Appendix G

Estimation of Reserves and Resources

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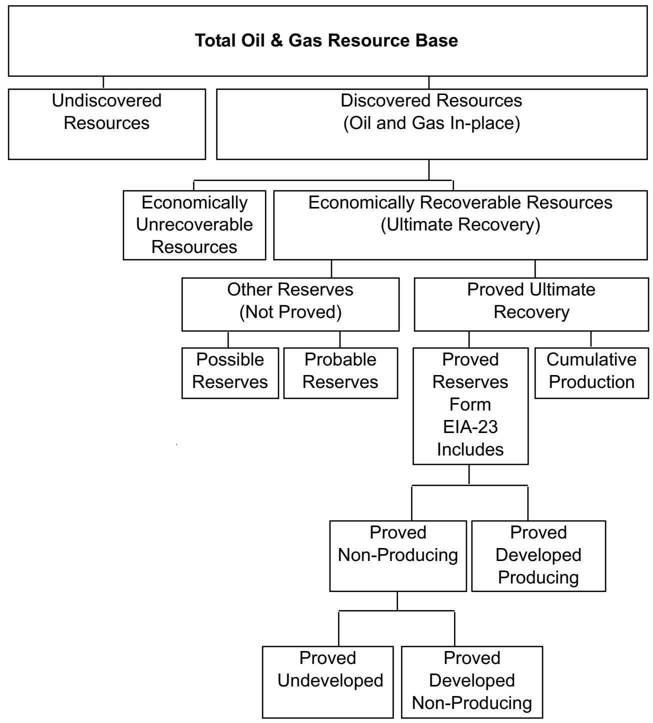
Oil and Gas Resource Base

Universally accepted definitions have not been developed for the many terms used by geologists, engineers, accountants and others to denote various components of overall oil and gas resources. In part, this is because most of these terms describe estimated and therefore uncertain, rather than measured, quantities. The lack of standardized terminology sometimes leads to inaccurate understanding of the meaning and/or import of estimates. Particularly common is an apparently widespread lack of understanding of the substantial difference between the terms "reserves" and "resources", as indicated by the frequent misuse of either term in place of the other.

The total resource base of oil and gas is the entire volume formed and trapped in–place within the Earth before any production. The largest portion of this total resource base is nonrecoverable by current or foreseeable technology. Most of the nonrecoverable volume occurs at very low concentrations throughout the earth's crust and cannot be extracted short of mining the rock or the application of some other approach that would consume more energy than it produced. An additional portion of the total resource base cannot be recovered because currently available production techniques cannot extract all of the in–place oil and gas even when present in commercially viable concentrations. The inability to recover all of the in–place oil and gas from a producible deposit occurs because of unfavorable economics, intractable physical forces, or a combination of both. Recoverable resources, the subset of the total resource base that is of societal and economic interest, are defined so as to exclude these nonrecoverable portions of the total resource base.

The structure presented in **Figure G1** outlines the total resource base and its components. The total resource base first consists of the recoverable and nonrecoverable portions discussed above. The next level down divides recoverable resources into discovered and undiscovered segments. Discovered resources are further separated into cumulative (i.e., all past) production, and reserves. Reserves are additionally subdivided into proved reserves and "other reserves".

Figure G1. Components of the Oil and Gas Resource Base



Source: Energy Information Administration, Office of Oil and Gas.

Recoverable Resources

Discovered recoverable resources are those economically recoverable quantities of oil and gas for which specific locations are known. While the specific locations of estimated undiscovered recoverable resources are not yet known, they are believed to exist in geologically favorable settings.

Current estimates of undiscovered recoverable resources merit discussion in order to provide a useful sense of scale relative to proved reserves. The sources of official estimates of domestic undiscovered recoverable resources are two agencies of the Department of the Interior (DOI), the United States Geological Survey (USGS) for onshore areas and those offshore waters subject to State jurisdiction, and the Minerals Management Service (MMS) for those offshore waters under Federal jurisdiction.

The USGS defines undiscovered recoverable conventional resources as those expected to be resident in accumulations of sufficient size and quality that they could be produced using conventional recovery technologies, without regard to present economic viability. Therefore, only part of the USGS undiscovered recoverable conventional resource is economically recoverable now. The USGS also defines a class of resources that occur in "continuous–type" accumulations. Unlike conventional oil and gas accumulations, continuous–type accumulations do not occur in discrete reservoirs of limited areal extent. They include accumulations in low–permeability (tight) sandstones, shales, and chalks, and those in coal beds. Again, only part of the continuous–type technically recoverable resource is economically recoverable now. In fact, only a small portion of the in–place continuous–type resource accumulations are estimated to be technically recoverable now. **Table G1** presents a compilation of USGS and MMS estimates.

Technically recoverable resources of dry natural gas (discovered, unproved, and undiscovered) are estimated at 1,431 trillion cubic feet (**Table G1**). Adding the 2003 U.S. proved reserves of 189 trillion cubic feet yields a technically recoverable resource target of 1,620 trillion cubic feet. This is about 83 times the 2003 dry gas production level.

Other organizations have also estimated unproven technically recoverable gas resources. For example, the Potential Gas Committee (PGC), an industry sponsored group, provides detailed geology–based gas resource estimates every 2 years. In 2000 the PGC mean estimate of potential gas resources was 1,091 trillion cubic feet, about 340 trillion cubic feet less than the estimates in **Table G1**. Another recent estimate was made by the National Petroleum Council (NPC), an industry–based group that serves in an advisory capacity to the U.S. Secretary of Energy. The NPC's estimate, based on data available at year–end 1999, was 1,555 trillion cubic feet, 124 trillion cubic feet more than the estimates summarized in **Table G1**. The differences among these estimates are usually due to the availability of newer data, differences in coverage or resource category definitions, and legitimate but differing data interpretations.

While the estimation of undiscovered resources is certainly a more imprecise endeavor than is the estimation of proved reserves, it is clear that substantial volumes of technically recoverable oil and gas resources remain to be found and produced domestically. Current estimates indicate that as much domestic gas remains to be found and then produced as has been to date. Of course, much effort, investment and time will be required to bring this gas to market.

There is a perception that the oil resource base has been more intensively developed than the gas resource base. And in fact, more oil has been produced in the United States than is estimated as remaining recoverable. Nevertheless, the ratio of unproven technically recoverable oil resources to 2003 oil production (**Table G1**) was about 93 to 1, higher than the comparable gas ratio.

Federal Land Resources

Estimates of technically recoverable resources that underlie Federal jurisdiction lands are listed in **Table G1**. These estimates are based on National assessments performed by the USGS and the MMS. It is estimated that 60 percent of the technically recoverable resources of crude oil, 52.4 percent of the dry gas resources, and 34.7 percent of the natural gas liquids resources underlie Federal lands.

Discovered Resources

In addition to cumulative production, which is the sum of current year production and the production in all prior years, estimates of discovered recoverable resources include estimates of reserves. Broadly, reserves are those volumes that are believed to be recoverable in the future from known deposits through the eventual application of present or anticipated technology.

Reserves

Reserves include both **proved reserves** and **other reserves**. Several different reserve classification systems are in use by different organizations, as preferred for operational reasons. These systems utilize and incorporate various definitions of terms such as *measured reserves*, *indicated reserves*, *inferred reserves*,

Table G1. Mean Estimates of Technically Recoverable Oil and Gas Resources by Deposit Type and Location

Area	Jurisdiction	Crude Oil[a] (billion barrels)	Natural Gas (Dry) (trillion cubic feet)	Natural Gas Liquids (billion barrels)
Undiscovered Conventionally Reservoired Fields				
Alaska Onshore + State Offshore	Federal	3.75	33.97	0.54
Alaska Onshore + State Offshore	Other	4.68	95.37	0.61
Alaska Federal Offshore	Federal	24.90	122.60	0.00
Lower 48 States Onshore + State Offshore	Federal	3.79	23.97	1.26
Lower 48 States Onshore + State Offshore	Other	17.83	166.41	5.64
Lower 48 States Federal Offshore	Federal	50.10	239.60	0.00
Alaska Subtotal		33.33	251.94	1.15
Alaska Percentage Federal		86.0%	62.1%	47.0%
Lower 48 States Subtotal		71.72	429.98	6.90
Lower 48 States Percentage Federal		75.1%	61.3%	18.3%
Technically Recoverable Resources in U.S. Undiscovered Conventionally Reservoired Fields		**105.05**	**681.92**	**8.05**
Percentage Federal		**78.6%**	**61.6%**	**22.4%**
Ultimate Recovery Appreciation				
U.S. Onshore + State Offshore	Federal	14.33	118.70	4.94
U.S. Onshore + State Offshore	Other	45.67	203.30	8.46
U.S. Federal Offshore	Federal	7.70	68.00	0.00
Technically Recoverable Resources in U.S. from Ultimate Recovery Appreciation in Discovered Conventionally Reservoired Fields		**67.70**	**390.00**	**13.40**
U.S. Percentage Federal		**32.5%**	**47.9%**	**36.9%**
Continuous Type Deposits				
Non-coal bed	Federal	0.32	127.08	1.45
Non-coal bed	Other	1.75	181.72	0.67
Coal bed	Federal	0.00	16.08	0.00
Coal bed	Other	0.00	33.83	0.00
Non-coal bed Subtotal		2.07	308.80	2.12
Non-coal bed Percentage Federal		15.5%	41.2%	68.4%
Coal bed Subtotal		0.00	49.91	0.00
Coal bed Percentage Federal		0.0%	32.2%	0.0%
Technically Recoverable Resources in U.S. from Continuous Type Deposits		**2.07**	**358.71**	**2.12**
Continuous Type Percentage Federal		**15.5%**	**39.9%**	**68.4%**
U.S. Totals All Sources				
U.S. Onshore + State Offshore	Federal	22.19	319.80	8.19
U.S. Onshore + State Offshore	Other	69.93	680.63	15.38
Federal Offshore	Federal	82.70	430.20	0.00
Federal Subtotal		104.89	750.00	8.19
U.S. Technically Recoverable Resources		**174.82**	**1,430.63**	**23.57**
Percentage Federal		**60.0%**	**52.4%**	**34.7%**

Notes:
Proved Reserves are not included in these estimates.
Federal Onshore excludes Indian and Native lands even when Federally managed in trust.
Zero (0) indicates either that none exists in this area or that no estimate of this resource has been made for this area.

Table G1. Mean Estimates of Technically Recoverable Oil and Gas Resources by Deposit Type and Location (continued)

Notes (continued): Federal Offshore indicates MMS estimates for Federal Offshore jurisdictions (Outer Continental Shelf and deeper water areas seaward of State Offshore).

Probable and Possible reserves are considered by USGS definition to be part of USGS Reserve Growth, but are separately considered by the MMS as its Unproved Reserves term. The USGS did not set a time limit for the duration of Reserve Growth; the MMS set the year 2020 as the time limit in its estimates of Reserve Growth in existing fields of the Gulf of Mexico.

Excluded from the estimates are undiscovered oil resources in tar deposits and oil shales, and undiscovered gas resources in geopressured brines and gas hydrates.

Data Sources: National Oil and Gas Resource Assessment Team, *1996 National Assessment of United States Oil and Gas Resources,* Circular 1118, United States Geological Survey, Washington DC, 1995.

D.L Gautier, G.L. Dolton, and E.D. Atanasi, *1995 National Oil and Gas Assessment and Onshore Federal Lands,* Open File Report 95-75-N, United States Geological Survey, Washington DC, January 1998.

Resource Evaluation Program, *Outer Continental Shelf Petroleum Assessment 2000,* Brochure 7, Minerals Management Service, Washington, DC, January 2001 at <http://www.mms.gov/revaldiv/RedNatAssessment.htm>.

Resource Evaluation Program, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf,* OCS Report MMS 96-0034, Minerals Management Service, Washington, DC, 1996.

Minerals Management Service, *Mineral Revenues 1996,* U.S. Department of the Interior, Washington, DC, 1997, Table 12 on p. 33 and Table 23 on p. 70.

Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996 Annual Report,* Washington, DC, December 1997, Table 15 on p. 39.

Energy Information Administration, *Petroleum Supply Annual 1996,* Washington, DC, June 1997, Volume 1, Table 14 on p. 96.

Energy Information Administration, *Natural Gas Annual 1996,* Washington, DC, September 1997, Table 3 on p. 12.

probable reserves, and *possible reserves*. As used by the different organizations, the definitions that attach to these terms sometimes overlap, or the terms may require a slightly different interpretation from one organization to the next. Nevertheless, all kinds of "other reserves" are generally less well known and therefore less precisely quantifiable than proved reserves, and their eventual recovery is less assured.

Measured reserves are defined by the USGS as that part of the identified (i.e., discovered) economically recoverable resource that is estimated from geologic evidence and supported directly by engineering data.{43} They are similarly defined by the MMS, although its system also subdivides them by degree of development and producing status.{44} Measured reserves are demonstrated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, and are essentially equivalent to proved reserves as defined by the EIA. Effectively, estimates of proved reserves may be thought of as reasonable estimates (as opposed to exact measures) of "on–the–shelf inventory".

Inferred reserves and indicated reserves, due to their more uncertain economic or technical recoverability, are included in the "other reserves" category. The USGS defines inferred reserves as that part of the identified economically recoverable resource, over and above both measured and indicated (see below) reserves, that will be added to proved reserves in the future through extensions, revisions, and the discovery of new pay zones in already discovered fields.{43} Inferred reserves are considered equivalent to "probable reserves" by many analysts, for example, those of the PGC.

Proved Reserves

The EIA defines proved reserves as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

When deterministic proved reserves estimation methods are used, the term reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. When probabilistic methods are used there should be at least a 90 percent probability that the actual quantities recovered will exceed the estimate.

Proved reserves are either proved producing or proved nonproducing (i.e., resident in reservoirs that did not produce during the report year). The latter may represent a substantial fraction of total proved reserves.

Reserve Estimation Methodologies

The adoption of a standard definition of proved reserves for each type of hydrocarbon surveyed by the Form EIA–23 program provided a far more consistent response from operators than if each operator had used their own definition. Such standards, however, do not guarantee that the resulting estimates themselves are determinate. Regardless of the definition selected, proved reserves cannot be measured directly. They are estimated quantities that are inferred on the basis of the best geological, engineering, and economic data available to the estimator, who generally uses considerable judgment in the analysis and interpretation of the data. Consequently, the accuracy of a given estimate varies with and depends on the quality and quantity of raw data available, the estimation method used, and the training and experience of the estimator. The element of judgment commonly accounts for the differences among independent estimates for the same reservoir or field.

Data Used in Making Reserve Estimates

The raw data used in estimating proved reserves include the engineering and geological data for reservoir rock and its fluid content. These data are obtained from direct and indirect measurements. The data available for a given reservoir vary in kind, quality, and quantity. When a reservoir is first discovered only data from a single well are available, and prior to flow testing or actual production, proved reserves can only be inferred. As development of the reservoir proceeds, and flow tests are made or actual production commences, more and more data become available, enabling proved reserves estimates to become more accurate.

Many different kinds of data are useful in making reserves estimates. They may include: data on porosity, permeability, and fluid saturations of the reservoir rocks (obtained directly from core analysis or from various types of electrical measurements taken in a well or several wells); data on the production of fluids from a well or several wells; geologic maps of the areal extent, thickness, and continuity of the reservoir rocks (inferred from well logs, geophysical, and geological data); and reservoir pressure and temperature data. Also involved are economic data including the current price of crude oil and natural gas, and various developmental and operating costs.

Reserve Estimation Techniques

Depending on the kinds and amounts of data available, and a judgment on the reliability of those data, the estimator will select one of several methods of making a proved reserves estimate. Methods based on production performance data are generally more accurate than those based strictly on inference from geological and engineering data. Such methods include the *Production Decline* method (for crude oil or natural gas reservoirs), the *Material Balance* method (for crude oil reservoirs), the *Pressure Decline* method (which is actually a material balance, for natural gas reservoirs), and the *Reservoir Simulation* method (for crude oil or natural gas reservoirs). The reservoir type and production mechanisms and the types and amounts of reliable data available determine which of these methods is more appropriate for a given reservoir. These methods are of comparable accuracy.

Methods not based upon production data include the *Volumetric* method (for crude oil or natural gas reservoirs) and the *Nominal* method. Of these, the *Volumetric* method is the more accurate. Both methods, however, are less accurate than those based on production data. **Table G2** summarizes the various methods.

Table G2. Reserve Estimation Techniques

Method	Comments
Volumetric	Applies to crude oil and natural gas reservoirs. Based on raw engineering and geologic data.
Material Balance	Applies to crude oil and natural gas reservoirs. Is used in estimating reserves. Usually of more value in predicting reserves, and reservoir performance.
Pressure Decline	Applies to nonassociated and associated gas reservoirs. The method is a special case of material balance equation in the absence of water influx.
Production Decline	Applies to crude oil and natural gas reservoirs during production decline (usually in the later stages of reservoir life).
Reservoir Simulation	Applies to crude oil and natural gas reservoirs. Is used in estimating reserves. Usually of more value in predicting reservoir performance. Accuracy increases when matched with past pressure and production data.
Nominal	Applied to crude oil and natural gas reservoirs. Based on rule of thumb or analogy with another reservoir or reservoirs believed to be similar; least accurate of methods used.

Judgmental Factors in Reserve Estimation

The determination of rock and hydrocarbon fluid properties involves judgment and is subject to some uncertainty; however, the construction of the geologic maps and cross sections and the determination of the size of the reservoir are the major judgmental steps in the *Volumetric* method, and are subject to the greatest uncertainty. Estimates made using the *Material Balance* method, the *Reservoir Simulation* method, or the *Pressure Decline* method are based on the estimator's judgment that the type of reservoir drive mechanism has been identified and on the specification of abandonment conditions. Estimates based on the *Production Decline* method are subject to judgment in constructing the trend line, and are based on the estimator's assumption of reservoir performance through abandonment.

Contributing to the degree of uncertainty inherent in the above methods for estimating reserves are other factors associated with economic considerations and the perceived reservoir limits, which together influence the final reserves estimate. A brief discussion of these other factors follows.

Economic considerations: There has been continuing debate about the effects of prices on proved reserves. Although no all–inclusive statement can be made on the impact of price, the points at issue can be discussed and some general remarks can be made about some circumstances where price may be a factor.

- *Developed gas fields* – In a gas reservoir, price affects the economic limit (i.e., the production rate required to meet operating costs) and, therefore, the abandonment pressure. Thus, price change has some effect on the conversion of noneconomic hydrocarbon resources to the category of proved reserves. In both nearly depleted reservoirs and newly developed reservoirs, the actual increase in the quantity of proved reserves resulting from price rises is generally limited in terms of national volumes (even though the percentage increase for a given reservoir may be great).

- *Developed oil fields* – In developed crude oil reservoirs many of the same comments apply; however, there is an additional consideration. If the price is raised to a level sufficient to justify initiation of an improved recovery project, and if the improved recovery technique is effective, then the addition to ultimate recovery from the reservoir can be significant. Because of the speculative nature of predicting prices and costs many years into the future, proved reserves are estimated on the basis of current prices, costs, and operating practices in effect as of the date the estimation was made.

- *Successful exploration efforts* – Price can have a major impact on whether a new discovery is produced or abandoned. For example, the decision to set casing in a new onshore discovery, or to install a platform as the result of an offshore discovery, are both price–sensitive. If the decision is made to set pipe or to install a platform, the discoveries in both cases will add to the proved reserves total. If such projects are abandoned, they will make no contribution to the proved reserves total.

Effect of operating conditions: Operating conditions are subject to change caused by changes in economic conditions, unforeseen production problems, new production practices or methods, and the operator's financial position. As with economic conditions, operating conditions to be expected at the time of abandonment are speculative. Thus, current operating conditions are used in estimating proved reserves. In considering the effect of operating conditions, a distinction must be made between processes and techniques that would normally be applied by a prudent operator in producing his oil and gas, and initiation of changes in operating conditions that would require substantial new investment.

- *Compression* – Compression facilities are normally installed when the productive capacity or deliverability of a natural gas reservoir or its individual wells declines. In other cases compression is used in producing shallow, low–pressure reservoirs or reservoirs in which the pressure has declined to a level too low for the gas to flow into a higher pressure pipeline. The application of compression increases the pressure and, when economical, is used to make production into the higher pressure pipeline possible. Compression facilities normally require a significant investment and result in a change in operating conditions. It increases the proved reserves of a reservoir, and reasonably accurate estimates of the increase can be made.

- *Well stimulation* – Procedures that increase productive capacity (workovers, such as acidizing or fracturing, and other types of production practices) are routine field operations. The procedures accelerate the rate of production from the reservoir, or extend its life, and they have only small effect on proved reserves. Reasonable estimates of their effectiveness can be made.

- *Improved recovery techniques* – These techniques involve the injection of a fluid or fluids into a reservoir to augment natural reservoir energy. Because the response of a given reservoir to the application of an improved recovery technique cannot be accurately predicted, crude oil production that may ultimately result from the application of these techniques is classified as "indicated additional reserves of crude oil" rather than as proved reserves until response of the reservoir to the technique has been demonstrated. In addition, improved recovery methods are not applicable to all crude oil reservoirs. Initiation of improved recovery techniques may require significant investment.

- *Infill drilling* – Infill drilling (drilling of additional wells within a field/reservoir) may result in a higher recovery factor, and, therefore, be economically justified. Predictions of whether infill drilling will be justified under current economic conditions are generally based on the expected production behavior of the infill wells.

Reservoir limits: The initial proved reserves estimate made from the discovery well is subject to significant uncertainty because one well provides little information on the size of the reservoir. The area proved by a discovery well is frequently estimated on the basis of experience in a given producing region. Where there is continuity of the producing formation over wide geographic areas, a relatively large proved area may be assigned. In some cases where reliable geophysical and geological data are available, a reasonable estimate of the extent of the reservoir can be made by drilling a relatively small number of delineation wells. Conversely, a relatively small proved area may be assigned when the producing formation is of limited continuity, owing to either structural or lithological factors.

Additional wells provide more information and reduce the uncertainty of the reserves estimate. As additional wells are drilled, the geometry of the reservoir and, consequently, its bulk volume, become more clearly defined. This process accounts for the large extensions to proved reserves typical of the early stages of most reservoir development.