:

- The tight gas in the E. Texas Basin (Texas Railroad District (TRR) #6) has had 509 Bcf of growth on original reserves of 5.9 Tcf or about 2% per year.
- The combined tight gas and coalbed methane play in the San Juan Basin (W. New Mexico) has had 1,845 Bcf of growth on original reserves of 13.7 Tcf or about 3% per year.
- The newer CBM and tight gas play in the Uinta Basin (Utah) and the shale gas plays in the Michigan and the Fort Worth basins (TRR #9) have seen reserve growth of 15% to 20% per year but may not be representative of the largest set of unconventional gas plays.

**Table 3C-11**

**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) | 6,170 | 6,157 |
| | North Basin (NM) | 586 | 550 |
| | South Basin (NM) | 152 | 150 |
| **Warrior** | Main Area | 972 | 823 |
| **Uinta** | Ferron Formation | 400 | 400 |
| **Raton** | North Basin Area | 0 | 31 |
| | Purgatory River Area | 100 | 249 |
| **Powder River** | Wyodak Upper Ft. Union | 100 | 150 |
| **Piceance** | Divide Creek | 56 | 52 |
| **Appalachia** | Central Basin | 1,137 | 1,172 |
| **Mid Continent** | Arkoma | 200 | 220 |
| | Cherokee & Forest City | 13 | 13 |
| **TOTALS** | | **10,582** | **10,667** |

Source: Advanced Resources, International

**Table 3C-12**

**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 | 1,122 | 1,137 |
| | Devonian Shale - Big Sandy Extension Area | 281 | 255 |
| **Michigan** | Antrim Shale - Developing Area | 1,005 | 1615 |
| **Fort Worth***| Barnett Shale - Core Area | 208 | 270 |
| **TOTALS** | | **2,616** | **3,277** |

Source: Advanced Resources, International

.

## Table 3C-13

## Tight Sand Plays With Proved Reserves

| Basin | Gas Plays | Proved Reserves (Bcf) 1/96 | Proved Reserves (Bcf) 1/97 |
|---|---|---|---|
| **Appalachia** | Clinton/Medina High | 815 | 961 |
| | Upper Devonian High | 3,262 | 3,484 |
| **San Juan** | Picture Cliffs | 900 | 960 |
| | Central Basin/Mesaverde | 5,200 | 5,200 |
| | Central Basin/Dakota | 2,700 | 2,600 |
| **Uinta** | Tertiary East | 500 | 500 |
| | Basin Flank MV | 10 | 9 |
| **Piceance** | S. Basin Williams Fork/Mesaverde | 600 | 700 |
| | Iles/Mesaverde | 150 | 140 |
| **Green River** | Ft. Union/Fox Hills/Lance | 100 | 500 |
| | Lewis | 200 | 200 |
| | Shallow Mesaverde(1) | 1,800 | 1,900 |
| | Deep MV | 70 | 70 |
| | Frontier (Moxa Arch) | 1,800 | 1,600 |
| | Frontier (Deep) | 10 | 0 |
| **Wind River** | Ft. Union/Lance Shallow | 300 | 700 |
| | Mesaverde/Frontier Shallow | 300 | 250 |
| **Denver** | Denver Jules - All Tight Gas | 1,000 | 1,050 |
| **LA/Mississippi Salt** | East Texas - Cotton Valley/Bossier | 4,200 | 4,000 |
| **Texas Gulf Coast** | Vicksburg | 1,750 | 2,030 |
| | Wilcox/Lobo | 2,700 | 2,900 |
| | Olmos | 300 | 400 |
| **Permian** | Canyon | 1,600 | 1,600 |
| | Abo | 1,200 | 1,100 |
| **Anadarko** | Cleveland | 300 | 300 |
| | Cherokee/Redfork | 1,400 | 1,400 |
| | Granite Wash/ Atoka | 200 | 200 |
| **Williston** | High Potential | 300 | 700 |
| **Arkoma** | Atoka | 700 | 600 |
| **TOTALS** | | **34,407** | **36,004** |

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. Since the productive areas in undeveloped plays are often difficult to identify, unconventional gas developers can drill a large number of economically dry wells with reserves of 0.1 Bcf per well or less. Because of these high numbers of dry and economically dry wells, the development success rates for new unconventional gas plays typically range from 50 to 90%.

**Technology Lever**

The R&D goal is to develop and demonstrate improved exploration technology to enable producers to find the best (i.e., "sweet spot") portions of these gas basins and to improve their success rates. Sweet spots are zones in generally tight reservoirs that produce commercial quantities of oil or gas mostly due to interconnecting natural fractures. The fractures can be due to tectonic movement, and the locations and orientations of the fractures can often be estimated by understanding the local tectonic stresses and applying data analysis and modeling. The quality of a sweet spot depends on the interaction of several attributes, including fracture porosity, location along migration pathways, favorable facies and a good regional pressure seal above the target horizon.

**Impacts and Benefits**

This 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 by the year the assumed year.

**Foundation for Technology Lever**

The basic assumption is that with trial and error drilling, industry would eventually establish the higher productivity portions of a play without new technology. The development and application of natural fracture and advanced logging technology enables this high grading process to occur sooner. The current industry capacity to high grade basin areas is illustrated in Attachment A by the still limited ability to identify higher productivity areas in the Drunkard's Wash CBM play in the Uinta Basin (Case Study 3).

The foundation for the "Exploration Efficiency" technology lever is based on the initial field demonstration of DOE-sponsored natural fracture detection R&D and improved logging technology in the southern Piceance Basin which provided an improved ability to high grade the potential drilling sites in the southern portion of the Rulison Field, as discussed in Attachment A (Case Study 1).

## 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. Fields are often developed 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.

### 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 low resistivity sands, 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

This technology increases recovery from new wells.

### Foundation for Technology Lever

The Individual case studies in Attachment A show a steady improvement in reserves per well with increased understanding of the geologic setting and the appropriate set of technologies for optimizing gas recovery from these deposits. The assumption is that this improvement continues, but at a slower pace than in the past due to reduced R&D investments in geology and technology matching.

## 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**

All unconventional gas plays, because of their low permeability, would benefit from improved well completion and stimulation.

**Foundation for Technology Lever**

The Case studies in Attachment A show a steady improvement in reserves per well with introduction of lower damage, more effective well completion and stimulation technology. The assumption is that this improvement continues, but at a slower pace than in the past due to reduced R&D investments in advanced, multi-zone well completions technology and appropriate, non-damaging well stimulation technology.

## 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**

Well drilling and completion costs are reduced, in real terms.

**Foundation for Technology Lever**

Natural gas well costs, after declining from the mid-1980s to the mid-1990's, reversed course and have climbed significantly in the past five years, as shown below:

**Table 3C-14**

**Natural Gas Well Drilling and Completion Costs**

| Year | Average Nominal Costs | | Adjusted for Drilling Activity And Inflation (01 dollars) | |
|---|---|---|---|---|
| | Per Well | Per Foot | Per Well | Per Foot |
| 1995 | 630 | 96 | 540 | 104 |
| 1996 | 622 | 98 | 566 | 109 |
| 1997 | 723 | 115 | 624 | 120 |
| 1998 | 816 | 128 | 676 | 131 |
| 1999 | 766 | 132 | 665 | 129 |
| 2000 | 684 | 125 | 661 | 128 |

Source: Advanced Resources, International

Using the activity and inflation adjusted data, natural gas well costs between 1995 and 2000 increased by $121,000 per well (22%) between 1995 to 1999 (@ 4% per year) and by $24 per foot (23%) in the 2000. Approximately, one-half of this increase has been in the rig day-rate and the other one-half has been due to higher fuel costs and adjustments from depressed mid-1990's costs.

With rig day-rates close to replacement costs (at least for the new HP flex-rigs), we expect that continued improvements in drilling efficiencies (due to the modest level of investment in technology), will counter increases in drilling costs (in real dollars) in future years. Without investment in R&D, well costs would increase by 2% per year (in real dollars).

## 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**

O&M costs remain flat, in real terms, in all 3 technology cases.

**Foundation for Technology Lever**

Natural gas well operating costs, after declining from the mid-1980s to the mid-1990s, reversed course and have increased in between 1995 and 1999, as shown below:

**Table 3C-15**

**Natural Gas Well Operating Costs Indices**

| Year | Inflation Adjusted Gas Recovery Operating Cost Index |
|---|---|
| 1995 | 90.7 |
| 1996 | 90.9 |
| 1997 | 95.3 |
| 1998 | 98.1 |
| 1999 | 97.6 |
| 2000 | n/a |

Source: Advanced Resources, International

Using the above operating cost index data, natural gas operating costs rose by 6.9 index points (7.6% in four years) or 2% per year.

We estimate that investment in gas and water treatment technology will counter increases in gas and water treatment O&M costs (in real dollars) in future years. Without investment in R&D, gas and water treatment costs would increase by 2% per year (in real dollars).

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

**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 sands has been disappointing to date, raising concerns about drilling damage and selection of geologically appropriate settings. For example, DOE supported horizontal wells at the MWX site in the Southern Piceance Basin and at Table Rock in the Eastern Greater Green River Basin turned to water after high initial gas rates.

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 on what combination of reservoir properties is essential or favorable for cavitation, and little has been invested in cavitation science, design or operating procedures. As a result, only one cavity fairway has been established in the U.S. to date -- in the central San Juan Basin.

Because gas shales generally have a thick pay section, multiple productive horizons, and low vertical permeability, horizontal wells may 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.

**Technology Lever**

Additional horizontal, multi-lateral and cavitation well R&D may help define the appropriate geologic settings for using this technology, particularly in damage sensitive, low permeability formations. DOE's R&D, including its participation in the SBIR program provides a modest level of investigation on these topics.

**Impact and Benefits**

The unconventional gas plays listed in **Table 3C-16** are potentially favorable for advanced well D&C technology.

**Table 3C-16**

**Unconventional Gas Plays Applicable for Advanced Well Drilling and Completion Technologies**

| Basin | Gas Play |
|---|---|
| **Tight Sands** | |
| **Appalachia** | Clinton/Medina High |
| **Denver** | Denver Jules - All Tight Gas |
| **Greater Green River** | Shallow Mesaverde (2) |
| | Frontier (Deep) |
| **Piceance** | Iles/Mesaverde |
| **San Juan** | Central Basin/Dakota |
| **Coalbed Methane** | |
| **San Juan** | Fairway (NM) (existing) |
| **Uinta** | Ferron |
| **Raton** | Purgatory River |
| **Piceance** | Shallow Coals |
| **Green River** | Washakie |
| **Gas Shales** | |
| **Michigan** | Antrim, Developing Area |
| | Antrim, Undeveloped Area |
| **Illinois** | New Albany, Developing Area |
| **Williston** | Shallow Niobrara |

**Foundation for Technology Lever**

The foundation for the "Advanced Drilling and Completion" technology lever is documented improvements in well performance reserves per well that have resulted from:

- Application of horizontal well drilling in "blanket" tight gas sand formations such as the Frontier Formation at Table Rock, Greater Green River Basin and several other settings.
- Application of cavity completion technology in the coalbed methane "fairway" of the San Juan Basin.
- Application of horizontal well drilling, with stimulation in the core area of the Barnett Shale in the Fort Worth Basin.

## 10. Improving and Accelerating Gas Production With Other ("Breakthrough") Unconventional Gas Technologies

### Background and Problem

A variety of longer-term and advanced "breakthrough" technologies could further improve the performance of unconventional gas plays and wells. For example, laboratory tests demonstrate that injection of adsorbing gases such as $CO_2$ and $N_2$ into coal seams and other unconventional gas formations can improve and accelerate the desorption and production of natural gas. However, major questions remain as to how the injected gases will flow in the reservoir, how effectively these injected gases will contact and displace methane adsorbed on the coals, and how to cost-efficiently treat the produced methane/injected gas mixtures. All basins and gas plays are potentially candidates for breakthrough technologies.

### Technology Lever

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

### Foundation for Technology Lever

The foundation for the "Breakthrough Technologies" lever is expert judgment. It is assumed that, under an aggressive "Rapid Technology progress world," enhanced tight sands and coalbed methane technology, such as the injection of CO2, will lead to significantly improved recovery from unconventional gas reservoirs and wells.

## 11. Mitigating Environmental and Other Constraints on Development

### Background and Problem

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

### Technology Lever

Federal lands legislatively or administratively excluded from access are set as "off limits" for development. Less severe development 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

For those plays not included in basins recently studied under the Energy Policy and Conservation Act.

# Attachment A

## Case Studies of Technology Progress

1. *Tight Gas Sands*. Piceance Basin, Colorado
   Williams Fork/Mesaverde Formation

2. *Gas Shales*. Fort Worth Basin, North Texas
   Barnett Shale Formation

3. *Coalbed Methane*. Uinta Basin, Utah
   Ferron Coal Trend

# CASE STUDIES OF TECHNOLOGY PROGRESS

In support of our overall assessment of technology progress, we have assembled a series of "case studies." These case studies illustrate how technology, in aggregate, has changed the performance and costs of key unconventional gas plays.

The case studies of technology progress discussed in this report represent three major tight gas, gas shales and coalbed methane plays in the UGRSS data base.

- *Tight Gas Sands*. The recent development of the multi-Tcf size tight gas sands accumulation in southern Piceance Basin, Colorado, in the Williams Fork (Mesaverde) Formation.

- *Gas Shales*. The active development of an estimated (by Devon Energy, the field's operator) 10 to 20 Tcf of technically recoverable natural gas in the Barnett Shale of the Fort Worth Basin.

- *Coalbed Methane*. The development of coalbed methane in what has become Utah's largest natural gas and fastest growing natural gas play, the Ferron coals of the Uinta Basin.

Each of these case studies illustrates a different aspect of technology progress in unconventional natural gas exploration and development. And, each provides guidelines for establishing the technology levers to be used in UGRSS.

**CASE STUDY 1.**
**TIGHT GAS SANDS, PICEANCE BASIN, COLORADO**
**WILLIAMS FORK FORMATION/MESAVERDE**

**1. Background.** The Piceance Basin contains a thick package of vertically stacked, lenticular sands in the Williams Fork/Mesaverde Formation. These tight gas sands contain an impressive volume of gas in-place, estimated at 300+ Tcf (Johnson and Others, 1987; ARI, 1997). Until recently, these sands were thought to be low productivity, high cost resources.

Regional geologic studies by the petroleum industry and the U.S. Geological Survey and detailed reservoir characterization at the MWX/Rulison Field site were instrumental in changing the outlook. These studies demonstrated that the basin-center Williams Fork Formation is widely gas charged and can be successfully developed in areas where thick, stacked sands and natural fractures coexist. Over the last decade, and particularly within the past five years, the integrated application of new E&P technologies has turned this uneconomic tight gas resource into an active, profitable gas play. Today, these lenticular sands are the primary tight gas target in the Piceance Basin.

The improved economics, due mainly to higher reserves per well, are responsible for the Williams Fork/Mesaverde tight gas play in the southern Piceance Basin. During the 1980s, this gas play had only low productivity wells, mostly uphole completions or "bail-outs" of unproductive deeper targets. Today, over 1,200 wells have been drilled and produce nearly 300 MMcfd from these Williams Fork stacked lenticular tight gas sands. Four fields account for the great bulk of activity, Figure 3C-2:

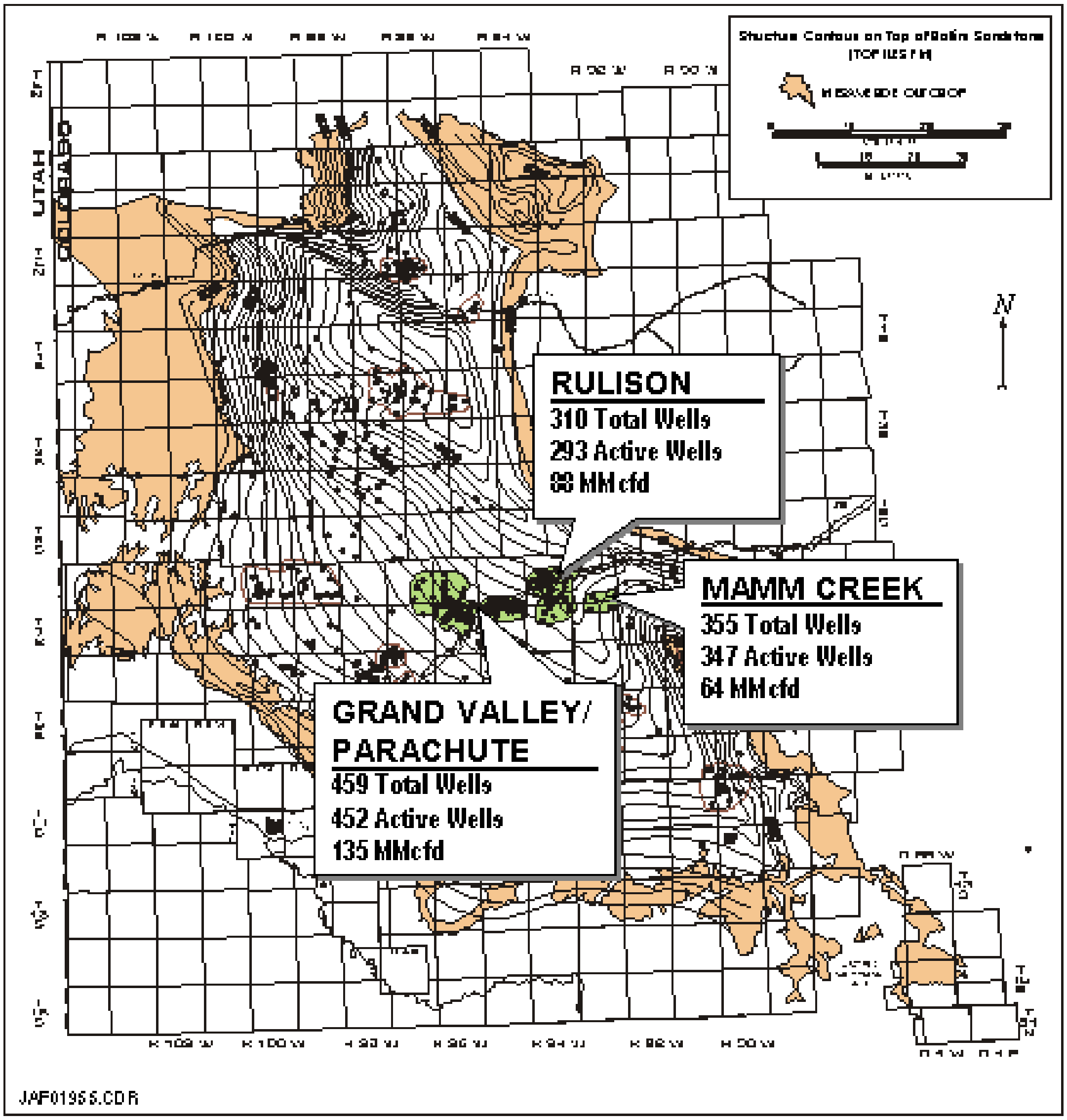
- Rulison Field, with 293 active (310 total) wells and producing 88 MMcfd, leads the way.
- Grand Valley Field, with 327 active (334 total) wells and producing 87 MMcfd, has been the most active field in this gas play.
- Parachute Field, with 125 active (and total) wells and producing 48 MMcfd, establishes this gas play on the west.
- Mamm Creek Field, with 347 active (355 total) wells and producing 64 MMcfd, establishes this gas play on the east.

Most likely this tight gas sands development area will continue to grow, as the ultimate boundaries and remaining "sweet spots" of the Williams Fork tight sands are yet to be defined.

**2. Natural Gas Development**. The Juhan #1 Rulison discovery well, drilled in the late 1950s (Sec. 26, T6S R94W), had strong initial gas flows, giving expectations that the Williams Fork would become a new, economically attractive natural gas play. When subsequent wells proved to be much less productive, with reserves of 0.2 to 0.5 Bcf per well, the play was abandoned in search of deeper Mesaverde Group sands.

The redevelopment of the Williams Fork/Mesaverde began in the 1990s and has continued strong through today. Currently, 1,092 active wells produce 288 MMcfd, with 216 of these wells brought on production in 2002 and early 2003. To date, the Williams Fork has produced over 500 Bcf, from the Rulison, Grand Valley/Parachute, and Mamm Creek fields and is headed toward a multi-Tcf natural gas play. Table 3C-17 provides a summary of the development status and historical well performance for the four major Williams Fork Formation gas fields of the Piceance Basin, as of mid-2003.

**Figure 3C-2. Major Williams Fork Formation Natural Gas Field Locations, Southern Piceance Basin.**




Source: Advanced Resources, International

**Table 3C-17**

**Gas Development and Well Performance**
**Williams Fork Formation Gas Fields, Piceance Basin**

| Field | Total Wells | Active Wells | New Wells (2002-2003) | Gas Recovery | | Well Performance | |
|---|---|---|---|---|---|---|---|
| | | | | Cumulative (Bcf) | Estimated Ultimate (Bcf) | Cumulative/ Well (Bcf) | EUR/ Well (Bcf) |
| **Rulison** | 310 | 293 | 56 | 186 | 450 | 0.62 | 1.48 |
| **Grand Valley** | 334 | 327 | 66 | 160 | 410 | 0.48 | 1.25 |
| **Parachute** | 125 | 125 | 58 | 54 | 300 | 0.43 | 1.55 |
| **Mamm Creek** | 355 | 347 | 36 | 111 | 190 | 0.32 | 0.86 |
| **Total** | 1,124 | 1,092 | 216 | 511 | 1,350 | | |

**3. Technology Progress Levers.**

***a. Gas Recovery Per Well.*** The single most important technology progress measure for tight gas sands is improvement in gas recovery per well. Application of advanced well logging practices, lower damaging well completion methods, and higher efficiency hydraulic fracturing technology have led to progressive improvements in well performance for the Williams Fork tight gas sand fields in the southern portion of the Piceance Basin, measured in terms of estimated ultimate recovery (EUR) per well.

The well performance in these fields is shown in Table 3C-18 below for four key time periods, starting with the initial group of wells drilled before active development of these fields began in the mid-1990s.

**Table 3C-18**

**Well Performance and Technology Progress**
**Williams Fork Formation Gas Fields, Piceance Basin**.

| Time Period | Number of Successful Wells | EUR/Successful Well (Bcf) | |
|---|---|---|---|
| | | Mean | F50 |
| **Pre-1995** | 181 | 0.79 | 0.55 |
| **1995-1998** | 270 | 0.98 | 0.9 |
| **1999-2001** | 428 | 1.12 | 1.07 |
| **1/2002-6/2002** | 103 | 1.98 | 1.9 |
| **Recent** | 113 | n/a | n/a |
| **TOTAL** | 1,095 | | |

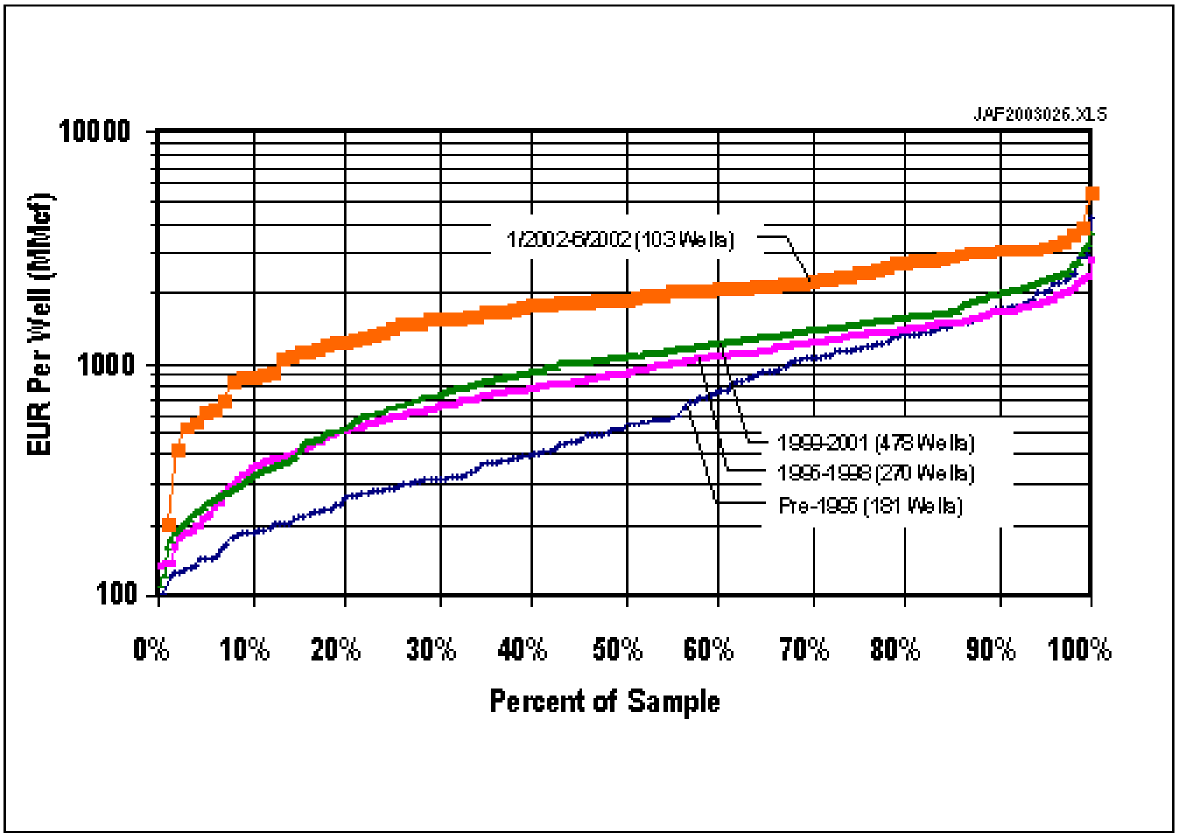
Source: Advanced Resources, International

Figure 3C-3 provides the distribution in well performance for the same four time periods, including the active well drilling during the first half of year 2002. As additional production data are obtained on the more recently drilled 113 wells, these wells will be added to the year 2002 performance time period.

The analysis of changes in well performance, due to improved knowledge and technology, shows that the mean EUR per well has improved steadily from 0.79 Bcf for the pre-1995 wells to 1.98 Bcf for the year 2002 wells. (The F50 (median) well performance value shows even greater, three-fold improvement in well performance between the initial group of pre-1995 wells and the year 2002 wells.)

***b. Dry Holes.*** While dry holes, particularly "economic dry holes" (wells with ultimate gas recovery of less than 0.1 Bcf) are not a major consideration in this tight gas play, the data show a steady improvement in this technology progress factor, as shown in Table 3C-19.

**Figure 3C-3. Well Performance and Technology Progress, Williams Fork Fomation Gas Fields, Piceance Basin.**




Source: Advanced Resources, International

**Table 3C-19**

**Dry Hole Rate and Technology Progress**
**Williams Fork Formation Gas Fields, Piceance Basin**

| Time Period | Total Wells | Successful Wells | Dry Wells | % Successful |
|---|---|---|---|---|
| **Pre-1995** | 199 | 181 | 17 | 91% |
| **1995-1998** | 279 | 270 | 9 | 97% |
| **1999-2001** | 430 | 428 | 2 | 99% |
| **1/2002-6/2002** | 103 | 103 | - | 100% |
| **Recent** | 113 | 113 | - | N/a |
| **TOTAL** | 1,124 | 1,095 | 28 | |

Source: Advanced Resources, International

The analysis of the change in dry hole rates, due to improved knowledge and technology, shows that the dry hole rate has steadily declined from 9% for the pre-1995 wells to essentially zero for wells drilled since 1998.

***c. Recompletion-Based Reserve Growth.*** An aggressive program of well recompletions and completion of behind-pipe formations has enabled these four fields to add 84 Bcf of reserve growth-based reserves, as shown in Table 3C-20.

**Table 3C-20**

**Reserve Growth and Technology Progress**
**Williams Fork Formation Gas Fields, Piceance Basin**

| Time Period | Total Wells | Successful Wells |
|---|---|---|
| **Pre-1995** | 93 | 72 |
| **1995-1998** | 20 | 12 |
| **1999-2001** | - | - |

Source: Advanced Resources, International

The recompletion program has added approximately 10% to the original proved reserves in these four tight gas fields but, more importantly, has significantly improved the performance of wells that were considered marginal or uneconomic based on their original completion.

***d. Natural Fracture Prediction***. A major natural fracture prediction R&D project was conducted in the Williams Fork tight sands of the Rulison Field. The project, using a combination of 3-D seismic, coherency mapping and a geomechanical stress model, identified a natural fracture cluster area (a permeability "sweet spot") that covers three sections in the southern portion of the Rulison Field (Figure 3C-4).

Wells drilled in this "sweet spot" area of the southern Rulison Field have reserves two or more times higher than reserves for wells drilled outside this area, giving confidence that "tight gas sand selectivity technology" could be developed and applied to future tight sand exploration and production.

***e. Field Development and Well Spacing***. An active program of intensive infill development is underway in the Williams Fork tight gas sands of the Rulison Field. In Section 20 (T6S, R94W) of this field, the operator has initiated a 20 acre per well (32 wells per section) field development and well spacing pilot (Figure 3C-5). Subsequently, the field operator has applied for and has begun an even more intensive development, adding additional wells, further reducing the spacing to 16 acres per well, on the way to a 10 acre per well test. The results of this pilot have been encouraging and indicate steadily increasing natural gas recoveries from this infill program, Table 3C-21 below:

**Table 3C-21**

**Intensive Field Development and Technology Progress**
**Williams Fork Formation. (Sec. 20, T6S, 94W, Rulison)**

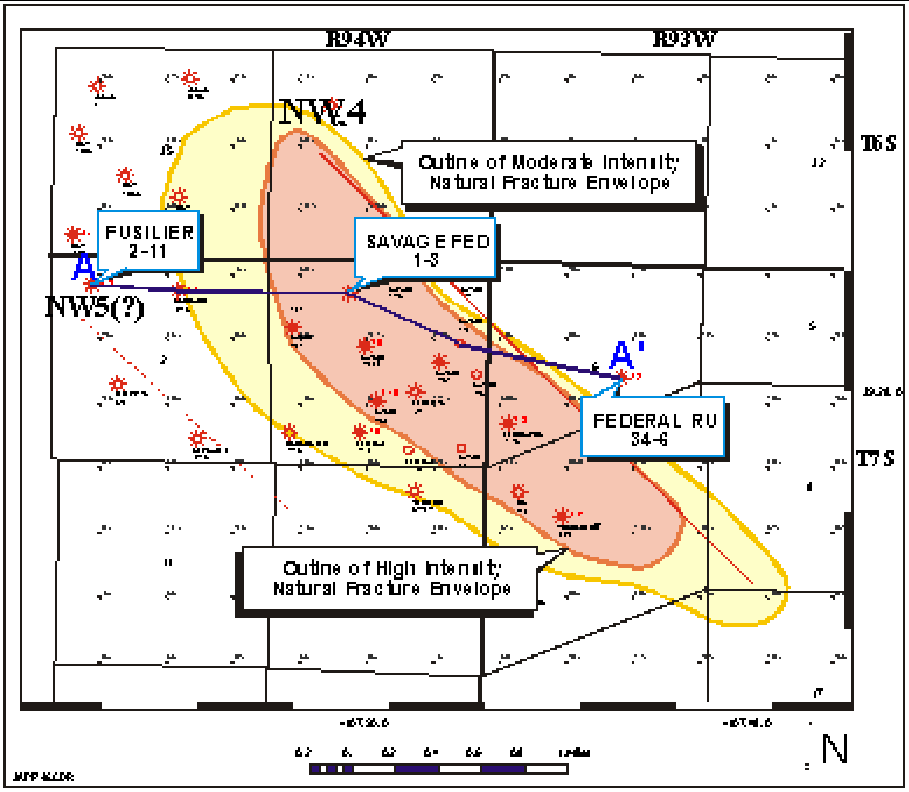
| Date | Wells and Spacing | Reserves/Well* (Bcf) | Total Reserves (Bcf) |
|---|---|---|---|
| **Initial** | First 2 wells @320A/W** | 2.1 | 4 |
| **1994** | Next 2 wells @160 A/W | 2.2 | 4 |
| **1995** | Next 4 wells @80 A/W | 1.9 | 8 |
| **1996-1997** | Next 6 wells @40 A/W | 1.7 | 10 |
| **1997-2000** | Next 16 @20A/W | 1.7 | 28 |
| **2001-2002** | Next 10 wells (@ 16 A/W) | 2 | 20 |
| **TOTAL (40 wells)** | | 1.85 | 74 |

* Estimated Based on History Matching With ARI-Tight Type Curve Model.
** After subsequent well recompletions.

Source: Advanced Resources, International

**4. Summary**. The cumulative effects of the technology progress actions discussed in this case study, have greatly improved the economic potential of the Williams Fork Formation tight gas field at Rulison and similar tight gas fields in the southern Piceance Basin. In addition, as is being demonstrated in the Rulison Field, the combined application of improved technology and intensive resource development has the potential to convert a modest and marginal gas 90 Bcf prospect into a major multi-Tcf natural gas field, as shown in Table 3C-22.

**Figure 3C-4. Geomechanics and 3-D Seismic Based Technology Progress, Williams Fork Formation**

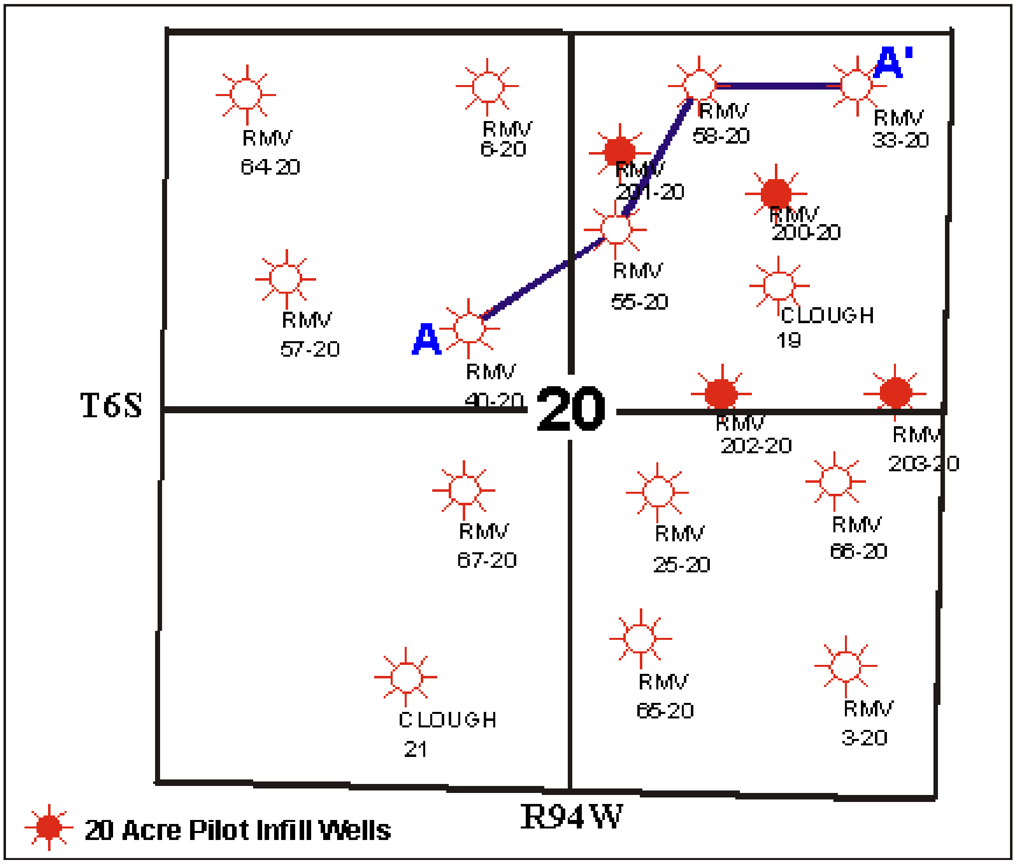



**Results of Geomechanics/3-D Seismic Technology Test**

| Natural Fracture Cluster Area | Cum. Recovery (Bcf) | Est. Ult. Recovery (Bcf) |
|---|---|---|
| Inside Envelope (12 wells) | | 2.5 Bcf/Well |
| • Savage Fed 1-3 | 2.0 | 2.8 |
| Outside Envelope (23 wells) | | 1.2 Bcf/Well |
| • Fed. RU 34-6 | 0.2 | 0.3 |
| • Fusiler 2-11 | 0.8 | 1.5 |

Source: Advanced Resources, International

**Figure 3C-5. Location of Intensive Field Development Pilot, Section 20 Rulison Field.**




Source: Advanced Resources, International

**Table 3C-22**

**Impact of Technology Progress and Intensive Resource Development, Rulison Field, Piceance Basin.**

| Field Development Options | Well Spacing (A/W) | No. of Locations* | Success Rate (%) | Reserves/ Well (Bcf) | Reserves/ Section (Bcf) | Potential Field Size (Bcf) |
|---|---|---|---|---|---|---|
| **Historical Practices** | 160 | 120 | 91 | 0.79 | 3 | 90 |
| **Advanced Strategy** | 16 | 1,200 | 99 | 1.85 | 74 | 2,200 |

*Assuming 30 square mile productive field area.

Source: Advanced Resources, International

## CASE STUDY 2.
## GAS SHALES, FORT WORTH BASIN, NORTH TEXAS
## BARNETT SHALE FORMATION

**1. Background.** The Fort Worth Basin holds the Mississippian-age Barnett Shale, an organically rich, low-permeability unconventional gas accumulation (Figure 3C-6). These gas shales are estimated to hold 120 Tcf of gas in-place, based on recent estimates prepared by Devon Energy (Petroleum News, May 2003).

In the early 1990s, the Gas Research Institute supported a series of reservoir characterization and engineering studies that contributed significantly to the improved understanding the gas storage mechanisms and gas production for this new gas play. Resource assessments by the USGS (USGS, 1995) and a subsequent USGS open-file study (Schmoker, 1996) provided the initial information on the resource potential of the Barnett Shale gas accumulation, estimating its technically recoverable resource potential at a modest 1 to 3 Tcf. A subsequent combined Advanced Resources and USGS joint study, published in the Oil and Gas Journal (Kuuskraa, 1998), updated the well performance and understanding of the actual drainage being achieved by wells in this gas play. The study set forth that the Barnett Shale might hold 10 Tcf of technically recoverable natural gas, greatly raising the visibility of this potential gas resource.

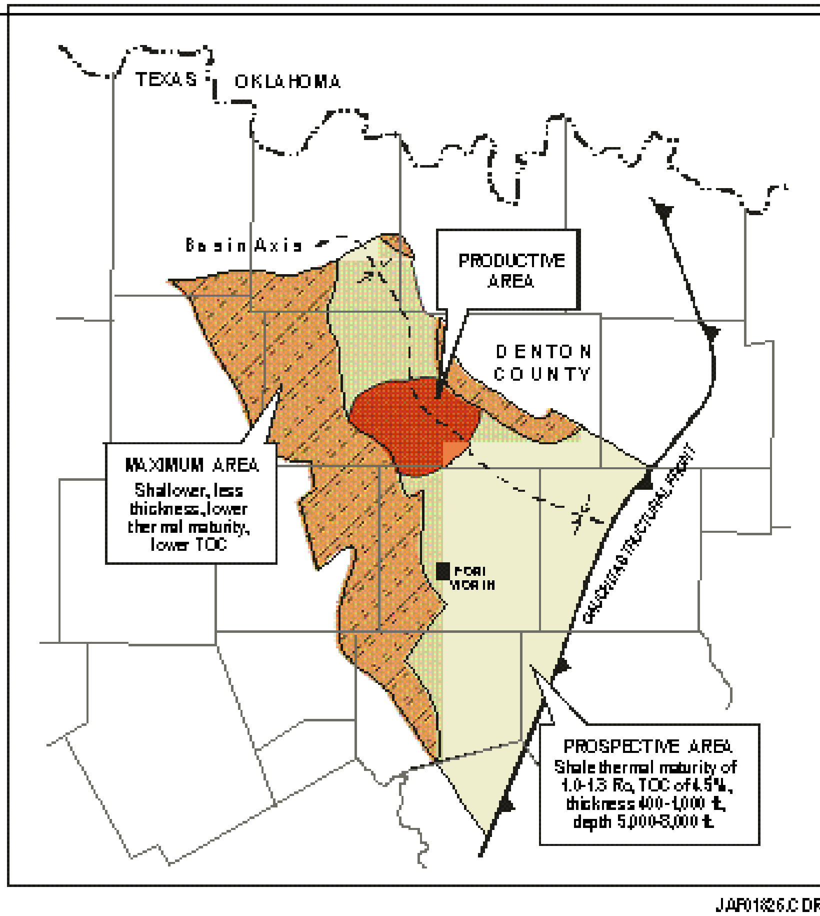
Today, Devon Energy, the Barnett shale's dominant producer with 10 times more production than any other operator, estimates that:

- Potentially 10 Tcf, or 8% of the estimated 120 Tcf of gas in-place, can be recovered using current technologies; and,
- Another 10 to 12 Tcf, or 8% to 10% of the gas in-place, may be recoverable with advanced technology, particularly with the use of horizontal, fraced wells.

**2. Natural Gas Development**. The development of the Barnett Shale began in the mid-1980s in the Newark East Field currently the primary natural gas field in the Barnett Shale gas play. Development progressed slowly as the early wells had low reserves, with an occasional high productivity well.

With steadily improving results based on using "light sand fracs" and completing a larger shale interval, starting in the mid-1990s, drilling in the Barnett shale accelerated. Today, nearly 1,800 wells have been drilled into the Barnett Shale, with gas production reaching 550 MMcfd. To date, the Barnett shale has produced a cumulative of over 600 Bcf. Table 3C-23 below provides a summary of Barnett Shale natural gas production and development through the end of 2002.

**Figure 3C-6. Barnett Shale Development Area, Fort Worth Basin, North Texas.**




<u>Productive Area</u>. **Area of existing production: 500 mi$^2$**

<u>Prospective Area</u>. **Along strike of existing production and updip to -2,000 m Ellenburger structural contour (high thermal maturity): 2,500 mi$^2$**

<u>Maximum Area</u>. **Updip to -1,600 m Ellenburger structural contour (lower thermal maturity): 4,200 mi$^2$**

Source: Advanced Resources, International

**Table 3C-23**

**Growth in Barnett Shale Production and Wells**

| Time Period | Annual Production (Bcf) | Cumulative Production (Bcf) | End of Year Producing Wells |
|---|---|---|---|
| 1990 | 3 | 12 | 66 |
| 1995 | 20 | 70 | 242 |
| 1999 | 40 | 198 | 517 |
| 2000 | 78 | 276 | 698 |
| 2001 | 131 | 407 | 1,171 |
| 2002 | 202 | 609 | 1,771 |

Source: Advanced Resources, International

**3. Technology Progress Levers**

***a. Gas Recovery Per Well***. Gas recovery per well has steadily improved as operators have changed their well completion practices by completing a larger portion of the shale interval (adding the Upper Barnett zone to the Lower Barnett zone), by introducing more effective (and lower cost) "light sand frac" technology, and by refracing previously completed wells.

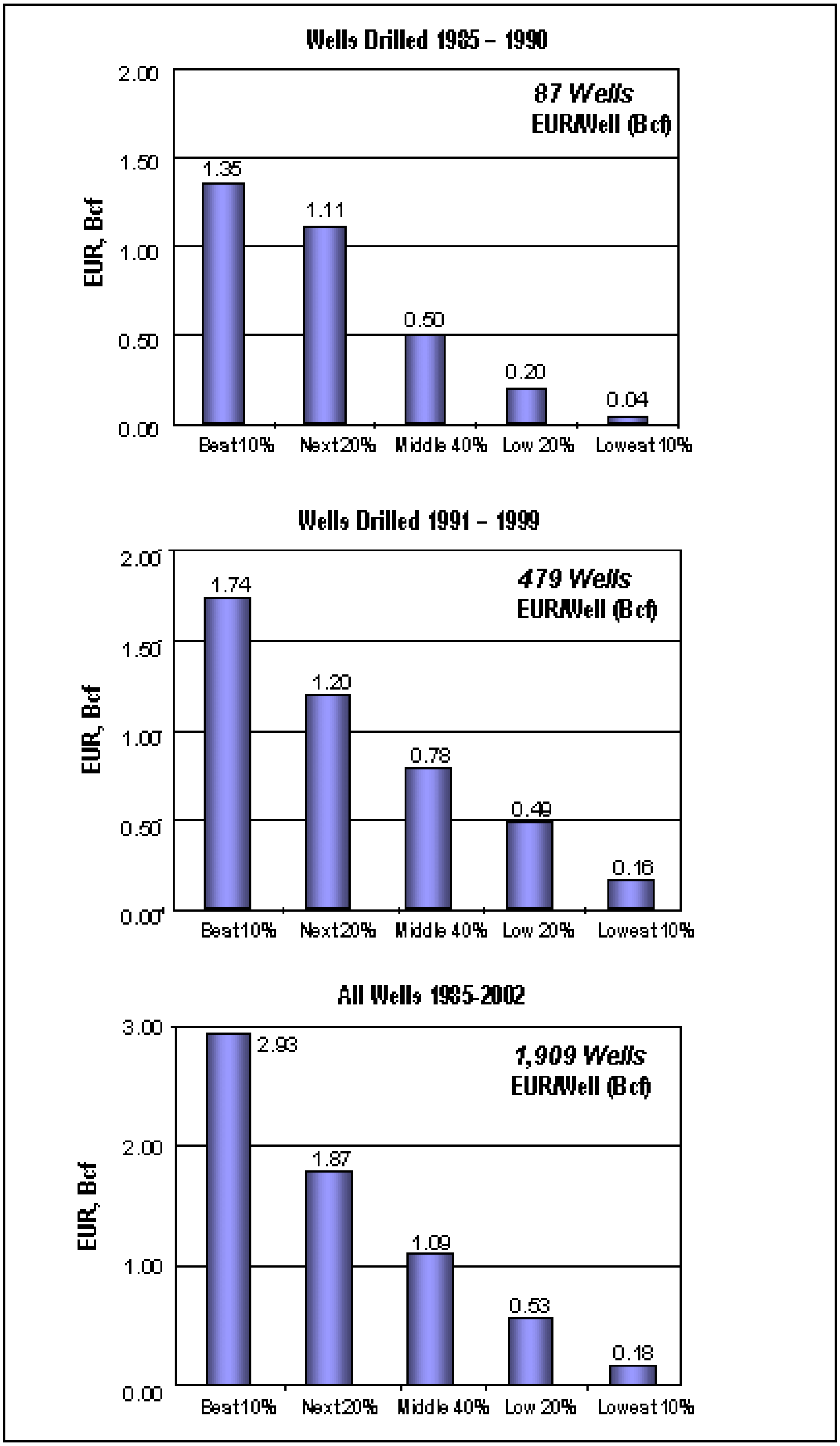
The combined application of these technologies have enabled well performance, the key technology progress parameter, to steadily improve with time, as set forth in Table 3C-24 below.

**Table 3C-24**

**Well Performance and Technology Progress**
**Barnett Shale, Fort Worth Basin.**

| Time Period | Average EUR/Well (Bcf) |
|---|---|
| • Initial Wells (74 wells, 1985-1989) | 0.35 |
| • Subsequent Wells (180 wells, 1985-1995) | 0.86 |
| • All Wells (1,909 wells, 1985-2002) | 1.23 |

Source: Advanced Resources, International




Source: Advanced Resources, International

**Figure 3C-7. Gas Recovery Per Well and Technology Progress, Barnett Shale, Fort Worth Basin.**

Using a separate data set of wells, Figure 3C-7 shows that the well performance for the middle 40% of the wells has increased from 0.5 Bcf for the 87 producing wells drilled through 1990 to 1.1 Bcf for all 1,909 producing drilled through 2002.

***b. Success Rate***. The success rate, another important technology progress parameter, has improved from 86% (150/180) for the initial 180 wells drilled through 1996 to 96% (1,909/1985) for all Barnett shale wells drilled to date.

***c. Recompletion Based Reserve Growth***. Considerable recompletion and refracturing has taken and is taking place in the Barnett Shale, particularly for the older wells. Table 3C-25, that provides the original and the latest distribution of well performance for the 87 wells drilled between 1985 and 1990, shows that application of this technology has improved performance for the middle 40% of these wells from 0.50 Bcf/well, as originally completed, to 1.44 Bcf/well after recompletion and refracturing.

**Table 3C-25**

**Well Recompletion Based Reserve Growth and Technology Progress, Barnett Shale, Fort Worth Basin**.

| Distribution | As Originally Completed (First 87 Wells Drilled 1985-1990) EUR/Well | After Recompletion (First 87 Wells Drilled 1985-1990) EUR/Well |
|---|---|---|
| **Top 10%** | 1.35 | 3.50 |
| **20%** | 1.11 | 2.41 |
| **Middle 40%** | 0.50 | 1.44 |
| **20%** | 0.20 | 0.54 |
| **Bottom 10%** | 0.04 | 0.04 |

Source: Advanced Resources, International

***d. General Resource Growth***. The estimated ultimate size of the Barnett Shale gas resource has steadily increased, as the understanding of this gas play has grown, as well performance has improved, and as the field has been more intensely developed, on smaller well spacings. Table 3C-26 shows the steady progress in the estimated technically recoverable resource for the Barnett Shale, from 1.4 Tcf in 1990, to 3.4 Tcf in 1996, and to 10 Tcf in 1998.

Recently, based on still additional improvements in well performance (as discussed above), even more intensive development (well spacing of 27 acres per well), and expansion in the defined areal extent of the productive area, this gas play's primary operator, Devon Energy, places the technically recoverable potential of the Barnett Shale at 20 Tcf.

**Table 3C-26**

**Increase in Resource Size/Productivity and Technology Progress, Barnett Shale, Fort Worth Basin**

| Time Period | Initial* Assessment, 1990 | USGS Special* Assessment, 1996 | Latest Assessment, 1998** |
|---|---|---|---|
| **Development Intensity (Acres/Well)** | 320 | 320 | 80 to 320 |
| **Completed Wells** | | | |
| **Productive** | 74 | 180 | 300 |
| **Unproductive** | 12 | 30 | 50 |
| **Play Area, Square Miles** | 2,439 | 2,439 | 2,439 |
| **Future Wells** | 4,792 | 4,668 | 10,148 |
| **Success Rate** | 0.86 | 0.86 | 0.86 |
| **EUR/Well (Bcf)** | 0.35 | 0.84 | 0.35 to 1.50 |
| **Technically Recoverable Resources (Tcf)** | 1.4 | 3.4 | 10 |

*Source: USGS (1990, 1996)
**Source: Advanced Resources, International/USGS, 1998

***e. Lower Well Costs***. Improved drilling and completion practices and substitution of new "light sand frac" technology for previous high cost gelled fluids and large volume sand treatments, steadily reduced overall well drilling and completion costs even as a large shale interval is being completed. Increasing rig day rates drove well drilling and completion costs back up in 2001 to nearly $900,000 per well. Since then improvements in rig efficiency and lower infrastructure costs for infill wells are, once again, enabling drilling and completion costs to decline to a projected $750,000 per well, Figure 3C-8.

***f. Horizontal Wells***. Horizontal well technology is starting to be applied in the Barnett Shale. While it is still too early to conclusively establish its performance, early indications based on gas flow rates are encouraging. The horizontal wells drilled to date have initial flow rates two to four times of a vertical well with well drilling and completion costs about two times a vertical well.

Devon has announced that it would drill 50 horizontal wells into the Barnett Shale in 2003, with seven horizontal wells already on line, producing an aggregate 15 MMcfd. Approximately half of the new horizontal wells would be drilled in Devon's core area at Newark East field, in Wise and Denton Counties of North Texas, the dominant Barnett Shale gas field. The remainder of the horizontal wells would be used to establish the viability of the relatively unexplored areas outside the core areas.

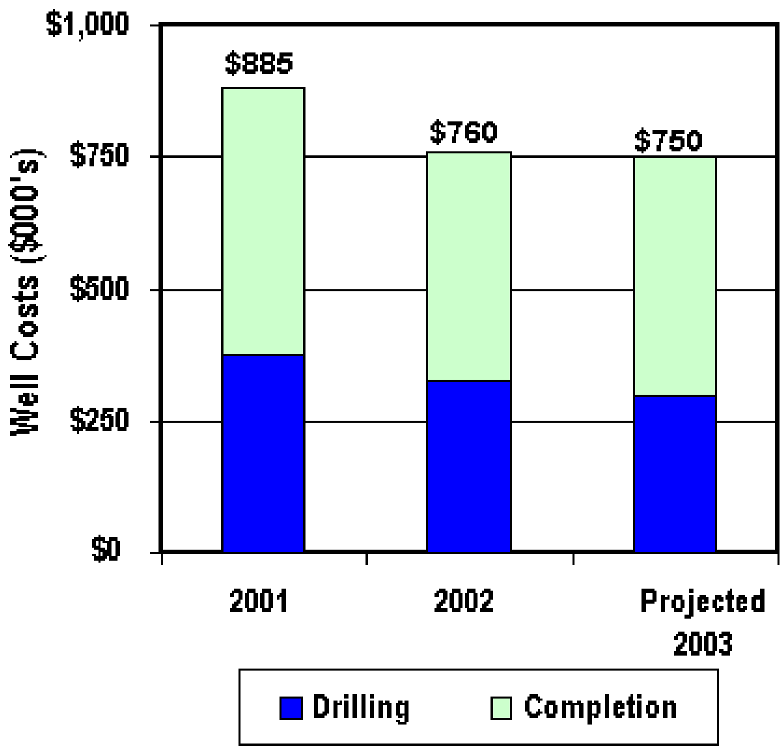
**4. SUMMARY.** The overall progress in Barnett Shale development technology, including improved well performance, lower costs and intense resource development, is summarized in Table 3C-27.

- Finding and development (F&D) costs, the overall well critical technology progress measure, has declined for the Barnett Shale by three fold, from a range of $1.50 to $2.00 per Mcf for the initial wells (drilled in the late 1980s) to about $0.75 per Mcf for wells drilled in 2001 and 2002. Further reductions in F&D costs are projected, by the field's operator, for 2003.

- Reserves per well have steadily increased from about 0.5 Bcf per well for the initial wells to 1.2 Bcf per well for recent wells. Assuming continued improvements in completion technology the average recovery per well could reach 2 Bcf over the full impact of the refrac program is realized in both previously drilled and newly drilled wells.

- Improvements in rig efficiencies and use of lower cost, more effective fracturing technology are helping counter increased rig day rates, helping to hold down overall well D&C costs.

**Figure 3C-8. Drilling Costs and Technology Progress, Barnett Shale, Fort Worth Basin.**




- Improved rig efficiency (2 wells/rig/month)
- Core area wells have lower costs due to existing infrastructure
- Results in 15% savings or $135,000/well

Source: Advanced Resources, International

**Table 3C-27**

**Impact of Technology Progress and Improved Well Drilling and Completions, Newark East Field, Fort Worth Basin.**

| Time Period | Pre-1991 | 1991-95 | 1996-2000 | 2001-02 | 2003 |
|---|---|---|---|---|---|
| **No. Producing Wells** | 66 | 176 | 456 | 1,073 | n/a |
| **Well Spacing** | 320 acres | 160-320 acres | 55-110 acres | 27-55 acres | 27 acres |
| **Completion Interval** | L. Barnett | L. Barnett | U./L. Barnett | U./L. Barnett | U/L Barnett |
| **Progress in Drilling and Completion Technology** | Variety of Completion Practices | MHF Technology | Introduction of Waterfrac Technology | Widespread Use of Waterfracs | Improved Rig Efficiencies |
| **Typical Well Cost** | $600-$1,000K | $600-$850K | $500-$750K | $750-$900K | $700-$800K(e) |
| **Typical Well EUR** | 0.4-0.5 Bcf | 0.8 Bcf | 1.0 Bcf | 1.0-1.2 Bcf | 1.25 Bcf |
| **F&D Costs** | $1.50-$2.00 | $0.75-$1.10 | $0.50-$0.75 | $0.75 | $0.60(e) |

Source: Advanced Resources, International

**CASE STUDY 3.**
**COALBED METHANE, UINTA BASIN, UTAH**
**FERRON COAL TREND**

**1. Background**. The Uinta Basin contains a thick section of Upper Cretaceous coals within the Ferron Sandstone Member of the Mancos Shale (Figure 3C-9). These coals have been estimated to contain on the order of 10 Tcf of gas in-place (Advanced Resources, 1996). Prior to 1990, these coals were bypassed in search of deeper conventional sandstone reservoirs.

Early resource characterization studies (sponsored by the Gas Research Institute) began to provide some of the basic reservoir data for this new gas play, such as gas content, coal depth and coal thickness. These studies and core data showed that the gas content of the coals decreased dramatically from north to south, independent of the rank and maturity of the coals. Regional mapping also indicated that the productive areas are associated with the updip stratigraphic pinchouts where the tight marine shales provide a seal enabling the coals to become "supercharged" with biogenic and migrated thermogenic gas from the southern basin margin.

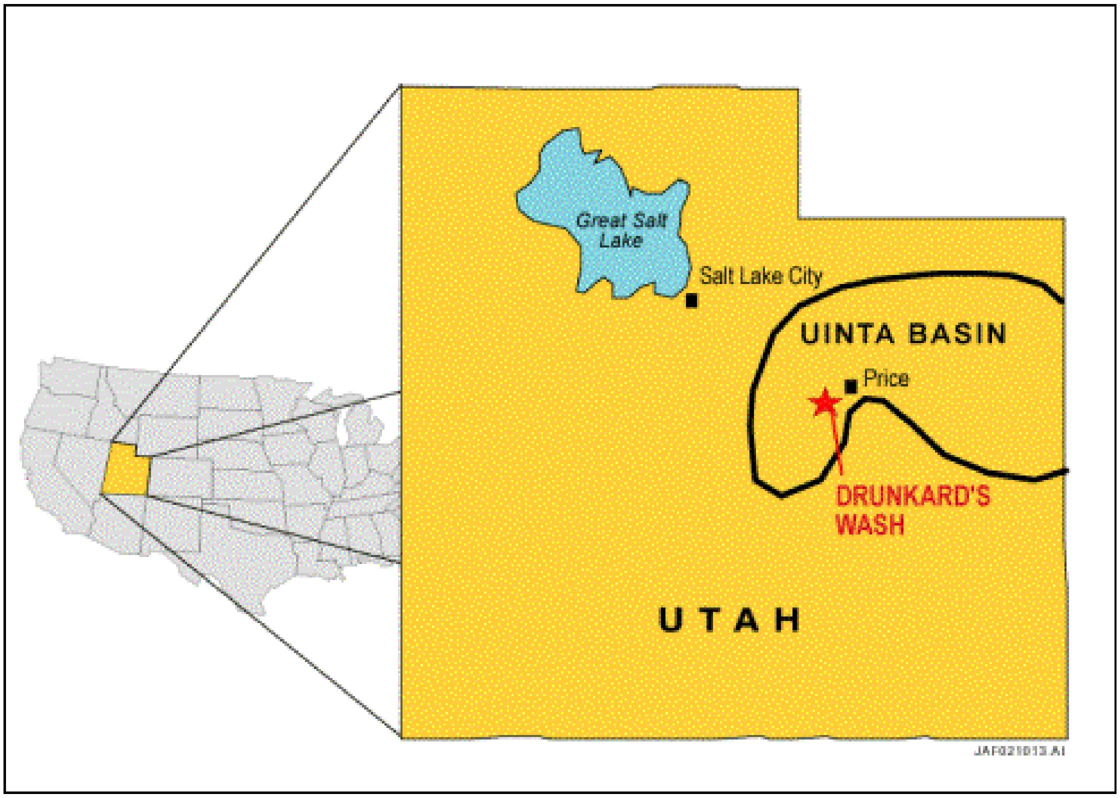
Improved understanding of this gas play, including advanced well completion technology has led to steadily increasing reserves per well from the coalbed methane play in this basin. Today, over 600 well have been drilled and produce 250 MMcfd from the Ferron coalbed methane trend. The Drunkards Wash Field, in the northern portion of the Ferron Coal Trend accounts for the great bulk of the wells and gas production (Figure 3C-10).

**2. Natural Gas Development**. The Ferron coalbed methane play was discovered in 1988 by Texaco E&P, Inc. at the northern end of the Ferron Trend, near Price. After several years of inactivity, Texaco and others began active exploration in the mid-1990s.

To date the Ferron CBM play has produced a cumulative of 400 Bcf, and has proved reserves of 1,700 Bcf, making this a multi-Tcf giant natural gas play, primarily from Drunkards Wash, Helper and Buzzards Bench fields.

***a. Ability to Identify Higher Productivity Well Performance Areas.*** Table 3C-28 provides a summary of the well drilling and well performance for the Drunkards Wash CBM field as of the end of 2002.

**Figure 3C-9. Drunkard's Wash Ferron Coalbed Methane Field, East-Central Utah**




Source: Advanced Resources, International

**Table 3C-28**

**Well Performance Selectivity and Technology Progress**
**Drunkard's Wash CBM Field, Uinta Basin.**

| Time Period | Number of Successful Wells | EUR/Successful Well (Bcf) Mean |
|---|---|---|
| **Pre-1995** | 78 | 3.4 |
| **1995-1998** | 103 | 2.7 |
| **1999-2000** | 149 | 2.0 |
| **2001** | 78 | 1.7 |
| **TOTAL** | 407 | |

Source: Advanced Resources, International

Looking at the history of well performance, where the more recent wells have lower EUR's than the marginal wells.

Table 3C-29 provides a perspective on this question and shows that the initial wells have, in general, been able to target the better 60% of the field placing 72% (293 of the 407) wells drilled to date in this portion of the field.

The analysis of well performance shows that the companies have been able to target the initial wells on the higher productivity, 3.4 Bcf/well area and now are steadily moving development toward the lower productivity, lower coal thickness portions of this gas play.

***b. Dry Holes.*** While dry holes, particularly "economic dry holes" (wells with ultimate gas recovery of less than 0.1 Bcf) are not a major consideration in this CBM play, the data show little change in this technology performance factor (Table 3C-30). The dry hole rate has remained at 97% to 100% essentially the same over time, for wells drilled in this play.

**Table 3C-29**

**Selectivity and Technology Progress, Drunkards Wash Coalbed Methane Field, Uinta Basin.**

| Well Distribution | Expected Well Selection Distribution | | | Actual Well Selection Distribution | | | | |
|---|---|---|---|---|---|---|---|---|
| | Avg. Well (Bcf) | Range (Bcf) | No. Wells | Pre-1995 | 1995-1998 | 1999-2000 | 2001 | TOTAL |
| **Top 10%** | 6 | >5 | 200 | 14 | 12 | 8 | 2 | 36 |
| **Next 20%** | 4 | 3-5 | 400 | 26 | 25 | 24 | 15 | 90 |
| **Middle 30%** | 2 | 1-3 | 600 | 28 | 43 | 71 | 25 | 167 |
| **Lowest 40%** | 0.5 | 0.1-1 | 800 | 10 | 22 | 46 | 36 | 114 |
| **No. of Wells** | | | 2,000 | 78 | 103 | 149 | 78 | 407 |
| **Average Well (Bcf)** | 2.0 | | | 3.4 | 2.7 | 2.0 | 1.7 | 2.4 |

**Source: Advanced Resources, International**

**Table 3C-30**

**Dry Hole Rate and Technology Progress Ferron Coal Trend, Uinta Basin**

| Time Period | Total Wells | Successful Wells | Dry Holes | % Successful |
|---|---|---|---|---|
| **Pre-1995** | 84 | 84 | 0 | 100% |
| **1995-1998** | 136 | 132 | 4 | 97% |
| **1999-2000** | 194 | 189 | 5 | 97% |
| **2001** | 107 | 107 | - | 100% |
| **Recent** | 18 | 18 | - | N/a |
| **TOTAL** | 539 | 530 | 9 | |

Source: Advanced Resources, International

**4. Summary.** The case study of the coalbed methane development in the Ferron Coal Trend helped establish the well productivities, dry hole rates and resource size for this important new natural gas play. It also demonstrates that for coalbed methane plays, where coal thickness and gas content are readily measured and can be regionally mapped, producers will have the ability to "high grade" their early development to pursue areas with higher potential for CBM development. This provides guidance on how to allocate and forecast the initial field development practices and expectations for well performance in coalbed methane.

# Appendix 3-D. Offshore Oil and Gas Supply Submodule

# Introduction

The Offshore Oil and Gas Supply Submodule (OOGSS) uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields is based on the Minerals Management Service's 2006 hydrocarbon resource assessment.[1]

- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.

- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas by 2007. The production volumes are from the Minerals Management Service database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters. The crosswalk between region and evaluation unit is shown in Table 3D-1.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and Gulf of Mexico. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

# Undiscovered Fields Component

Significant undiscovered oil and gas resources are estimated to exist in the Outer Continental Shelf, particularly in the Gulf of Mexico. Exploration and development of these resources is determined in this component of the OOGSS.

Within each evaluation unit, a field size distribution is assumed based on MMS's latest[1] resource assessment (Table 3D-2). The volume of resource in barrels of oil equivalence by field size class as defined by the MMS is shown in Table 3D-3. In the OOGSS, the mean estimate represents the size of each field in the field size class. Water depth and field size class are used for specifying many of the technology assumptions in the OOGSS. The total number of undiscovered fields as of August 31, 2006 in the OOGSS is 3,367. Fields smaller than field size class 2 are assumed to be uneconomic to develop. Resources in the Pacific, Atlantic, and Eastern GOM are not under drilling moratoria and are available for exploration and development—Pacific and Atlantic in 2010 and Eastern GOM in 2022.

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[1]U.S. Department of Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S.OCS Oil and Natural Gas Resources*, February 2006.

**Table 3D-1. Offshore Region and Evaluation Unit Crosswalk**

| No. | Region Name | Planning Area | Water Depth (meters) | Drilling Depth (feet) | Evaluation Unit Name | Region ID |
|---|---|---|---|---|---|---|
| 1 | Shallow GOM | Western GOM | 0 - 200 | < 15,000 | WGOM0002 | 3 |
| 2 | Shallow GOM | Western GOM | 0 - 200 | > 15,000 | WGOMDG02 | 3 |
| 3 | Deep GOM | Western GOM | 201 - 400 | All | WGOM0204 | 4 |
| 4 | Deep GOM | Western GOM | 401 - 800 | All | WGOM0408 | 4 |
| 5 | Deep GOM | Western GOM | 801 - 1,600 | All | WGOM0816 | 4 |
| 6 | Deep GOM | Western GOM | 1,601 - 2,400 | All | WGOM1624 | 4 |
| 7 | Deep GOM | Western GOM | > 2,400 | All | WGOM2400 | 4 |
| 8 | Shallow GOM | Central GOM | 0 - 200 | < 15,000 | CGOM0002 | 3 |
| 9 | Shallow GOM | Central GOM | 0 - 200 | > 15,000 | CGOMDG02 | 3 |
| 10 | Deep GOM | Central GOM | 201 - 400 | All | CGOM0204 | 4 |
| 11 | Deep GOM | Central GOM | 401 - 800 | All | CGOM0408 | 4 |
| 12 | Deep GOM | Central GOM | 801 - 1,600 | All | CGOM0816 | 4 |
| 13 | Deep GOM | Central GOM | 1,601 – 2,400 | All | CGOM1624 | 4 |
| 14 | Deep GOM | Central GOM | > 2,400 | All | CGOM2400 | 4 |
| 15 | Shallow GOM | Eastern GOM | 0 - 200 | All | EGOM0002 | 3 |
| 16 | Deep GOM | Eastern GOM | 201 - 400 | All | EGOM0204 | 4 |
| 17 | Deep GOM | Central GOM | 401 - 800 | All | EGOM0408 | 4 |
| 18 | Deep GOM | Eastern GOM | 801 - 1600 | All | EGOM0816 | 4 |
| 19 | Deep GOM | Eastern GOM | 1601 - 2400 | All | EGOM1624 | 4 |
| 20 | Deep GOM | Eastern GOM | > 2400 | All | EGOM2400 | 4 |
| 21 | Deep GOM | Eastern GOM | > 200 | All | EGOML181 | 4 |
| 22 | Atlantic | North Atlantic | 0 - 200 | All | NATL0002 | 1 |
| 23 | Atlantic | North Atlantic | 201 - 800 | All | NATL0208 | 1 |
| 24 | Atlantic | North Atlantic | > 800 | All | NATL0800 | 1 |
| 25 | Atlantic | Mid Atlantic | 0 - 200 | All | MATL0002 | 1 |
| 26 | Atlantic | Mid Atlantic | 201 - 800 | All | MATL0208 | 1 |
| 27 | Atlantic | Mid Atlantic | > 800 | All | MATL0800 | 1 |
| 28 | Atlantic | South Atlantic | 0 - 200 | All | SATL0002 | 1 |
| 29 | Atlantic | South Atlantic | 201 - 800 | All | SATL0208 | 1 |
| 30 | Atlantic | South Atlantic | > 800 | All | SATL0800 | 1 |
| 31 | Atlantic | Florida Straits | 0 – 200 | All | FLST0002 | 1 |
| 32 | Atlantic | Florida Straits | 201 - 800 | All | FLST0208 | 1 |
| 33 | Atlantic | Florida Straits | > 800 | All | FLST0800 | 1 |
| 34 | Pacific | Pacific Northwest | 0-200 | All | PNW0002 | 2 |
| 35 | Pacific | Pacific Northwest | 201-800 | All | PNW0208 | 2 |
| 36 | Pacific | North California | 0-200 | All | NCA0002 | 2 |
| 37 | Pacific | North California | 201-800 | All | NCA0208 | 2 |
| 38 | Pacific | North California | 801-1600 | All | NCA0816 | 2 |
| 39 | Pacific | North California | 1600-2400 | All | NCA1624 | 2 |
| 40 | Pacific | Central California | 0-200 | All | CCA0002 | 2 |
| 41 | Pacific | Central California | 201-800 | All | CCA0208 | 2 |
| 42 | Pacific | Central California | 801-1600 | All | CCA0816 | 2 |
| 43 | Pacific | South California | 0-200 | All | SCA0002 | 2 |
| 44 | Pacific | South California | 201-800 | All | SCA0208 | 2 |
| 45 | Pacific | South California | 801-1600 | All | SCA0816 | 2 |
| 46 | Pacific | South California | 1601-2400 | All | SCA1624 | 2 |

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

**Table 3D-2. Number of Undiscovered Fields by Evaluation Unit and Field Size Class, as of January 1, 2003**

| Evaluation Unit | Field Size Class (FSC) | | | | | | | | | | | | | | | | Number of Fields | Total Resource (BBOE) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | | |
| WGOM0002 | 1 | 5 | 11 | 14 | 20 | 23 | 24 | 27 | 30 | 8 | 6 | 8 | 2 | 0 | 0 | 0 | 179 | 4.348 |
| WGOMDG02 | 0 | 0 | 2 | 4 | 5 | 6 | 8 | 9 | 9 | 3 | 2 | 2 | 1 | 0 | 0 | 0 | 51 | 1.435 |
| WGOM0204 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 3 | 3 | 4 | 2 | 1 | 1 | 0 | 0 | 0 | 16 | 1.027 |
| WGOM0408 | 0 | 0 | 0 | 0 | 0 | 1 | 3 | 3 | 7 | 7 | 3 | 2 | 1 | 0 | 0 | 0 | 27 | 1.533 |
| WGOM0816 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 7 | 16 | 16 | 15 | 9 | 3 | 2 | 1 | 0 | 73 | 8.082 |
| WGOM1624 | 0 | 0 | 0 | 1 | 2 | 6 | 10 | 14 | 18 | 18 | 14 | 10 | 6 | 4 | 1 | 0 | 104 | 10.945 |
| WGOM2400 | 0 | 0 | 0 | 0 | 2 | 3 | 3 | 6 | 7 | 6 | 5 | 3 | 3 | 2 | 0 | 0 | 40 | 4.017 |
| CGOM0002 | 1 | 1 | 6 | 11 | 28 | 52 | 79 | 103 | 81 | 53 | 20 | 1 | 0 | 0 | 0 | 0 | 436 | 8.063 |
| CGOMDG02 | 0 | 0 | 1 | 1 | 4 | 4 | 4 | 6 | 7 | 6 | 5 | 3 | 1 | 0 | 0 | 0 | 42 | 3.406 |
| CGOM0204 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 3 | 2 | 2 | 2 | 1 | 0 | 0 | 0 | 13 | 1.102 |
| CGOM0408 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 4 | 4 | 4 | 1 | 1 | 1 | 1 | 0 | 0 | 18 | 1.660 |
| CGOM0816 | 0 | 0 | 0 | 0 | 2 | 4 | 8 | 11 | 20 | 22 | 19 | 14 | 7 | 3 | 1 | 0 | 111 | 11.973 |
| CGOM1624 | 0 | 0 | 0 | 1 | 2 | 5 | 9 | 15 | 18 | 19 | 15 | 13 | 8 | 4 | 1 | 0 | 110 | 12.371 |
| CGOM2400 | 0 | 0 | 0 | 0 | 2 | 2 | 3 | 5 | 5 | 5 | 5 | 4 | 3 | 2 | 0 | 0 | 36 | 4.094 |
| EGOM0002 | 4 | 6 | 7 | 11 | 16 | 18 | 18 | 16 | 13 | 10 | 6 | 1 | 0 | 0 | 0 | 0 | 126 | 1.843 |
| EGOM0204 | 0 | 1 | 1 | 2 | 3 | 4 | 4 | 3 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 21 | 0.233 |
| EGOM0408 | 0 | 1 | 2 | 3 | 5 | 5 | 5 | 4 | 3 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 31 | 0.348 |
| EGOM0816 | 0 | 1 | 1 | 3 | 4 | 4 | 4 | 3 | 3 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 26 | 0.326 |
| EGOM1624 | 0 | 0 | 0 | 0 | 2 | 1 | 1 | 1 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 7 | 0.250 |
| EGOM2400 | 0 | 0 | 0 | 1 | 1 | 3 | 5 | 7 | 8 | 9 | 7 | 6 | 3 | 2 | 0 | 0 | 52 | 4.922 |
| EGOML181 | 0 | 0 | 0 | 0 | 1 | 3 | 3 | 5 | 8 | 5 | 4 | 2 | 2 | 1 | 1 | 0 | 35 | 1.836 |
| NATL0002 | 5 | 7 | 10 | 14 | 16 | 17 | 15 | 11 | 10 | 8 | 3 | 2 | 1 | 0 | 0 | 0 | 119 | 1.896 |
| NATL0208 | 1 | 1 | 1 | 2 | 2 | 3 | 3 | 3 | 2 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 20 | 0.246 |
| NATL0800 | 1 | 2 | 3 | 5 | 7 | 10 | 13 | 12 | 7 | 6 | 4 | 1 | 0 | 0 | 0 | 0 | 71 | 1.229 |
| MATL0002 | 4 | 6 | 8 | 12 | 13 | 14 | 13 | 11 | 8 | 7 | 5 | 2 | 0 | 0 | 0 | 0 | 103 | 1.585 |
| MATL0208 | 1 | 1 | 2 | 3 | 3 | 3 | 3 | 4 | 2 | 2 | 2 | 2 | 0 | 0 | 0 | 0 | 28 | 0.377 |
| MATL0800 | 2 | 4 | 5 | 8 | 9 | 10 | 10 | 8 | 5 | 5 | 3 | 2 | 0 | 0 | 0 | 0 | 71 | 1.173 |
| SATL0002 | 1 | 2 | 2 | 3 | 5 | 6 | 5 | 5 | 4 | 4 | 1 | 1 | 0 | 0 | 0 | 0 | 39 | 0.658 |
| SATL0208 | 4 | 5 | 7 | 10 | 12 | 13 | 12 | 10 | 8 | 7 | 3 | 2 | 0 | 0 | 0 | 0 | 93 | 1.382 |
| SATL0800 | 2 | 2 | 4 | 5 | 9 | 15 | 20 | 17 | 11 | 7 | 2 | 1 | 1 | 0 | 0 | 0 | 96 | 1.854 |
| FLST0002 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0.012 |
| FLST0208 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0.009 |
| FLST0800 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 |
| PNW0002 | 10 | 17 | 24 | 29 | 27 | 21 | 13 | 8 | 5 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 157 | 0.597 |
| PNW0208 | 4 | 6 | 9 | 10 | 11 | 7 | 6 | 3 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 0.209 |
| NCA0002 | 1 | 2 | 3 | 5 | 5 | 5 | 5 | 4 | 3 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 38 | 0.485 |
| NCA0208 | 9 | 17 | 24 | 28 | 26 | 22 | 15 | 10 | 5 | 3 | 1 | 1 | 0 | 0 | 0 | 0 | 161 | 0.859 |
| NCA0816 | 3 | 6 | 9 | 12 | 12 | 11 | 9 | 7 | 4 | 3 | 2 | 1 | 0 | 0 | 0 | 0 | 79 | 0.784 |
| NCA1624 | 1 | 2 | 3 | 5 | 6 | 6 | 7 | 6 | 4 | 2 | 1 | 1 | 0 | 0 | 0 | 0 | 44 | 0.595 |
| CCA0002 | 1 | 4 | 6 | 11 | 15 | 19 | 20 | 17 | 12 | 8 | 4 | 2 | 0 | 0 | 0 | 0 | 119 | 1.758 |
| CCA0208 | 1 | 2 | 3 | 5 | 8 | 10 | 10 | 8 | 7 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 61 | 0.761 |
| CCA0816 | 0 | 1 | 1 | 2 | 3 | 4 | 5 | 3 | 2 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 0.218 |
| SCA0002 | 1 | 2 | 4 | 10 | 16 | 21 | 22 | 19 | 12 | 6 | 2 | 1 | 0 | 0 | 0 | 0 | 116 | 1.348 |
| SCA0208 | 3 | 6 | 12 | 25 | 38 | 49 | 51 | 43 | 28 | 14 | 5 | 3 | 1 | 0 | 0 | 0 | 278 | 3.655 |
| SCA0816 | 1 | 3 | 6 | 9 | 13 | 17 | 18 | 15 | 12 | 8 | 2 | 2 | 1 | 0 | 0 | 0 | 107 | 1.906 |
| SCA1624 | 0 | 1 | 2 | 3 | 4 | 5 | 5 | 5 | 4 | 3 | 1 | 1 | 0 | 0 | 0 | 0 | 34 | 0.608 |

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, Oil and Gas Division

**Table 3D-3. MMS Field Size Definition (MMBOE)**

| Field Size Class | Mean |
|---|---|
| 2 | 0.083 |
| 3 | 0.188 |
| 4 | 0.356 |
| 5 | 0.743 |
| 6 | 1.412 |
| 7 | 2.892 |
| 8 | 5.919 |
| 9 | 11.624 |
| 10 | 22.922 |
| 11 | 44.768 |
| 12 | 89.314 |
| 13 | 182.144 |
| 14 | 371.727 |
| 15 | 690.571 |
| 16 | 1418.883 |
| 17 | 2954.129 |

Source: Minerals Management Service

## Determination of Discoveries

The number and size of discoveries is determined based on a simple model developed by J. J. Arps and T. G. Roberts in 1958[2]. For a given evaluation unit in the OOGSS, the number of cumulative discoveries for each field size class is determined by

$$\mathrm{DiscoveredFields}_{\mathrm{EU,iFSC}} = \mathrm{TotalFields}_{\mathrm{EU,iFSC}} * (1 - e^{\gamma_{\mathrm{EU,iFSC}} * \mathrm{CumNFW}_{\mathrm{EU}}}) \tag{3D-1}$$

where,

| | | |
|---|---|---|
| TotalFields | = | Total number of fields by evaluation unit and field size class |
| CumNFW | = | Cumulative new field wildcats drilled in an evaluation unit |
| $\gamma$ | = | search coefficient |
| EU | = | evaluation unit |
| iFSC | = | field size class. |

The search coefficient ($\gamma$) was chosen to make the Equation 3D-1 fit the data. In many cases, however, the sparse exploratory activity in an evaluation unit made fitting the discovery model problematic. To provide reasonable estimates for a search coefficient in every evaluation unit, the data in various field size classes within a region were grouped as needed to provide enough data points to determine a reasonable fit to the discovery model. A polynomial was fit to all of the relative search coefficients in the region. A polynomial was fit to the resulting search coefficients as follows:

$$\gamma_{\mathrm{EU,iFSC}} = \beta 1 * \mathrm{iFSC}^2 + \beta 2 * \mathrm{iFSC} + \beta 3 * \gamma_{\mathrm{EU,10}} \tag{3D-2}$$

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

where,

| | | |
|---|---|---|
| β1 | = | 0.243 for Western GOM and 0.0399 for Central and Eastern GOM |
| β2 | = | -0.3525 for Western GOM and -0.6222 for Central and Eastern GOM |
| β3 | = | 2.3326 for Western GOM and 3.0477 for Central and Eastern GOM |
| iFSC | = | field size class |
| γ | = | search coefficient for field size class 10. |

Cumulative new field wildcat drilling is determined by

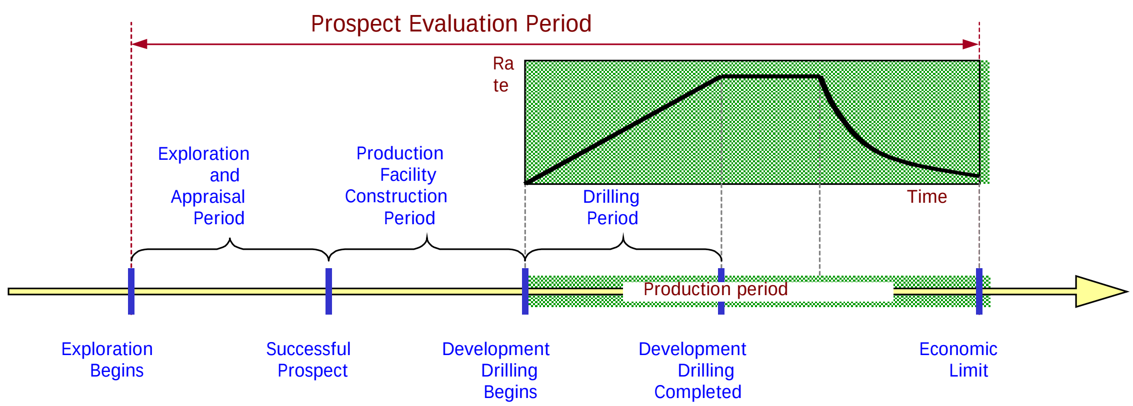
$$\mathrm{CumNFW}_{\mathrm{EU,t}} = \mathrm{CumNFW}_{\mathrm{EU,t-1}} + \alpha 1_{\mathrm{EU}} + \beta_{\mathrm{EU}} * (\mathrm{OILPRICE}_{\mathrm{t-nlag1}} * \mathrm{GASPRICE}_{\mathrm{t-nlag2}}) \quad (3D\text{-}3)$$

where,

| | | |
|---|---|---|
| OILPRICE | = | oil wellhead price |
| GASPRICE | = | natural gas wellhead price |
| α, β | = | estimated parameter |
| nlag1 | = | number of years lagged for oil price |
| nlag2 | = | number of years lagged for gas price |
| EU | = | evaluation unit |

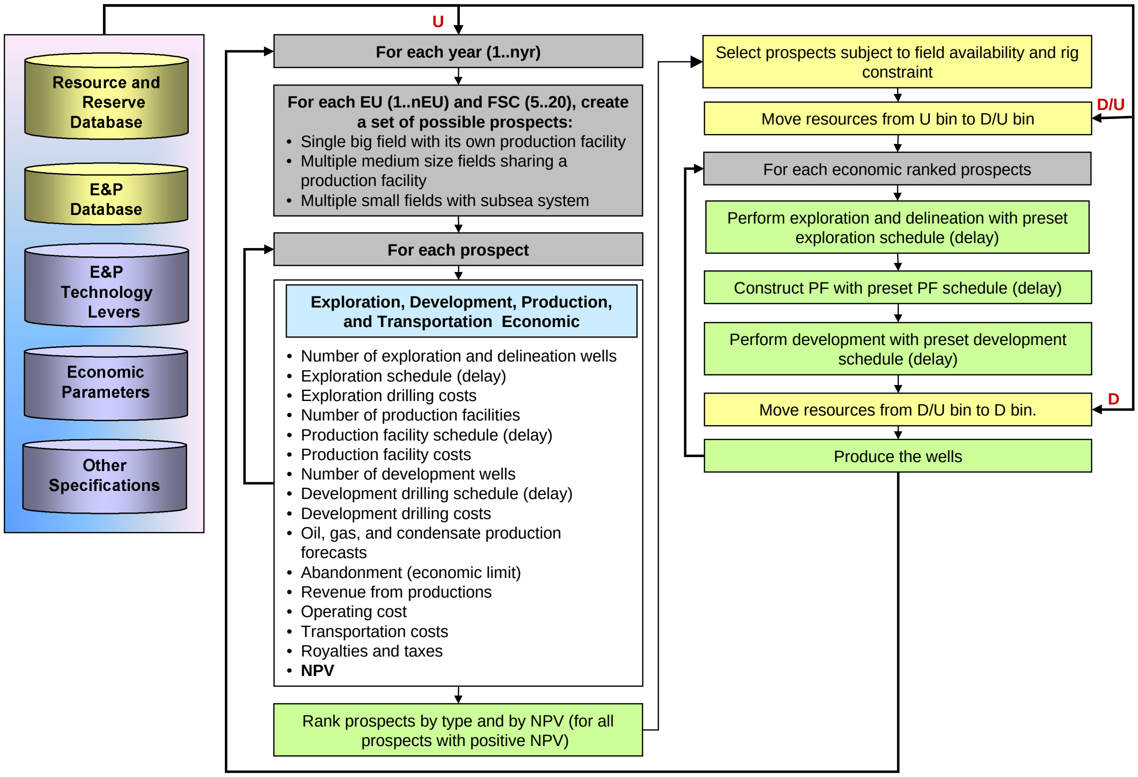
The decision for exploration and development of the discoveries determine from Equation 3D-1 is performed at a prospect level that could have more than one field. A prospect is defined as a potential project that covers exploration, appraisal, production facility construction, development, production, and transportation (Figure 3D-1). There are three types of prospects: (1) a single field with its own production facility, (2) multiple medium size fields sharing a production facility, and (3) multiple small fields utilizing nearby production facility. The net present value (NPV) of each possible prospect is generated using the calculated exploration costs, production facility costs, development costs, completion costs, operating costs, flowline costs, transportation costs, royalties, taxes, and production revenues. Delays for exploration, production facility construction, and development are incorporated in this NPV calculation. The possible prospects are then ranked from best (highest NPV) to worst (lowest NPV). The best prospects are selected subject to field availability and rig constraint. The basic flowchart is presented in Figure 3D-2.

**Figure 3D-1. Prospect Exploration, Development, and Production Schedule**




Source: ICF Consulting

**Figure 3D-2. Flowchart for the Undiscovered Field Component of the OOGSS**




Note: U = Undiscovered, D/U = Discovered/Undeveloped, D=Developed
Source: ICF Consulting

## Calculation of Costs

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. 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. The following base costs are adjusted with the oil price to capture the variation in costs over time as activity level and demand for equipment and other supplies change. The adjustment factor is [1 + (oilprice/30 – 1)*0.4].

### *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. Three types of drilling rigs are incorporated into the OOGSS. The exploration drilling costs per well for each rig type are a function of water depth (WD) and well drilling depth (DD), both in feet.

**Jack-up** rigs are limited to a water depth of about 600 feet or less. Jack-ups are towed to their location where heavy machinery is used to jack the legs down into the water until they rest on the ocean floor. When this is completed, the platform containing the work area rises above the water. After the platform has risen about 50 feet out of the water, the rig is ready to begin drilling.

$$\text{ExplorationDrillingCosts}(\$/\text{well}) = 2{,}000{,}000 + 5.0\text{E}-09 * \text{WD} * \text{DD}^3 \quad (3D\text{-}4)$$

**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.

$$\begin{aligned}\text{ExplorationDrillingCosts}(\$ / \text{well}) &= 2{,}500{,}000 + 200 * (\text{WD} + \text{DD}) \\ &\quad + \text{WD} * (400 + 2.0\text{E-}05 * \text{DD}^2)\end{aligned} \tag{3D-5}$$

**Dynamically positioned drill ships** are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3,000 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.

$$\text{ExplorationDrillingCosts}(\$ / \text{well}) = 7{,}000{,}000 + 1.0\text{E} - 05 * \text{WD} * \text{DD}^2 \tag{3D-6}$$

Water depth is the primary criterion for selecting a drilling rig. Drilling in shallow waters (up to 1,500 feet) can be done with jack-up rigs. Drilling in deeper water (greater than 1,500 feet) can be done with semi-submersible drilling rigs or drill ships. The number of rigs available for exploration is limited and varies by water depth levels. Drilling rigs are allowed to move one water depth level lower if needed.

#### *Production and Development Structure*

Six different options for development/production of offshore prospects are currently assumed in OOGSS, 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. Production facility costs are a function of water depth (WD) and number of slots per structure (SLT).

**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.

$$\text{StructureCost}(\$) = 2{,}000{,}000 + 9{,}000 * \text{SLT} + 1{,}500 * \text{WD} * \text{SLT} + 40 * \text{WD}^2 \tag{3D-7}$$

**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.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (1{,}500{,}000 + 2{,}000 * (\text{WD} - 1{,}000)) \tag{3D-8}$$

**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.

$$\mathrm{StructureCost}(\$) = (\mathrm{SLT} + 30) * (3{,}000{,}000 + 750 * (\mathrm{WD} - 1{,}000)) \tag{3D-9}$$

**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.

$$\mathrm{StructureCost}(\$) = (\mathrm{SLT} + 20) * (7{,}500{,}000 + 250 * (\mathrm{WD} - 1{,}000)) \tag{3D-10}$$

**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.

$$\mathrm{StructureCost}(\$) = (\mathrm{SLT} + 20) * (3{,}000{,}000 + 500 * (\mathrm{WD} - 1{,}000)) \tag{3D-11}$$

**Subsea Wells System (SS)**. Subsea systems range 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 subsea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet. Since the cost to complete a well is included in the development well drilling and completion costs, no cost is assumed for the subsea well system. However, a subsea template is required for all development wells producing to any structure other than a fixed platform.

$$\mathrm{SubseaTemplateCost}(\$ / \mathrm{well}) = 2{,}500{,}000 \tag{3D-12}$$

The type of production facility for development and production depends on water depth level as shown in Table 3D-4.

**Table 3D-4. Production Facility by Water Depth Level**

| Water Depth Range (feet) | | Production Facility Type | | | | | |
|---|---|---|---|---|---|---|---|
| Minimum | Maximum | FP | CT | TLP | FPS | SPAR | SS |
| 0 | 656 | X | | | | | X |
| 656 | 2625 | | X | | | | X |
| 2625 | 5249 | | | X | | | X |
| 5249 | 7874 | | | | X | X | X |
| 7874 | 10000 | | | | X | X | X |

Source: ICF Consulting

***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.

For water depths less than or equal to 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$ / \text{well}) = {} & 1{,}500{,}000 + (1{,}500 + 0.04 * \text{DD}) * \text{WD} \\ & +(0.035 * \text{DD} - 300) * \text{DD}\end{aligned} \tag{3D-13}$$

For water depths greater tan 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$ / \text{well}) = {} & 4{,}500{,}000 + (150 + 0.004 * \text{DD}) * \text{WD} \\ & +(0.035 * \text{DD} - 250) * \text{DD}\end{aligned} \tag{3D-14}$$

where,

WD = water depth in feet
DD = drilling depth in feet.

***Completion and Operating***

Completion costs per well are a function of water depth range and drilling depth as shown in Table 3D-5.

**Table 3D-5. Well Completion and Equipment Costs per Well**

| Water Depth (feet) | Development Drilling Depth (feet) | | |
|---|---|---|---|
| | < 10,000 | 10,001 - 20,000 | > 20,000 |
| 0 - 3,000 | 800,000 | 2,100,000 | 3,300,000 |
| > 3,000 | 1,900,000 | 2,700,000 | 3,300,000 |

Platform operating costs for all types of structures are assumed to be a function of water depth (WD) and the number of slots (SLT). 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.

Annual operating costs are determined by

$$\text{OperatingCost}(\$ / \text{structure} / \text{year}) = 1{,}265{,}000 + 135{,}000 * \text{SLT} + 0.0588 * \text{SLT} * \text{WD}^2 \tag{3D-15}$$

### *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.

### *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 follows:

| | **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 |

## Exploration, Development, and Production Scheduling

The typical project development in the offshore consists of the following phases:[3]

- 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, and
- 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.

[3]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*

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.** 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 a field as follows:

number of exploratory wells = 1/ [exploration success rate]

For example, a 25 percent exploration success rate will require four exploratory wells: one finds the field and three are dry holes.

**Delineation drilling.** Exploratory drilling is followed by delineation drilling for field appraisal (1 to 4 wells depending on the size of the field). The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. All delineation wells are converted to production wells at the end of the production facility construction.

### *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 required time for construction and installation of the various development structures used in the model is shown in Table 3D-6. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

**Table 3D-6. Production Facility Design, Fabrication, and Installation Period (Years)**

| PLATFORMS | Water Depth (Feet) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Number of Slots | 0 | 100 | 400 | 800 | 1000 | 1500 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 | 9000 | 10000 |
| 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 3 | 3 | 4 | 4 | 4 |
| 8 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 4 | 4 | 4 |
| 12 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 4 | 4 | 4 |
| 18 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 4 | 4 | 4 |
| 24 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 4 | 4 | 4 | 5 |
| 36 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 4 | 4 | 4 | 5 |
| 48 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 5 |
| 60 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 5 |
| **OTHERS** | | | | | | | | | | | | | | | |
| SS | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 3 | 3 | 3 | 4 | 4 | 4 |
| FPS | | | | | | | | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 5 |

Source: ICF Consulting

**Development drilling schedule.** The number of development wells varies by water depth and field size class as follows.

$$\text{DevelopmentWells} = 5 / \text{FSC} * \text{FSIZE}^{\beta_{\text{DepthClass}}} \tag{3D-16}$$

where,

FSC = field size class
FSIZE = resource volume
β = 0.8 for water depths < 200 meters; 0.7 for water depths 200-800 meters; 0.65 for water depths > 800 meters.

The development drilling schedule is determined based on the assumed drilling capacity (maximum number of wells that could be drilled in a year). This drilling capacity varies by type of production facility and water depth. For a platform type production facility (FP, CT, or TLP), the development drilling capacity is also a function of the number of slots. The assumed drilling capacity by production facility type is shown in Table 3D-7.

**Table 3D-7. Development Drilling Capacity by Production Facility Type**

| **Maximum Number of Wells Drilled (wells/platform/year, 1 rig)** | |
|---|---|
| **Drilling Depth (feet)** | **Drilling Capacity (24 slots)** |
| 0 | 24 |
| 6000 | 24 |
| 7000 | 24 |
| 8000 | 20 |
| 9000 | 20 |
| 10000 | 20 |
| 11000 | 20 |
| 12000 | 16 |
| 13000 | 16 |
| 14000 | 12 |
| 15000 | 8 |
| 16000 | 4 |
| 17000 | 2 |
| 18000 | 2 |
| 19000 | 2 |
| 20000 | 2 |
| 30000 | 2 |

| **Maximum Number of Wells Drilled (wells/field/year)** | | | |
|---|---|---|---|
| **Water Depth (feet)** | **SS** | **FPS** | **FPSO** |
| 0 | 4 | [redacted] | 4 |
| 1000 | 4 | [redacted] | 4 |
| 2000 | 4 | [redacted] | 4 |
| 3000 | 4 | 4 | 4 |
| 4000 | 4 | 4 | 4 |
| 5000 | 3 | 3 | 3 |
| 6000 | 2 | 2 | 2 |
| 7000 | 2 | 2 | 2 |
| 8000 | 1 | 1 | 1 |
| 9000 | 1 | 1 | 1 |
| 10000 | 1 | 1 | 1 |

Source: ICF Consulting

**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.

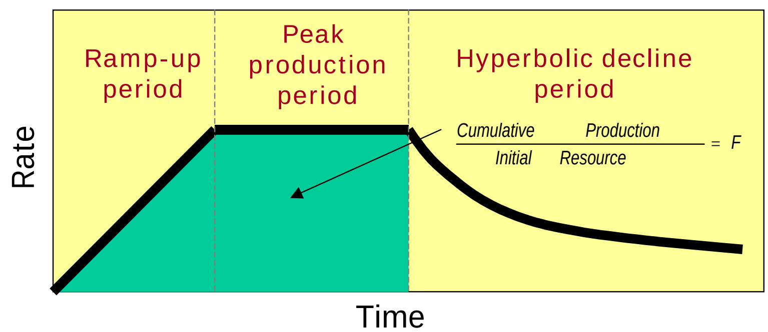
***Production Operations***

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. First production is from delineation wells that were converted to production wells. Development drilling starts at the end of the production facility construction period.

**Production profiles**

The original hydrocarbon resource (in BOE) is divided between oil and natural gas using a user specified proportion. Due to the development drilling schedule, not all wells in the same field will produce at the same time. This yields a ramp-up profile in the early production period (Figure 3D-3). The initial production rate is the same for all wells in the field and is constant for a period of time. Field production reaches its peak when all the wells have been drilled and start producing. The production will start to decline (at a user specified rate) when the ratio of cumulative production to initial resource equals a user specified fraction.

**Figure 3D-3. Undiscovered Field Production Profile**




Source: ICF Consulting

Gas (plus lease condensate) production is calculated based on gas resource and oil (plus associated gas) production is calculated based on the oil resource. Lease condensate production is separated from the gas production using the user specified condensate yield. Likewise, associated-dissolved gas production is separated from the oil production using the user specified associated gas-to-oil ratio. Associated-dissolved gas production is then tracked separately from the nonassociated gas production throughout the projection. Lease condensate production is added to crude oil production and is not tracked separately.

**Field Abandonment**

All wells in a field are assumed to be shut -in when the net revenue from the field is less than total State and Federal taxes. Net revenue is total revenue from production less royalties, operating costs, transportation costs, and severance taxes.

## Discovered Undeveloped Fields Component

Announced discoveries that have not been brought into production by 2002 are included in this component of the OOGSS. The data required for these fields include location, field size class, gas percentage of BOE resource, condensate yield, gas to oil ratio, start year of production, initial production rate, fraction produced before decline, and hyperbolic decline parameters. The BOE resource is for each field corresponds to the field size class as specified in Table 3D-3.

The number of development wells is the same as that of an undiscovered field in the same water depth and of the same field size class (Equation 3D-13). The production profile is also the same as that of an undiscovered field (Figure 3D-3).

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2007 are shown in Table 3D-8. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

## Producing Fields Component

A separate database is used to track currently producing fields. The data required for each producing field includes location, field size class, field type (oil or gas), total recoverable resources, historical production (1990-2002), and hyperbolic decline parameters.

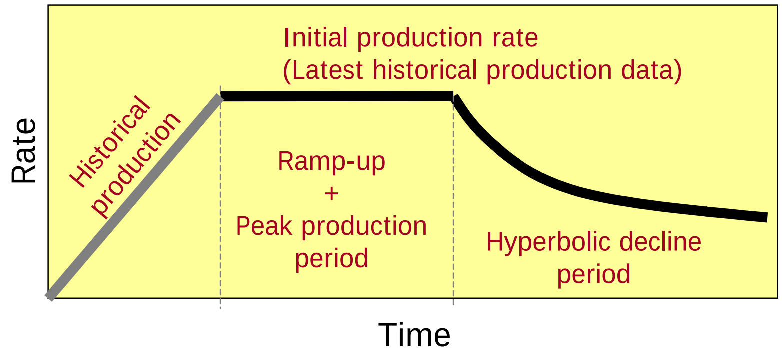
Projected production from the currently producing fields will continue to decline if, historically, production from the field is declining (Figure 3D-4). Otherwise, production is held constant for a period of time equal to the sum of the specified number ramp-up years and number of years at peak production after which it will decline (Figure 3D-5). Production will decline using a hyperbolic decline curve until the economic limit is achieved and the field is abandoned. Typical production profile data are shown in Table 3D-9. Associated-dissolved gas and lease condensate production is determined the same way as in the undiscovered field component.

**Table 3D-8. Assumed Size and Initial Production Year of Major Announced Deepwater Discoveries**

| Field/Project Name | Block | Water Depth (feet) | Year of Discovery | Field Size Class | Field Size (MMBoe) | Start Year of Production |
|---|---|---|---|---|---|---|
| Telemark | AT063 | 4457 | 2000 | 12 | 89 | 2009 |
| Neptune | AT575 | 6220 | 1995 | 13 | 182 | 2009 |
| GC238/GC282 | GC238 | 2386 | 2001 | 13 | 182 | 2009 |
| Shenzi | GC653 | 4238 | 2002 | 14 | 372 | 2009 |
| Atlantis North | GC699 | 6130 | 2002 | 12 | 89 | 2009 |
| Raton | MC248 | 3400 | 2006 | 13 | 182 | 2009 |
| Thunder Hawk | MC734 | 5724 | 2004 | 13 | 182 | 2009 |
| Thunder Horse | MC778 | 5993 | 1999 | 17 | 2954 | 2009 |
| Great White | AC857 | 8717 | 2002 | 14 | 372 | 2010 |
| Trident | AC903 | 9743 | 2001 | 13 | 182 | 2010 |
| Sturgis | AT182 | 3710 | 2003 | 12 | 89 | 2010 |
| Entrada | GB782 | 4690 | 2000 | 14 | 372 | 2010 |
| Hornet | GC379 | 3878 | 2001 | 13 | 182 | 2010 |
| Puma | GC823 | 4129 | 2003 | 14 | 372 | 2010 |
| Goose | MC751 | 1624 | 2002 | 12 | 89 | 2010 |
| Thunder Horse North | MC776 | 5660 | 2000 | 15 | 691 | 2010 |
| Cascade | WR206 | 8143 | 2002 | 14 | 372 | 2010 |
| Chinook | WR469 | 8831 | 2003 | 14 | 372 | 2010 |
| Knotty Head | GC512 | 3557 | 2005 | 14 | 372 | 2011 |
| Ringo | MC546 | 2460 | 2006 | 14 | 372 | 2011 |
| Tubular Bells | MC726 | 4334 | 2003 | 12 | 89 | 2011 |
| Pony | GC468 | 3497 | 2006 | 13 | 182 | 2012 |
| La Femme | MC427 | 5800 | 2004 | 12 | 89 | 2012 |
| Stones | WR508 | 9556 | 2005 | 12 | 89 | 2012 |
| Tiger | AC818 | 9004 | 2004 | 12 | 89 | 2013 |
| Jack | WR759 | 6963 | 2004 | 14 | 372 | 2013 |
| St. Malo | WR678 | 7036 | 2003 | 14 | 372 | 2014 |
| Big Foot | WR029 | 5235 | 2006 | 12 | 89 | 2015 |

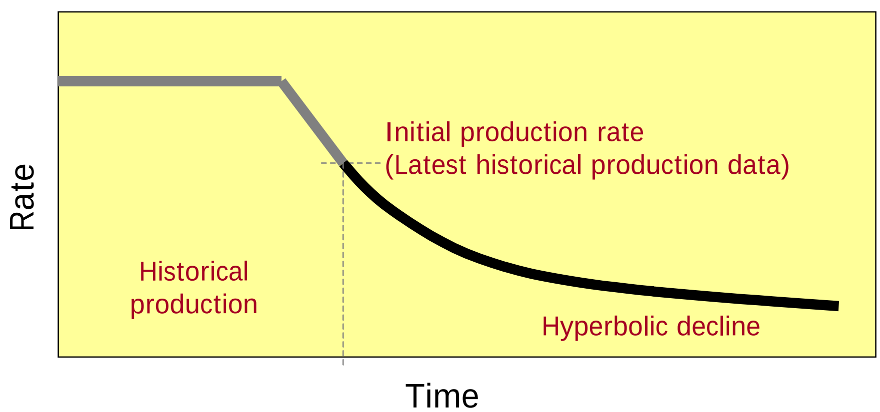
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, Oil and Gas Division.

**Figure 3D-4. Production Profile for Producing Fields - Constant Production Case**




Source: ICF Consulting

**Figure 3D-5. Production Profile for Producing Fields - Declining Production Case**




Source: ICF Consulting

**Table 3D-9. Production Profile Data for Oil & Gas Producing Fields**

| Region | Crude Oil | | | | | | Natural Gas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | FSC 2 - 10 | | | FSC 11 - 17 | | | FSC 2 - 10 | | | FSC 11 - 17 | | |
| | Ramp-up (years) | At Peak (years) | Initial Decline Rate | Ramp-up (years) | At Peak (years) | Initial Decline Rate | Ramp-up (years) | At Peak (years) | Initial Decline Rate | Ramp-up (years) | At Peak (years) | Initial Decline Rate |
| Shallow GOM | 2 | 2 | 0.15 | 3 | 3 | 0.10 | 2 | 1 | 0.20 | 3 | 2 | 0.10 |
| Deep GOM | 2 | 2 | 0.20 | 2 | 3 | 0.15 | 2 | 2 | 0.25 | 3 | 2 | 0.20 |
| Atlantic | 2 | 2 | 0.20 | 3 | 3 | 0.20 | 2 | 1 | 0.25 | 3 | 2 | 0.20 |
| Pacific | 2 | 2 | 0.10 | 3 | 2 | 0.10 | 2 | 1 | 0.20 | 3 | 2 | 0.20 |

FSC = Field Size Class
Source: ICF Consulting

## Generation of Supply Curves

As mentioned earlier, the OOGSS does not determine the actual volume of crude oil and nonassociated natural gas produced in the given year but rather provides the parameters for the short-term supply functions used to determine regional supply and demand market equilibration as described in Chapter 3. In each year, t, and offshore region, r, the OGSM calculates the stock of proved reserves at the beginning of year t+1 and the expected production-to-reserves (PR) ratio for year t+1 as follows.

The volume of proved reserves in any year is calculated as:

$$RESOFF_{r,k,t+1} = RESOFF_{r,k,t} - PRDOFF_{r,k,t} + NRDOFF_{r,k,t} + REVOFF_{r,k,t} \quad (3D\text{-}17)$$

where,

| | | |
|---|---|---|
| RESOFF | = | beginning- of-year reserves |
| PRDOFF | = | production |
| NRDOFF | = | new reserve discoveries |
| REVOFF | = | reserve extensions, revisions, and adjustments |
| r | = | region (1=Atlantic, 2=Pacific, 3=GOM) |
| k | = | fuel type (1=oil; 2=nonassociated gas) |
| t | = | year. |

Expected production, EXPRDOFF, is the sum of the field level production determined in the undiscovered fields component, the discovered, undeveloped fields component, and the producing field component. The volume of crude oil production (including lease condensate), PRDOFF, passed to the PMM is equal to EXPRDOFF. Nonassociated natural gas production in year t is the market equilibrated volume passed to the OGSM from the NGTDM.

Reserves are added through new field discoveries as well as delineation and developmental drilling. Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. The allocation between proved and inferred reserves is based on historical reserves growth statistics provided by the Minerals Management Service. Specifically,

$$NRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(\frac{1}{RSVGRO_k}\right) \quad (3D\text{-}18)$$

$$NIRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(1 - \frac{1}{RSVGRO_k}\right) \quad (3D\text{-}19)$$

where,

| | | |
|---|---|---|
| NRDOFF | = | new reserve discovery |
| NIRDOFF | = | new inferred reserve additions |
| NFDISC | = | new field discoveries |
| RSVGRO | = | reserves growth factor (8.2738 for oil and 5.9612 for gas) |
| r | = | region (1=Atlantic, 2=Pacific, 3=GOM) |
| k | = | fuel type (1=oil; 2=gas) |
| t | = | year. |

Reserves are converted from inferred to proved with the drilling of other exploratory (or delineation) wells and developmental wells. Since the expected offshore PR ratio is assumed to remain constant at the last historical value, then the reserves need to support the total expected production, EXPRDOFF, can be calculated by dividing EXPRDOFF by the PR ratio. Reconfiguring Equation 3D-1 to solve for REVOFF gives

$$REVOFF_{r,k,t} = \frac{EXPRDOFF_{r,k,t}}{PR_{r,k}} + PRDOFF_{r,k,t} - RESOFF_{r,k,t} - NRDOFF_{r,k,t} \qquad (3D\text{-}20)$$

The remaining proved reserves, inferred reserves, and undiscovered resources are tracked throughout the projection period to ensure that production from offshore sources does not exceed the assumed resource base.
Field level associated-dissolved gas is summed to the regional level and passed to the NGTDM.

## 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. The OOGSS has been designed to give due consideration to the effect of future advances in technology that may occur in the future. The specific technology levers and values are presented in Table 3D-10.

**Table 3D-10. Offshore Exploration and Production Technology Levers**

| Technology Lever | Total Improvement (percent) | Number of Years |
|---|---|---|
| Exploration success rates | 30 | 30 |
| Delay to commence first exploration and between exploration | 15 | 30 |
| Exploration & development drilling costs | 30 | 30 |
| Operating cost | 30 | 30 |
| Time to construct production facility | 15 | 30 |
| Production facility construction costs | 30 | 30 |
| Initial constant production rate | 15 | 30 |
| Decline rate | 0 | 30 |

Source: ICF Consulting

# Appendix 3-E. Oil Shale Supply Submodule (OSSS)

# Introduction

Oil shale rock contains a hydrocarbon known as kerogen,[1] which can be processed into a synthetic crude oil (syncrude). During the 1970s and early 1980s, the petroleum companies conducted extensive research, often with the assistance of public funding, into the mining of oil shale rock and the chemical conversion of the kerogen into syncrude. The technologies and processes developed during that period are well understood and well documented with extensive technical data on demonstration plant costs and operational parameters, which were published in the professional literature. The oil shale supply submodule in OGSM relies extensively on this published technical data for providing the cost and operating parameters employed to model the "typical" oil shale syncrude production facility.

In the 1970s and 1980s, two engineering approaches to creating the oil shale syncrude were envisioned. One approach, which the majority of the oil companies pursued, mines the oil shale rock in underground mines, followed by surface facility retorting of the rock to create bitumen, which is then be further processed into syncrude. Occidental Petroleum Corp. pursed the other approach known as "modified in-situ," in which some of the oil shale rock is mined in underground mines, and then the remaining underground rock would be "rubblized" using explosives to create large caverns filled with oil shale rock. The oil shale rock would then be set on fire to cause the kerogen to convert into bitumen, and the bitumen would then be pumped to the surface for further processing into syncrude. The latter approach was not widely pursued because the conversion of kerogen into bitumen could not be controlled with any precision and because of the presence of underground bitumen and other petroleum compounds might contaminate underground aquifers.

A completely in-situ oil shale process is currently being experimentally tested by Shell Oil Co., wherein the oil shale rock is directly heated using heat injection wells, while petroleum products[2] are produced from separate production wells. The in-situ process has substantial environment and cost benefits relative to the other 2 approaches. The environmental benefits are primarily much lower water usage and much less land disturbance, along with an absence of oil shale waste piles on the surface. Other advantages of the in-situ process are: 1) it can access deeper oil shale resources, 2) it produces more oil and gas per acre because the process uses the entire resource column and not just the richest portion of the resource column, and 3) it directly produces petroleum products rather than a synthetic crude oil, which requires more processing at a refinery. The cost benefit is that the drilling of heater wells, production wells, and freeze-wall wells can be done in a modular fashion, which allows for a streamlined manufacturing-like process. Moreover, the in-situ process reduces the capital risk by building self-contained modular production units, which can then be multiplied to reach a desired total production level. Although the technical and economic feasibility of the in-situ approach has not been fully demonstrated, there is already a substantial body of evidence from field testing conducted by Shell Oil Co. that the in-situ process is technologically feasible.[3] The current Shell field research program is expected to conclude around 2010 with the construction of a small scale demonstration plant expected to begin shortly thereafter.

The section is intended to document the representation of the oil shale industry in Oil and Gas Supply Module of NEMS. There are a number of technical and environmental issues, which will need to be resolved if oil shale is to become a major contributor to domestic petroleum production. On the technical side, the cost and performance of the technology will have to improve significantly over those developed in the 1970's and 1980's to become economic at prices below $60 per barrel (2004 dollars). On the environmental side, issues regarding facility water supply, rock waste disposal and remediation along with potential air and water pollution will have to be satisfactorily resolved in a manner, which does not impose exorbitant costs. The Oil Shale Supply Submodule (OSSS) only represents economic decision making. Potential environmental

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[1] Kerogen is a solid organic compound, which is also found in coal.
[2] Approximately, 30 percent naphtha, 30 percent jet fuel, 30 percent diesel, and 10 percent residual fuel oil.
[3] *See* "Shell's In-situ Conversion Process," a presentation by Harold Vinegar at the Colorado Energy Research Institute's 26th Oil Shale Symposium held on October 16 – 18, 2006 in Boulder, Colorado.

constraints are not represented in the model. Given the considerable potential environmental impacts[4] of an oil shale industry based on 1980s technologies, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, it was assumed that only one new facility can begin construction in any specific future year, and as more facilities are built over time, the intervening time interval between each new facility declines to the point where one new facility can be built every year. The latter assumption is intended to mimic a technology penetration curve even though there is no informational basis for defining a more rigorously specified penetration rate. A full-scale facility has never been constructed nor operated for an extended period of time. Although the Canadian oil sands industry development history might be viewed as an analogous situation, it would be misleading. The first commercial Canadian oil sands facility began operating in 1967 and it took over 30 years to develop into a rapidly growing industry. This slow penetration rate was caused by low world oil prices from the mid-1980s through the 1990s and the lower cost of developing conventional crude oil supply.[5]

Extensive oil shale resources exist in the United States both in eastern Appalachian black shales and western Green River Formation shales. Almost all of the domestic high-grade oil shale deposits with 25 gallons or more of syncrude per ton of rock are located in the Green River Formation, which is situated in Northwest Colorado (Piceance Basin), Northeast Utah (Uinta Basin), and Southwest Wyoming. It has been estimated that over 400 billion barrels of syncrude potential exists in Green River Formation deposits that would yield at least 30 gallons of syncrude per ton of rock in zones at least 100 feet thick.[6] Consequently, the oil shale supply submodule was based on the concept that oil shale syncrude production would occur exclusively in the Rocky Mountains within the 2030 time frame of the projections. Moreover, the immense size of the western oil shale resource base precluded the need for the submodule to explicitly track oil shale resource depletion through 2030.

Within the oil shale submodule, during each year of the projection, the submodule calculates the net present cash flow of operating a commercial oil shale syncrude production facility, based on that future year's prevailing crude oil price. If the calculated discounted net present value of the cash flow exceeds zero, then an oil shale syncrude facility would begin construction, so long as the construction of that facility is not precluded by the construction constraints specified within the submodule. So the submodule contains two major decision points for determining whether an oil shale syncrude production facility is built in any particular year: first, whether the discounted net present value of a facility's cash flow exceeds zero, followed by whether the construction of a facility in that year is precluded by the construction constraints assumed within OSSS.

## Oil Shale Facility Cost and Operating Parameter Assumptions

The oil shale supply submodule is based on underground mining and surface retorting technology and costs. During the late 1970s and early 1980s, when petroleum companies were building oil shale demonstration plants, almost all demonstration facilities employed this technology.[7] The facility parameter values and cost

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[4] For example, it has been estimated that a 1 million barrel per day surface-retorting oil shale syncrude industry would produce over 500 million tons of waste rock per year and consume between 2.1 to 5.2 million barrels of water per day. Sources: Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, *Strategic Significance of America's Oil Shale Resource, Volume II, Oil Shale Resource Technology and Economic*, March 2004, Washington DC, page 24, and James T. Bartis, Tom LaTourrette, Lloyd Dixon, D.J. Peterson, Gary Cecchine, Rand Corporation, *Oil Shale Development in the United States: Prospects and Policy Issues*, 2005, Santa Monica, California, page 50.

[5] The first Canadian commercial oil sands facility started operations in 1967. It took 30 years later until the mid to late 1990s for a building boom of Canadian oil sands facilities to materialize. Source: Suncor Energy, Inc. internet website at www.suncor.com, under "our business," under "oil sands."

[6] Source: Culbertson, W. J. and Pitman, J. K. "Oil Shale" in *United States Mineral Resources*, USGS Professional Paper 820, Probst and Pratt, eds. P 497-503, 1973.

[7] Out of the many demonstration projects in the 1970s only Occidental Petroleum tested a modified in-situ approach which used caved-in mining areas to perform underground retorting of the kerogen.

estimates of the OSSS are based on information reported for the Paraho Oil Shale Project, and which are inflated to reflect the current cost environment.[8] Oil shale rock mining costs are based on Western United States underground coal mining costs, which would be representative of the cost of mining oil shale rock, [9] because coal mining techniques and technology would be employed to mine oil shale rock. However, the OSSS assumes that oil shale production costs fall at a rate of 1 percent per year, starting in 2005, to reflect the role of technological progress in reducing production costs. This cost reduction assumption results in oil shale production costs being 22 percent lower in 2030 relative to the initial 2005 cost structure.

For the *Annual Energy Outlook 2009* projections, the oil shale facility capital cost was increased by 50 percent to reflect the higher energy facility costs that were experienced on a world-wide basis due to higher commodity costs (e.g., steel). Under the revised oil shale facility cost assumption, oil shale production becomes profitable around $70 per barrel, absent any technological progress

Although the Paraho cost structure seem unrealistic relative to the notion that the application of the in-situ process is more likely than the application of the underground mining/surface retorting process, the Paraho cost structure is well documented, whereas there is no information whatsoever regarding the expected cost of the in-situ process. Moreover, even though the in-situ process is expected to be cheaper per barrel of output than the Parado process, this should be weighted against the fact that 1) oil and gas drilling costs have increased dramatically over the last 5 years, somewhat narrowing that cost difference, and 2) the Parado costs were determined at a time when environmental requirements were considerably less stringent. Consequently, the environmental costs that a Parado-like project would incur today are considerably more than what was envisioned in the late-1970s and early-1980s. It should also be noted that the Paraho process produces about the same volume of natural gas as the in-situ process does, and requires about the same electricity consumption as the in-situ process. Finally, to the degree that the Paraho process costs reported here are greater than the in-situ costs, the use of the Paraho cost structure provides a more conservative assessment, which is warranted for a completely new technology.

Another implicit assumption in the OSSS is that the natural gas produced by the facility is sold to other parties, and transported offsite, while the electricity consumed on site is purchased from the local power grid. This means that both the natural gas and the electricity are valued in the Net Present Value of the cash flow calculations at their respective regional prices , which are determined elsewhere in the NEMS. Although the oil shale facility owner has the option to use the natural gas produced on-site to generate electricity for on-site consumption, building a separate on-site/offsite power generation decision process within OSSS would unduly complicate the OSSS logic structure and would not necessarily provide a more accurate portrayal of what might actually occur in the future.[10]

## Paraho Oil Shale Facility Configuration and Costs

Because the cost parameters reported for the Paraho Oil Shale Project are reported in 1976 dollars, all costs were inflated to 2004 dollar values. The Paraho facility parameters are as follows, with the text in parentheses indicating the variable name in the submodule.

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[8] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97.

[9] Based on the coal mining cost per ton data provided in coal company 2004 annual reports, particularly those of Arch Coal, Inc, CONSOL Energy Inc, and Massey Energy Company. Reported underground mining costs per ton range for $14.50 per ton to $27.50 per ton. The high cost figures largely reflect higher union wage rates, than the low cost figures reflect non-union wage rates. Because most of the Western underground mines are currently non-union, the cost used in OSSS was pegged to the lower end of the cost range. For example, the $14.50 per ton cost represents Arch Coal's average western underground mining cost.

[10] This Colorado/Utah/Wyoming region enjoys relatively low electric power generation costs due to 1) the low cost of mining Powder River Basin subbituminous coal, and 2) because the cost of existing electricity generation equipment is inherently lower than new generation equipment, because of the inflation and depreciation effects over time.

**Table 3E-1. Paraho Oil Shale Facility Configuration and Cost Parameters**

| Facility Parameters | OSSM Variable Name | Parameter Value |
|---|---|---|
| Facility project size | OS_PROJ_SIZE | 100,000 barrels per day |
| Oil shale syncrude per ton of rock | OS_GAL_TON | 30 gallons |
| Plant conversion efficiency | OS_CONV_EFF | 90 percent |
| Average facility capacity factor | OS_CAP_FACTOR | 90 percent per year |
| Facility lifetime | OS_PRJ_LIFE | 25 years[11] |
| Facility construction time | OS_PRJ_CONST | 5 year |
| Surface facility capital costs | OS_PLANT_INVEST | $4.8 billion (2004 dollars) |
| Surface facility operating costs | OS_PLANT_OPER_CST | $400 million per year (2004 dollars) |
| Underground mining costs | OS_MINE_CST_TON | $17.50 per ton (2004 dollars) |
| Royalty rate | OS_ROYALTY_RATE | 12.5 percent of syncrude value |

The construction lead time for oil shale facilities is assumed to be 5 years, based on construction time estimates developed for the Paraho Project.[12] Because it is not clear when during the year a new plant will begin operation and achieve full productive capacity, OSSS assumes that production in the first full year will be at half its rated output. In an effort to mimic the fact that an in-situ oil shale process is most likely to be developed rather than underground mining and surface retorting process, the facility linearly ramps up production over a 5 year period (i.e., 20 percent per year).[13]

To mimic the fact that an industry's costs decline over time due to technological progress, better management techniques, and so on, the OSSS initializes the oil shale facility costs in 2005 at the values shown above (i.e., surface facility construction and operating costs, and underground mining costs). After 2005, these costs are reduced by 1 percent per year through 2030, which is consistent with the rate of technological progress witnessed in the petroleum industry over the last few decades.

## Paraho Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters

A Paraho oil shale facility produces natural gas and consumes electricity. The parameters provided below represent the level of annual gas production and annual electricity consumption for a 100,000 barrel per day, operating at 100 percent capacity utilization for a full calendar year.[14]

**Table 3E-2. Paraho Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters**

| Facility Parameters | OSSM Variable Name | Parameter Value |
|---|---|---|
| Natural gas production | OS_GAS_PROD | 32.25 billion cubic feet per year |
| Electricity consumption | OS_ELEC_CONSUMP | 1.66 billion kilowatt-hours per year |

## Project Yearly Cash Flow Calculations

The OSSS first calculates the annual revenues minus expenditures, including income taxes and depreciation, which is then discounted to a net present value. In those years in which the net present value exceeds zero,

[11] The facility's operational period was extended from 20 years to 25 years for the AEO2009 projections to take into account the 5-year ramp-up to full production. A discussion of this and other parameter changes in the OSSS for the AEO2009 is discussed in an EIA/OIAF/OGD memorandum to Andy Kydes from Philip Budzik, entitled: "Oil Shale Project Size and Production Ramp-Up," dated November 16, 2007.
[12] An in-situ facility would also require about five years before initial production began. Ibid.
[13] Ibid.
[14] Op. cit. Noyes Data Corporation.

then a new oil shale facility can be constructed, subject to the timing constraints outlined below.

The discounted cash flow algorithm is calculated for a 30 year period, composed of 5 years for construction and 25 years for plant operations. During the first 5 years of the 30-year period, only plant construction costs are considered with the facility investment cost being evenly apportioned across the 5 years. In the sixth year, the plant goes into partial operation, and produces 20 percent of the rated output. So in the sixth year revenues and operating expenses are assumed to be 20 percent of their full-production values. In years 7, 8, and 9, the plant output increases an additional 20 percent per year, while operating expenses increase by the same proportion each year. In years 10 through 30, the plant operates at its maximum utilization rate. During years 10 through 30, total revenues equal oil revenues plus natural gas revenues.[15]

Oil revenues are calculated based on current year oil prices. In other words, the OSSS assumes that the economic analysis undertaken by potential project sponsors is solely based on the prevailing price of oil at that time and is not based either on historical price trends or future expected prices. Oil revenues per plant are calculated as follows:

$$OIL\_REVENUE_t = OIT\_WOP(t,1) * (1.083/0.732) * OS\_PRJ\_SIZE * OS\_CAP\_FACTOR * 365 \tag{3E-1}$$

where,

| | | |
|---|---|---|
| OIT_WOP(t,1) | = | World oil price at time t in 1987 dollars |
| (1.083 / 0.732) | = | GDP chain-type price deflators to convert 1987 dollars into 2004 dollars |
| OS_PROJ_PRJ_SIZE | = | Facility project size in barrels per day |
| OS_CAP_FACTOR | = | Facility capacity factor |
| 365 | = | Days per year. |

During year 10 through 30, natural gas revenues are calculated as follows:

$$GAS\_REVENUE_t = OS\_GAS\_PROD * OGPRCL48_t(5,3,1) * (1.083/.732) * OS\_CAP\_FACTOR \tag{3E-2}$$

where,

| | | |
|---|---|---|
| OS_GAS_PROD | = | Annual natural gas production for 100,000 barrel per day facility |
| $OGPRCL48_t(5,3,1)$ | = | Natural gas price in Rocky Mtn. at time t in 1987 dollars |
| (1.083 / 0.732) | = | GDP chain-type price deflators to convert 1987 dollars into 2004 dollars |
| OS_CAP_FACTOR | = | Facility capacity factor. |

During year 10 through 30, electricity consumption costs are calculated as follows:

$$\begin{aligned} ELEC\_COST_t = {} & OS\_ELEC\_CONSUMP * PELIN(8,t) * (1.083/.732) * 0.003412 * \\ & OS\_CAP\_FACTOR \end{aligned} \tag{3E-3}$$

where,

[15] Natural gas production revenues result from the fact that significant volumes of natural gas are produced when the kerogen is retorted in the surface facilities. See prior table regarding the volume of natural gas produced for a 100,000 barrel per day oil shale syncrude facility.

| | | |
|---|---|---|
| OS_ELEC_CONSUMP | = | Annual electricity consumption for a 100,000 barrel per day facility |
| PELIN(8,t) | = | Electricity price in Colorado/Utah/Wyoming at time t |
| (1.083 / .732) | = | GNP chain-type price deflators to convert 1987 dollars into 2004 dollars |
| OS_CAP_FACTOR | = | Facility capacity factor. |

In any given year, pre-tax project cash flow is:

$$PRETAX\_CASH\_FLOW_t = TOT\_REVENUE_t - TOTAL\_COST_t \tag{3E-4}$$

where,

| | | |
|---|---|---|
| $TOT\_REVENUE_t$ | = | Total project revenues at time t |
| $TOT\_COST_t$ | = | Total project costs at time t. |

Total project revenues are calculated as follows:

$$TOT\_REVENUE_t = OIL\_REVENUE_t + GAS\_REVENUE_t \tag{3E-5}$$

While total project costs are calculated as follows:

$$TOT\_COST_t = OS\_PLANT\_OPER\_CST + ROYALTY_t + PRJ\_MINE\_CST + ELEC\_COST_t + INVEST \tag{3E-6}$$

where,

| | | |
|---|---|---|
| $OS\_PLANT\_OPER\_CST$ | = | Annual plant operating costs per year |
| $ROYALTY_t$ | = | Annual royalty costs at time t |
| $PRJ\_MINE\_COST$ | = | Annual plant mining costs |
| $ELEC\_COST_t$ | = | Annual electricity costs at time t |
| $INVEST$ | = | Annual surface facility investment costs. |

While the plant is under construction (in years 1 through 5) only INVEST has a positive value, while the other four cost elements equal zero. When the plant goes into operation (in years 6 through 30), the capital costs (INVEST) are zero, while the other four cost elements take on positive values. The annual investment cost for the five years of construction assumes that the construction costs are evenly spread over the 5-year construction period and is calculated as follows:

$$INVEST = OS\_PLANT\_INVEST / OS\_PRJ\_CONST \tag{3E-7}$$

Because the plant output is composed of both shale oil syncrude and natural gas, the annual royalty cost (ROYALTY) is calculated by applying the royalty rate to total revenues, as follows:

$$ROYALTY_t = OS\_ROYALTY\_RATE * TOT\_REVENUE_t \tag{3E-8}$$

Annual project mining costs are calculated as the mining cost per barrel of syncrude multiplied by the number of barrels produced, as follows:

(3E-9)

$$PRJ\_MINE\_COST = (OS\_MINE\_CST\_TON * (42 / (OS\_GALLON\_TON * OS\_CONV\_EFF))) * (OS\_PROJ\_SIZE * OS\_CAP\_FACTOR * 365)$$

where,

| | | |
|---|---|---|
| 42 | = | gallons per barrel |
| 365 | = | days per year. |

After the plant goes into operation and after a pre-tax cash flow is calculated, then a post-tax cash flow has to be calculated based on income taxes and depreciation tax credits. When the prevailing world oil price is sufficiently high and the pre-tax cash flow is positive, then the following post-tax cash flow is calculated as:

$$CASH\_FLOW_t = (PRETAX\_CASH\_FLOW_t * (1 - OS\_CORP\_TAX\_RATE)) + (OS\_CORP\_TAX\_RATE * OS\_PLANT\_INVEST / OS\_PRJ\_LIFE) \tag{3E-10}$$

The above depreciation tax credit calculation assumes straight-line depreciation over the operating life of the investment (OS_PRJ_LIFE).

## Discount Rate Financial Parameters

The discounted cash flow algorithm uses the following financial parameters to determine the discount rate used in calculating the net present value of the discounted cash flow.

**Table 3E-3. Discount Rate Financial Parameters**

| Financial Parameters | OSSM Variable Name | Parameter Value |
|---|---|---|
| Corporate income tax rate | OS_CORP_TAX_RATE | 38 percent |
| Equity share of total facility capital | OS_EQUITY_SHARE | 70 percent |
| Facility equity beta | OS_EQUITY_VOL | 1.75 |
| Expected market risk premium | OS_EQUITY_PREMIUM | 6.75 percent |
| Facility debt risk premium | OS_DEBT_PREMIUM | 0.5 percent |

The corporate equity beta (OS_EQUITY_VOL) is a project risk beta, not a firm's volatility of stock returns relative to the stock market's volatility. Because of the technology and construction uncertainties associated with oil shale plants, the project's equity holder's risk is expected to be somewhat greater than the average industry firm beta. In 2005, a median beta for oil and gas field exploration service firms was 1.65. Because a project's equity holders' investment risk level is higher, the facility equity beta assumed for oil shale projects is 1.75.

The expected market risk premium (OS_EQUITY_PREMIUM), which is 6.75 percent, is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). A Monte Carlo simulation methodology was used to estimate the expected market return.

Oil shale project bond ratings are expected to be in Ba range. Since the NEMS macroeconomic module endogenously determines the industrial Baa bond rates for the forecasting period, the cost of debt rates are different in each year. The debt premium (OS_DEBT_PREMIUM) adjusts the bond rating for the project from the Baa to the Ba range, which is assumed to be constant at the average historical differential over the forecasting period.

## Discount Rate Calculation

A seminal parameter used in the calculation of the net present value of the cash flow is the discount rate. The discount rate used in the oil shale submodule is consistent with the way the discount rate is calculated through the National Energy Modeling System. The discount rate equals the post-tax weighted average cost of capital, which is calculated in the OSSS as follows:

$$\begin{aligned} OS\_DISCOUNT\_RATE_t = & (((1 - OS\_EQUITY\_SHARE) * (MC\_RMCORPBAA_t / 100 + \\ & OS\_DEBT\_PREMIUM)) * (1 - OS\_CORP\_TAX\_RATE) + \\ & (OS\_EQUITY\_SHARE * ((OS\_EQUITY\_PREMIUM * \\ & OS\_EQUITY\_VOL) + MC\_RMGFCM\_10NS_t / 100)) \end{aligned} \tag{3E-11}$$

where,

| | | |
|---|---|---|
| OS_EQUITY_SHARE | = | Equity share of total facility capital |
| $MC\_RMCORPBAA_t / 100$ | = | BAA corporate bond rate |
| OS_DEBT_PREMIUM | = | Facility debt risk premium |
| OS_CORP_TAX_RATE | = | Corporate income tax rate |
| OS_EQUITY_PREMIUM | = | Expected market risk premium |
| OS_EQUITY_VOL | = | Facility equity volatility beta |
| $MC\_RMGFCM\_10NS_t / 100$ | = | 10-year Treasury note rate. |

In calculating the facility's cost of equity, the equity risk premium (which is a product of the expected market premium and the facility equity beta, is added to a "risk-free" rate of return, which is considered to be the 10-year Treasury note rate.

The nominal discount rate is translated into a constant, real discount rate using the following formula:

$$OS\_DISCOUNT\_RATE_t = ((1.0 + OS\_DISCOUNT\_RATE_t) / (1.0 + INFL_t)) - 1.0 \tag{3E-12}$$

where,

| | | |
|---|---|---|
| $INFL_t$ | = | Inflation rate at time t. |

## Net Present Value Discounted Cash Flow Calculation

So far a potential project's yearly cash flows have been calculated along with the appropriate discount rate. Using these calculated quantities, the net present value of the yearly cash flow values is calculated as follows:

$$NET\_CASH\_FLOW_{t-1} = \sum_{t=1}^{OS\_PRJ\_LIFE + OS\_PRJ\_CONST} \left[ CASH\_FLOW_t * \left[ \frac{1}{1 + OS\_DISCOUNT\_RATE_t} \right]^t \right] \tag{3E-13}$$

If the net present value of the projected cash flows exceeds zero, then the potential oil shale facility is considered to be economic and begins construction, so long as this facility construction does not violate the construction timing constraints detailed below.

## Oil Shale Facility Construction Timing Constraints

As noted in the introduction, there is no empirical basis for determining how rapidly new oil shale facilities would be built, once the OSSS determines that surface-retorting oil shale facilities are economically viable, because no full-scale commercial facilities have ever been constructed. However, there are two constraints to further oil shale facility construction. The first constraint on oil shale facility construction is imposed by the absence of a Federal land leasing program for commercial oil shale facilities. The second constraint on oil shale facility construction is the financial and technical risk of building a full-scale commercial oil shale syncrude production facility. The following discussion describes which of these two constraints determines the earliest possible date for a commercial oil shale facility within the OSSS.

The highest grade oil shale resources are located on Federal land located in Colorado, Utah, and Wyoming, where these three States meet. So, Federal land is the most desirable location for siting commercial oil shale facilities. The U.S. Department of Interior, Bureau of Land Management (BLM), however, must first implement a commercial oil shale facility leasing program before commercial oil shale syncrude facilities can be built on Federal land.[16] The OSSS assumes that a BLM leasing program, including the award of Federal oil shale leases will be accomplished by 2009, so that the first commercial plant could begin construction in 2010. This BLM leasing schedule assumes that between 2 to 3 years will be required to complete the final environmental impact statement and that an additional 1 to 2 years are required to complete the first oil shale land lease auction. Of course, if the draft environmental impact statement faces significant Court challenges, the completion of the first BLM auction could occur well after 2009. Although the BLM could have a commercial oil shale lands leasing program in place by 2010 or shortly thereafter, this leasing process is not the primary constraint to building the first commercial oil shale facility.

The binding constraint to first commercial production is the rate at which field testing can be conducted and concluded so as to reduce the technical and financial risks associated with oil shale production. In June of 2005, the BLM solicited requests for oil shale RD&D leases. Each oil shale RD&D lease nomination encompasses a 160-acre tract and associated preference rights to an additional contiguous area of 4,960 acres to be reserved for a preferential right to convert to a commercial lease at a future time after additional BLM review. In 2006 and 2007, the BLM awarded 4 RD&D leases with 3 in Colorado and 1 in Utah. Of the four leases, only one will employ surface retorting using previously mined oil shale, while the other three leases employ variations of the in-situ process approach.

Because Shell's in-field research program began in 1997 on private land, the Shell oil shale RD&D program is considered to be the most advanced, and Shell is most likely to be the first party to build and operate a commercial scale oil shale production facility. Based on conversations between Shell personnel and EIA personnel, Shell is likely to conclude its field experiments, which test the various components of a commercial facility, by 2010. Around 2010, Shell expects to build a non-commercial demonstration plant that would test the commercial feasibility of the in-situ process. The permitting, planning, and construction of a demonstration plant will take approximately 2 years. Another 5 years is required to complete one production cycle on one or more parcels of land. This 7-year demonstration plant process in conjunction with a 2010 starting date results in the earliest possible initiation of a full-scale commercial plant being 2017.[17]

New technology penetration is constrained by financial and technical risks. The financial risks are largely determined by the size of the investment (relative to the size of the corporation), the length of the construction period (with longer construction periods potentially resulting in significant market changes since construction

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[16] On June 9, 2005, BLM published a Federal Register notice (page 33753) soliciting nominations for oil shale research, development and demonstration leases.

[17] Op. cit. EIA/OIAF/OGD memorandum entitled, "Oil Shale Project Size and Production Ramp-Up."

began), and by the product's price volatility. The technical risks include: low production rates to due technology failures, equipment breakdowns, construction cost overruns, lower than expected production rates, etc. Because the risk of employing a new untested technology is considerably greater than that associated with well established technologies, industry participants often take a wait-and-see approach, in which they hope to learn from an early implementer's mistakes and improvements. Consequently, technology penetration is slow after the new technology first becomes available, followed by a subsequent acceleration of its penetration after the technology has been perfected and proven.

In order to mimic the initially slow market penetration, followed by increasing rate of penetration, the OSSS implements a technology penetration algorithm, which specifies that 5 years must pass since the first facility began construction before the second facility can begin construction. Subsequent facilities are permitted to begin construction 3 years, 2 years, and then every year after a prior facility began construction. This technology penetration algorithm implicitly assumes that only a single oil shale plant can begin construction in any future year. Under the oil price scenarios used in the *Annual Energy Outlook 2009* the single facility per year assumption is realistic given that oil shale only becomes economic in the high price case, such that the first plant begins operation in 2023; the second goes into operation in 2028, the third in 2031, which is beyond the 2030 timeframe of the projections. Consequently, the 5-year, 3-year, 2-year, 1-year construction delay algorithm is more constraining than the single plant per year assumption.[18]

While the OSSS costs and performance profiles are based on technologies evaluated in the 1970's and early 1980's, the complete absence of any oil shale production makes its future economic development highly uncertain. If the technological, environmental, and economic hurdles are as high or higher than those experienced during the 1970's, then the prospects for oil shale development remain weak through 2030. However, technological progress can totally alter the economic and environmental landscape in ways currently unanticipated. For example, if the Shell Oil in-situ process were to be demonstrated to be both technically and economically feasible, it would significantly improve the prospects for an oil shale industry, and add vast economically recoverable oil resources in the United States and possibly elsewhere in the world.

[18] Alternatively, one can view the fact that OSSS assumes a the large commercial plant size of 100,000 barrels per day to indicate the possibility that smaller oil shale facilities (e.g., 50,000 barrels per day) are initiated at a more rapid penetration rate.

# Appendix A.  Data Inventory

An inventory of OGSM variables is presented in the following tables. These variables are divided into four categories:

| | |
|---|---|
| Variables: | Variables calculated in OGSM |
| Data: | Input data |
| Parameters: | Estimated parameters |
| Output: | OGSM outputs to other modules in NEMS. |

The data inventory for the Offshore Supply Submodule is presented in a separate table.

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

| Equation Number | Variables | | | | | |
|---|---|---|---|---|---|---|
| | Subroutine | Variable Name | | Description | Unit | Classification |
| | | Code | Text | | | |
| 1 | OG_DCF | CF | NCFON | Net cash flow for a representative project | 1987$ | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 2, 5 | OG_DCF | DCFTOT | PROJDCFON | Discounted cash flow for a representative project | 1987$ | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 3, 4, 6 | OG_DCF | OG_DCF | DCFON | Discounted cash flow for a representative well | 1987$ | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 7, 8 | OGEXP_CALC | SODCF | ODCFON | Discounted cash flow for oil | 1987$ | Class(Exploratory,Developmental); 6 Lower 48 onshore regions |
| 7, 9 | OGEXP_CALC | SGDCF | SGDCFON | Discounted cash flow for shallow gas | 1987$ | Class(Exploratory,Developmental); 6 Lower 48 onshore regions |
| 10 | OGEXP_CALC | CASHFLOW | CASHFLOW | Industry cash flow | 1997$ | NA |
| 11 | OGEXP_CALC | WELLSL48 | WELLSON | Lower 48 onshore wells drilled | Wells | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 12 | OGEXP_CALC | SUCWELLL48 | SUCWELSON | Successful Lower 48 onshore wells drilled | Wells | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 13 | OGEXP_CALC | DRYWELLL48 | DRYWELON | Dry Lower 48 onshore wells drilled | Wells | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 14 | OGCST_L48 | ESTOWELLSL48 | ESTOWELLS | Estimated lower 48 onshore oil drilling (successful and dry) | Wells | Lower 48 onshore |
| 15 | OGCST_L48 | ESTGWELLSL48 | ESTGWELLS | Estimated lower 48 onshore gas drilling (successful and dry) | Wells | Lower 48 onshore |
| 16 | OGCST_L48 | RIGSL48 | RIGSL48 | Available rigs | Rigs | Lower 48 onshore |
| 17 | OGCST_L48 | DRILLL48 | DRILLCOST | Successful well drilling costs | 1987$ per well | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 18 | OGCST_L48 | DRYL48 | DRYCOST | Dry well drilling costs | 1987$ per well | Class(Exploratory,Developmental); |

| | Variables | | | | | |
|---|---|---|---|---|---|---|
| | | Variable Name | | | | |
| Equation Number | Subroutine | Code | Text | Description | Unit | Classification |
| | | | | | | 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 19 | OGCST_L48 | LEASL48 | LEQC | Lease equipment costs | 1987$ per well | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 20 | OGCST_L48 | OPERL48 | OPC | Operating costs | 1987$ per well | Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 21 | OGOUT_L48 | FR1L48 | FR1 | Finding rates for new field wildcat drilling | Oil-MMB per well Gas-BCF per well | 6 Lower 48 onshore regions; Fuel(2 oil,2 gas) |
| 22 | OGOUT_L48 | NRDL48 | NRD | Proved reserves added by new field discoveries | Oil-MMB Gas-BCF | 6 Lower 48 onshore regions; Fuel(2 oil,2 gas); |
| 23 | OGOUT_L48 | FR2L48 | FR2 | Finding rates for other exploratory | Oil-MMB per well Gas-BCF per well | 6 Lower 48 onshore regions; Fuel(2 oil,2 gas) |
| 24 | OGOUT_L48 | FR3L48 | FR3 | Finding rates for developmental wells | Oil-MMB per well Gas-BCF per well | 6 Lower 48 onshore regions; Fuel(2 oil,2 gas) |
| 25 | OGOUT_L48 | RESADL48 | RA | Total additions to proved reserves | Oil-MMB Gas-BCF | 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 26 | OGOUT_L48 | RESBOYL48 | R | End of year reserves for current year | Oil-MMB Gas-BCF | 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 27-28 | OGOUT_L48 | PRRATL48 | PR | Production to reserves ratios | Fraction | 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 29 | OGOUT_L48 | EXPRDL48 | Q | Production | Oil-MMB Gas-BCF | 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas) |
| 30 | OGCOMP_AD | X | X | Associated-dissolved gas reserves to production ratio in logistic form | Fraction | 6 Lower 48 onshore regions |
| 31 | OGCOMP_AD | PR_ADGAS | PR_ADGAS | Associated-dissolved gas production to reserves ratio | Fraction | 6 Lower 48 onshore regions |
| 32 | OGCOMP_AD | RA_ADGAS | RA_ADGAS | Associated-dissolved gas reserve additions | BCF | 6 Lower 48 onshore regions |
| 33 | OGCOMP_AD | R_ADGAS | R_ADGAS | Associated-dissolved gas reserves | BCF | 6 Lower 48 onshore regions |

| | Variables | | | | | |
|---|---|---|---|---|---|---|
| | | Variable Name | | | | |
| Equation Number | Subroutine | Code | Text | Description | Unit | Classification |
| 34 | OGCOMP_AD | OGPRDAD | Q_ADGAS | Associated-dissolved gas production | BCF | 6 Lower 48 onshore regions |
| 35 | OGCOST_AK | DRILLAK | DRILLCOST | Drilling costs | 1987$ per well | Class(Exploratory,Developmental); 3 Alaska regions,Fuel (oil, gas) |
| 36 | OGCOST_AK | LEASAK | EQUIP | Lease equipment costs | 1987$ per well | Class(Exploratory,Developmental); 3 Alaska regions,Fuel (oil, gas) |
| 37 | OGCOST_AK | OPERAK | OPCOST | Operating costs | 1987$ per well | Class(Exploratory,Developmental); 3 Alaska regions,Fuel (oil, gas) |
| 38 | OG_DCF | REV | REV | Revenue from a representative project | 1987$ | Alaska field |
| 39 | OG_DCF | DCFTOT | DCF | Discounted cash flow for a representative project | 1987$ | Alaska field |
| 40 | OGNEW_AK | COST_AK | COST | Capital costs | 1987$ | Alaska field |
| 41 | OGNEW_AK | PROF_AK | PROF | Profitability indicator | NA | Alaska field |
| 42 | XOGOUT_IMP | SUCWELL | SUCWELL | Successful conventional Canadian wells drilled in WCSB | Wells | Fuel(gas) |
| 43 | XOGOUT_IMP | FRCAN | FRCAN | Canadian finding rate for WCSB, conventional only | Gas:BCF per well | Fuel(gas) |
| 44 | XOGOUT_IMP | URRCAN | URRCAN | Canadian remaining WCSB conventional resources | Gas Bcf | Fuel(gas) |
| 45 | XOGOUT_IMP | RESADCAN | RESADCAN | Conventional Canadian reserve additions in WCSB | Gas: BCF | Fuel(gas) |
| 46 | XOGOUT_IMP | RESBOYCAN | RESBOYCAN | Conventional Canadian reserves in WCSB (BOY for t+1) | Gas: BCF | Fuel(gas) |
| 47 | XOGOUT_IMP | PRRATCAN | PRRATCAN | Conventional Canadian production to reserves ratio in WCSB | Fraction | Fuel(gas) |
| 3A-1 | OG_DCF | DCFTOT | DCF | Discounted cash flow for a representative project | 1987$ per project | NA |
| 3A-2 | OG_DCF | PVSUM(1) | PVREV | Present value of expected | 1987$ per project | NA |

| Equation Number | Subroutine | Variable Name: Code | Variable Name: Text | Description | Unit | Classification |
|---|---|---|---|---|---|---|
| | | | | revenue | | |
| 3A-4 | OG_DCF | PVSUM(2) | PVROY | Present value of expected royalty payments | 1987$ per project | NA |
| 3A-5 | OG_DCF | PVSUM(3) | PVPRODTAX | Present value of expected production taxes | 1987$ per project | NA |
| 3A-6 | OG_DCF | PVSUM(4) | PVDRILLCOST | Present value of expected drilling costs | 1987$ per project | NA |
| 3A-7 | OG_DCF | PVSUM(5) | PVEQUIP | Present value of expected lease equipment costs | 1987$ per project | NA |
| 3A-8 | OG_DCF | PVSUM(8) | PVKAP | Present value of expected capital costs | 1987$ per project | NA |
| 3A-9 | OG_DCF | PVSUM(6) | PVOPCOST | Present value of expected operating costs | 1987$ per project | NA |
| 3A-10 | OG_DCF | PVSUM(7) | PVABANDON | Present value of expected abandonment costs | 1987$ per project | NA |
| 3A-11 | OG_DCF | PVSUM(13) | PVTAXBASE | Present value of expected tax base | 1987$ per project | NA |
| 3A-12 | OG_DCF | XIDC | XIDC | Expensed Costs | 1987$ per project | NA |
| 3A-14 | OG_DCF | DHC | DHC | Dry hole costs | 1987$ per project | NA |
| 3A-15 | OG_DCF | DEPREC | DEPREC | Depreciable costs | 1987$ per project | NA |
| 3A-16 | OG_DCF | PVSUM(15) | PVSIT | Expected value of state income taxes | 1987$ per project | NA |
| 3A-17 | OG_DCF | PVSUM(16) | PVFIT | Expected value of federal income taxes | 1987$ per project | NA |
| 3D-1 | DeterminePossibleExplorationProjects | CUMDISC | DiscoveredFields | Cumulative number of dicovered offshore fields | NA | Offshore evaluation unit: Field size class |
| 3D-2 | DeterminePossibleExplorationProjects | SC | $\gamma$ | Search coefficient for discovery model | Fraction | Offshore evaluation unit: Field size class |
| 3D-3 | DeterminePossibleExplorationProjects | CUMNFW | CumNFW | Cumulative number of new fields wildcats drilled | NA | Offshore evaluation unit: Field size class |
| 3D-4 | EXPLCOST | EXPLCOST | ExplorationDrilling Costs | Exploration well drilling cost | $ per wells | Offshore evaluation unit |

| | Variables | | | | | |
|---|---|---|---|---|---|---|
| | | Variable Name | | | | |
| Equation Number | Subroutine | Code | Text | Description | Unit | Classification |
| 3D-5 | EXPLCOST | EXPLCOST | ExplorationDrilling Costs | Exploration well drilling cost | $ per wells | Offshore evaluation unit |
| 3D-6 | EXPLCOST | EXPLCOST | ExplorationDrilling Costs | Exploration well drilling cost | $ per structure | Offshore evaluation unit |
| 3D-7 | PFCOST | PFCOST | StructureCost | Offshore production facility cost | $ per structure | Offshore evaluation unit |
| 3D-8 | PFCOST | PFCOST | StructureCost | Offshore production facility cost | $ per structure | Offshore evaluation unit |
| 3D-9 | PFCOST | PFCOST | StructureCost | Offshore production facility cost | $ per structure | Offshore evaluation unit |
| 3D-10 | PFCOST | PFCOST | StructureCost | Offshore production facility cost | $ per structure | Offshore evaluation unit |
| 3D-11 | PFCOST | PFCOST | StructureCost | Offshore production facility cost | $ per structure | Offshore evaluation unit |
| 3D-12 | PFCOST | PFCOST | SubseaTemplateC ost | Subsea Template Cost | $ per template | Offshore evaluation unit |
| 3D-13 | DEVLCOST | DEVLCOST | DevelopmentDrillin gCost | Development drilling cost | $ per well | Offshore evaluation unit |
| 3D-14 | DEVLCOST | DEVLCOST | DevelopmentDrillin gCost | Development drilling cost | $ per well | Offshore evaluation unit |
| 3D-15 | OPRCOST | OPRCOST | OperatingCost | Operating cost | $ per well | Offshore evaluation unit |
| 3D-16 | OGINIT_OFF | NDEVWLS | DevelopmentWells | Number of development wells drilled | NA | Offshore evaluation unit |
| 3D-17 | OGReportToOGSM | RESOFF | RESOFF | Offshore reserves | Oil-MMB per well Gas-BCF per well | Offshore region; Offshore fuel(oil,gas) |
| 3D-18 | OGReportToOGSM | NRDOFF | NRDOFF | Offshore new reserve discoveries | Oil-MMB per well Gas-BCF per well | Offshore region; Offshore fuel(oil,gas) |
| 3D-19 | OGReportToOGSM | NIRDOFF | NIRDOFF | Offshore new inferred reserves | Oil-MMB per well Gas-BCF per well | Offshore region; Offshore fuel(oil,gas) |
| 3D-20 | OGReportToOGSM | REVOFF | REVOFF | Offshore reserve revisions | Oil-MMB per well Gas-BCF per well | Offshore region; Offshore fuel(oil,gas) |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| ACCESS_YR | -- | OGINIT_BFW | Year in which Federal access restrictions would be reduced in the Rocky Mountain Region in an increased ACCESS Case | Year | NA | Office of Integrated Analysis and Forecasting |
| ADVLTXL48 | PRODTAX | OGFOR_L48<br>OGINIT_L48 | Lower 48 onshore ad valorem tax rates | Fraction | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Colorado School of Mines. Oil Propert Evaluation, 1983, p. 9-7 |
| ADVLTXOFF | PRODTAX | OGFOR_OFF<br>OGINIT_OFF | Offshore ad valorem tax rates | Fraction | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Colorado School of Mines. Oil Propert Evaluation, 1983, p. 9-7 |
| ANGTSMAX | -- | OGINIT_AK<br>OGPIP_AK | ANGTS maximum flow | BCF/D | Alaska | National Petroleum Council |
| ANGTSPRC | -- | OGINIT_AK<br>OGPIP_AK | Minimum economic price for ANGTS start up | 1987$/MCF | Alaska | National Petroleum Council |
| ANGTSRES | -- | OGINIT_AK<br>OGPIP_AK | ANGTS reserves | BCF | Alaska | National Petroleum Council |
| ANGTSYR | -- | OGINIT_AK<br>OGPIP_AK | Earliest start year for ANGTS flow | Year | NA | National Petroleum Council |
| BUILDLAG | -- | OGEXPAND_LNG<br>OGINIT_LNG | Buildup period for expansion of LNG facilities | Year | NA | Office of Integrated Analysis and Forecasting |
| CPRDL48 | COPRD | OGFOR_L48<br>OGINIT_L48 | Lower 48 onshore coproduct rate | Fraction | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| CPRDOFF | COPRD | OGFOR_OFF<br>OGINIT_OFF | Offshore coproduct rate | Fraction | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| CURPRRCAN | PR | OGINIT_IMP<br>OGOUT_IMP | Canadian 1989 P/R ratio | Fraction | Canada; Fuel (gas) | Derived using data from the Canadian Petroleum Association |
| CURPRRL48 | omega | OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | Lower 48 initial P/R ratios | Fraction | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| CURPRROFF | omega | OGINIT_OFF<br>OGINIT_RES<br>OGOUT_OFF | Offshore initial P/R ratios | Fraction | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| CURPRRTDM | -- | OGINIT_L48<br>OGOUT_L48 | Lower 48 initial P/R ratios at NGTDM level | Fraction | 17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| CURRESL48 | R | OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | Lower 48 onshore initial reserves | MMB<br>BCF | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Derived from Annual Reserves Report Data |
| CURRESOFF | R | OGINIT_OFF<br>OGINIT_RES<br>OGOUT_OFF | Offshore initial reserves | MMB<br>BCF | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Derived from Annual Reserves Report Data |
| CURRESTDM | -- | OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | Lower 48 natural gas reserves at NGTDM level | MMB<br>BCF | 17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| DECFAC | DECFAC | OGOUT_L48 | Inferred resource simultaneous draw down decline rate adjustment factor | Fraction | NA | Office of Integrated Analysis and Forecasting |
| DECLL48 | -- | OGFOR_L48<br>OGINIT_L48<br>WELL | Lower 48 onshore decline rates | Fraction | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| DECLOFF | -- | OGFOR_OFF<br>OGINIT_OFF<br>WELL | Offshore decline rates | Fraction | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| DECLPRO | -- | OGINIT_AK<br>OGPRO_AK | Alaska decline rates for currently producing fields | Fraction | Field | Office of Integrated Analysis and Forecasting |
| DEPLETERT | -- | OGINIT_IMP | Depletion rate | Fraction | NA | Not Used<br>Office of Integrated Analysis and Forecasting |
| DEV_AK | -- | OGDEV_AK<br>OGINIT_AK<br>OGSUP_AK | Alaska drilling schedule for developmental wells | Wells per year | 3 Alaska regions; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| DISC | disc | OGDCF_AK<br>OGFOR_L48<br>OGFOR_OFF | Discount rate | Fraction | National | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| | | OGINIT_BFW | | | | |
| DRILLAK | DRILL | OGCOST_AK<br>OGINIT_AK | Alaska drilling cost (not including new field wildcats) | 1990$/well | Class (exploratory, developmental);<br>3 Alaska regions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| DRILLOFF | DRILL | OGALL_OFF<br>OGFOR_OFF<br>OGINIT_OFF | Offshore drilling cost | 1987$ | 4 Lower 48 offshore subregions | Mineral Management Service |
| DRLNFWAK | -- | OGCOST_AK<br>OGINIT_AK | Alaska drilling cost of a new field wildcat | 1990$/well | 3 Alaska regions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| DRYAK | DRY | OGDCF_AK<br>OGDEV_AK<br>OGINIT_AK<br>OGNEW_AK | Alaska dry hole cost | 1990$/hole | Class (exploratory, developmental);<br>3 Alaska regions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| DRYOFF | DRY | OGALL_OFF<br>OGEXP_CALC<br>OGFOR_OFF<br>OGINIT_OFF | Offshore dry hole cost | 1987$ | Class (exploratory, developmental);<br>4 Lower 48 offshore subregions | Minerals Management Service |
| DVWELLOFF | -- | OGFOR_OFF<br>OGINIT_OFF | Offshore development project drilling schedules | wells per year | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Minerals Management Service |
| DVWLCBML48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 development project drilling schedules for coalbed methane | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| DVWLDGSL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 development project drilling schedules for deep gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| DVWLDVSL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 development project drilling schedules for devonian shale | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| DVWLOILL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 development project drilling schedules for oil | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| DVWLSGSL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 development project drilling schedules for shallow gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| DVWLTSGL48 | -- | OGFOR_L48<br>OGINIT_L48 | Development project drilling schedules for tight gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| ELASTL48 | -- | OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | Lower 48 onshore production elasticity values | Fraction | 6 OGSm Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| ELASTOFF | -- | OGINIT_OFF<br>OGINIT_RES<br>OGOUT_OFF | Offshore production elasticity values | Fraction | 4 Lower 48 offshore subregions | Office of Integrated Analysis and Forecasting |
| EMCO | -- | OGCOMP_EMIS<br>OGINIT_EMIS | Emission factors for crude oil production | Fraction | Census regions | EPA - Energy Technology Characterizations Handbook |
| EMFACT | -- | OGCOMP_EMIS<br>OGINIT_EMIS | Emission factors | MMB<br>MMCF | Census regions | EPA - Energy Technology Characterizations Handbook |
| EMNG | -- | OGCOMP_EMIS<br>OGINIT_EMIS | Emission factors for natural gas production | Fraction | Census regions | EPA - Energy Technology Characterizations Handbook |
| EQUIPAK | EQUIP | OGCOST_AK<br>OGINIT_AK | Alaska lease equipment cost | 1990$/well | Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas) | U.S. Geological Survey |
| EXOFFRGNLAG | -- | OGEXP_CALC<br>OGINIT_BFW | Offshore exploration & development regional expenditure (1989) | 1987$ | Class (exploratory, developmental);<br>4 Lower 48 offshore subregions | Office of Integrated Analysis and Forecasting |
| EXP_AK | -- | OGDEV_AK<br>OGINIT_AK<br>OGSUP_AK | Alaska drilling schedule for other exploratory wells | wells per year | 3 Alaska regions | Office of Integrated Analysis and Forecasting |
| EXWELLOFF | -- | OGFOR_OFF<br>OGINIT_OFF | Offshore exploratory project drilling schedules | wells per year | 4 Lower 48 offshore subregions | Minerals Management Service |
| EXWLCBML48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 exploratory project drilling schedules for coalbed methane | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| EXWLDGSL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 exploratory and developmental project drilling schedules for deep gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| EXWLDVSL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 exploratory project drilling schedules for devonian shale | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| EXWLOILL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 exploratory project drilling schedules for oil | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| EXWLSGSL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 exploratory project drilling schedules for shallow gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| EXWLTSGL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 exploratory project drilling schedules for tight gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| FACILAK | -- | OGDEV_AK<br>OGFAC_AK<br>OGINIT_AK<br>OGSUP_AK | Alaska facility cost (oil field) | 1990$/bls | Field size class | U.S. Geological Survey |
| FEDTXR | FDRT | OGDCF_AK<br>OGEXP_CALC<br>OGFOR_L48<br>OGFOR_OFF<br>OGINIT_BFW | U.S. federal tax rate | fraction | Canada | U.S. Tax Code |
| FLOWCAN | -- | OGINIT_IMP | Canadian flow rates | bls, MCF per year | Canada; Fuel (oil, gas) | Not used.<br>Office of Integrated Analysis and Forecasting |
| FLOWL48 | -- | OGFOR_L48<br>OGINIT_L48 | Lower 48 onshore flow rates | bls, MCF per year | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | EIA, Office of Oil and Gas |
| FLOWOFF | -- | OGFOR_OFF<br>OGINIT_OFF | Offshore flow rates | bls, MCF per year | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| FPRDCST | -- | OGINIT_LNG<br>OGPROF_LNG | Foreign production costs | 1991$/MCF per year | LNG Source Country | National Petroleum Council |
| FRMINL48 | FRMIN | OGINIT_L48<br>OGOUT_L48 | Lower 48 onshore minimum exploratory well finding rate | MMB<br>BCF<br>per well | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| FRMINOFF | FRMIN | OGINIT_OFF<br>OGOUT_OFF | Offshore minimum exploratory well finding rate | MMB<br>BCF<br>per well | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| FRTECHCAN | FRTECH | XOGOUT_IMP | Canada technology factor applied to finding rate | fraction | Canada | Office of Integrated Analysis and Forecasting |
| FR1L48 | FR1 | OGINIT_L48<br>OGOUT_L48 | Lower 48 onshore new field wildcat well finding rate | MMB<br>BCF<br>per well | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 2 gas) | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| FR1OFF | FR1 | OGINIT_OFF<br>OGOUT_OFF | Offshore new field wildcat well finding rate | MMB<br>BCF<br>per well | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| FR2L48 | FR3 | OGINIT_L48<br>OGOUT_L48 | Lower 48 onshore developmental well finding rate | MMB<br>BCF<br>per well | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 2 gas) | Office of Integrated Analysis and Forecasting |
| FR2OFF | FR3 | OGINIT_OFF<br>OGOUT_OFF | Offshore developmental well finding rate | MMB<br>BCF<br>per well | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| FR3L48 | FR2 | OGINIT_L48<br>OGOUT_L48 | Lower 48 other exploratory well finding rate | MMB<br>BCF<br>per well | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 2 gas) | Office of Integrated Analysis and Forecasting |
| FR3OFF | FR2 | OGINIT_OFF<br>OGOUT_OFF | Offshore other exploratory well finding rate | MMB<br>BCF<br>per well | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| FSZCOAK | — | OGFOR_AK<br>OGINIT_AK<br>OGNEW_AK | Alaska oil field size distributions | MMB | 3 Alaska regions | U.S. Geological Survey |
| FSZNGAK | -- | OGFOR_AK<br>OGINIT_AK<br>OGNEW_AK | Alaska gas field size distributions | BCF | 3 Alaska regions | U.S. Geological Survey |
| HISTADL48 | -- | OGINIT_L48 | Lower 48 historical associated-dissolved natural gas reserves | BCF | NA | Annual Reserves report |
| HISTADOFF | -- | OGINIT_OFF | Offshore historical associated-dissolved natural gas reserves | BCF | NA | Annual Reserves Report |
| HISTFRCAN | -- | OGINIT_IMP<br>XOGOUT_IMP | Historical Canadian finding rate for gas | BCF<br>per well | Canada | Office of Integrated Analysis and Forecasting |
| HISTPRDCO | -- | OGINIT_AK<br>OGPRO_AK | Alaska historical crude oil production | MB/D | Field | Alaska Oil and Gas Conservation Commission |
| HISTPRRCAN | -- | OGINIT_IMP<br>XOGOUT_IMP | Canadian gas production to reserves ratio for historical years | BCF | Canada; Fuel (gas) | Office of Integrated Analysis and Forecasting |
| HISTPRRL48 | -- | OGINIT_L48 | Lower 48 historical P/R ratios | fraction | 6 Lower 48 onshore regions; | Derived from Annual Reserves Report |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| **Variable Name** | | | | | | |
| **Code** | **Text** | **Subroutine** | **Description** | **Unit** | **Classification** | **Source** |
| | | | | | Fuel (2 oil, 5 gas) | |
| HISTPRROFF | -- | OGINIT_OFF | Offshore historical P/R ratios | fraction | 4 Lower 48 offshore subregions; Fuel (oil, gas) | Derived from Annual Reserves Report |
| HISTPRRTDM | -- | OGINIT_L48 | Lower 48 onshore historical P/R ratios at the NGTDM level | fraction | 17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| HISTRESAD | -- | OGINIT_IMP XOGOUT_IMP | Canadian gas reserves additions for historical years | BCF | Canada; Fuel (gas) | Office of Integrated Analysis and Forecasting |
| HISTRESCAN | -- | OGINIT_IMP XOGOUT_IMP | Canadian beginning of year gas reserves for historical years | BCF | Canada; Fuel (gas) | Canadian Petroleum Association |
| HISTWELCAN | -- | OGINIT_IMP XOGOUT_IMP | Canadian gas wells drilled in historical years | BCF | Canada; Fuel (gas) | Office of Integrated Analysis and Forecasting |
| HISTRESL48 | -- | OGINIT_L48 | Lower 48 onshore historical beginning-of-year reserves | MMB BCF | 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas) | Annual Reserves Report |
| HISTRESOFF | -- | OGINIT_OFF | Offshore historical beginning-of-year reserves | MMB BCF | 4 Lower 48 offshore subregions; Fuel (oil, gas) | Annual Reserves Report |
| HISTRESTDM | -- | OGINIT_L48 | Lower 48 onshore historical beginning-of-year reserves at the NGTDM level | MMB BCF | 17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas) | Annual Reserves Report |
| IMPBYR | -- | WELL OGEXPAND_LNG OGINIT_IMP XOGOUT_IMP | Base start-year for Foreign Natural Gas Supply Submodule | -- | -- | Office of Integrated Analysis and Forecasting |
| INFL | infl | OGDCF_AK OGFOR_L48 OGFOR_OFF OGINIT_BFW | U.S. inflation rate | fraction | National | Office of Integrated Analysis and Forecasting |
| INFRSVL48 | I | OGINIT_L48 OGOUT_L48 | Lower 48 onshore inferred reserves | MMB BCF | 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| INFRSVOFF | I | OGINIT_OFF | Offshore inferred reserves | MMB | 4 Lower 48 offshore | Office of Integrated Analysis and |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| | | OGOUT_OFF | | BCF | subregions;<br>Fuel (oil, gas) | Forecasting |
| INFRT | -- | OGINIT_IMP | Canadian inflation rate | fraction | Canada | Not used.<br>Office of Integrated Analysis and Forecasting |
| KAPFRCAK | EXKAP | OGDCF_AK<br>OGINIT_AK | Alaska drill costs that are tangible & must be depreciated | fraction | Alaska | U.S. Tax Code |
| KAPFRCL48 | EXKAP | OGFOR_L48<br>OGINIT_L48 | Lower 48 onshore drill costs that are tangible & must be depreciated | fraction | Class (exploratory, developmental) | U.S. Tax Code |
| KAPFRCOFF | EXKAP | OGFOR_OFF<br>OGINIT_OFF | Offshore drill costs that are tangible & must be depreciated | fraction | Class (exploratory, developmental) | U.S. Tax Code |
| KAPSPNDL48 | KAP | OGFOR_L48<br>OGINIT_L48 | Lower 48 onshore other capital expenditures | 1987$ | Class (exploratory, developmental);<br>6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Not used |
| KAPSPNDOFF | KAP | OGFOR_OFF<br>OGINIT_OFF | Offshore other capital expenditures | 1987$ | Class (exploratory, developmental);<br>4 Lower 48 offshore subregions | Minerals Mangement Service |
| LAGDRILL48 | -- | OGFOR_L48<br>OGINIT_L48 | 1989 Lower 48 drill cost | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| LAGDRYL48 | -- | OGFOR_L48<br>OGINIT_L48 | 1989 Lower 48 dry hole cost | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| LAGLEASL48 | -- | OGFOR_L48<br>OGINIT_L48 | 1989 Lower 48 lease equipment cost | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| LAGOPERL48 | -- | OGFOR_L48<br>OGINIT_L48 | 1989 Lower 48 operating cost | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| LEASOFF | EQUIP | OGFOR_OFF<br>OGINIT_OFF | Offshore lease equipment cost | 1987$ per project | Class (exploratory, developmental);<br>4 Lower 48 offshore subregions | Minerals Mangement Service |
| LIQCAP | -- | OGEXPAND_LNG<br>OGINIT_LNG | Liquefaction capacity | BCF | LNG Source Country | National Petroleum Council |
| LIQCST | -- | OGINIT_LNG<br>OGPROF_LNG | Liquefaction costs | 1991$/MCF | LNG Source Country | National Petroleun Council |
| LIQSTAGE | -- | OGEXPAND_LNG<br>OGPROF_LNG | Liquefaction stage | NA | NA | National Petroleum Council |
| LST_CONV | -- | OGINIT_BFW | Share of the conventional resources in the Rocky Mountains that are subject to Federal lease stipulations | Percent | Fuel (oil, gas) | ARI |
| MAXPRO | -- | OGFOR_AK<br>OGINIT_AK<br>OGPRO_AK | Alaska maximum crude oil production | MB/D | Field | Announced Plans |
| MEXEXP | -- | OGINIT_IMP<br>OGOUT_MEX | Exports from Mexico | BCF | 3 US/Mexican border crossing | Office of Integrated Analysis and Forecasting |
| MEXIMP | -- | OGINIT_IMP<br>OGOUT_MEX | Imports from Mexico | BCF | 3 US/Mexican border crossing | Office of Integrated Analysis and Forecasting |
| NAC_CONV | -- | OGINIT_BFW | Share of the conventional resources in the Rocky Mountains that are legally inaccessible | Percent | Fuel (oil, gas) | ARI |
| NFW_AK | -- | OGINIT_AK<br>OGNEW_AK | Alaska drilling schedule for new field wildcats | wells | NA | Office of Integrated Analysis and Forecasting |
| NFWCOSTOFF | COSTEXP | OGFOR_OFF<br>OGINIT_OFF | Offshore new field wildcat cost | 1987$ | Class (exploratory, developmental);<br>4 Lower 48 offshore subregions | Minerals Management Service |
| NFWELLOFF | -- | OGFOR_OFF<br>OGINIT_OFF | Offshore exploratory and developmental project drilling schedules | wells per project per year | Class (exploratory, developmental);<br>r=1 | Minerals Management Service |
| NGTDMMAP | -- | OGINIT_L48 | Mapping of NGTDM regions to | NA | 17 OGSM/NGTDM | Office of Integrated Analysis and |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| | | OGINIT_RES<br>OGOUT_L48 | OGSM regions | | regions | Forecasting |
| OGCNPPRD | -- | OGINIT_PRICE | Canadian price of oil and gas | oil: 87$s/B<br>gas: 87$s/mcf | Canada | NGTDM |
| OGPNGIMP | -- | OGPIP_AK<br>OGPROF_LNG | Natural gas import price | 87$s/mcf | US/Canadian & US/Mexican border crossings and LNG destination points | NGTDM |
| OPEROFF | OPCOST | OGFOR_OFF<br>OGINIT_OFF | Offshore operating cost | 1987$ per well per year | Class (exploratory, developmental);<br>4 Lower 48 offshore subregions | Mineral Management Service |
| PRJAK | n | OGDCF_AK<br>OGINIT_AK | Alaska oil project life | Years | Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| PRJL48 | n | OGFOR_L48<br>OGINIT_L48 | Lower 48 project life | Years | Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| PRJOFF | n | OGFOR_OFF<br>OGINIT_OFF | Offshore project life | Years | Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| PROYR | -- | OGFOR_AK<br>OGINIT_AK<br>OGPRO_AK | Start year for known fields in Alaska | Year | Field | Announced Plans |
| QLNG | -- | OGEXPAND_LNG<br>OGINIT_LNG<br>OGLNG_OUT | LNG operating flow capacity | BCF | LNG destination points | National Petroleum Council |
| QLNGMAX | -- | OGEXPAND_LNG<br>OGINIT_LNG<br>OGLNG_OUT | LNG maximum capacity | BCF | LNG destination Points | National Petroleum Council |
| RCPRDAK | m | OGDCF_AK<br>OGINIT_AK | Alaska recovery period of intangible & tangible drill cost | Years | Alaska | U.S. Tax Code |
| RCPRDL48 | m | OGFOR_L48<br>OGINIT_L48 | Lower 48 recovery period for intangible & tangible drill cost | Years | Lower 48 Onshore | U.S. Tax Code |
| RCPRDOFF | m | OGFOR_OFF<br>OGINIT_OFF | Offshore recovery period intangible & tangible drill cost | Years | Lower 48 Offshore | U.S. Tax Code |
| RECRES | -- | OGFOR_AK | Alaska crude oil resources for | MMB | Field | OFE, *Alaska Oil and Gas - Energy* |

| Data | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Variable Name** | | | | | | | |
| **Code** | **Text** | **Subroutine** | **Description** | **Unit** | **Classification** | **Source** |
| | | OGINIT_AK<br>OGPRO_AK | known fields | | | *Wealth or Vanishing Opportunity* |
| REGASCST | -- | OGINIT_LNG<br>OGPROF_LNG | Regasification costs | 1991$/MCF per year | Operational Stage; LNG destination points | National Petroleum Council |
| REGASEXPAN | -- | OGEXPAND_LNG<br>OGINIT_LNG | Regasification capacity | BCF | LNG destination points | National Petroleum Council |
| REGASSTAGE | -- | OGEXPAND_LNG<br>OGINIT_LNG<br>OGPROF_LNG | Regasification stage | NA | NA | National Petroleum Council |
| RESBASE | Q | OGINIT_IMP<br>XOGOUT_IMP | Canadian recoverable resource estimate | BCF | Canada | Canadian Geological Survey |
| ROYRT | ROYRT | OGDCF_AK<br>OGFOR_L48<br>OGINIT_BFW | Alaska royalty rate | fraction | Alaska | U.S. Geological Survey |
| SEVTXAK | PRODTAX | OGINIT_AK<br>OGSEVR_AK | Alaska severance tax rates | fraction | Alaska | U.S. Geological Survey |
| SEVTXL48 | PRODTAX | OGFOR_L48<br>OGINIT_L48 | Lower 48 onshore severance tax rates | fraction | 6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Commerce Clearing House |
| SEVTXOFF | PRODTAX | OGFOR_OFF<br>OGINIT_OFF | Offshore severance tax rates | fraction | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Commerce Clearing House |
| SPENDIRKLAG | -- | | 1989 Lower 48 exploration & development expenditures | 1987$ | Class (exploratory, developmental) | Office of Integrated Analysis and Forecasting |
| SRAK | SR | OGDCF_AK<br>OGDEV_AK<br>OGINIT_AK<br>OGNEW_AK | Alaska drilling success rates | fraction | Alaska | Office of Oil and Gas |
| SRL48 | SR | OGEXP_CALC<br>OGEXP_FIX<br>OGFOR_L48<br>OGINIT_L48<br>OGOUT_L48 | Lower 48 drilling success rates | fraction | Class (exploratory, developmental);<br>6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| SROFF | SR | OGALL_OFF | Offshore drilling success rates | fraction | Class (exploratory, | Minerals Management Service |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| | | OGFOR_OFF<br>OGINIT_OFF<br>OGOUT_OFF | | | developmental);<br>4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | |
| STARTLAG | -- | OGEXPAND_LNG<br>OGINIT_LNG | Number of year between stages (regasification and liquefaction) | years | NA | Office of Integrated Analysis and Forecasting |
| STL_CONV | -- | OGINIT_BFW | Share of the conventional resources in the Rocky Mountains that are subject to Standard Lease Terms | Percent | Fuel (oil, gas) | ARI |
| STTXAK | STRT | OGDCF_AK<br>OGINIT_AK | Alaska state tax rate | fraction | Alaska | U.S. Geological Survey |
| STTXL48 | STRT | OGEXP_CALC<br>OGFOR_L48<br>OGINIT_L48 | State tax rates | fraction | 6 Lower 48 onshore regions | Commerce Clearing House |
| STTXOFF | STRT | OGEXP_CALC<br>OGFOR_OFF<br>OGINIT_L48 | State tax rates | fraction | 4 Lower 48 offshore subregions | Commerce Clearing House |
| TECHAK | TECH | OGCOST_AK<br>OGINIT_AK | Alaska technology factors | fraction | Alaska | Office of Integrated Analysis and Forecasting |
| TECHL48 | TECH | OGFOR_L48<br>OGINIT_L48 | Lower 48 onshore technology factors applied to costs | fraction | Lower 48 Onshore | Office of Integrated Analysis and Forecasting |
| TECHOFF | TECH | OGFOR_OFF<br>OGINIT_OFF | Offshore technology factors applied to costs | fraction | Lower 48 Offshore | Office of Integrated Analysis and Forecasting |
| TRANCST | -- | OGINIT_LNG<br>OGPROF_LNG | LNG transportation costs | 1990/MCF | NA | National Petroleum Council |
| TRANSAK | TRANS | OGDCF_AK<br>OGINIT_AK | Alaska transportation cost | 1990$ | 3 Alaska regions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| TRANSL48 | TRANS | OGFOR_L48<br>OGINIT_L48 | Lower 48 onshore expected transportation costs | NA | 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas) | Not Used |
| TRANSOFF | TRANS | OGFOR_OFF<br>OGINIT_OFF | Offshore expected transportation costs | NA | 4 Lower 48 offshore subregions; Fuel (oil, gas) | Not Used |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | Subroutine | Description | Unit | Classification | Source |
| Code | Text | | | | | |
| UNRESOFF | Q | OGINIT_OFF<br>OGOUT_OFF | Offshore undiscovered resources | MMB<br>BCF | 4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| URRCRDL48 | Q | OGINIT_L48<br>OGOUT_L48 | Lower 48 onshore undiscovered recoverable crude oil resources | MMB | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| URRTDM | -- | OGINIT_L48<br>OGOUT_L48 | Lower 48 onshore undiscovered recoverable natural gas resources | TCF | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| WDCFIRKLAG | -- | OGEXP_CALC<br>OGINIT_BFW | 1989 Lower 48 exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental);<br>6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| WDCFIRLAG | -- | OGEXP_CALC<br>OGINIT_BFW | 1989 Lower 48 regional exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental);<br>6 Lower 48 onshore regions; | Office of Integrated Analysis and Forecasting |
| WDCFL48LAG | -- | OGEXP_CALC<br>OGINIT_BFW | 1989 Lower 48 onshore exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental) | Office of Integrated Analysis and Forecasting |
| WDCFOFFIRKLAG | -- | OGEXP_CALC<br>OGINIT_BFW | 1989 offshore exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental);<br>4 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| WDCFOFFIRLAG | -- | OGEXP_CALC<br>OGINIT_BFW | 1989 offshore regional exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental);<br>4 Lower 48 offshore subregions; | Office of Integrated Analysis and Forecasting |
| WDCFOFFLAG | -- | OGEXP_CALC<br>OGINIT_BFW | 1989 offshore exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental) | Office of Integrated Analysis and Forecasting |
| WELLAGL48 | WELLSON | OGEXP_CALC<br>OGEXP_FIX<br>OGINIT_L48 | 1989 Lower 48 wells drilled | Wells per year | Class (exploratory, developmental);<br>6 Lower 48 onshore regions;<br>Fuel (2 oil, 5 gas) | Office of Oil & Gas |
| WELLAGOFF | WELLSOFF | OGALL_OFF<br>OGEXP_CALC<br>OGINIT_OFF | 1989 offshore wells drilled | Wells per year | Class (exploratory, developmental);<br>4 Lower 48 offshore | Office of Oil & Gas |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Variable Name | | | | | | |
| Code | Text | Subroutine | Description | Unit | Classification | Source |
| | | | | | subregions;<br>Fuel (oil, gas) | |
| XDCKAPAK | XDCKAP | OGDCF_AK<br>OGINIT_AK | Alaska intangible drill costs that must be depreciated | fraction | Alaska | U.S. Tax Code |
| XDCKAPL48 | XDCKAP | OGFOR_L48<br>OGINIT_L48 | Lower 48 intangible drill costs that must be depreciated | fraction | NA | U.S. Tax Code |
| XDCKAPOFF | XDCKAP | OGFOR_OFF<br>OGINIT_OFF | Offshore intangible drill costs that must be depreciated | fraction | NA | U.S. Tax Code |

| Outputs | | | | | |
|---|---|---|---|---|---|
| **OGSM Subroutine** | **Variable Name** | **Description** | **Unit** | **Classification** | **Passed To Module** |
| OGFOR_AK<br>OGPIP_AK | OGANGTSMX | Maximum natural gas flow through ANGTS | BCF | NA | NGTDM |
| OGINIT_RES<br>OGOUT_L48<br>OGOUT_OFF | OGELSCO | Oil production elasticity | fraction | 6 Lower 48 onshore & 3 Lower 48 offshore regions | PMM |
| OGINIT_RES<br>OGOUT_OFF | OGELSNGOF | Offshore nonassociated dry gas production elasticity | fraction | 3 Lower 48 offshore regions | NGTDM |
| OGINIT_RES<br>OGOUT_L48 | OGELSNGON | Onshore nonassociated dry gas production elasticity | fraction | 17 OGSM/NGTDM regions | NGTDM |
| OGOUT_EOR | OGEORCOGC | Electric cogeneration capacity from EOR | MWH | 6 Lower 48 onshore regions | Industrial (not used) |
| OGOUT_EOR | OGEORCOGG | Electric cogeneration volumes from EOR | MWH | 6 Lower 48 onshore regions | Industrial (not used) |
| OGCOMP_AD | OGPRDAD | Associated-dissolved gas production | BCF | 6 Lower 48 onshore regions & 3 Lower 48 offshore regions | NGTDM |
| OGINIT_RES<br>XOGOUT_IMP | OGPRRCAN | Canadian P/R ratio | fraction | Fuels (oil, gas) | NGTDM |
| OGINIT_RES<br>OGOUT_L48 | OGPRRCO | Oil P/R ratio | fraction | 6 Lower 48 onshore & 3 Lower 48 offshore regions | PMM |
| OGINIT_RES<br>OGOUT_OFF | OGPRRNGOF | Offshore nonassociated dry gas P/R ratio | fraction | 3 Lower 48 offshore regions | NGTDM |
| OGINIT_RES<br>OGOUT_L48 | OGPRRNGON | Onshore nonassociated dry gas P/R ratio | fraction | 17 OGSM/NGTDM regions | NGTDM |
| OGFOR_AK<br>OGPIP_AK<br>OGPRO_AK | OGQANGTS | Gas flow at U.S. border from ANGTS | BCF | NA | NGTDM |
| OGINIT_IMP<br>XOGOUT_IMP<br>OGOUT_MEX | OGQNGEXP | Natural gas exports | BCF | 6 US/Canada & 3 US/Mexico border crossings | NGTDM |
| OGLNG_OUT<br>XOGOUT_IMP<br>OGOUT_MEX | OGQNGIMP | Natural gas imports | BCF | 3 US/Mexico border crossings; 4 LNG terminals | NGTDM |
| OGINIT_RES<br>XOGOUT_IMP | OGRESCAN | Canadian end-of-year reserves | oil: MMB<br>gas: BCF | Fuel (oil, gas) | NGTDM |
| OGINIT_RES | OGRESCO | Oil reserves | MMB | 6 Lower 48 onshore & 3 Lower | PMM |

| Outputs | | | | | |
|---|---|---|---|---|---|
| **OGSM Subroutine** | **Variable Name** | **Description** | **Unit** | **Classification** | **Passed To Module** |
| OGOUT_L48<br>OGOUT_OFF | | | | 48 offshore regions | |
| OGINIT_RES<br>OGOUT_OFF | OGRESNGOF | Offshore nonassociated dry gas reserves | BCF | 3 Lower 48 offshore regions | NGTDM |
| OGINIT_RES<br>OGOUT_L48 | OGRESNGON | Onshore nonassociated dry gas reserves | BCF | 17 OGSM/NGTDM regions | NGTDM |

| OFFSHORE OIL AND GAS SUPPLY SUBMODULE | | |
|---|---|---|
| **Parameter** | **Description** | **Value** |
| nREG | Region ID (1: CENTRAL & WESTERN GOM; 2: EASTERN GOM; 3: ATLANTIC; 4: PACIFIC) | 4 |
| nPA | Planning Area ID (1: WESTERN GOM; 2: CENTRAL GOM; 3: EASTERN GOM; 4: NORTH ATLANTIC; 5: MID ATLANTIC; 6: SOUTH ATLANTIC; 7: FLORIDA STRAITS; 8: PACIFIC; NORTHWEST; 9: CENTRAL CALIFORNIA; 10: SANTA BARBARA - VENTURA BASIN; 11: LOS ANGELES BASIN; 12: INNER BORDERLAND; 13: OUTER BORDERLAND) | 13 |
| ntEU | Total number of evaluation units (43) | 43 |
| nMaxEU | Maximum number of EU in a PA (6) | 6 |
| TOTFLD | Total number of evaluation units | 3600 |
| nANN | Total number of announce discoveries | 127 |
| nPRD | Total number of producing fields | 1132 |
| nRIGTYP | Rig Type ( 1: JACK-UP 0-1500; 2: JACK-UP 0-1500 (Deep Drilling); 3: SUBMERSIBLE 0-1500; 4: SEMI-SUBMERSIBLE 1500-5000; 5: SEMI-SUBMERSIBLE 5000-7500; 6: SEMI-SUBMERSIBLE 7500-10000; 7: DRILL SHIP 5000-7500; 8: DRILL SHIP 7500-10000) | 8 |
| nPFTYP | Production facility type (1: FIXED PLATFORM (FP); 2: COMPLIANT TOWER (CT); 3: TENSION LEG PLATFORM (TLP); 4: FLOATING PRODUCTION SYSTEM (FPS); 5: SPAR; 6: FLOATING PRODUCTION STORAGE & OFFLOADING (FPSO); 7: SUBSEA SYSTEM (SS)) | 7 |
| nPFWDR | Production facility water depth range (1: 0 - 656 FEET; 2: 656 - 2625 FEET; 3: 2625 - 5249 FEET; 4: 5249 - 7874 FEET; 5: 7874 - 9000 FEET) | 5 |
| NSLTIdx | Number of platform slot data points | 8 |
| NPFWD | Number of production facility water depth data points | 15 |
| NPLTDD | Number of platform water depth data points | 17 |
| NOPFWD | Number of other production facitlity water depth data points | 11 |
| NCSTWD | Number of water depth data points for production facility costs | 39 |
| NDRLWD | Number of water depth data points for well costs | 15 |
| NWLDEP | Number of well depth data points | 30 |
| TRNPPLNCSTNDIAM | Number of pipeline diameter data points | 19 |
| MAXNFIELDS | Maximum number of fields for a project/prospect | 10 |
| nMAXPRJ | Maximum number of projects to evaluate per year | 500 |
| PRJLIFE | Maximum project life in years | 10 |

| OFFSHORE OIL AND GAS SUPPLY SUBMODULE | | | |
|---|---|---|---|
| Variable | Description | Unit | Source |
| ann_EU | Announced discoveries - Evaluation unit name | - | OIAF |
| ann_FAC | Announced discoveries - Type of production facility | - | MMS |
| ann_FN | Announced discoveries - Field name | - | OIAF |
| ann_FSC | Announced discoveries - Field size class | integer | MMS |
| ann_OG | Announced discoveries - fuel type | - | MMS |
| ann_PRDSTYR | Announced discoveries - Start year of production | integer | MMS |
| ann_WD | Announced discoveries - Water depth | feet | MMS |
| ann_WL | Announced discoveries - Number of wells | integer | MMS |
| ann_YRDISC | Announced discoveries - Year of discovery | integer | MMS |
| beg_rsva | AD gas reserves | bcf | calculated in model |
| BOEtoMcf | BOE to Mcf conversion | Mcf/BOE | ICF |
| chgDrlCstOil | Change of Drilling Costs as a Function of Oil Prices | fraction | ICF |
| chgOpCstOil | Change of Operating Costs as a Function of Oil Prices | fraction | ICF |
| chgPFCstOil | Change of Production facility Costs as a Function of Oil Prices | fraction | ICF |
| cndYld | Condensate yield by PA, EU | Bbl/mmcf | MMS |
| cstCap | Cost of capital | percent | MMS |
| dDpth | Drilling depth by PA, EU, FSC | feet | MMS |
| deprSch | Depreciation schedule (8 year schedule) | fraction | MMS |
| devCmplCst | Completion costs by region, completion type (1=Single, 2=Dual), water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index | million 2003 dollars | MMS |
| devDrlCst | Mean development well drilling costs by region, water depth index, drilling depth index | million 2003 dollars | MMS |
| devDrlDly24 | Maximum number of development wells drilled from a 24-slot PF by drilling depth index | wells/PF/year | ICF |
| devDrlDlyOth | Maximum number of development wells drilled for other PF by PF type, water depth index | wells/field/year | ICF |
| devOprCst | Operating costs by region, water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index | 2003 $/well/year | MMS |
| devTangFrc | Development Wells Tangible Fraction | fraction | ICF |
| dNRR | Number of discovered producing fields by PA, EU, FSC | integer | MMS |
| drillcap | Drilling Capacity | wells/year/rig | ICF |
| duNRR | Number of discovered/undeveloped fields by PA, EU, FSC | integer | ICF |

| | OFFSHORE OIL AND GAS SUPPLY SUBMODULE | | |
|---|---|---|---|
| **Variable** | **Description** | **Unit** | **Source** |
| EUID | Evaluation unit ID | integer | ICF |
| EUname | Names of evaluation units by PA | integer | ICF |
| EUPA | Evaluation unit to planning area x-walk by EU_Total | integer | ICF |
| exp1stDly | Delay before commencing first exploration by PA, EU | number of years | ICF |
| exp2ndDly | Total time (Years) to explore and appraise a field by PA, EU | number of years | ICF |
| expDrlCst | Mean Exploratory Well Costs by region, water depth index, drilling depth index | million 2003 dollars | MMS |
| expDrlDays | Drilling days/well by rig type | number of days/well | ICF |
| expSucRate | Exploration success rate by PA, EU, FSC | fraction | ICF |
| expTangFrc | Exploration and Delineation Wells Tangible Fraction | fraction | ICF |
| fedTaxRate | Federal Tax Rate | percent | ICF |
| fldExpRate | Maximum Field Exploration Rate | percent | ICF |
| gasprice | Gas wellhead price by region | 2003$/mcf | NGTDM |
| gasSevTaxPrd | Gas production severance tax | 2003$/mcf | ICF |
| gasSevTaxRate | Gas severance tax rate | percent | ICF |
| GOprop | Gas proportion of hydrocarbon resource by PA, EU | fraction | ICF |
| GOR | Gas-to-Oil ratio (Scf/Bbl) by PA, EU | Scf/Bbl | ICF |
| GORCutOff | GOR cutoff for oil/gas field determination | - | ICF |
| gRGCGF | Gas Cumulative Growth Factor (CGF) for gas reserve growth calculation by year index | - | MMS |
| levDelWls | Exploration drilling technology (reduces number of delineation wells to justify development | percent | OIAF |
| levDrlCst | Drilling costs R&D impact (reduces exploration and development drilling costs) | percent | OIAF |
| levExpDly | Pricing impact on drilling delays (reduces delays to commence first exploration and between exploration | percent | OIAF |
| levExpSucRate | Seismic technology (increase exploration success rate) | percent | OIAF |
| levOprCst | Operating costs R&D impact (reduces operating costs) | percent | OIAF |
| levPfCst | Production facility cost R&D impact (reduces production facility construction costs | percent | OIAF |
| levPfDly | Production facility design, fabrication and installation technology (reduces time to construct production facility) | percent | OIAF |
| levPrdPerf1 | Completion technology 1 (increases initial constant production facility) | percent | OIAF |
| levPrdPerf2 | Completion technology 2 (reduces decile rates) | percent | OIAF |
| nDelWls | Number of delineation wells to justify a production facility by PA, EU, FSC | integer | ICF |

| | OFFSHORE OIL AND GAS SUPPLY SUBMODULE | | |
|---|---|---|---|
| Variable | Description | Unit | Source |
| nDevWls | Maximum number of development wells by PA, EU, FSC | integer | ICF |
| nEU | Number of evaluation units in each PA | integer | ICF |
| nmEU | Names of evaluation units by PA | - | ICF |
| nmPA | Names of planning areas by PA | - | ICF |
| nmPF | Name of production facility and subsea-system by PF type index | - | ICF |
| nmReg | Names of regions by region | - | ICF |
| ndiroff | Additions to inferred reserves by region and fuel type | oil: MBbls; gas: Bcf | calculated in model |
| nrdoff | New reserve discoveries by region and fuel type | oil: Mbbls; gas: Bcf | calculated in model |
| nRigs | Number of rigs by rig type | integer | ICF |
| nRigWlsCap | Number of well drilling capacity (Wells/Rig) | wells/rig | ICF |
| nRigWlsUtl | Number of wells drilled (Wells/Rig) | wells/rig | ICF |
| nSlt | Number of slots by # of slots index | integer | ICF |
| oilPrcCstTbl | Oil price for cost tables | 2003$/Bbl | ICF |
| oilprice | Oil wellhead price by region | 2003$/Bbl | PMM |
| oilSevTaxPrd | Oil production severance tax | 2003$/Bbl | ICF |
| oilSevTaxRate | Oil severance tax rate | percent | ICF |
| oRGCGF | Oil Cumulative Growth Factor (CGF) for oil reserve growth calculation by year index | fraction | MMS |
| paid | Planning area ID | integer | ICF |
| PAname | Names of planning areas by PA | - | ICF |
| pfBldDly1 | Delay for production facility design, fabrication, and installation (by water depth index, PF type index, # of slots index (0 for non platform) | number of years | ICF |
| pfBldDly2 | Delay between production facility construction by water depth index | number of years | ICF |
| pfCst | Mean Production Facility Costs in by region, PF type, water depth index, # of slots index (0 for non-platform) | million 2003 $ | MMS |
| pfCstFrc | Production facility cost fraction matrix by year index, year index | fraction | ICF |
| pfMaxNFld | Maximum number of fields in a project by project option | integer | ICF |
| pfMaxNWls | Maximum number of wells sharing a flowline by project option | integer | ICF |
| pfMinNFld | Minimum number of fields in a project by project option | integer | ICF |
| pfOptFlg | Production facility option flag by water depth range index, FSC | - | ICF |

| OFFSHORE OIL AND GAS SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **Variable** | **Description** | **Unit** | **Source** |
| pfTangFrc | Production Facility Tangible Fraction | fraction | ICF |
| pfTypFlg | Production facility type flag by water depth range index, PF type index | - | ICF |
| platform | Flag for platform production facility | - | ICF |
| prd_DEPTH | Producing fields - Total drilling depth | feet | MMS |
| prd_EU | Producing fields - Evaluation unit name | - | ICF |
| prd_FLAG | Producing fields - Production decline flag | - | ICF |
| prd_FN | Producing fields - Field name | - | MMS |
| prd_ID | Producing fields - MMS field ID | - | MMS |
| prd_OG | Producing fields - Fuel type | - | MMS |
| prd_YRDISC | Producing fields - Year of discovery | year | MMS |
| prdDGasDecRatei | Initial gas decline rate by PA, EU, FSC range index | fraction/year | ICF |
| prdDGasHyp | Gas hyperbolic decline coefficient by PA, EU, FSC range index | fraction | ICF |
| prdDOilDecRatei | Initial oil decline rate by PA, EU, | fraction/year | ICF |
| prdDOilHyp | Oil hyperbolic decline coefficient by PA, EU, FSC range index | fraction | ICF |
| prdDYrPeakGas | Years at peak production for gas by PA, EU, FSC, range index | number of years | ICF |
| prdDYrPeakOil | Years at peak production for oil by PA, EU, FSC, range index | number of years | ICF |
| prdDYrRampUpGas | Years to ramp up for gas production by PA, EU, FSC range index | number of years | ICF |
| prdDYrRampUpOil | Years to ramp up for oil production by PA, EU, FSC range index | number of years | ICF |
| prdGasDecRatei | Initial gas decline rate by PA, EU | fraction/year | ICF |
| prdGasFrc | Fraction of gas produced before decline by PA, EU | fraction | ICF |
| prdGasHyp | Gas hyperbolic decline coefficient by PA, EU | fraction | ICF |
| prdGasRatei | Initial gas production (Mcf/Day/Well) by PA, EU | mcf/day/well | ICF |
| PR | Expected production to reserves ratio by fuel typ | fraction | OIAF |
| prdoff | Expected production by fuel type | oil:MBbls; gas: Bcf | calculated in model |
| prdOilDecRatei | Initial oil decline rate by PA, EU | fraction/year | ICF |
| prdOilFrc | Fraction of oil produced before decline by PA, EU | fraction | ICF |
| prdOilHyp | Oil hyperbolic decline coefficient by PA, EU | fraction | ICF |
| prdOilRatei | Initial oil production (Bbl/Day/Well) by PA, EU | Bbl/day/well | ICF |

| OFFSHORE OIL AND GAS SUPPLY SUBMODULE | | | |
|---|---|---|---|
| Variable | Description | Unit | Source |
| prod | Producing fields - annual production by fuel type | oil:MBbls; gas:Mmcf | MMS |
| prod_asg | AD gas production | bcf | calculated in model |
| revoff | Extensions, revisions, and adjustments by fuel type | oil:MBbls; gas:Bcf | |
| rigBldRatMax | Maximum Rig Build Rate by rig type | percent | ICF |
| rigIncrMin | Minimum Rig Increment by rig type | integer | ICF |
| RigUtil | Number of wells drilled | wells/rig | ICF |
| rigUtilTarget | Target Rig Utilization by rig type | percent | ICF |
| royRateD | Royalty rate for discovered fields by PA, EU, FSC | fraction | MMS |
| royRateU | Royalty rate for undiscovered fields by PA, EU, FSC | fraction | MMS |
| stTaxRate | Federal Tax Rate by PA, EU | percent | ICF |
| trnFlowLineLen | Flowline length by PA, EU | miles/prospect | ICF |
| trnPpDiam | Oil pipeline diameter by PA, EU | inches | ICF |
| trnPplnCst | Pipeline cost by region, pipe diameter index, water depth index | million 2003 $/mile | MMS |
| trnTrfGas | Gas pipeline tariff ($/Mcf) by PA, EU | 2003 $/Bbl | ICF |
| trnTrfOil | Oil pipeline tariff ($/Bbl) by PA, EU | 2003 $/Bbl | ICF |
| uNRR | Number of undiscovered fields by PA, EU, FSC | integer | calculated in model |
| vMax | Maximum MMBOE of FSC | MMBOE | MMS |
| vMean | Geometric mean MMBOE of FSC | MMBOE | MMS |
| vMin | Minimum MMBOE of FSC | MMBOE | MMS |
| wDpth | Water depth by PA, EU, FSC | feet | MMS |
| yrAvl | Year lease available by PA, EU | year | ICF |
| yrCstTbl | Year of cost tables | year | ICF |
| Sources: MMS = Minerals Management Service; ICF = ICF Consulting; OIAF = EIA, Office of Integrating Analysis and Forecasting | | | |

| Unconventional Gas Recovery Supply Submodule | | | | | |
|---|---|---|---|---|---|
| Variable Name | | Brief Description | Unit | Classification | Source |
| Code | Text | | | | |
| - | BASLOC | Basin Location: The basin/play name | NA | UGR Type; Play | ARI/USGS |
| - | PNUM | Play Number: The play number established by ARI | - | UGR Type; Play | ARI |
| ATUNDRLOC | ATUL | Undrilled Locations - Advanced Technology: Number of locations available to drill under advanced technology | - | UGR Type; Play; Quality[1] | ARI |
| AVDEPTH | AVGDPTH | Average Depth: Average depth of the play | Feet | UGR Type; Play; Quality | ARI |
| BASINDIFF | BASNDIF | Basin Differential: This is a sensitivity on the gas price at a basin level. Depending on their proximity to market and infrastructure, the price varies throughout the country. The numbers are constant throughout the model. | 1996$/ Mcf | UGR Type; Play; Quality | ARI |
| BNAREA | BASAR | Basin Area: Area in square miles | Square Miles | UGR Type; Play; Quality | ARI |
| CAPCSTDH | CCWDH | Capital Costs with Dry Hole Costs | 1996$/ Mcf | UGR Type; Play; Quality | ARI |
| CTUNDRLOC | CTUL | Undrilled Locations - Current Technology: Current number of locations available to drill | - | UGR Type; Play; Quality | ARI |
| DCCOST | DACC | Drilling and completion costs | 1996$ | UGR Type; Play; Quality | ARI |
| DCCOSTGT | DCC_G2K | Drilling and completion cost per foot, well is greater than 2000 feet. | 1996$/ Foot | UGR Type | ARI |
| DCCOSTLT | DCC_L2K | Cost per foot, well is less than 2000 feet. | 1996$/ Foot | UGR Type | ARI |

[1] The four “Quality” Categories are Total, Best 30%, Next Best 30%, and Worst 40%.

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | Brief Description | Unit | Classification | Source |
|---|---|---|---|---|---|
| Code | Text | | | | |
| DEVCELLS | DEV_CEL | Developed Cells: Number of locations already drilled | - | UGR Type; Play; Quality | ARI |
| DISCFAC | DIS_FAC | Discount Factor: This is the discount factor that is applied to the EUR for each well. The Present Value of a production stream from a typical coalbed methane, tight sands, or gas shales well is discounted at a rate of 15%.over a twenty year period. | Fraction | UGR Type | ARI |
| DISCRES | DISCRES | Discounted Reserves: The mean EUR per well multiplied by the discount factor. | Bcf | UGR Type; Play; Quality | Calculated |
| DRILLSCHED | DRL_SCHED | Drilling Schedule | Years | UGR Type; Play; Quality | ARI |
| DRILLSCHED | DRL_SCHED2 | Drilling Schedule adjusted to account for technological progress | Years | UGR Type; Play; Quality | ARI |
| DRILLSCHED | DRL_SCHED3 | Drilling Schedule: This variable ensures that adjustment for technology did not result in negative value for emerging basin Drilling Schedule. | Years | UGR Type; Play; Quality | ARI |
| DRILLSCHED | DRL_SCHED4 | Drilling Schedule: This variable adjusts to account for the time-delaying effect of access limitations | Years | UGR Type; Play; Quality | ARI |
| DRRESADDS | DRA | Drilled Reserve Additions | Bcf | UGR Type; Play; Quality | Calculated |
| DRYHOLECOST | DHC | Dry Hole Costs | 1996$/ Well | UGR Type; Play; Quality | Calculated |
| EMBASINYRS* FINFAC | EMERG# | The number of years taken off the drilling schedule for an advancement in technology. | Years | UGR Type; Play | ARI |
| EMERGBAS | EMRG | The parameter that determines if the play is an emerging basin. This designation was made by ARI (1=yes). | - | UGR Type; Play; Quality | ARI |

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | Brief Description | Unit | Classification | Source |
|---|---|---|---|---|---|
| Code | Text | | | | |
| ENCBMYRCST | ECBM_OC | Enhanced CBM Operating Costs Variable - $1.00 | 1996$/ Mcf | UGR Type[CBM]; Basin; Quality | ARI |
| ENVIRONREG | ENV% | The percentage of the play that is not restricted from development due to environmental or pipeline regulations | Fraction | UGR Type; Play | ARI |
| ENVPIPREG | ENPRGS | Establishes if the play is pipeline or environmentally regulated (1=yes). | - | UGR Type; Play; Quality | ARI |
| EXNPVREV | ENPVR | Expected NPV Revenues: Gives the value of the entire discounted production stream for one well in real $. | 1996$/ Well | UGR Type; Play; Quality | Calculated |
| FINFAC | TECHYRS | Number of years (from base year) over which incremental advances in indicated technology have occurred | Years | - | Calculated |
| FIXOMCOST | FOMC | Fixed Operating and Maintenance Costs | 1996$/ Well | UGR Type; Play; Quality | Calculated |
| GA10 | GAA10 | Variable General and Administrative (G&A) Costs: | 1996$/ Well | UGR Type; Play; Quality | Calculated |
| GABASE | RST | Variable G&A Cost factor - Currently 10% of equipment costs, stimulation costs, and drilling costs | Fraction | UGR Type; Play; Quality | Calculated |
| H2OBASE | WOML_WTR | Water Producing Well Lease Equipment Costs | 1996$/ Well | UGR Type; EUR Level | ARI |
| H2ODISP | WATR_DISP | Establishes if the play requires water disposal (1 = yes) | - | UGR Type; Play; Quality | ARI |
| HYPPLAYS | HYP% | Establishes whether or not the play is hypothetical (1=yes) | - | UGR Type; Play; Quality | ARI |
| | | | 1996$/ | UGR Type; EUR | |

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | | | | |
|---|---|---|---|---|---|
| Code | Text | Brief Description | Unit | Classification | Source |
| LANDGG | DCC_G&G | Land / G&G Costs | Well | level | ARI |
| LANDGGH2O | WOMM_OMW | Operating & Maintenance - Medium well with H2O disposal | $1996/ Well | UGR Type; EUR Level | ARI |
| LANDGGH2O | WOMS_OMW | Operating & Maintenance - Small well with H2O disposal | $1996/ Well | UGR Type; EUR Level | ARI |
| LANDGGH2O | WOML_OMW | Operating & Maintenance - Large well with H2O disposal | $1996/ Well | UGR Type; EUR Level | ARI |
| LEASSTIP | LEASSTIP | Lease Stipulated Share: The percentage of undrilled locations in a play that are subject to Federal lease stipulations | Percent | UGR Type; Play | ARI |
| LEASEQUIP | LSE_EQ | Lease Equipment Costs | $1996/ Well | UGR Type; Play; Quality | ARI |
| LSEQBASE | WOML_LE | Large Well Lease Equipment Costs | $1996/ Well | UGR Type; EUR Level | ARI |
| LSEQBASE | WOMS_LE | Small Well Lease Equipment Costs | $1996/ Well | UGR Type; EUR Level | ARI |
| LSEQBASE | WOMM_LE | Medium Well Lease Equipment Costs | $1996/ Well | UGR Type; EUR Level | ARI |
| MEANEUR | MEUR1 | A weighted average of the EUR values for each (entire) basin | Bcf/Well | UGR Type; Play; Quality | Calculated |
| MEANEUR | MEUR1 | A weighted average of the EUR values for the best 30% of the wells in the basin | Bcf/Well | UGR Type; Play; Quality | Calculated |
| MEANEUR | MEUR1 | A weighted average of the EUR values for the middle 30% of the wells in the basin | Bcf/Well | UGR Type; Play; Quality | Calculated |

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | Brief Description | Unit | Classification | Source |
|---|---|---|---|---|---|
| Code | Text | | | | |
| MEANEUR | MEUR1 | A weighted average of the EUR values for the worst 40% of the wells in the basin | Bcf/Well | UGR Type; Play; Quality | Calculated |
| MEANEUR | MEUR2 | For Coalbed Methane, “MEUR1" adjusted for technological progress in the development of new cavity fairways | Bcf/Well | UGR Type; Play; Quality | Calculated |
| MEANEUR | MEUR3 | For Enhanced Coalbed Methane, “MEUR2" adjusted for technological progress in the commercialization of Enhanced Coalbed Methane | Bcf/Well | UGR Type; Play; Quality | Calculated |
| MEANEUR | MEUR4 | Mean EUR: This variable establishes whether or not the play is profitable and if so, allows the EUR to appear for development. | Bcf/Well | UGR Type; Play; Quality | Calculated |
| MIN_ROI | MIN_ROI | A risk premium - the minimum rate of return that a project must be expected to achieve to offset risk of investment | 1996$/Mcf | UGR Type | ARI |
| NETPR | NET_PRC | Net Price ($/Mcf): Including Royalty and Severance Tax | 1996$/Mcf | UGR Type; Play; Quality | Calculated |
| NETPROFIT | NET_PROF | Net Profits ($/Mcf) | 1996$/Mcf | UGR Type; Play; Quality | Calculated |
| NETPROFIT | NET_PROF2 | Net Profits (changed to 0 if < 0): Allows only the profitable plays to become developed | 1996$/Mcf | UGR Type; Play; Quality | Calculated |
| NEWWELLS | NW_WELLS | New Wells: The amount of wells drilled for the play in that year | Wells | UGR Type; Play; Quality | Calculated |
| NEWWELLS_LAG | NW_WELLS_LAG | New Wells Lagged: The amount of wells drilled for the play in the previous year | Wells | UGR Type; Play; Quality | Calculated |
| NEWWELLS | NW_WELLS2 | New Wells: This variable ensures the wells drilled is a positive value. | Wells | UGR Type; Play; Quality | Calculated |
| NOACCESS | NOACCESS | No Access Share: The percentage of undrilled locations in a | Percent | UGR Type; | ARI |

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | Brief Description | Unit | Classification | Source |
|---|---|---|---|---|---|
| Code | Text | | | | |
| | | play that are legally inaccessible | | Play | |
| NYR_UNDEVWELLS | UNDV_WELLS2 | Undeveloped wells available to be drilled for the next year | Wells | UGR Type; Play; Quality | Calculated |
| 1.32*OGPRCL48 | WHGP | Wellhead Gas Price | 1996$/ Mcf | UGR Type; OGSM Region | NGTDM (Integrated); Input (Standalone) |
| OPCOSTH2O | OCWW$ | Operating Costs with H2O - $0.30 | 1996$/ Mcf | UGR Type; H2O Disposal Level | ARI |
| OPCOSTH2O | OCNW$ | Operating Costs without H2O - $0.25 | $1996/ Mcf | UGR Type; H2O Disposal Level | ARI |
| OPCSTGASTRT | GASTR | Gas Treatment and Fuel costs - $0.25 | $1996/ Mcf | UGR Type | ARI |
| OPCSTH2ODISP | WTR_DSPT | Water Disposal Fee: $0.05 | $1996/ Mcf | UGR Type | ARI |
| OPCSTOMS | WOMS | H2O Costs, Small Well | $1996/ Mcf | UGR Type | ARI |
| PLAYPROBBASE | PLPROB | The play probability: Only hypothetical plays have a PLPROB < 100%. | Fraction | UGR Type; Play; Quality | ARI |
| PLAYPROB | PLPROB2 | The play probability adjusted for technological progress, if initial play probability less than 1. | Fraction | UGR Type; Play; Quality | Calculated |
| PMPSFEQBASE | BASET | Variable cost of Pumping and Surface equipment when H2O disposal is required. | 1996$/ Well | UGR Type; Play; Quality | ARI |
| PMPSURFEQ | PASE | Pumping and Surface Equipment Costs | 1996$/ Well | UGR Type; Play; Quality | Calculated |

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | Brief Description | Unit | Classification | Source |
|---|---|---|---|---|---|
| Code | Text | | | | |
| PROD | PROD | Current Production | Bcf | UGR Type; Play; Quality | Calculated |
| PROD | PROD2 | Production for the next year | Bcf | UGR Type; Play; Quality | Calculated |
| PROVRESV | PROV_RES | Proved Reserves | Bcf | UGR Type; Play; Quality | Calculated |
| PROVRESV | PROV_RES2 | Proved Reserves for the next year | Bcf | UGR Type; Play; Quality | Calculated |
| RESADDS | R_ADD | Total Reserve Additions | Bcf | UGR Type; Play; Quality | Calculated |
| RESGRADDS | RGA | Reserve Growth Additions | Bcf | UGR Type; Play; Quality | Calculated |
| RESGRWTH | RES_GR | Establishes whether or not the play will have reserve growth (1=yes) | - | UGR Type; Play; Quality | ARI |
| RESWELLBCFB | RW101 | Reserves per Well for the best 10% of the play (year 1): an EUR estimate | Bcf/Well | UGR Type; Play; Quality | ARI |
| RESWELLBCFB | RW201 | Reserves per Well for the next (lesser) 20% of the play (year 1): an EUR estimate | Bcf/Well | UGR Type; Play; Quality | ARI |
| RESWELLBCFB | RW301 | Reserves per Well for the next (lesser) 30% of the play (year 1): an EUR estimate | Bcf/Well | UGR Type; Play; Quality | ARI |
| RESWELLBCFB | RW401 | Reserves per Well for the worst 40% of the play (year 1): an EUR estimate | Bcf/Well | UGR Type; Play; Quality | ARI |
| RESWELLBCF | RW101 | Reserves per Well for the best 10% of the play (years 2,20) | Bcf/Well | UGR Type; Play; | Calculated |

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | Brief Description | Unit | Classification | Source |
|---|---|---|---|---|---|
| Code | Text | | | | |
| | | | | Quality | |
| RESWELLBCF | RW201 | Reserves per Well for the next (lesser) 20% of the play (years 2,20) | Bcf/Well | UGR Type; Play; Quality | Calculated |
| RESWELLBCF | RW301 | Reserves per Well for the next (lesser) 30% of the play (years 2,20) | Bcf/Well | UGR Type; Play; Quality | Calculated |
| RESWELLBCF | RW401 | Reserves per Well for the worst 40% of the play (years 2,20) | Bcf/Well | UGR Type; Play; Quality | Calculated |
| RES_GRTH_DEC | RGR | Reserve Growth Rate | Fraction | UGR Type; Year | ARI |
| ROYSEVTAX | RST | Variable Royalty and Severance Tax - Set at 17% | Fraction | UGR Type | ARI |
| RP | R/P_RAT | Reserves-to-Production (R/P) Ratio | Fraction | UGR Type; Play; Quality | Calculated |
| RP | RP_RAT2 | R/P Ratio for the next year | Fraction | UGR Type; Play; Quality | Calculated |
| RSVPRD | RESNPROD | Reserves and Production | Bcf | UGR Type; Play; Quality | Calculated |
| STIMCOST | STIMC | Stimulation Costs: Provides the cost of stimulating a well in the specific basin by multiplying the given average stimulation cost by the number of stimulation zones. | 1996$/Well | UGR Type; Play; Quality | ARI |
| STIMCSTBASE | STIM_CST | Variable average cost of stimulating one zone. (Number of zones is a variable) | 1996$/Zone | UGR Type | ARI |
| STIMUL | SZONE | Stimulation Zones: Number of times a single well is stimulated in the play | - | UGR Type; Play; Quality | ARI |
| | | Success Rate : The ratio of successful wells over total wells | | UGR Type; Play; | |

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | Brief Description | Unit | Classification | Source |
|---|---|---|---|---|---|
| Code | Text | | | | |
| SUCRATE | SCSSRT | drilled (This can also be called the dry hole rate if you use the equation 1 - SCSSRT). | Fraction | Quality | ARI |
| TECHRECWELL | TRW1 | The amount of technically recoverable wells available regardless of economic feasibility. | Wells | UGR Type; Play; Quality | Calculated |
| TECH_PROG_ SCHED_DR | REDAM% | Total percentage increase over development period due to advances in “Reduced Damage D&S” technology | Fraction | UGR Type | ARI |
| TECH_PROG_ SCHED_DR | FRCLEN% | Total percentage increase over development period due to advances in “Increased Fracture Length L&C” technology | Fraction | UGR Type | ARI |
| TECH_PROG_ SCHED_DR | PAYCON% | Total percentage increase over development period due to advances in “Improved Pay Contact” technology | Fraction | UGR Type | ARI |
| TECH_PROG_ SCHED_EX | EMERG% | The number of years added onto the drilling schedule because of the hindrance of the play being an emerging basin. | Years | UGR Type | ARI |
| TECH_PROG_ SCHED_PT | WDT% | Total percentage decrease in H2O disposal and treatment costs over the development period due to technological advances | Fraction | UGR Type | ARI |
| TECH_PROG_ SCHED_PT | PUMP% | Total percentage decrease in pumping costs over the development period due to technological advances | Fraction | UGR Type | ARI |
| TECH_PROG_ SCHED_PT | GTF% | Total percentage decrease in gas treatment and fuel costs over the development period due to technological advances | Fraction | UGR Type | ARI |
| TECH_PROG_ SCHED_PT | LOW% | The percentage of the play that is restricted from development due to environmental or pipeline regulations | Fraction | UGR Type | ARI |
| TECH_PROG_ SCHED_PT | LOWYRS | The number of years the environmental and or pipeline regulation will last. | Years | UGR Type | ARI |
| TECH_PROG_ SCHED_PT | ENH_CBM% | Enhanced CBM EUR Percentage gain | Fraction | UGR Type[CBM] | ARI |

## Unconventional Gas Recovery Supply Submodule

| Variable Name | | Brief Description | Unit | Classification | Source |
|---|---|---|---|---|---|
| Code | Text | | | | |
| TECH_PROG_ SCHED_EX | DEVPER | Development period for “Favorable Settings” technological advances | Years | UGR Type | ARI |
| TOTCAPCOST | TCC | Total Capital Costs: The sum of Stimulation Costs, Pumping and Surface Equipment Costs, Lease Equipment Costs, G&A Costs and Drilling and Completion Costs | 1996$/Well | UGR Type; Play; Quality | Calculated |
| TOTCOST | TOTL_CST | Total Costs ($/Mcf) | 1996$/Mcf | UGR Type; Play; Quality | Calculated |
| ULTRECV | URR | Ultimate Recoverable Resources | Bcf | UGR Type; Play; Quality | Calculated |
| UNDEVRES | UNDEV_RES | Undeveloped resources | Bcf | UGR Type; Play; Quality | Calculated |
| UNDEV_WELLS | UNDV_WELLS | Undeveloped wells available for development under current economic conditions | Wells | UGR Type; Play; Quality | Calculated |
| VAROPCOST | VOC | Variable Operating Costs | 1996$/Mcf | UGR Type; Play; Quality | Calculated |
| VAROPCOST | VOC2 | Variable Operating Costs: Includes an extra operating cost for plays that will incorporate the technology of Enhanced CBM in the future | 1996$/Mcf | UGR Type; Play; Quality | Calculated |
| WELLSP | WSPAC_CT | Well Spacing - Current Technology: Current spacing in acres | Acres | UGR Type; Play; Quality; Technology Level | ARI |
| WELLSP | WSPAC_AT | Well Spacing - Advanced Technology: Spacing in acres under Advanced Technology | Acres | UGR Type; Play; Quality; Technology Level | ARI |

| Unconventional Gas Recovery Supply Submodule | | | | | |
|---|---|---|---|---|---|
| Variable Name | | Brief Description | Unit | Classification | Source |
| Code | Text | | | | |
| .6*LANDGGH2O | WOMS_OM | Operating & Maintenance - Small well without H2O disposal | $1996/ Well | UGR Type; EUR Level | ARI |
| .6*LANDGGH2O | WOMM_OM | Operating & Maintenance - Medium well without H2O disposal | $1996/ Well | UGR Type; EUR Level | ARI |
| .6*LANDGGH2O | WOML_OM | Operating & Maintenance - Large well without H2O disposal | $1996/ Well | UGR Type; EUR Level | ARI |

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# Appendix C.  Model Abstract

1. Model Name
   Oil and Gas Supply Module

2. Acronym
   OGSM

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

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

5. Date of Last Update
   2008

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

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

8. Official Model Representative
   Office: Integrating Analysis and Forecasting
   Division: Oil and Gas Analysis
   Model Contact: Dana Van Wagener
   Telephone: (202) 586-4725

9. Documentation Reference
   U.S. Department of Energy. 2008. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, Energy Information Administration, Washington, DC.

10. Archive Media and Installation Manual
    NEMS2009

11. Energy Systems Described

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

The OGSM also projects natural gas trade via pipeline with Canada. U.S. natural gas trade with Canada is represented by seven entry/exit points.

12. Coverage

Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
Time Units/Frequency: Annually 1990 through 2030
Product(s): Crude oil and natural gas
Economic Sector(s): Oil and gas field production activities and Canadian natural gas trade

13. Model Features

Model Structure: Modular, containing six major components

- Lower 48 Onshore Supply Submodule
- Unconventional Gas Recovery Supply Submodule
- Offshore Oil and Gas Supply Submodule
- Foreign Natural Gas Supply Submodule
- Alaska Oil and Gas Supply Submodule
- Oil Shale Supply Submodule

Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are determined by the discounted cash flow that measures the expected present value profits for the proposed effort and other key economic variables.
Special Features: Can run stand-alone or within the NEMS. Integrated NEMS runs employ short-term natural gas supply functions for efficient market equilibration.

14. Non-DOE Input Data

- Alaskan Oil and Gas Field Size Distributions - U.S. Geological Survey
- Alaska Facility Cost By Oil Field Size - U.S. Geological Survey
- Alaska Operating cost - U.S. Geological Survey
- Basin Differential Prices - Natural Gas Week, Washington, DC
- State Corporate Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
- State Severance Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
- Federal Corporate Tax Rate, Royalty Rate - U.S. Tax Code
- Onshore Drilling Costs - (1.) American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-2006)*, Washington, D.C.; (2.) Additional unconventional gas recovery drilling and operating cost data from operating companies
- Offshore Technically Recoverable Oil and Gas Undiscovered Resources - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
- Offshore Exploration, Drilling, Platform, and Production Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
- Canadian Wells drilled - Canadian Association of Petroleum Producers. *Statistical Handbook.*

- Canadian Recoverable Resource Base - National Energy Board. *Canada's Conventional Natural Gas Resources: A Status Report*, Canada, April 2004.
- Canadian Reserves - Canadian Association of Petroleum Producers. *Statistical Handbook*.
- Unconventional Gas Resource Data - (1) USGS *1995 National Assessment of United States Oil and Natural Gas Resources*; (2) Additional unconventional gas data from operating companies
- Unconventional Gas Technology Parameters - (1) Advanced Resources International Internal studies; (2) Data gathered from operating companies

15. DOE Input Data
    - Onshore Lease Equipment Cost - Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2006)*, DOE/EIA-0815(80-06)
    - Onshore Operating Cost - Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2006)*, DOE/EIA-0815(80-06)
    - Emissions Factors - Energy Information Administration
    - Oil and Gas Well Initial Flow Rates - Energy Information Administration, Office of Oil and Gas
    - Wells Drilled - Energy Information Administration, Office of Oil and Gas
    - Expected Recovery of Oil and Gas Per Well - Energy Information Administration, Office of Oil and Gas
    - Oil and Gas Reserves - Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-2007), DOE/EIA-0216(77-08)

16. Computing Environment
    - Hardware Used: PC
    - Operating System: Windows 95/Windows NT/Windows XP
    - Language/Software Used: FORTRAN
    - Memory Requirement: Unknown
    - Storage Requirement: 992 bytes for input data storage; 180,864 bytes for output storage; 1280 bytes for code storage; and 5736 bytes for compiled code storage
    - Estimated Run Time: 9.8 seconds

17. Reviews conducted
    - Independent Expert Review of the Offshore Oil and Gas Supply Submodule - Turkay Ertekin from Pennsylvania State University; Bob Speir of Innovation and Information Consultants, Inc.; and Harry Vidas of Energy and Environmental Analysis , Inc., June 2004
    - Independent Expert Review of the Annual Energy Outlook 2003 - Cutler J. Cleveland and Robert K. Kaufmann of the Center for Energy and Environmental Studies, Boston University; and Harry Vidas of Energy and Environmental Analysis, Inc., June-July 2003
    - Independent Expert Reviews, Model Quality Audit; Unconventional Gas Recovery Supply Submodule - Presentations to Mara Dean (DOE/FE - Pittsburgh) and Ray Boswell (DOE/FE - Morgantown), April 1998 and DOE/FE (Washington, DC)

18. Status of Evaluation Efforts

    Not applicable

19. Bibliography

    See Appendix B of this document.

# Appendix D. Parameter Estimation

The major portion of the lower 48 oil and gas supply component of the OGSM consists of a system of equations that are used to forecast exploratory and developmental wells drilled. The equations, the estimation techniques, and the statistical results are documented below. Documentation is also provided for the estimation of the drilling, lease equipment, and operating cost equations as well as the associated-dissolved gas equations and the Canada gas wells equation. Finally, the appendix documents the estimation of oil and gas supply price elasticities for possible use in short run supply functions. The econometric software package, TSP, was used for the estimations.

## Onshore Lower 48 Total Wells Equations

The equations for total (successful plus dry) onshore oil wells and conventional natural gas wells were estimated using data for the onshore Lower 48 over the time period 1970 through 2004. The equations were estimated in log-linear form with correction for first order serial correlation using TSP version 4.5.

**Total Onshore Oil Wells**

$$\ln ESTWELLS_{k,t} = b0_k + b1_k * \ln POIL_t + \rho_k * \ln ESTWELLS_{k,t-1} - \rho_k * (b0_k + b1_k * \ln POIL_{t-1}) \quad \text{(D-1)}$$

for k = oil.

```
Dependent variable: LNTOTOILWELLS
Current sample:  1 to 35
Number of observations:  35

       Mean of dep. var. = 9.80675           R-squared = .890509
  Std. dev. of dep. var. = .669445  Adjusted R-squared = .883665
Sum of squared residuals = 1.69571       Durbin-Watson = 1.87815
   Variance of residuals = .052991      Schwarz B.I.C. = -.260316
Std. error of regression = .230198      Log likelihood = 5.59334
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $b0_k$ | 8.01558 | .636090 | 12.6013 | [.000] |
| $b1_k$ | .535231 | .137432 | 3.89452 | [.000] |
| $\rho_k$ | .950729 | .046576 | 20.4125 | [.000] |

**Total Onshore Conventional Natural Gas Wells**

$$\ln ESTWELLS_{k,t} = b0_k + b1_k * \ln PGAS_t + \rho_k * \ln ESTWELLS_{k,t-1} - \rho_k * (b0_k + b1_k * \ln PGAS_{t-1}) \quad \text{(D-2)}$$

for k = gas.

```
Dependent variable: LNTOTGASWELLS
Current sample:  1 to 35
Number of observations:  35

       Mean of dep. var. = 9.59757           R-squared = .878884
  Std. dev. of dep. var. = .365107  Adjusted R-squared = .871314
Sum of squared residuals = .573567       Durbin-Watson = 1.72432
   Variance of residuals = .017924      Schwarz B.I.C. = -16.4080
Std. error of regression = .133880      Log likelihood = 21.7411
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $b0_k$ | 9.15143 | .129261 | 70.7979 | [.000] |
| $b1_k$ | .594489 | .098560 | 6.03176 | [.000] |
| $\rho_k$ | .823041 | .087371 | 9.42002 | [.000] |

## Onshore Lower 48 Available Rigs Equation

The equation for total available onshore rigs was estimated using data for the onshore Lower 48 over the time period 1970 through 2002. The equations were estimated in log-linear form with correction for first order serial correlation using TSP version 4.5.

$$\begin{aligned} \ln RIGSL48_t &= b0 + b1 * \ln RIGSL48_{t-1} + b2 * \ln REVRIG_{t-1} + \rho * \ln RIGSL48_{t-1} \\ &\quad - \rho * (b0 + b1 * \ln RIGSL48_{t-2} + b2 * \ln REVRIG_{t-2}) \end{aligned} \tag{D-3}$$

Dependent variable: $\ln RIGSL48_t$
Number of observations: 31

```
        Mean of dep. var. = 7.71468   Adjusted R-squared = .977595
   Std. dev. of dep. var. = .412360        Durbin-Watson = 1.69993
 Sum of squared residuals = .102867   Common Factor test = .01249[.911]
    Variance of residuals = .380991E-02   Schwarz B.I.C. = -37.6236
 Std. error of regression = .061724       Log likelihood = 44.4916
                R-squared = .979836
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| b0 | -.575248 | 1.03514 | -.555720 | [.578] |
| b1 | .713897 | .135602 | 5.26466 | [.000] |
| b2 | .172923 | .048995 | 3.52942 | [.000] |
| ρ | .929042 | .131129 | 7.08496 | [.000] |

## Onshore Lower 48 Drilling Cost Equations

The onshore Lower 48 per well drilling costs equations were estimated for onshore regions 1 through 6 for successful and dry oil wells and for successful and dry conventional natural gas wells using region-specific data for the 1970-2006 time period. The equations were estimated simultaneously by Three Stage Least Squares with corrections for first order serial correlation and heteroscedasticity using TSP version 4.5. An adjustment factor was also estimated to correct for the downward bias caused by the logarithmic transformation. Instruments included six regional dummy variables, lagged values of the dependent and independent variables, and constant values for the technology improvement factor (-0.25% per year) and the capital cost escalation factor (0.37 per year).

(D-4)

$$\ln DRILLCOST_{r,k,t} = b0_{r,k} + b1_k * \ln ESTWELLS_t + b2_k * DEPTH_{r,k,t} + b3_k * TIME_t + CAPCOST +$$

$$\rho_k * (\ln DRILLCOST_{r,k,t-1} - (b0_{r,k} + b1_k * \ln ESTWELLS_{t-1} + b2_k * DEPTH_{r,k,t-1} + b3_k * TIME_{t-1} + CAPCOST))$$

(D-5)

$$\ln DRYCOST_{r,k,t} = c0_{r,k} + c1_k * \ln ESTWELLS_t + c2_k * DEPTH_{r,k,t} + c3_k * TIME_t + CAPCOST +$$

$$\rho_k * (\ln DRYCOST_{r,k,t-1} * (c0_{r,k} + c1_k * \ln ESTWELLS_t + c2_k * DEPTH_{r,k,t-1} + c3_k * TIME_{t-1} + CAPCOST))$$

for regions 1 through 6, O = oil, and G = shallow gas and deep gas combined, DO = dry oil hole, and DG = dry gas hole.

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| O1 | 12.9390 | .406253 | 31.8495 | [.000] |
| O2 | 13.5436 | .372746 | 36.3346 | [.000] |
| O3 | 13.2742 | .370204 | 35.8564 | [.000] |
| O4 | 13.3673 | .372409 | 35.8941 | [.000] |
| O5 | 13.6773 | .371631 | 36.8035 | [.000] |
| O6 | 14.3608 | .467604 | 30.7115 | [.000] |
| OWELL | .316692 | .031725 | 9.98251 | [.000] |
| ODPTH | .170991E-03 | .863543E-05 | 19.8012 | [.000] |
| ORHO | .895112 | .010872 | 82.3310 | [.000] |
| G1 | 12.3813 | .376303 | 32.9024 | [.000] |
| G2 | 12.9718 | .349626 | 37.1019 | [.000] |
| G3 | 12.7605 | .348057 | 36.6620 | [.000] |
| G4 | 12.8562 | .349998 | 36.7322 | [.000] |
| G5 | 13.0841 | .349794 | 37.4051 | [.000] |
| G6 | 13.0715 | .422603 | 30.9309 | [.000] |
| GWELL | .363180 | .030518 | 11.9004 | [.000] |
| GDPTH | .191762E-03 | .824080E-05 | 23.2698 | [.000] |
| GRHO | .880454 | .011413 | 77.1480 | [.000] |
| DO1 | 13.2578 | .493210 | 26.8807 | [.000] |
| DO2 | 13.6690 | .394607 | 34.6395 | [.000] |
| DO3 | 13.3552 | .393391 | 33.9489 | [.000] |
| DO4 | 13.4182 | .393427 | 34.1061 | [.000] |
| DO5 | 13.8649 | .394134 | 35.1782 | [.000] |
| DO6 | 14.3498 | .606688 | 23.6527 | [.000] |
| DODPTH | .107794E-03 | .482757E-05 | 22.3288 | [.000] |
| DORHO | .907380 | .910757E-02 | 99.6293 | [.000] |
| DG1 | 12.8193 | .477307 | 26.8576 | [.000] |
| DG2 | 13.2852 | .383800 | 34.6148 | [.000] |
| DG3 | 13.0172 | .382280 | 34.0516 | [.000] |
| DG4 | 13.1016 | .382763 | 34.2291 | [.000] |
| DG5 | 13.4726 | .384658 | 35.0247 | [.000] |
| DG6 | 13.1757 | .587837 | 22.4138 | [.000] |
| DGDPTH | .111507E-03 | .687309E-05 | 16.2237 | [.000] |
| DGRHO | .911637 | .885985E-02 | 102.895 | [.000] |

Number of observations = 1116

Equation: OILEQ
Dependent variable: LNOILDCST

| | |
|---|---|
| Mean of dep. var. = 12.7286 | Std. error of regression = .193152 |
| Std. dev. of dep. var. = 1.13954 | R-squared = .971996 |
| Sum of squared residuals = 41.6355 | Durbin-Watson = 2.21321 [<1.00] |
| Variance of residuals = .037308 | |

Equation: GASEQ
Dependent variable: LNGASDCST

| | |
|---|---|
| Mean of dep. var. = 12.8472 | Std. error of regression = .192445 |
| Std. dev. of dep. var. = 1.15461 | R-squared = .972649 |
| Sum of squared residuals = 41.3312 | Durbin-Watson = 2.37494 [<1.00] |
| Variance of residuals = .037035 | |

Equation: DRYOEQ
Dependent variable: LNDRYODCST

| | |
|---|---|
| Mean of dep. var. = 12.3536 | Std. error of regression = .281329 |
| Std. dev. of dep. var. = 1.27991 | R-squared = .952932 |
| Sum of squared residuals = 88.3269 | Durbin-Watson = 2.23128 [<1.00] |
| Variance of residuals = .079146 | |

Equation: DRYGEQ
Dependent variable: LNDRYGDCST

| | |
|---|---|
| Mean of dep. var. = 12.4732 | Std. error of regression = .266047 |
| Std. dev. of dep. var. = 1.28594 | R-squared = .958218 |
| Sum of squared residuals = 78.9916 | Durbin-Watson = 2.26826 [<1.00] |
| Variance of residuals = .070781 | |

## Onshore Lower 48 Lease Equipment Cost Equations

The onshore Lower 48 per well lease equipment cost equations were estimated for onshore regions 1 through 6 for successful oil wells, successful shallow natural gas wells, and successful deep natural gas wells using region-specific data for the 1970-2006 time period. The equations were estimated in log-linear form using TSP version 4.5. Oil and shallow gas equations were estimated simultaneously by Three Stage Least Squares with corrections for first order serial correlation and heteroscedasticity. Deep gas equations were estimated by nonlinear two stage least squares also with corrections for first order serial correlation and heteroscedasticity. Time trends were included as proxies for technological change. Instruments included six regional dummy variables, lagged values of the dependent and independent variables (depth, time), the lagged values of total onshore successful wells drilled, and the contemporaneous and lagged values of real oil and natural gas wellhead prices.

**Lease Equipment Cost Equations for Oil and Shallow Gas**

$$\begin{aligned} lnLEQC_{r,k,t} = {} & b0_{r,k} + b1_k * lnDEPTH_{r,k,t} + b2_k * lnESTSUCWELLS_t + b3 * TIME_t \\ & + \rho_k * lnLEQC_{r,k,t-1} - \rho_k * ( b0_{r,k} + b1_k * lnDEPTH_{r,k,t-1} \\ & + b2_k * lnESTSUCWELLS_{t-1} + b3 * TIME_{t-1} ) \end{aligned} \tag{D-6}$$

for regions 1 through 6, O = oil and SG = shallow gas.

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| O1 | 15.5166 | 4.20335 | 3.69148 | [.000] |
| O2 | 15.3378 | 4.20396 | 3.64843 | [.000] |
| O3 | 15.4060 | 4.20697 | 3.66201 | [.000] |
| O4 | 15.5436 | 4.20406 | 3.69729 | [.000] |
| O5 | 15.5780 | 4.20049 | 3.70862 | [.000] |
| O6 | 15.9121 | 4.19429 | 3.79374 | [.000] |
| ODEPTH | .524674 | .046161 | 11.3661 | [.000] |
| OWELL | .057718 | .018341 | 3.14690 | [.002] |
| TECH | -.453382E-02 | .208810E-02 | -2.17126 | [.030] |
| ORHO | .840698 | .031082 | 27.0478 | [.000] |
| SG1 | 16.0897 | 4.15290 | 3.87432 | [.000] |
| SG2 | 16.5116 | 4.15440 | 3.97449 | [.000] |
| SG3 | 16.3795 | 4.15289 | 3.94412 | [.000] |
| SG4 | 16.6310 | 4.15407 | 4.00354 | [.000] |
| SG5 | 16.9644 | 4.15286 | 4.08500 | [.000] |
| SG6 | 16.1392 | 4.14795 | 3.89088 | [.000] |
| SGDEPTH | .212790 | .039064 | 5.44718 | [.000] |
| SGWELL | .106135 | .020644 | 5.14127 | [.000] |
| SGRHO | .841635 | .034227 | 24.5900 | [.000] |

Number of observations = 210

```
Equation: Oil Equation
Dependent variable: LNOILLEQ

        Mean of dep. var. = 11.3297
   Std. dev. of dep. var. = .259713
 Sum of squared residuals = .807648
    Variance of residuals = .384594E-02
 Std. error of regression = .062016
                R-squared = .942720
            Durbin-Watson = 1.97558 [<.898]

 Equation: Shallow Gas Equation
 Dependent variable: LNSGLEQ

        Mean of dep. var. = 10.1898
   Std. dev. of dep. var. = .335659
 Sum of squared residuals = .616182
    Variance of residuals = .293420E-02
 Std. error of regression = .054168
                R-squared = .973835
```

Durbin-Watson = 1.68573 [<.203]

**Lease Equipment Cost Equation for Deep Gas**

$$\ln LEQC_{r,k,t} = b0_{r,k} + b1_k * ESTSUCWELLS_t + b2_k * TIME_t + \rho_k * \ln LEQC_{t-1} - \rho_k * (b0_{r,k} + b1_k * ESTSUCWELLS_{t-1} + b2_k * TIME_{t-1} \tag{D-7}$$

for regions 2 through 5 and DG = deep gas.

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| DG2 | 23.8611 | 3.26876 | 7.29974 | [.000] |
| DG3 | 23.8857 | 3.26842 | 7.30803 | [.000] |
| DG4 | 23.8560 | 3.26774 | 7.30048 | [.000] |
| DG5 | 23.9316 | 3.26771 | 7.32364 | [.000] |
| DGWELL | .165207 | .021673 | 7.62277 | [.000] |
| TECH | -.718515E-02 | .166759E-02 | -4.30870 | [.000] |
| DGRHO | .761232 | .055713 | 13.6635 | [.000] |

```
 Equation: Deep Gas Equation
 Dependent variable: LNDGLEQ

        Mean of dep. var. = 10.7555
   Std. dev. of dep. var. = .115595
 Sum of squared residuals = .274296
    Variance of residuals = .200216E-02
 Std. error of regression = .044745
                R-squared = .856940
       Adjusted R-squared = .850674
            Durbin-Watson = 1.45535 [<.008]
```

# Onshore Lower 48 Operating Cost Equations

The onshore Lower 48 per well operating cost equations were estimated for onshore regions 1 through 6 for successful oil wells, successful shallow natural gas wells, and successful deep natural gas wells using region-specific data for the 1970-2006 time period. The equations were estimated in log-linear form using TSP version 4.5. For regions 2 through 5, oil, shallow gas, and deep gas equations were estimated simultaneously by Three Stage Least Squares with corrections for first order serial correlation and heteroscedasticity. For regions 1 and 6, oil and shallow gas equations were estimated simultaneously by Three Stage Least Squares with corrections for first order serial correlation and heteroscedasticity. A time trend was included to proxy for technological change. Instruments included the six regional dummy variables, lagged values of the dependent and independent variables (depth, time), the lagged values of total onshore successful wells drilled (by fuel type), and the contemporaneous and lagged values of real natural gas wellhead prices. The equation was developed under the assumption that improvements in technology reduce operating costs by 0.25 percent per year. The technology improvement factor was re- adjusted down to 0.20 percent per year, but the coefficients were not changed.

**<u>Operating Cost Equations for Regions 2 through 5</u>**

$$\begin{aligned}\ln OPC_{r,k,t} &= b0_{r,k} + b1_k * \ln DEPTH_{r,k,t} + b2_k * \ln ESTSUCWELLS_{k,t} + b3 * TIME_t + b4 * PGAS_{r,t} \\ &+ \rho_k * \ln OPC_{r,k,t-1} - \rho_k * (b0_{r,k} + b1_k * \ln DEPTH_{r,k,t-1} + b2_k * \ln ESTSUCWELLS_{k,t-1} \\ &+ b3 * TIME_{t-1} + b4 * PGAS_{r,t-1})\end{aligned} \tag{D8}$$

for regions 2 through 5 and O = oil, SG = shallow gas, DG = deep gas

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| O2 | 8.04938 | .606869 | 13.2638 | [.000] |
| O3 | 7.82058 | .590459 | 13.2449 | [.000] |
| O4 | 7.73674 | .600554 | 12.8827 | [.000] |
| O5 | 7.93784 | .613613 | 12.9362 | [.000] |
| ODEPTH | .533719 | .055155 | 9.67668 | [.000] |
| OWELL | .197146 | .033516 | 5.88220 | [.000] |
| OGDPGAS | .058113 | .013892 | 4.18308 | [.000] |
| ORHO | .874291 | .034886 | 25.0611 | [.000] |
| SG2 | 12.2695 | .276526 | 44.3702 | [.000] |
| SG3 | 12.1222 | .270787 | 44.7666 | [.000] |
| SG4 | 12.1995 | .274881 | 44.3810 | [.000] |
| SG5 | 12.4478 | .270203 | 46.0685 | [.000] |
| SGDEPTH | .144129 | .019007 | 7.58293 | [.000] |
| SGWELL | .121528 | .019130 | 6.35273 | [.000] |
| SGRHO | .875618 | .025956 | 33.7344 | [.000] |
| DG2 | 10.8643 | .478608 | 22.6997 | [.000] |
| DG3 | 10.8774 | .481622 | 22.5850 | [.000] |
| DG4 | 10.7970 | .479241 | 22.5294 | [.000] |
| DG5 | 10.9802 | .479200 | 22.9136 | [.000] |
| DGDEPTH | .323460 | .047208 | 6.85186 | [.000] |
| DGWELL | .108922 | .015975 | 6.81815 | [.000] |
| DGRHO | .849989 | .026957 | 31.5313 | [.000] |

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

Equation: Oil equation
Dependent variable: LNOILOPR

```
        Mean of dep. var. = 9.56849
   Std. dev. of dep. var. = .327338
 Sum of squared residuals = .517374
    Variance of residuals = .359288E-02
 Std. error of regression = .059941
                R-squared = .966234
            Durbin-Watson = 2.08689 [<.996]

 Equation: Shallow Gas equation
 Dependent variable: LNSGOPR

        Mean of dep. var. = 9.65639
   Std. dev. of dep. var. = .164242
 Sum of squared residuals = .262851
    Variance of residuals = .182536E-02
 Std. error of regression = .042724
                R-squared = .931866
            Durbin-Watson = 1.95621 [<.966]

 Equation: Deep Gas equation
 Dependent variable: LNDGOPR

        Mean of dep. var. = 9.99752
   Std. dev. of dep. var. = .114120
 Sum of squared residuals = .184990
    Variance of residuals = .128465E-02
 Std. error of regression = .035842
                R-squared = .900681
            Durbin-Watson = 1.74130 [<.705]
```

**Operating Cost Equations for Region 1 and Region 6**

$$\ln OPC_{r,k,t} = b0_{r,k} + b1_k * DEPTH_{r,k,t} + b2_k * ESTSUCWELLS_t + b3 * PGAS_{r,t} + \rho_k * \ln OPC_{r,k,t-1}$$
$$- \rho_k * (b0_{r,k} + b1_k * DEPTH_{r,k,t-1} + b2_k * ESTSUCWELLS_{t-1} + b3 * PGAS_{r,t-1})$$

(D-9)

for regions 1 and 6, O = oil and SG = shallow gas.

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| O1 | 11.3507 | .455231 | 24.9328 | [.000] |
| O6 | 11.4450 | .442444 | 25.8662 | [.000] |
| ODEPTH | .218227 | .039519 | 5.52122 | [.000] |
| OWELL | .126143 | .026979 | 4.68080 | [.000] |
| OPGAS | .023870 | .834498E-02 | 2.84960 | [.004] |
| ORHO | .844985 | .032840 | 25.7483 | [.000] |
| SG1 | 10.6233 | .443715 | 23.9289 | [.000] |
| SG6 | 10.5870 | .465789 | 22.7171 | [.000] |
| SGDEPTH | .319402 | .050327 | 6.35426 | [.000] |
| SGWELL | .091546 | .019545 | 4.68756 | [.000] |
| SGRHO | .871083 | .032387 | 26.8432 | [.000] |

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

Equation: Oil
 Dependent variable: LNOILOPR

        Mean of dep. var. = 9.36821
   Std. dev. of dep. var. = .145491
```

```
Sum of squared residuals = .082663
   Variance of residuals = .114810E-02
Std. error of regression = .033884
               R-squared = .945101
           Durbin-Watson = 1.92512 [<.866]
```

```
Equation: Shallow Gas
Dependent variable: LNSGOPR

       Mean of dep. var. = 9.16664
  Std. dev. of dep. var. = .133612
Sum of squared residuals = .067630
   Variance of residuals = .939303E-03
Std. error of regression = .030648
               R-squared = .946646
           Durbin-Watson = 1.90176 [<.843]
```

## Return on Investment Equations

The return on domestic and foreign (drilling) investment (ROI) equations were estimated in log form over the sample period 1981-2003 for the domestic ROI and 1978-2003 for the foreign ROI. The natural log of the world oil price in US$1997 served as the explanatory variable for both equations. The equations were estimated with least squares using TSP version 5.0.

**Return on Investment, U.S.**

$$\ln ROI\_US_t = \alpha 0 + \alpha 1 * \ln POIL97_t \tag{D-10}$$

```
Method of estimation = Ordinary Least Squares

 Dependent variable: lnROI_US
 Number of observations:  23

       Mean of dep. var. = -2.18587      LM het. test = 4.31949 [.038]
  Std. dev. of dep. var. = .499339      Durbin-Watson = 2.13573 [<.678]
Sum of squared residuals = 1.42871   Jarque-Bera test = 30.8425 [.000]
   Variance of residuals = .068034    Ramsey's RESET2 = 16.0370 [.001]
Std. error of regression = .260833    F (zero slopes) = 59.6285 [.000]
               R-squared = .739546     Schwarz B.I.C. = 3.81577
      Adjusted R-squared = .727144     Log likelihood = -.680279
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| α0 | -5.51544 | .434599 | -12.6909 | [.000] |
| α1 | 1.08797 | .140894 | 7.72195 | [.000] |

**Return on Investment, Foreign**

$$\text{lnROI\_FOREIGN}_t = \alpha 0 + \alpha 1 * \text{lnPOIL97}_t \tag{D-11}$$

```
Method of estimation = Ordinary Least Squares

 Dependent variable: lnROI_FOREIGN
 Number of observations:  26

        Mean of dep. var. = -2.10756      LM het. test = 4.15958 [.041]
   Std. dev. of dep. var. = .520279      Durbin-Watson = 2.09367 [<.643]
 Sum of squared residuals = 1.66202   Jarque-Bera test = 29.8888 [.000]
    Variance of residuals = .069251    Ramsey's RESET2 = 24.6236 [.000]
 Std. error of regression = .263155    F (zero slopes) = 73.7210 [.000]
                R-squared = .754403     Schwarz B.I.C. = 4.39967
       Adjusted R-squared = .744170     Log likelihood = -1.14157

                      Standard
 Parameter  Estimate    Error       t-statistic   P-value
 α0         -5.51668   .400391       -13.7782      [.000]
 α1         1.05394    .122750       8.58609       [.000]
```

## U.S. Exploration and Development Budget Equation

The U.S. exploration and development budget equation was estimated using data over the 1981-2003 time period. Explanatory variables included the return on foreign drilling investment, the ratio of price to operating cost for both oil and natural gas, and the lagged value of natural gas production. The equation was estimated using least squares with TSP version 4.5.

$$\begin{aligned} \text{lnUS\_ED\_97}_t &= \beta 0 + \beta 1 * \text{lnROI\_FOREIGN}_t + \beta 2 * \text{lnPCRATIO\_GAS}_t \\ &+ \beta 3 * \text{lnPCRATIO\_OIL}_t + \beta 4 * \text{lnGAS\_PROD}_{t-1} \end{aligned} \tag{D-12}$$

for t = 1981 to 2003.

```
Dependent variable: LN_ED_OGJ_97
Number of observations:  22

        Mean of dep. var. = 9.99804      LM het. test = .323036 [.570]
   Std. dev. of dep. var. = .490090     Durbin-Watson = 2.10409 [<.849]
 Sum of squared residuals = .681234  Jarque-Bera test = .628891 [.730]
    Variance of residuals = .040073   Ramsey's RESET2 = .123819 [.730]
 Std. error of regression = .200181   F (zero slopes) = 27.2176 [.000]
                R-squared = .864941    Schwarz B.I.C. = .720445
       Adjusted R-squared = .833162    Log likelihood = 7.00716

                                Standard
 Parameter         Estimate       Error       t-statistic   P-value
 β0                -62.8289      15.9899       -3.92928      [.001]
 β1                -.273901      .076222       -3.59344      [.002]
 β2                1.38388       .246907       5.60488       [.000]
 β3                1.05841       .247702       4.27292       [.001]
 β4                4.30038       .948648       4.53317       [.000]
```

## Onshore Lower 48 Regional Wells Equations

Lower 48 onshore wells equations were estimated for each fuel type (oil, shallow gas, deep gas) by well type [exploratory (i = 1) disaggregated into new field wildcat wells and other exploratory wells, developmental (i = 2)] using panel data, i.e., data across regions over time. For oil and shallow gas, equations were estimated using data for the six onshore regions over the 1978-2004 time period; for deep gas, equations were estimated using data for regions 2 through 5 over the same time frame. All equations were estimated with corrections for heteroscedasticity and first-order serial correlation when necessary using TSP version 4.5. All equations assumed that the total number of wells drilled by fuel and well types is a function of the fuel- and well-specific regional discounted cash flow, the total industry exploration and development budget, and, in some instances, a measure of the remaining reserves (undiscovered or inferred) in the region.

**Onshore Oil New Field Wildcat Wells**

(D-13)

$$\begin{aligned} \ln WELLSON_{i,r,k,t} &= \sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_t + m2_{i,k} * \ln R\_UND_{r,k,t} \\ &+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (\sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-2} * US\_ED\_97_{t-1} \\ &+ m2_{i,k} * \ln R\_UND_{r,k,t-1}) \end{aligned}$$

for i = 1 (exploratory), r = 1 through 6, and k = 1 (oil).

Dependent variable: $\ln WELLSON_{1,r,1,t}$
Number of observations: 150

| | | | |
|---|---|---|---|
| Mean of dep. var. | = 7.39904 | R-squared | = .971270 |
| Std. dev. of dep. var. | = 3.94108 | Adjusted R-squared | = .969640 |
| Sum of squared residuals | = 66.5974 | Durbin-Watson | = 1.91470 |
| Variance of residuals | = .472322 | Schwarz B.I.C. | = 172.476 |
| Std. error of regression | = .687257 | Log likelihood | = -149.928 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $m00_{1,1,1}$ | -48.9984 | 12.8764 | -3.80529 | [.000] |
| $m00_{1,2,1}$ | -57.5013 | 15.0413 | -3.82289 | [.000] |
| $m00_{1,3,1}$ | -46.2699 | 12.5139 | -3.69747 | [.000] |
| $m00_{1,4,1}$ | -54.7330 | 14.4310 | -3.79274 | [.000] |
| $m00_{1,5,1}$ | -58.3667 | 15.3091 | -3.81254 | [.000] |
| $m00_{1,6,1}$ | -56.5894 | 14.1044 | -4.01218 | [.000] |
| m1 | .140351E-11 | .628077E-12 | 2.23461 | [.025] |
| m2 | 7.30301 | 1.75897 | 4.15187 | [.000] |
| ρ | .787026 | .051240 | 15.3597 | [.000] |

**Onshore Oil Other Exploratory Wells**

(D-14)

$$\ln\mathrm{WELLSON}_{i,r,k,t} = \sum_{r=1}^{6} m00_{i,r,k} * REGr + \mathrm{m1}_{i,k} * \mathrm{DCFON}_{i,k,t-1} * \mathrm{US\_ED\_97}_{t} + \mathrm{m2}_{i,k} * \ln\mathrm{R\_INFR}_{r,k,t}$$
$$+ \rho_{i,k} * \ln\mathrm{WELLSON}_{i,r,k,t-1} - \rho_{i,k} * (\sum_{r=1}^{6} m00_{i,r,k} * REGr + \mathrm{m1}_{i,k} * \mathrm{DCFON}_{i,k,t-2} * \mathrm{US\_ED\_97}_{t-1}$$
$$+ \mathrm{m2}_{i,k} * \ln\mathrm{R\_INFR}_{r,k,t-1})$$

for i = 1 (exploratory), r = 1 through 6, and k = 1 (oil).

Dependent variable: $\ln\mathrm{WELLSON}_{1,r,1,t}$
Number of observations: 150

| | | | |
|---|---|---|---|
| Mean of dep. var. | = 8.43928 | R-squared | = .965244 |
| Std. dev. of dep. var. | = 4.08531 | Adjusted R-squared | = .963272 |
| Sum of squared residuals | = 86.4543 | Durbin-Watson | = 1.92757 |
| Variance of residuals | = .613151 | Schwarz B.I.C. | = 192.858 |
| Std. error of regression | = .783040 | Log likelihood | = -170.311 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $m00_{1,1,1}$ | -35.0701 | 4.67527 | -7.50118 | [.000] |
| $m00_{1,2,1}$ | -41.3879 | 5.31142 | -7.79225 | [.000] |
| $m00_{1,3,1}$ | -38.9167 | 5.17651 | -7.51793 | [.000] |
| $m00_{1,4,1}$ | -45.4082 | 5.91510 | -7.67665 | [.000] |
| $m00_{1,5,1}$ | -45.2594 | 5.79226 | -7.81377 | [.000] |
| $m00_{1,6,1}$ | -45.8844 | 5.63399 | -8.14421 | [.000] |
| m1 | .600747E-12 | .458465E-12 | 1.31034 | [.190] |
| m2 | 5.13909 | .595271 | 8.63319 | [.000] |
| ρ | .701345 | .062672 | 11.1907 | [.000] |

**Onshore Oil Development Wells**

(D-15)

$$\ln WELLSON_{i,r,k,t} = \sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97 + m2_{i,k} * \ln R\_INFR_{r,k,t}$$
$$+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (\sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-2} * US\_ED\_97_{t-1}$$
$$+ m2_{i,k} * \ln R\_INFR_{r,k,t-1})$$

for i = 2 (development), r = 1 through 6, and k = 1 (oil).

Dependent variable: $\ln WELLSON_{2,r,1,t}$
Number of observations: 150

| | | | |
|---|---|---|---|
| Mean of dep. var. = | 17.9141 | R-squared = | .976499 |
| Std. dev. of dep. var. = | 4.53544 | Adjusted R-squared = | .975165 |
| Sum of squared residuals = | 72.0702 | Durbin-Watson = | 1.62616 |
| Variance of residuals = | .511136 | Schwarz B.I.C. = | 178.444 |
| Std. error of regression = | .714938 | Log likelihood = | -155.896 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $m00_{2,1,1}$ | -9.95568 | 3.73839 | -2.66310 | [.008] |
| $m00_{2,2,1}$ | -12.7462 | 4.23823 | -3.00744 | [.003] |
| $m00_{2,3,1}$ | -11.7387 | 4.14953 | -2.82892 | [.005] |
| $m00_{2,4,1}$ | -14.2369 | 4.73799 | -3.00483 | [.003] |
| $m00_{2,5,1}$ | -15.5569 | 4.63462 | -3.35668 | [.001] |
| $m00_{2,6,1}$ | -14.2120 | 4.47833 | -3.17351 | [.002] |
| m1 | .710357E-11 | .373928E-11 | 1.89972 | [.057] |
| m2 | 2.28002 | .476042 | 4.78955 | [.000] |
| ρ | .804734 | .052294 | 15.3887 | [.000] |

**Onshore Shallow Gas New Field Wildcat Wells**

(D-16)

$$\ln WELLSON_{i,r,k,t} = \sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t} * US\_ED\_97_t + m2_{i,k} * \ln R\_UND_{r,k,t}$$
$$+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (\sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_{t-1}$$
$$+ m2_{i,k} * \ln R\_UND_{r,k,t-1})$$

for i = 1 (exploratory), r = 1 through 6, and k = 2 (shallow gas).

Dependent variable: $\ln WELLSON_{1,r,2,t}$
Number of observations: 156

| | | | |
|---|---|---|---|
| Mean of dep. var. | = 13.1430 | R-squared | = .997716 |
| Std. dev. of dep. var. | = 15.5845 | Adjusted R-squared | = .997592 |
| Sum of squared residuals | = 88.0765 | Durbin-Watson | = 2.29828 |
| Variance of residuals | = .599160 | Schwarz B.I.C. | = 201.396 |
| Std. error of regression | = .774054 | Log likelihood | = -178.672 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $m00_{1,1,2}$ | -22.2692 | 3.53876 | -6.29293 | [.000] |
| $m00_{1,2,2}$ | -29.4147 | 4.44775 | -6.61338 | [.000] |
| $m00_{1,3,2}$ | -26.2669 | 3.87367 | -6.78087 | [.000] |
| $m00_{1,4,2}$ | -24.0902 | 3.78638 | -6.36233 | [.000] |
| $m00_{1,5,2}$ | -25.6279 | 3.94535 | -6.49573 | [.000] |
| $m00_{1,6,2}$ | -23.6128 | 3.48430 | -6.77689 | [.000] |
| m1 | .227326E-11 | .533986E-12 | 4.25715 | [.000] |
| m2 | 3.13375 | .385827 | 8.12216 | [.000] |
| ρ | .817317 | .061727 | 13.2409 | [.000] |

## Onshore Shallow Gas Other Exploratory Wells

(D-17)

$$\begin{aligned}\ln WELLSON_{i,r,k,t} &= m0_{i,k} + m00_{i,r,k} + m1_{i,k} * DCFON_{i,k,t} * US\_ED\_97_{t} + m2_{i,k} * \ln R\_INFR_{r,k,t} \\ &+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (m0_{i,k} + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_{t-1} \\ &+ m2_{i,k} * \ln R\_INFR_{r,k,t-1})\end{aligned}$$

for i = 1 (exploratory), r = 1 through 6, and k = 2 (shallow gas).

Dependent variable: $\ln WELLSON_{1,r,2,t}$
Number of observations: 156

| | | | |
|---|---|---|---|
| Mean of dep. var. | = 6.67374 | R-squared | = .992907 |
| Std. dev. of dep. var. | = 6.18510 | Adjusted R-squared | = .992671 |
| Sum of squared residuals | = 45.9562 | Durbin-Watson | = 2.10779 |
| Variance of residuals | = .306375 | Schwarz B.I.C. | = 143.710 |
| Std. error of regression | = .553511 | Log likelihood | = -128.560 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $m0_{1,2}$ | 1.83585 | .243514 | 7.53897 | [.000] |
| $m00_{1,1,2}$ | 1.74587 | .133854 | 13.0431 | [.000] |
| $m00_{1,4,2}$ | .731004 | .206640 | 3.53757 | [.000] |
| m1 | .154583E-11 | .545188E-12 | 2.83541 | [.005] |
| m2 | .360699 | .024302 | 14.8424 | [.000] |
| ρ | .922195 | .027029 | 34.1185 | [.000] |

### Onshore Shallow Gas Development Wells

(D-18)

$$\begin{aligned}\ln \mathrm{WELLSON}_{\mathrm{i,r,k,t}} &= m0_{i,k} + m00_{i,r,k} * REG1 + \mathrm{m1}_{\mathrm{i,k}} * \mathrm{DCFON}_{\mathrm{i,k,t}} * \mathrm{US\_ED\_97}_{\mathrm{t}} + m2_{i,k} * \ln R\_INFR_{r,k,t} \\ &+ \rho_{\mathrm{i,k}} * \ln \mathrm{WELLSON}_{\mathrm{i,r,k,t-1}} - \rho_{\mathrm{i,k}} * (m0_{i,k} + m00_{i,1,k} * REG1 + \mathrm{m1}_{\mathrm{i,k}} * \mathrm{DCFON}_{\mathrm{i,k,t-1}} * \mathrm{US\_ED\_97}_{\mathrm{t-1}} \\ &+ m2_{i,k} * \ln R\_INFR_{r,k,t-1})\end{aligned}$$

for i = 2 (development), r = 1 through 6, k = 2 (shallow gas).

Dependent variable: $\ln\mathrm{WELLSON}_{2,r,2,t}$
Number of observations: 156

| | | | |
|---|---|---|---|
| Mean of dep. var. | = 9.18117 | R-squared | = .992109 |
| Std. dev. of dep. var. | = 7.78523 | Adjusted R-squared | = .991791 |
| Sum of squared residuals | = 74.3310 | Durbin-Watson | = 2.11147 |
| Variance of residuals | = .498866 | Schwarz B.I.C. | = 183.465 |
| Std. error of regression | = .706304 | Log likelihood | = -165.791 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $m0_{2,2}$ | 5.51539 | .459426 | 12.0050 | [.000] |
| $m00_{2,3,2}$ | 1.18807 | .214753 | 5.53228 | [.000] |
| $m00_{2,5,2}$ | -1.22316 | .163754 | -7.46948 | [.000] |
| $m00_{2,6,2}$ | -3.01663 | .222988 | -13.5282 | [.000] |
| m1 | .743867E-11 | .450369E-11 | 1.65168 | [.099] |
| m2 | .130644 | .054813 | 2.38345 | [.017] |
| ρ | .802331 | .048795 | 16.4428 | [.000] |

**Onshore Deep Gas New Field Wildcat Wells**

$$\begin{aligned} \ln WELLSON_{i,r,k,t} &= m0_{i,k} + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_{t} + m2_{i,k} * \ln R\_UND_{r,k,t} \\ &+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (m0_{i,k} + m1_{i,k} * DCFON_{i,k,t-2} * US\_ED\_97_{t-1} \\ &+ m2_{i,k} * \ln R\_UND_{r,k,t-1}) \end{aligned} \tag{D-19}$$

for i = 1 (exploratory), r = 2 through 5, k = 3 (deep gas).

Dependent variable: $\ln WELLSON_{i,r,3,t}$
Number of observations: 104

| | | | |
|---|---|---|---|
| Mean of dep. var. | = 7.29474 | R-squared | = .982634 |
| Std. dev. of dep. var. | = 6.21483 | Adjusted R-squared | = .982113 |
| Sum of squared residuals | = 69.1450 | Durbin-Watson | = 1.89787 |
| Variance of residuals | = .691450 | Schwarz B.I.C. | = 136.063 |
| Std. error of regression | = .831535 | Log likelihood | = -126.775 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| m0 | -9.69872 | 1.37000 | -7.07938 | [.000] |
| m1 | .206872E-12 | .470777E-13 | 4.39428 | [.000] |
| m2 | 1.29070 | .127450 | 10.1271 | [.000] |
| ρ | .614229 | .084444 | 7.27383 | [.000] |

## Onshore Deep Gas Other Exploratory Wells

(D-20)

$$\begin{aligned}\mathrm{lnWELLSON}_{\mathrm{i,r,k,t}} = {} & m0_{i,k} + \mathrm{m1}_{\mathrm{i,k}} * \mathrm{DCFON}_{\mathrm{i,k,t-1}} * \mathrm{US\_ED\_97}_{\mathrm{t}} + \mathrm{m2}_{\mathrm{i,k}} * \mathrm{lnR\_INFR}_{\mathrm{r,k,t}} \\ & + \rho_{\mathrm{i,k}} * \mathrm{lnWELLSON}_{\mathrm{i,r,k,t-1}} - \rho_{\mathrm{i,k}} * (m0_{i,k} + \mathrm{m1}_{\mathrm{i,k}} * \mathrm{DCFON}_{\mathrm{i,k,t-2}} * \mathrm{US\_ED\_97}_{\mathrm{t-1}} \\ & + \mathrm{m2}_{\mathrm{i,k}} * \mathrm{lnR\_INFR}_{\mathrm{r,k,t-1}})\end{aligned}$$

for i = 1 (exploratory), r = 2 through 5, k = 3 (deep gas).

Dependent variable: $\mathrm{lnWELLSON}_{i,r,3,t}$
Number of observations: 104

```
        Mean of dep. var. = 4.76518          R-squared = .849755
   Std. dev. of dep. var. = 1.83332  Adjusted R-squared = .845248
 Sum of squared residuals = 52.3937       Durbin-Watson = 1.94943
    Variance of residuals = .523937     Schwarz B.I.C. = 121.625
 Std. error of regression = .723835     Log likelihood = -112.336
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| m0 | -6.00632 | 1.92582 | -3.11883 | [.002] |
| m1 | .179215E-12 | .494514E-13 | 3.62406 | [.000] |
| m2 | .879172 | .180255 | 4.87737 | [.000] |
| ρ | .693837 | .068047 | 10.1964 | [.000] |

**Onshore Deep Gas Development Wells**

$$\ln WELLSON_{i,r,k,t} = \sum_{r=2}^{5} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t} * US\_ED\_97_{t} + \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (\sum_{r=2}^{5} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_{t-1}) \tag{D-21}$$

for i = 2 (development), r = 2 through 5, k = 3 (deep gas).

Dependent variable: $\ln WELLSON_{2,r,3,t}$
Number of observations: 104

| | | | |
|---|---|---|---|
| Mean of dep. var. | = 12.3347 | R-squared | = .988072 |
| Std. dev. of dep. var. | = 6.08501 | Adjusted R-squared | = .987463 |
| Sum of squared residuals | = 45.4958 | Durbin-Watson | = 1.78930 |
| Variance of residuals | = .464243 | Schwarz B.I.C. | = 118.971 |
| Std. error of regression | = .681354 | Log likelihood | = -105.037 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $m00_{2,2,3}$ | 6.80643 | .205391 | 33.1389 | [.000] |
| $m00_{2,3,3}$ | 6.14543 | .230012 | 26.7179 | [.000] |
| $m00_{2,4,3}$ | 4.38842 | .333534 | 13.1573 | [.000] |
| $m00_{2,5,3}$ | 4.83123 | .498723 | 9.68719 | [.000] |
| m1 | .613493E-12 | .258855E-12 | 2.37003 | [.018] |
| ρ | .803774 | .062599 | 12.8401 | [.000] |

# Onshore Lower 48 Conventional Finding Rates

## New Field Wildcat Finding Rate (FR1): Oil

Oil discoveries per successful new field wildcat oil well were assumed to be a function of beginning of year remaining undiscovered oil reserves, the level of contemporaneous new field wildcat oil wells drilled, and the real average wellhead price of oil. The equation was estimated in log-linear form using OLS with correction for cross sectional heteroscedasticity using TSP version 4.5. The intercept was allowed to vary across regions. A dummy variable was included for those few observations for which conventional oil discoveries were estimated.

$$\ln FR1_{r,k,t} = \beta 0_k + \sum_{r=2}^{5} \beta 00_{r,k} * REGr + \beta 1_k * \ln RESOURCE_{r,k,t} + \beta 2_k * \ln SW1_{r,k,t} + \beta 3_k DUM_{r,k,t} \tag{D-22}$$

for r = 1 through 5 and k = 1 (oil).

Dependent variable: $\ln FR1_{r,1,t}$
Number of observations: 135

| | | | |
|---|---|---|---|
| Mean of dep. var. | = -3.31654 | LM het. test | = .414327 [.520] |
| Std. dev. of dep. var. | = 2.04718 | Durbin-Watson | = 1.87111 [<.477] |
| Sum of squared residuals | = 133.389 | Jarque-Bera test | = 44.6543 [.000] |
| Variance of residuals | = 1.05031 | Ramsey's RESET2 | = .228119 [.634] |
| Std. error of regression | = 1.02485 | F (zero slopes) | = 58.2409 [.000] |
| R-squared | = .762478 | Schwarz B.I.C. | = 210.368 |
| Adjusted R-squared | = .749386 | Log likelihood | = -190.746 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\beta 0_1$ | -48.4099 | 5.97457 | -8.10265 | [.000] |
| $\beta 00_{2,1}$ | -6.21458 | 1.05862 | -5.87047 | [.000] |
| $\beta 00_{3,1}$ | 1.09617 | .396569 | 2.76413 | [.007] |
| $\beta 00_{4,1}$ | -4.24787 | .782054 | -5.43168 | [.000] |
| $\beta 00_{5,1}$ | -7.75580 | 1.19954 | -6.46564 | [.000] |
| $\beta 1_1$ | 6.20903 | .845037 | 7.34765 | [.000] |
| $\beta 2_1$ | -.251571 | .136088 | -1.84859 | [.067] |
| $\beta 3_1$ | -6.48964 | .485741 | -13.3603 | [.000] |

## New Field Wildcat Finding Rate (FR1): Conventional Natural Gas (Shallow plus Deep)

Conventional natural gas discoveries per successful new field wildcat gas well were assumed to be a function of beginning of year remaining undiscovered gas reserves, the level of contemporaneous new field wildcat gas wells drilled, and the average depth of a new field wildcat gas well. The equation was estimated in log-linear form using OLS with correction for cross sectional heteroscedasticity using TSP version 4.5. The intercept was allowed to vary across regions. A dummy variable was included for those few observations for which conventional natural gas discoveries were estimated.

(D-23)

$$\ln FR1_{r,k,t} = \beta 0_k + \sum_{r=2}^{5} \beta 00_{r,k} * REGr + \beta 1_k * \ln RESOURCE_{r,k,t} + \beta 2_k * \ln SW1_{r,k,t} + \beta 3_k * \ln DEPTH_{r,k,t}$$
$$+ \beta 4_k \, DUM_{r,k,t}$$

for r = 1 through 6 and k = 2 & 3 (shallow gas and deep gas combined).

Dependent variable: $\ln FR1_{r,2\&3,t}$
Number of observations: 156

| | | | |
|---|---|---|---|
| Mean of dep. var. | = .062788 | LM het. test | = .014487 [.904] |
| Std. dev. of dep. var. | = 1.34369 | Durbin-Watson | = 1.87873 [<.497] |
| Sum of squared residuals | = 117.797 | Jarque-Bera test | = .741855 [.690] |
| Variance of residuals | = .801339 | Ramsey's RESET2 | = 1.58927 [.209] |
| Std. error of regression | = .895175 | F (zero slopes) | = 25.2789 [.000] |
| R-squared | = .579075 | Schwarz B.I.C. | = 222.169 |
| Adjusted R-squared | = .556168 | Log likelihood | = -199.445 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\beta 0_{2\&3}$ | -42.1606 | 5.06971 | -8.31618 | [.000] |
| $\beta 00_{2,2\&3}$ | -6.97907 | 1.06511 | -6.55243 | [.000] |
| $\beta 00_{3,2\&3}$ | -2.86506 | .460140 | -6.22648 | [.000] |
| $\beta 00_{4,2\&3}$ | -1.74551 | .365197 | -4.77965 | [.000] |
| $\beta 00_{5,2\&3}$ | -3.50929 | .481650 | -7.28598 | [.000] |
| $\beta 1_{2\&3}$ | 3.72825 | .439988 | 8.47353 | [.000] |
| $\beta 2_{2\&3}$ | -.412044 | .091341 | -4.51108 | [.000] |
| $\beta 3_{2\&3}$ | 1.16490 | .327734 | 3.55440 | [.001] |
| $\beta 4_{2\&3}$ | -1.96640 | .388600 | -5.06022 | [.000] |

## Other Exploratory Finding Rate (FR2): Oil

The other exploratory finding rate for oil was assumed to be a function of beginning of year remaining inferred oil reserves and the level of contemporaneous other exploratory oil wells drilled. The equation was estimated in log-linear form with correction for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5.

(D-24)

$$\begin{aligned} \ln FR2_{r,k,t} &= \beta 0_k + \beta 1_k * \ln INFR_{r,k,t} + \beta 2_k * \ln SW2_{r,k,t} + \rho_k * \ln FR2_{r,k,t-1} \\ &\quad - \rho_k * (\beta 0_k + \beta 1_k * \ln INFR_{r,k,t-1} + \beta 2_k * \ln SW2_{r,k,t-1}) \end{aligned}$$

for r = 1 to 6, k = 1 (oil).

Dependent variable: $\ln FR2_{r,1,t}$
Number of observations = 156

| | | | |
|---|---|---|---|
| Mean of dep. var. | = -.339276 | R-squared | = .862872 |
| Std. dev. of dep. var. | = 2.07949 | Adjusted R-squared | = .860165 |
| Sum of squared residuals | = 92.3697 | LM het. test | = 1.23033 [.267] |
| Variance of residuals | = .607695 | Durbin-Watson | = 2.26826 [<.973] |
| Std. error of regression | = .779548 | | |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\beta 0_1$ | -3.31186 | 1.18521 | -2.79433 | [.005] |
| $\beta 1_1$ | .711852 | .131742 | 5.40336 | [.000] |
| $\beta 2_1$ | -.787856 | .061746 | -12.7596 | [.000] |
| $\rho_1$ | .646368 | .066212 | 9.76212 | [.000] |

## Other Exploratory Finding Rate (FR2): Conventional Natural Gas (Shallow plus Deep)

The other exploratory finding rate for conventional natural gas was assumed to be a function of beginning of year remaining natural gas inferred reserves, the number of contemporaneous other exploratory gas wells drilled, the real wellhead price of natural gas, and the average depth of other exploratory wells drilled. The equation was estimated with corrections for heteroscedasticity and first order serial correlation using TSP version 4.5.

$$\begin{aligned} \ln FR2_{r,k,t} &= \beta 0_k + \beta 1_k * \ln INFR_{r,k,t} + \beta 2_k * \ln SW2_{r,k,t} + \beta 3_k * \ln WHP_{r,k,t} + \rho_k * \ln FR2_{r,k,t-1} \\ &\quad - \rho_k * (\beta 0_k + \beta 1_k * \ln INFR_{r,k,t-1} + \beta 2_k * \ln SW2_{r,k,t-1} + \beta 3_k * \ln WHP_{r,k,t-1}) \end{aligned} \tag{D-25}$$

for r = 1 through 6 and k = 2 & 3 (shallow and deep gas combined).

Dependent variable: $\ln FR2_{r,2\&3,t}$
Number of observations = 150

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\beta 0_{2\&3}$ | -3.58149 | .610333 | -5.86810 | [.000] |
| $\beta 1_{2\&3}$ | .878160 | .061767 | 14.2172 | [.000] |
| $\beta 2_{2\&3}$ | -.942982 | .069517 | -13.5647 | [.000] |
| $\beta 3_{2\&3}$ | 1.01654 | .155763 | 6.52618 | [.000] |
| $\rho_{2\&3}$ | .566078 | .070594 | 8.01876 | [.000] |

## Onshore Lower 48 Oil Production to Reserves (PR) Ratio Equation

The oil production to reserves (PR) ratio, defined as the ratio of oil production to beginning of year oil reserves, is assumed to be a function of the natural log of successful developmental drilling and the ratio of reserve revisions to the number of successful development wells drilled. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5. The estimation allows for region specific intercepts.

(D-26)

$$\ln\left(\frac{PR_{r,k,t}}{1-PR_{r,k,t}}\right)=\sum_{r=1}^{6}\alpha0_{r,k} * REGr+\alpha1_{k} * REVISIONS\_PER\_WELL_{r,k,t}+\alpha2_{k} * \ln SW3_{r,k,t}$$
$$+\rho_{k} * \ln\left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)-\rho_{k} * (\sum_{r=1}^{6}\alpha0_{r,k} * REGr+\alpha1_{k} * REVISIONS\_PER\_WELL_{r,k,t-1}$$
$$+\alpha2_{k} * \ln SW3_{r,k,t-1})$$

for r = 1 through 6 and k = 1 (oil).

Dependent Variable: $\ln(PR_{r,1,t}/(1-PR_{r,1,t}))$
Number of observations = 108

| | | | |
|---|---|---|---|
| Mean of dep. var. | = -2.14611 | R-squared | = .958028 |
| Std. dev. of dep. var. | = .314726 | Adjusted R-squared | = .954636 |
| Sum of squared residuals | = .444845 | LM het. test | = 2.27812 [.131] |
| Variance of residuals | = .449338E-02 | Durbin-Watson | = 2.31934 [<.994] |
| Std. error of regression | = .067033 | | |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\alpha0_{1,1}$ | -2.43406 | .342062 | -7.11585 | [.000] |
| $\alpha0_{2,1}$ | -2.14204 | .160423 | -13.3525 | [.000] |
| $\alpha0_{3,1}$ | -2.38258 | .214144 | -11.1260 | [.000] |
| $\alpha0_{4,1}$ | -2.94240 | .198909 | -14.7927 | [.000] |
| $\alpha0_{5,1}$ | -2.77332 | .245255 | -11.3079 | [.000] |
| $\alpha0_{6,1}$ | -2.95383 | .221416 | -13.3406 | [.000] |
| $\alpha1_{1}$ | .091517 | .025010 | 3.65922 | [.000] |
| $\alpha2_{1}$ | .048324 | .023466 | 2.05931 | [.039] |
| $\rho_{1}$ | .880020 | .071250 | 12.3511 | [.000] |

## Onshore Lower 48 Conventional Natural Gas Production to Reserves (PR) Ratio Equation

The conventional natural gas production to reserves (PR) ratio, defined as the ratio of conventional natural gas production to beginning of year conventional natural gas reserves, is assumed to be a function of the natural log of successful conventional natural gas developmental drilling, natural gas reserve revisions per successful development well drilled, natural gas reserve additions (new field discoveries plus extensions) per successful development well drilled, the natural log of successful development wells drilled, and a dummy variable to account for a change in the calculation of natural gas production for regions 2 and 4 in 2004. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5. The estimation allows for region specific intercepts.

(D-27)

$$\ln\left(\frac{PR_{r,k,t}}{1-PR_{r,k,t}}\right) = \sum_{r=1}^{6}\alpha 0_{r,k} * REGr + \alpha 1_k * REVISIONS\_PER\_WELL_{r,k,t} + \alpha 2_k * DUM\_REG24$$
$$+ \alpha 3_k * RESADD\_PER\_WELL_{r,k,t} + \alpha 4_k * \ln SW3_{r,k,t} + \rho_k * \ln\left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)$$
$$- \rho_k * (\sum_{r=1}^{6}\alpha 0_{r,k} * REGr + \alpha 1_k * REVISIONS\_PER\_WELL_{r,k,t-1} + \alpha 2_k * DUM\_REG24$$
$$+ \alpha 3_k * RESADD\_PER\_WELL_{r,k,t-1} + \alpha 4_k * \ln SW3_{r,k,t-1})$$

for r = 1 through 6 and k = 2 & 3 (conventional shallow and deep natural gas).

Dependent Variable: $\ln(PR_{r,2\&3,t}/(1-PR_{r,2\&3,t}))$
Number of observations = 102

| | | | |
|---|---|---|---|
| Mean of dep. var. | = -2.21778 | R-squared | = .931920 |
| Std. dev. of dep. var. | = .398649 | Adjusted R-squared | = .924439 |
| Sum of squared residuals | = 1.09358 | LM het. test | = 1.33845 [.247] |
| Variance of residuals | = .012017 | Durbin-Watson | = 2.18371 [<.980] |
| Std. error of regression | = .109624 | | |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\alpha 0_{1,2\&3}$ | -3.10882 | .289334 | -10.7447 | [.000] |
| $\alpha 0_{2,2\&3}$ | -2.40467 | .337556 | -7.12376 | [.000] |
| $\alpha 0_{3,2\&3}$ | -2.82057 | .318842 | -8.84628 | [.000] |
| $\alpha 0_{4,2\&3}$ | -2.49732 | .285467 | -8.74819 | [.000] |
| $\alpha 0_{5,2\&3}$ | -3.33491 | .345818 | -9.64353 | [.000] |
| $\alpha 0_{6,2\&3}$ | -2.39950 | .162027 | -14.8092 | [.000] |
| $\alpha 1_{2\&3}$ | .829007E-04 | .246515E-04 | 3.36291 | [.001] |
| $\alpha 2_{2\&3}$ | .052320 | .027436 | 1.90699 | [.057] |
| $\alpha 3_{2\&3}$ | .294641E-04 | .152410E-04 | 1.93322 | [.053] |
| $\alpha 4_{2\&3}$ | .076172 | .041289 | 1.84485 | [.065] |
| $\rho_{2\&3}$ | .693567 | .089510 | 7.74845 | [.000] |

## Onshore Lower 48 Production to Reserves (PR) Ratio Equation for Tight Sands Natural Gas

The production to reserves (PR) ratio for tight sands natural gas, defined as the ratio of tight sands natural gas production to beginning of year tight sands natural gas reserves, is assumed to be a function of the contemporaneous and lagged values of the ratio of tight sands natural gas reserve additions to beginning of year tight sands natural gas reserves. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated using unbalanced data for 31 tight sands plays over the 1997-2004 time period with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5.

(D-28)

$$\ln\left(\frac{PR_{p,k,t}}{1-PR_{p,k,t}}\right) = \alpha 0_k + \alpha 1_k * RA\_RATIO_{p,k,t} + \alpha 2_k * RA\_RATIO_{p,k,t-1} + \rho_k * \ln\left(\frac{PR_{p,k,t-1}}{1-PR_{p,k,t-1}}\right) - \rho_k * (\alpha 0_k + \alpha 1_k * RA\_RATIO_{p,k,t-1} + \alpha 2_k * RA\_RATIO_{p,k,t-2})$$

for p = 1 through 31 and k = 4 (tight sands natural gas).

Dependent variable: $\ln(PR_{p,4,t}/(1-PR_{p,4,t}))$
Number of observations = 178

| | | | |
|---|---|---|---|
| Mean of dep. var. | = -2.32742 | R-squared | = .815451 |
| Std. dev. of dep. var. | = .540829 | Adjusted R-squared | = .812269 |
| Sum of squared residuals | = 9.56401 | LM het. test | = .103186 [.748] |
| Variance of residuals | = .054966 | Durbin-Watson | = 1.72267 [<.054] |
| Std. error of regression | = .23444 | | |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\alpha 0_4$ | -2.47345 | .079514 | -31.1069 | [.000] |
| $\alpha 1_4$ | .495388 | .097745 | 5.06814 | [.000] |
| $\alpha 2_4$ | -.144926 | .049234 | -2.94364 | [.003] |
| $\rho_4$ | .778747 | .052683 | 14.7818 | [.000] |

## Onshore Lower 48 Production to Reserves (PR) Ratio Equation for Gas Shales

The production to reserves (PR) ratio for gas shales, defined as the ratio of gas shales production to beginning of year gas shales reserves, is assumed to be a function of the contemporaneous value of the ratio of gas shales reserve additions to beginning of year gas shales reserves. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated using data for 5 gas shales plays over the 1998-2003 time period with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5.

$$\ln\left(\frac{PR_{p,k,t}}{1-PR_{p,k,t}}\right)=\alpha0_k+\alpha1_k*RA\_RATIO_{p,k,t}+\rho_k*\ln\left(\frac{PR_{p,k,t-1}}{1-PR_{p,k,t-1}}\right)-\rho_k*(\alpha0_k+\alpha1_k*RA\_RATIO_{p,k,t-1}) \tag{D-29}$$

for p = 1 through 5 and k = 5 (gas shales).

Dependent variable: $\ln(PR_{p,5,t}/(1-PR_{p,5,t}))$
Number of observations: 29

| | | | |
|---|---|---|---|
| Mean of dep. var. | = -2.10552 | R-squared | = .887558 |
| Std. dev. of dep. var. | = .768375 | Adjusted R-squared | = .878908 |
| Sum of squared residuals | = 1.98627 | Durbin-Watson | = 1.34175 |
| Variance of residuals | = .076395 | Schwarz B.I.C. | = 7.60181 |
| Std. error of regression | = .276397 | Log likelihood | = -2.55087 |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\alpha0_5$ | -2.39273 | .187478 | -12.7627 | [.000] |
| $\alpha1_5$ | .527364 | .083357 | 6.32657 | [.000] |
| $\rho_5$ | .870551 | .067910 | 12.8192 | [.000] |

## Onshore Lower 48 Production to Reserves (PR) Ratio Equation for Coalbed Methane

The production to reserves (PR) ratio for coalbed methane, defined as the ratio of coalbed methane production to beginning of year coalbed methane reserves, is assumed to be a function of the contemporaneous value of the ratio of coalbed methane reserve additions to beginning of year coalbed methane reserves and the contemporaneous number of successful coalbed methane wells drilled. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated using data for 11 coalbed methane plays over the 1998-2003 time period with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5.

$$\ln\left(\frac{PR_{p,k,t}}{1-PR_{p,k,t}}\right) = \alpha0_k + \alpha1_k * RA\_RATIO_{p,k,t} + \alpha2_k * SW_{p,k,t} + \rho_k * \ln\left(\frac{PR_{p,k,t-1}}{1-PR_{p,k,t-1}}\right) - \rho_k * (\alpha0_k + \alpha1_k * RA\_RATIO_{p,k,t-1} + \alpha2_k * SW_{p,k,t-1}) \quad \text{(D-30)}$$

for p = 1 through 11 and k = 6 (coalbed methane)

Dependent variable: $\ln(PR_{p,6,t}/(1-PR_{p,6,t}))$
Number of observations: 65

| | | | |
|---|---|---|---|
| Mean of dep. var. | = -2.08662 | R-squared | = .852772 |
| Std. dev. of dep. var. | = .584389 | Adjusted R-squared | = .844112 |
| Sum of squared residuals | = 2.75815 | LM het. test | = 2.67810 [.102] |
| Variance of residuals | = .054081 | Durbin-Watson | = 1.87761 [<.476] |
| Std. error of regression | = .232554 | | |

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\alpha0_6$ | -2.45649 | .141236 | -17.3927 | [.000] |
| $\alpha1_6$ | .333254 | .061970 | 5.37763 | [.000] |
| $\alpha2_6$ | .285353E-03 | .530457E-04 | 5.37939 | [.000] |
| $\rho_6$ | .784110 | .066556 | 11.7813 | [.000] |

## Onshore Lower 48 Equation for Tight Sands Natural Gas Wells

The dependent variable in the estimating equation is the ratio of successful tight sands gas wells drilled to the total number accessible tight sands gas wells. Because the number of wells in some of the various plays is zero, the equation was estimated using the Tobit procedure in TSP version 4.5. Independent variables in the regression include a measure of the maturity of the play, the profitability of the play, and a proxy for total E&D spending.

$$\mathrm{WELLSRATIO}_{p,k,t} = b0_k + b1_k * \mathrm{CUM\_RATIO}_{p,k,t} + b2_k * \mathrm{NET\_PROFIT}_{p,k,t} + b3_k * \mathrm{US\_ED\_97} \tag{D-31}$$

for k = 4 (tight sands).

Dependent variable: $\mathrm{WELLSRATIO}_{p,4,t}$

```
Number of observations = 336  Schwarz B.I.C. = -458.012
Number of positive obs. = 249  Log likelihood = 469.646
Fraction of positive obs. =    0.741071
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $b0_4$ | -.023639 | .513810E-02 | -4.60075 | [.000] |
| $b1_4$ | .114494 | .779810E-02 | 14.6823 | [.000] |
| $b2_4$ | .340047E-02 | .527367E-03 | 6.44802 | [.000] |
| $b3_4$ | .521823E-06 | .132872E-06 | 3.92727 | [.000] |
| σ | .030561 | .137479E-02 | 22.2294 | [.000] |

The parameter σ is the estimated standard deviation of the residual. It is necessary to have this estimate for prediction in the context of the Tobit model.

## Onshore Lower 48 Equation for Gas Shales Wells

The dependent variable in the estimating equation is the ratio of successful gas shales wells drilled to the total number accessible gas shales wells. Because the number of wells in some of the various plays is zero, the equation was estimated using the Tobit procedure in TSP version 4.5. Independent variables in the regression include a measure of the maturity of the play, a proxy for industry E&D spending, and the profitability of the play.

$$WELLSRATIO_{p,k,t} = b0_k + b1_k * CUM\_RATIO_{p,k,t} + b2_k * NET\_PROFIT_{p,k,t} + b3_k * US\_ED\_97 \tag{D-32}$$

for k = 5 (gas shales).

Dependent variable: $WELLSRATIO_{p,5,t}$

```
Number of observations = 104  Schwarz B.I.C. = -87.7557
Number of positive obs. = 47   Log likelihood = 97.0445
Fraction of positive obs. =    0.451923
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $b0_5$ | -.464386E-02 | .821758E-02 | -.565113 | [.572] |
| $b1_5$ | .030603 | .014201 | 2.15502 | [.031] |
| $b2_5$ | .016466 | .343806E-02 | 4.78936 | [.000] |
| $b3_5$ | .187086E-06 | .213797E-06 | .875063 | [.382] |
| σ | .022368 | .236527E-02 | 9.45666 | [.000] |

The parameter σ is the estimated standard deviation of the residual. It is necessary to have this estimate for prediction in the context of the Tobit model.

## Onshore Lower 48 Equation for Coalbed Methane Wells

The dependent variable in the estimating equation is the ratio of successful coalbed methane wells drilled to the total number accessible coalbed methane wells. Because the number of wells in some of the various plays is zero, the equation was estimated using the Tobit procedure in TSP version 4.5. Independent variables in the regression include a measure of the maturity of the play, the profitability of the play, and a proxy for industry E&D spending,

$$WELLSRATIO_{p,k,t} = b0_k + b1_k * CUM\_RATIO_{p,k,t} + b2_k * NET\_PROFIT_{p,k,t} + b3_k * US\_ED\_9 \quad \text{(D-33)}$$

for k = 6 (coalbed methane).

```
Dependent variable: WELLSRATIO

Number of observations = 232  Schwarz B.I.C. = -233.148
Number of positive obs. = 131  Log likelihood = 244.042
Fraction of positive obs. =    0.564655
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $b0_6$ | .669034E-02 | .636868E-02 | 1.05051 | [.293] |
| $b1_6$ | .069564 | .997325E-02 | 6.97510 | [.000] |
| $b2_6$ | .013832 | .138241E-02 | 10.0059 | [.000] |
| $b2_6$ | .557494E-06 | .156996E-06 | 3.55101 | [.000] |
| σ | .027652 | .173971E-02 | 15.8946 | [.000] |

The parameter σ is the estimated standard deviation of the residual. It is necessary to have this estimate for prediction in the context of the Tobit model.

## Onshore Lower 48 Regional Associated Dissolved Gas Equations

**Associated Dissolved Gas Production**

The production of associated dissolved gas was assumed to be a function of the previous year's production and end-of year reserves and oil production from the current year. The equation was estimated using Eviews.

(D-34)

$$\mathrm{Q\_ADGAS}_{r,t} = e^{\alpha 0_r} * \mathrm{Q\_ADGAS}^{\alpha 1}_{r,t-1} * R\_ADGAS^{\alpha 2}_{r,t-1} * \mathrm{OILPRD}^{\alpha 3}_{r,t}$$

for r = 1 through 6 and k = 1 (oil).

Dependent variable: Q_ADGAS

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| $\alpha 0_5$ | -0.051486 | | | |
| $\alpha 0_6$ | -.156821 | | | |
| α1 | 0.714167 | | | |
| α2 | 0.113347 | | | |
| α3 | 0.138403 | | | |

**Associated Dissolved Gas Reserve Additions**

Reserve additions of associated dissolved gas are forecasted from the parameters of an estimating equation in which the ratio of gross end-of-year reserves to beginning-of-year reserves for associated dissolved gas is assumed to be a function of the ratio of gross end-of-year reserves to beginning-of-year reserves for crude oil and region-specific dummy variables. The equation is estimated in log-linear form with corrections for cross-sectional heteroscedasticity using TSP version 4.5.

(D-35)

$$\mathrm{RA\_ADGAS}_{r,t} = \beta 0 + \beta 1 * NRD_{r,t} + \beta 2 * EXTENSIONS_{r,t} + \beta 3 * REVISIONS_{r,t}$$

for r = 1 through 6 and k = 1 (oil).

Dependent variable: RA_ADGAS
Number of observations: 150

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| β0 | 78.8486 | | | |
| β1 | 1.34968 | | | |
| β3 | 1.39759 | | | |
| β3 | 0.592806 | | | |

# Price Elasticities of Short Run Supply

As noted in chapter 4, the PMM and NGTDM calculate production levels through the use of short-run supply functions that require estimates of the price elasticities of supply. The section below documents the estimations.

**Onshore Lower 48 Oil**

Price elasticities were estimated using the AR1 technique in TSP which corrects for serial correlation using the maximum likelihood iterative technique of Beach and MacKinnon (1978). Equations for onshore regions 1 and 6 were estimated separately due to the regions' unique characteristics. The functional form is given by:

$$\begin{aligned} LCRUDE_t &= a0 + a1 * LOILRES_t + a2 * LPOIL_t + \rho * LCRUDE_{t-1} \\ &\quad - \rho * (a0 + a1 * LOILRES_{t-1} + a2 * LPOIL_{t-1}) \end{aligned} \tag{D-36}$$

where,

| | | |
|---|---|---|
| LCRUDE | = | natural log of crude oil production |
| LOILRES | = | natural log of beginning of year oil reserves |
| LPOIL | = | natural log of the regional wellhead price of oil in 1987 dollars |
| $\rho$ | = | autocorrelation parameter |
| t | = | year. |

**Region 1**

**Results**

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| a0 | -.977125 | .680644 | -1.43559 |
| LOILRES | .814563 | .114311 | 7.12584 |
| LPOIL | .08385 | .040682 | 2.06115 |
| ρ | .334416 | .297765 | 1.12309 |

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 13

Dependent variable:  LCRUDE
(Statistics based on transformed data)
  Mean of dependent variable = 3.03941
 Std. dev. of dependent var. = .365187
    Sum of squared residuals = .015765
       Variance of residuals = .157651E-02
    Std. error of regression = .039705
                   R-squared = .990477
          Adjusted R-squared = .988573
      Durbin-Watson statistic = 1.58775
   F-statistic (zero slopes) = 502.556
  Log of likelihood function = 25.1414

(Statistics based on original data)
  Mean of dependent variable = 4.43559
 Std. dev. of dependent var. = .142410
    Sum of squared residuals = .015832
       Variance of residuals = .158323E-02
    Std. error of regression = .039790
                   R-squared = .936035
          Adjusted R-squared = .923242
     Durbin-Watson statistic = 1.57879
```

### Region 6

### Results

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| a0 | 6.69155 | 2.14661 | 3.11727 |
| LOILRES | -.123763 | .255535 | -.484329 |
| LPOIL | .031845 | .038040 | .837163 |
| ρ | .833915 | .135664 | 6.14691 |

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 13

Dependent variable:  LCRUDE
(Statistics based on transformed data)
  Mean of dependent variable = 1.13005
 Std. dev. of dependent var. = .605103
    Sum of squared residuals = .013218
       Variance of residuals = .132176E-02
    Std. error of regression = .036356
                   R-squared = .997230
          Adjusted R-squared = .996676
     Durbin-Watson statistic = .896816
   F-statistic (zero slopes) = 1657.10
  Log of likelihood function = 25.7519

(Statistics based on original data)
  Mean of dependent variable = 5.78242
 Std. dev. of dependent var. = .061666
    Sum of squared residuals = .014455
       Variance of residuals = .144552E-02
    Std. error of regression = .038020
                   R-squared = .707387
          Adjusted R-squared = .648864
     Durbin-Watson statistic = .892422
```

For onshore regions 2 through 5, the data were pooled and regional dummy variables were used to allow the estimated production elasticity to vary across the regions. Region 2 is taken as the base region. The form of the equation is given by:

$$\begin{aligned} LCRUDE_t &= a0 + a1 * LOILRES_t + a2 * LPOIL_t + a3 * LPDUM3_t + a4 * LPDUM4_t \\ &+ a5 * LPDUM5_t + \rho * LCRUDE_{t-1} - \rho * (a0 + a1 * LOILRES_{t-1} \\ &+ a2 * LPOIL_{t-1} a3 * LPDUM3_{t-1} + a4 * LPDUM4_{t-1} + a5 * LPDUM5_{t-1}) \end{aligned} \tag{D-37}$$

where,

| | | |
|---|---|---|
| LPDUMr | = | DUMr*LPOIL |
| DUMr | = | a dummy variable that equals 1 if region=r and 0 otherwise |
| r | = | onshore regions 2 through 5 |
| ρ | = | autocorrelation parameter |
| t | = | year. |

## Regions 2 through 5

### Results

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| a0 | 1.38487 | .646290 | 2.14279 |
| LOILRES | .549313 | .077877 | 7.05360 |
| LPOIL | .105051 | .032631 | 3.21932 |
| LPDUM3 | -.077217 | .034067 | -2.26660 |
| LPDUM4 | -.028657 | .034318 | -.835047 |
| LPDUM5 | -.089397 | .032700 | -2.73387 |
| ρ | .867072 | .080470 | 10.7751 |

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 52

Dependent variable:  LCRUDE

(Statistics based on transformed data)
  Mean of dependent variable = .936528
 Std. dev. of dependent var. = .612526
    Sum of squared residuals = .109259
       Variance of residuals = .237519E-02
    Std. error of regression = .048736
                   R-squared = .994731
          Adjusted R-squared = .994159
     Durbin-Watson statistic = 1.42150
   F-statistic (zero slopes) = 1602.00
  Log of likelihood function = 83.7253

(Statistics based on original data)
  Mean of dependent variable = 5.93153
 Std. dev. of dependent var. = .428916
    Sum of squared residuals = .110274
       Variance of residuals = .239725E-02
    Std. error of regression = .048962
                   R-squared = .988524
          Adjusted R-squared = .987277
     Durbin-Watson statistic = 1.40740
```

The estimated coefficient on LPOIL is the price elasticity of crude oil production for region 2. The elasticity for region r (r = 3,4,5) is obtained by adding the coefficient on $LPDUM_r$ to the coefficient on LPOIL.

## Offshore Gulf of Mexico Crude Oil

Price elasticities were estimated using OLS. The functional form is given by:

$$LCRUDE_t = a0 + a1 * LOILRES_t + a2 * LPOIL_t + a3 * LCRUDE(-1) + a4 * DUM \qquad \text{(D-38)}$$

where,

| | | |
|---|---|---|
| LCRUDE | = | natural log of crude oil production |
| LOILRES | = | natural log of beginning of year oil reserves |
| LPOIL | = | natural log of the regional wellhead price of oil in 1987 dollars |
| LCRUDE(-1) | = | natural log of crude oil production in the previous year |
| DUM | = | a dummy variable that equals 1 for years after 1986 and 0 otherwise. |

**Results**

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| a0 | -6.48638 | 2.65947 | -2.43897 |
| LOILRES | .821851 | .313405 | 2.62233 |
| LPOIL | .115556 | .051365 | 2.24969 |
| LCRUDE(-1) | .974244 | .137890 | 7.06538 |
| DUM | .079112 | .045683 | 1.73175 |

```
SAMPLE:  1978 to 1991
NUMBER OF OBSERVATIONS = 14

Dependent variable:  LCRUDE
 Mean of dependent variable = 5.65758
Std. dev. of dependent var. = .106897
   Sum of squared residuals = .021640
      Variance of residuals = .240446E-02
   Std. error of regression = .049035
                  R-squared = .854325
         Adjusted R-squared = .789581
    Durbin-Watson statistic = 1.47269
                Durbin's h = 1.04017
     Durbin's h alternative = .725714
  F-statistic (zero slopes) = 13.1954
 Schwarz Bayes. Info. Crit. = -5.52974
 Log of likelihood function = 25.4407
```

**Pacific Offshore Crude Oil**

Price elasticities were estimated using the AR1 procedure in TSP which corrects for first order serial correlation using a maximum likelihood iterative technique. The regression equation is given by:

$$\begin{aligned} LCRUDE_t &= a0 + a1 * LOILRES_t + a2 * LPOIL_t + \rho * LCRUDE_{t-1} \\ &\quad - \rho * (a0 + a1 * LOILRES_{t-1} + a2 * LPOIL_{t-1}) \end{aligned} \tag{D-39}$$

where,

| | | |
|---|---|---|
| LCRUDE | = | natural log of crude oil production |
| LOILRES | = | natural log of beginning of year crude oil reserves |
| LPOIL | = | natural log of the regional wellhead price of crude oil in 1987 dollars |
| $\rho$ | = | autocorrelation parameter |
| t | = | year. |

**Results**

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| a0 | 1.34325 | .443323 | 3.02995 |
| LOILRES | .310216 | .067090 | 4.62390 |
| LPOIL | .181190 | .067391 | 2.68865 |
| $\rho$ | -.355962 | .320266 | -1.11146 |

```
SAMPLE:  1977 to 1991
NUMBER OF OBSERVATIONS = 15

Dependent variable:  LCRUDE
(Statistics based on transformed data)
        Mean of dependent variable = 5.31728
       Std. dev. of dependent var. = .646106
          Sum of squared residuals = .209786
             Variance of residuals = .017482
          Std. error of regression = .132220
                         R-squared = .971382
                Adjusted R-squared = .966613
           Durbin-Watson statistic = 1.61085
         F-statistic (zero slopes) = 161.152
        Log of likelihood function = 10.6711

(Statistics based on original data)
        Mean of dependent variable = 4.001171
       Std. dev. of dependent var. = .231415
          Sum of squared residuals = .220359
             Variance of residuals = .018363
          Std. error of regression = .135511
                         R-squared = .711359
                Adjusted R-squared = .663252
           Durbin-Watson statistic = 1.61258
```

# Conventional Western Canada Equations

**Successful Gas Wells**

The equation to forecast successful gas wells in Western Canada was estimated for the time period 1978-2005 using aggregated wells and production data for the Western Canadian provinces of Alberta, British Columbia and Saskatchewan and price data for Western Canada as a whole. The form of the estimating equation is given by:

(D-40)

$$\text{lnGWELLS}_t = \beta 0 + \beta 1 * \text{lnGPRICE}_t + \beta 2 * \ln REMAIN_t + \beta 3 * PR_{t-1} + \beta 4 * \ln DRILLCOSTPERWELL_{t-1}$$

where lnGWELLS is the natural log of successful gas wells drilled in Western Canada, lnGPRICE is the natural log of the Western Canada gas price in 2000 US$ per thousand cubic feet, lnREMAIN is the natural log remaining undiscovered recoverable resources in the region at the beginning of the year, PR is the realized production-to-reserve ratio from the previous year, and lnDRILLCOSTPERWELL is the natural log of drilling costs per gas well in 2000 US$ from the previous year. The equation was estimated by instrumental variables using version 4.4 of the econometric software package TSP. Additional instruments included the natural logs of the number of available and active rigs (lnRIGS_AVAIL, lnRIGS_ACT) and the natural logs of the contemporaneous and lagged world oil price in 2000 US$ (lnWOP2000, lnWOP2000(-1)). Parameter estimates and regression diagnostics are given below.

```
Method of estimation = Instrumental Variable

 Dependent variable: lnGWELLS
 Endogenous variables: lnGPRICE
 Included exogenous variables: C lnREMAIN PR_LAG LNDRILLCOSTPERGASWELLLAG
 Excluded exogenous variables: LNRIGS_AVAIL LNRIGS_ACT LNWOP2000
     LNWOP2000(-1)
 Current sample:  32 to 59
 Number of observations:  28

        Mean of dep. var. = 8.22053  Adjusted R-squared = .867711
   Std. dev. of dep. var. = .770092       Durbin-Watson = 1.46771 [<.458]
 Sum of squared residuals = 1.81930     F (zero slopes) = 44.7735 [.000]
    Variance of residuals = .079100  F (over-id. rest.) = 3.03557 [.050]
 Std. error of regression = .281247              E'PZ*E = .720341
                R-squared = .887309
```

| Variable | Estimated Coefficient | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| C | -1.24038 | 10.6119 | -.116886 | [.907] |
| lnGPRICE | 1.10382 | .276816 | 3.98756 | [.000] |
| lnREMAIN | 1.52862 | .747054 | 2.04620 | [.041] |
| PR_LAG | 33.6137 | 5.96311 | 5.63694 | [.000] |
| lnDRILLCOSTPERGASWELLLAG | -.863675 | .414260 | -2.08486 | [.037] |

**Finding Rate**

The equation to forecast the average natural gas finding rate in Western Canada was estimated for the time period 1965-2006 using aggregated reserves and production data for the Western Canadian provinces of Alberta, British Columbia and Saskatchewan. The form of the estimating equation is given by:

(D-41)

$$\ln FR_t = \beta 0 + \beta 1 * \ln REMAIN_t - \rho * (\beta 0 + \beta 1 * \ln REMAIN_{t-1})$$

where lnFR is the natural log of gas reserves added per successful gas well drilled in Western Canada and lnREMAIN is the natural log of remaining undiscovered recoverable resources in the region at the beginning of the year. The equation was estimated with correction for first-order serial correlation using version 4.4 of the econometric software package TSP. Parameter estimates and regression diagnostics are given below.

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR

 CONVERGENCE ACHIEVED AFTER   6 ITERATIONS

 Dependent variable: lnFR
 Current sample:  19 to 60
 Number of observations:  42

        Mean of dep. var. = .276043           R-squared = .529783
   Std. dev. of dep. var. = 1.02067  Adjusted R-squared = .505669
 Sum of squared residuals = 20.0904       Durbin-Watson = 2.21231
    Variance of residuals = .515139      Schwarz B.I.C. = 49.7335
 Std. error of regression = .717732      Log likelihood = -44.1270

                         Standard
 Parameter  Estimate       Error      t-statistic   P-value
 C          -27.3542      7.03961      -3.88575     [.000]
 lnREMAIN   2.31124       .588521      3.92720      [.000]
 RHO(ρ)     .417206       .140020      2.97962      [.003]
```

**<u>Natural Gas Production to Reserves Ratio</u>**

The equation to forecast the natural gas production to reserves ratio in Western Canada was estimated for the time period 1978-2006 using aggregated wells, reserves, and production data for the Western Canadian provinces of Alberta, British Columbia and Saskatchewan. The form of the estimating equation is given by:

$$\ln\left(\frac{PR_t}{1-PR_t}\right) = \beta 0 + \beta 1 * \ln GWELLS_t + \beta 2 * \ln RESADDPERWELL_t + \beta 3 * YEAR_t$$

$$\rho * \ln\left(\frac{PR_{t-1}}{1-PR_{t-1}}\right) - \rho * (\beta 0 + \beta 1 * \ln GWELLS_{t-1} + \beta 2 * \ln RESADDPERWELL_{t-1} + \beta 3 * YEAR_{t-1}$$

where PR is the natural gas production to reserves ratio, lnGWELLS is the natural log of successful natural gas wells drilled, lnRESADDPERWELL is the natural log of natural gas reserve additions per successful natural gas well completed, and YEAR is the calendar year. Because the PR ratio is bounded between zero and one, the dependent variable was measured in logistic form using version 4.4 of the econometric software package TSP. Parameter estimates and regression diagnostics are given below.

```
FIRST-ORDER SERIAL CORRELATION OF THE ERROR

 CONVERGENCE ACHIEVED AFTER   8 ITERATIONS

 Dependent variable: LOGISTIC of PR
 Current sample:  32 to 60
 Number of observations:  29

        Mean of dep. var. = -2.70096              R-squared = .985841
   Std. dev. of dep. var. = .476412      Adjusted R-squared = .983481
 Sum of squared residuals = .090453          Durbin-Watson = 1.29395
    Variance of residuals = .376886E-02     Schwarz B.I.C. = -33.6205
 Std. error of regression = .061391         Log likelihood = 42.0387
```

| Parameter | Estimate | Standard Error | t-statistic | P-value |
|---|---|---|---|---|
| C | -74.5150 | 14.2729 | -5.22075 | [.000] |
| lnGWELLS | .115314 | .032908 | 3.50418 | [.000] |
| lnRESADDPERWELL | .041412 | .018094 | 2.28874 | [.022] |
| YEAR | .035578 | .718349E-02 | 4.95273 | [.000] |
| RHO(ρ) | .912281 | .064992 | 14.0367 | [.000] |