Paper #1-1

OIL AND GAS GEOLOGIC ENDOWMENT

Prepared by the Resource Endowment Subgroup
of the
Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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Geologic Endowment for Prudent Development of North American Natural Gas and Oil Resources

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Abstract:

This paper focuses on the gaseous and liquid hydrocarbons that form the North American hydrocarbon endowment. It describes:

- the major types of petroleum resource endowment hydrocarbons and how they are formed;
- commonly used North American petroleum endowment classification systems;
- the distinction between proved reserves and other classes of petroleum resources,
- reserves growth,
- the distinction between conventional and unconventional resources,
- current estimates of North American petroleum resources, and
- study observations and suggestions for future estimates

1.0 Why we do resource assessments

Oil and natural gas resource assessments serve a variety of fundamental needs of consumers, policy makers, land and resource managers, investors, regulators, industry planners, and others. Governments utilize resource assessments to exercise responsible stewardship on public lands, to estimate future revenues to the government, and to establish energy, fiscal, and national security policies. The petroleum industry and the financial community use resource estimates to establish corporate strategies and make investment decisions. Regulatory organizations such as government energy ministries, corporation commissions, and the Bureau of Land Management and Bureau of Ocean Energy Management of the U.S. Department of the Interior utilize resource estimates in designating acreage for leasing and drilling.

1.1 Types of Hydrocarbons

Petroleum is a collective term for hydrocarbons in the gaseous, liquid, or solid phase; in other words - natural gas, crude oil, natural gas liquids (NGL), and tar. The hydrocarbon endowment includes crude oil, natural gas, and NGL. Following are definitions for the different forms of petroleum.

CRUDE OIL is defined as a mixture of hydrocarbons that exists in a liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separation facilities (American Petroleum Institute (API), 1995). The constituents of crude oil are mainly complex hydrocarbon compounds having carbon/hydrogen ratios ranging typically from 6 to 8.

Crude oil has specific gravities ranging typically from 0.76 (55º API gravity) to 1.00 (10º API gravity). API gravity, defined by the American Petroleum Institute, is a measure of the density of oils relative to water

Crude oil is refined to produce a wide array of petroleum products, including heating oils, gasoline, diesel, jet fuels, lubricants, asphalt, ethane, propane, butane, and many other products used for their energy content or chemical attributes.

NATURAL GAS is a mixture of hydrocarbon compounds existing in the gaseous phase or in solution with oil in natural underground reservoirs at reservoir temperature and pressure conditions and produced as a gas under standard temperature and pressure conditions (American Petroleum Institute, 1995). Natural gas is principally methane, but may contain ethane, propane, butanes, and pentanes, as well as certain non-hydrocarbon gases, such as carbon dioxide, hydrogen sulfide, nitrogen, and helium.

Natural gas can be associated with or dissolved in oil accumulations ('associated' gas) or not associated with any liquid hydrocarbons ('non-associated' gas). Associated gas is free natural gas which overlies and is in contact with crude oil in the reservoir. Dissolved gas is natural gas in solution with crude oil in the reservoir at reservoir temperature and pressure conditions (American Petroleum Institute, 1995). Produced associated or dissolved gas is often re-injected into the reservoir to maintain a pressure drive for oil production and may therefore not be an economically feasible resource in a near-term assessment time frame. Non-associated gas is free natural gas that is not in contact with crude oil in the reservoir (American Petroleum Institute, 1995).

NATURAL GAS LIQUIDS (NGLs) are those portions of the hydrocarbon resource that exist in the gaseous phase when in natural underground reservoir conditions, but are liquid at surface conditions (that is, standard temperature and pressure conditions: 60º F /15º C and 1 atmosphere) or at higher pressure and/or lower temperature conditions. The NGLs are separated from the produced gas and liquefied at the surface in lease separators, field facilities, or gas processing plants (American Petroleum Institute, 1995).

PETROLEUM LIQUIDS are undifferentiated crude oil and natural gas liquids.

Oil and gas accumulations are usually treated separately in the assessment process. Gas-to-oil ratios (GOR) are calculated for each accumulation to identify the proportions of the two major commodities (oil or gas). An oil accumulation is commonly defined as having a GOR of less than 20,000 cubic feet of gas per barrel of oil; a gas accumulation is defined as having a GOR equal to or greater than 20,000 cubic feet of gas per barrel of oil.

What is not covered herein

- Petroleum liquids that are manufactured from naturally-occurring **solids** using a thermal or dilution process:

Oil Sands (bitumen)
Coal-to-Liquids products

- Liquid fuels sourced from agricultural products:
  Ethanol
  Other biofuels

- Petroleum liquids condensed from **dry natural gas** using a cryogenic process:
  Liquefied Natural Gas (LNG)
  Gas-to-Liquids products

1.11 Hydrocarbon Formation

While the natural processes that generate oil and gas are active today, the amount generated annually represents only a tiny fraction of the amount extracted for consumption. For all practical purposes, the total volume of North America's in-place hydrocarbon resources – its endowment – is finite. It consists of a very large number of individual petroleum accumulations that occur in many shapes and sizes, often finely compartmentalized. Although the *individual attributes* that describe a single accumulation are quite variable, there are some commonalities (Figure 1):

- Hydrocarbons are generated in "kitchens" (underground areas where temperature is sufficiently high) from sedimentary strata (layers), called *source rocks*, containing high concentrations of organic material. The degree to which the source rocks have been heated, and the types of organic material in the rocks, control the type of hydrocarbons that are generated; some source rocks yield gas, some yield oil, and some yield both. "Cooking" in the "kitchens" generally leads to expulsion of hydrocarbons from the source rocks, with crude oil generally being formed at lower temperatures than natural gas. Nevertheless, it should be noted that some natural gas – biogenic gas, composed primarily of methane – can also be generated from thermally immature source rocks.

- Once expelled, the buoyant (relative to groundwater), and thus mobile, hydrocarbons can *migrate* upward. During this migration, large quantities of resource are commonly lost along the way, often leaving behind a trail of accumulations. In some cases, hydrocarbons do not migrate and remain in the source rocks.

- During migration some hydrocarbon volumes may find their way to a *reservoir*, which has *trapping boundaries* of sufficient size, composition, and shape as to catch and hold most or all the hydrocarbons that migrate into it, and which is capped by an impermeable layer called a *seal rock*. Reservoirs can be formed from many different rock types and are therefore quite variable, with different porosities, permeabilities, residual water saturations, and other rock and native fluid attributes. All of these properties influence the proportion of hydrocarbons that may one day be recovered *if* the accumulation is discovered and *if* the available technologies and prevailing economic environment favors development and production. These variable reservoir attributes also affect the extraction techniques applied as well as the success of eventual production.

- Last, though not least, all of these individual attributes - source rock deposition and maturation; hydrocarbon expulsion; migration; and reservoir deposition and trap formation and filling – must have taken place in the *correct time sequence*. In addition, the trapping elements of the accumulation must subsequently have been maintained through post-fill time -- often for tens of millions of years. For instance, the traps cannot have been breached by the upward movement of rocks in the subsurface or by downward erosion of the surface above them after the hydrocarbons were trapped.

Figure 1. Elements of a petroleum system (from AAPG Slide Bank).

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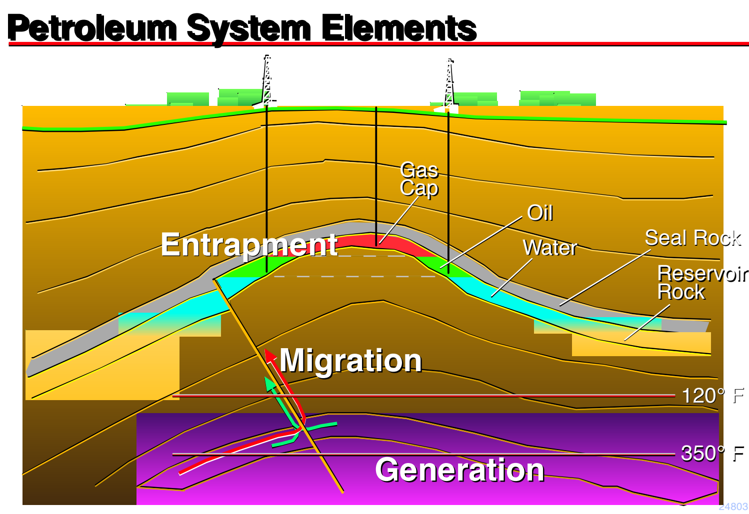


Further discussion on the configuration of hydrocarbon accumulations is included in section 1.27.

1.2 North American Hydrocarbon Endowment Classification Systems and Definitions

By definition the endowment of a particular type of hydrocarbon is the sum of those volumes already produced *(cumulative production)*, those volumes expected to be recoverable in the future *(estimated reserves and resources)*, and those additional in-place volumes that are not currently recoverable by any means (unrecoverable in-place volumes but that may conceivably become recoverable in the future. The sum of remaining producible volumes in discovered accumulations plus undiscovered technically recoverable volumes is often called *remaining resources.* These volumes, their geographical distribution, and the sizes of the accumulations in which they will occur, are of great importance to strategy and policy decisions and land and resource managers.

A key attribute distinguishing crude oil and natural gas resources from many other natural resources is the fact that they predominantly occur in deep underground accumulations and are consequently unavailable for direct observation and measurement. Petroleum resource volumes and other characteristics can only be estimated, typically based on some combination of

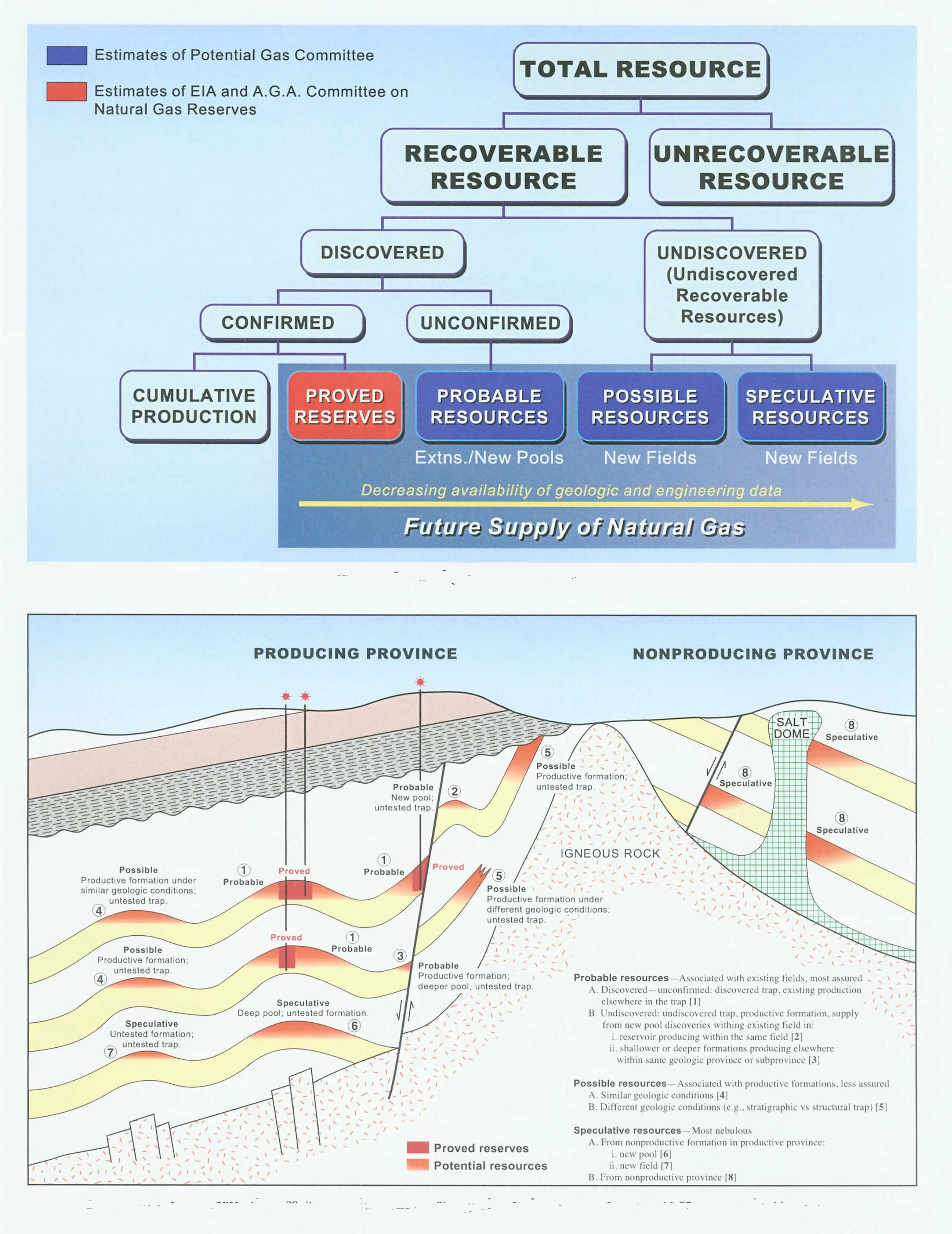
- direct or indirect evidence regarding the physical characteristics of the oil or gas reservoir and its fluid contents;
- extrapolation of data regarding volumes that have already been produced from an accumulation to those volumes that may yet remain to be produced from it; and
- analogy to the better-known characteristics of similar accumulations that have significantly longer (or fully completed) exploration, development, and production histories.

The accuracy of such estimates or assessments varies primarily with the types, amounts, and quality of the available data, the analytical methodologies employed, and the assessors' expertise. The uncertainties associated with all assessments of crude oil and natural gas resource volumes are large and can vary widely in magnitude depending on the particular resource quantity being estimated and the factors that bear on its existence and volume.

Several different classification systems have been developed to systematically describe and label measured and estimated hydrocarbon resource volumes according to two or three of the principal uncertainties (primarily geologic and economic uncertainty, and sometimes commercial status). Though these systems have many similarities as well as overlaps, each was developed with its own intended estimation focus. Each also has its own terms that do not always have exact equivalents in the other system's lexicons.

Of the handful of classification systems currently in common North American use, the earliest was initiated by the Potential Gas Committee (PGC) in 1964. Its structure, terminology, and relationship to both gas occurrence and the exploration process are shown in Figure 2. Because proved reserves of known fields are estimated separately (formerly by the American Gas Association, now by the Energy Information Administration), the PGC classification system covers only undiscovered United States resources, some of which are associated with known fields and some of which are not. Because the PGC biennially updates its estimates, this system only addresses resources that can be produced using currently available technology. Therefore there is just one uncertainty axis that focuses on the degree of geologic assurance.

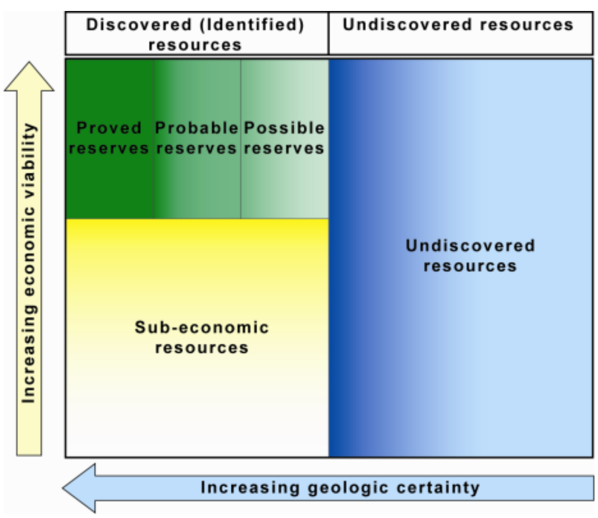
Figure 2. Potential Gas Committee Natural Gas Resource Classification System (Potential Supply of Natural Gas in the United States (December 31, 2008); PGC, 2008)



The framework of the next commonly used classification system was proposed in 1972 by Vincent McKelvey of the U.S. Geological Survey and is shown in Figure 3. Unlike the PGC system it incorporates three categories of reserves – proved, probable, and possible. The probable-plus-possible reserves are roughly equivalent to the PGC's probable resources category. There are also two uncertainty axes, one for geologic uncertainty and one for economic uncertainty. Undiscovered resources are not separated as to economic viability, whereas discovered resources that are sub-economic are so identified. Note that the McKelvey classification system itself imposes neither technological limits nor a time limit on resource assessment, though it does introduce a distinction between reserves and resources based on economic viability.

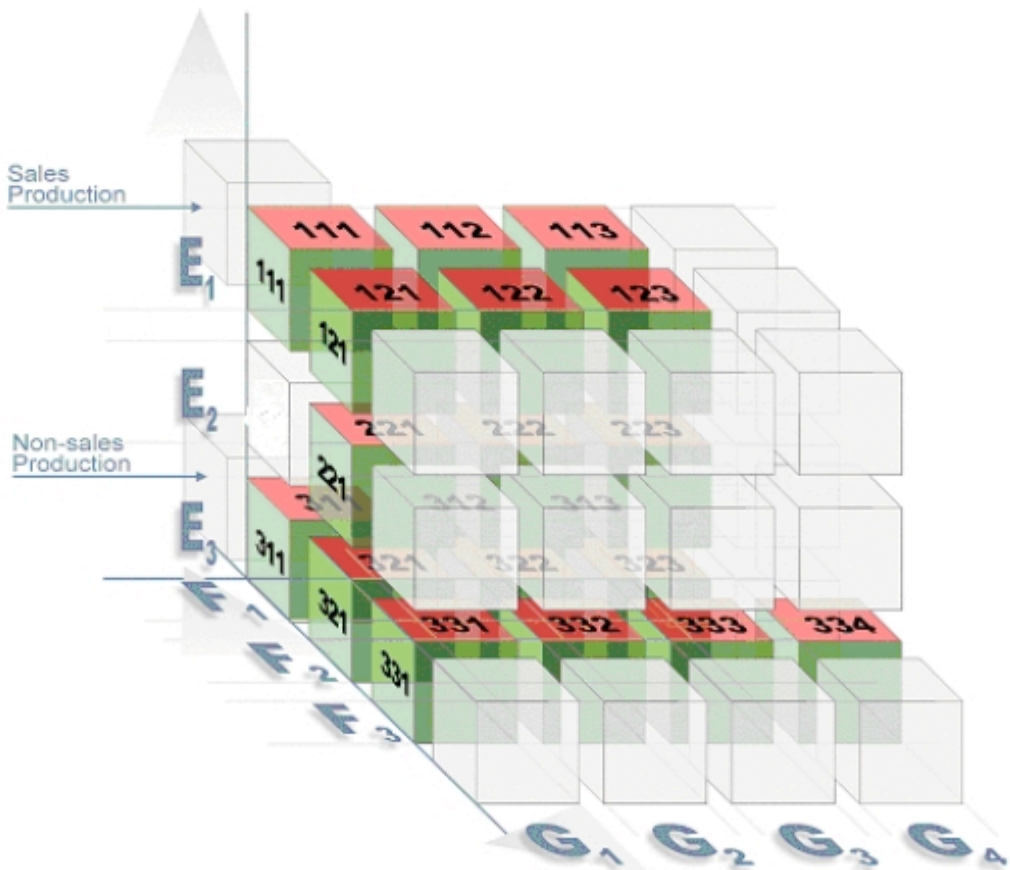
Figure 3. Example of a McKelvey diagram (modified from USGS Circular 831, 1980)

Terms – Resources versus Reserves



More than 30 years later, another classification system was adopted by the United Nations in 2004. Although it has not been adopted as the basis for any of the North American estimations, it is mentioned here as an intellectual antecedent to the next described system. The United Nation's Framework Classification (UNFC) was designed to cover all fossil fuels and mineral resources, rather than just oil and gas, so it is the most complex of the systems. The portions of the United Nations system that are applicable to oil and gas resources are shown in Figure 4. There are three uncertainty axes, one for the degree of economic assurance (the E axis), one for project status/commercial viability (the F axis), and one for the degree of geologic assurance (the G axis). For the G axis, approximate correspondences to the McKelvey system are that the G1 category is equivalent to proved reserves, the G2 category is equivalent to probable reserves, the G3 category is equivalent to possible reserves, and the G4 category is undiscovered resources. The E axis ranges from “normal economics” to “unrecoverable” and the F axis ranges from project already in production through various stages of project commitment and non-commitment to project undefined. Further discussion of this system can be found on the UNECE website at http://www.unece.org/energy/se/reserves.html.

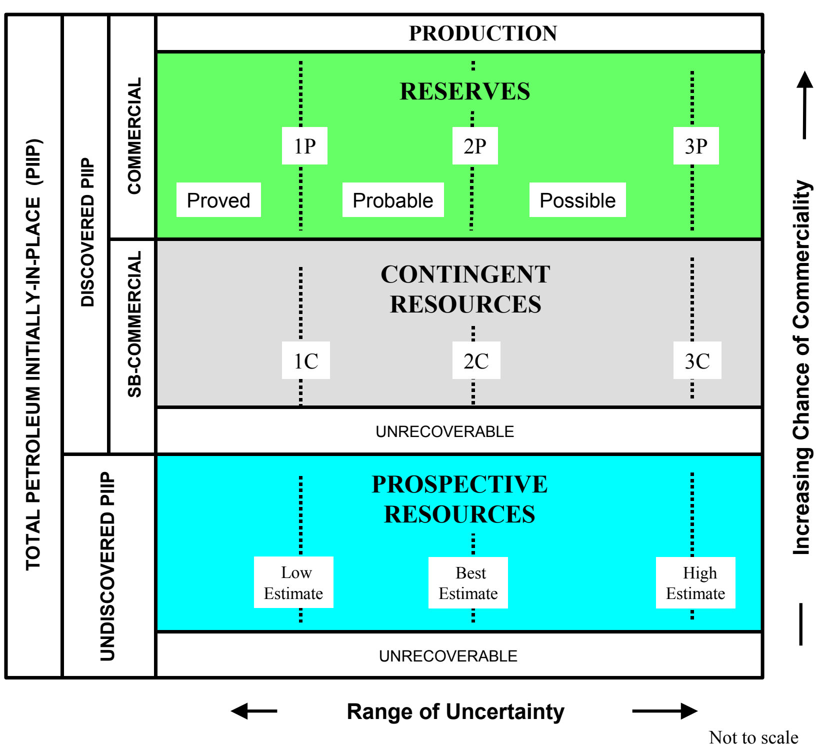
Figure 4. Petroleum Resource Classes Per the United Nations Framework Classification (UNFC) (United Nations Framework Classification for Fossil Energy and Mineral Resources, Section 3) http://www.unece.org/energy/se/reserves.html



The newest classification system, the Petroleum Resources Management System (PRMS) resulted from a very long history of reserves estimation and classification. This system, evolved from earlier Society of Petroleum Engineers (SPE) classification systems, was developed over a three-year period primarily by the Oil and Gas Reserves Committee of SPE with inputs from many groups, including the international mining community, the International Accounting Standards Board (IASB), the United Nations, and various industry societies and groups. It was approved for use in March 2007 by the SPE, World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), and was subsequently endorsed by the Society of Exploration Geophysicists (SEG).

As can be discerned from the presence of the word "management" in its title, as well as the graphical representation in Figure 5, the PRMS is focused on estimating resource and reserves associated with projects, which can range from exploration activities in a frontier basin (prospective resources) to actively producing wells (proved developed producing reserves). There are two axes, one for the degree of commerciality (essentially equating to a combination of the UNCF's E and F axes) and one for the range of uncertainty in the estimate. The reserves classes in this system are broadly similar to those of the other systems. Contingent resources are similar to those of the UNCF in that there are technological or project-related hurdles that must be overcome before they can become commercial projects. Prospective resources are equivalent to possible plus speculative resources in the PGC system, undiscovered resources in the McKelvey system, and G4 resources in the UNCF system. For purposes of reserves reporting the U.S. Securities and Exchange Commission has adopted rules that reflect most aspects of the PRMS. The PRMS has also been adopted by other countries. Further discussion on the PRMS can be found on the SPE website at http://www.spe.org/industry/reserves/.

Figure 5. Portions of the hydrocarbon endowment, as defined in the 2007 SPE/WPC/AAPG/SPEE resources classification system



1.21 Reserves versus Resources

The term 'Reserves' applies only to remaining, recoverable, commercial volumes associated with known fields, while the term 'resources' is more inclusive in that it covers both known and undiscovered petroleum accumulations. As one moves from undiscovered resources to reserves there is increasing geologic certainty and economic viability (Figure 3). Specifically:

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions (such as prevailing economic conditions, operating practices, and government regulations). Reserves must satisfy four criteria: they must be *discovered*, *recoverable*, *commercial*, and *remaining* based on the development project(s) applied. Reserves are further subdivided as Proved, Probable, or Possible, also commonly referred to as P1, P2, or P3, respectively, in accordance with the level of certainty associated with the estimates and their development and production status.

PROVED (P1) – Proved Reserves is a category of estimated recoverable volumes associated with defined technical uncertainty. Proved Reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. Proved Reserves can be categorized as Developed or Undeveloped. If deterministic methods (see below) are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods (see below) are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

PROBABLE (P2) – Probable Reserves is an incremental category of estimated recoverable volumes associated with defined technical uncertainty. Probable Reserves are additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

POSSIBLE (P3) – Possible Reserves is an incremental category of estimated recoverable volume associated with defined technical uncertainty. Possible Reserves are those additional Reserves that are less certain to be recovered than Probable Reserves. The actual remaining quantities recovered have a low probability of equaling or exceeding the sum of Proved plus Probable plus Possible Reserves (3P). In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Note that immediately after discovery only a very small portion of a field's ultimate productive volume may be classified as 'proved' owing to very stringent principles regarding that classification. What is important to understand is that, through time, the categorization of volumes in an oil or gas field changes – Probable and Possible Reserves can be converted to the Proved category, and Proved Reserves are depleted through production (increasing the Cumulative Production volume).

RESOURCES, as used herein, are those quantities of petroleum estimated, as of a given date, to be potentially (or technically) recoverable from known or undiscovered accumulations, exclusive of reserves. Such resources are classified, by some, as contingent or prospective depending on whether the accumulation is known or undiscovered, respectively.

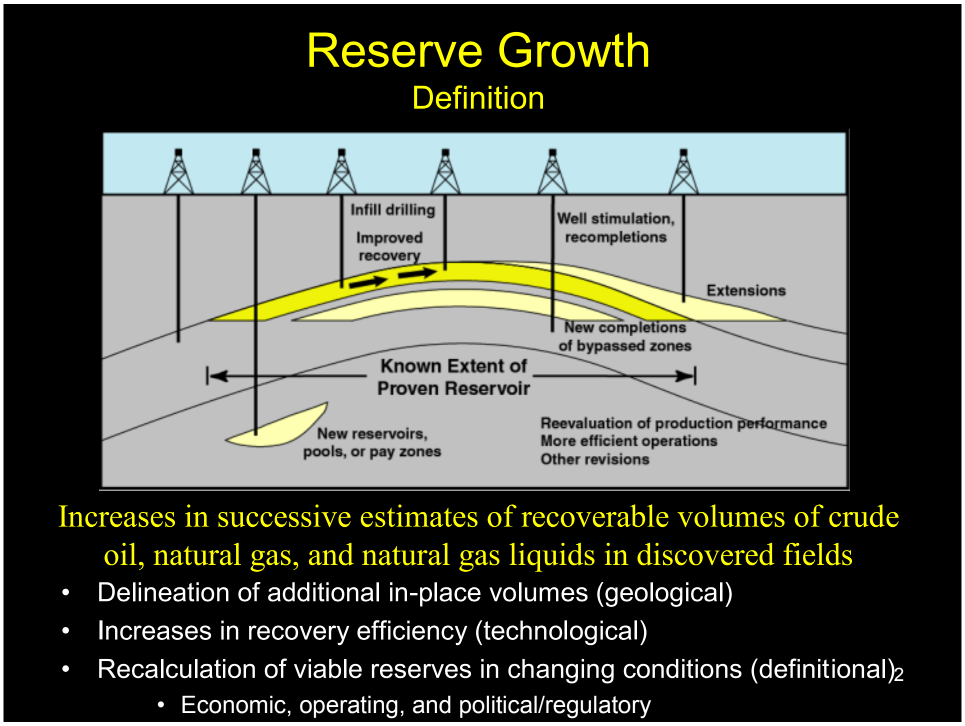
1.22 In-place Resources versus Technically Recoverable Resources

It is evident from the preceding definitions that oil and gas reserves and resources in known or yet to be discovered accumulations represent at a given time only the technically recoverable portion of the in-place oil or gas endowment. Failure to clearly characterize an announced resource estimate as in-place, technically recoverable, or economically recoverable is a too common occurrence of which users of resource estimates must always be wary. Developments in technology as well as geologic understanding of a reservoir or commodity can make previously uneconomic resources economic and commercially viable. Improvement of recovery factors over time is one reason for "Reserves Growth" as discussed below in section 1.23. Examples of such progress include the development of coalbed gas, tight gas and shale gas reservoirs, shale oil reservoirs, deeper and more subtle conventional targets, and offshore deep water development.

1.23 Reserves Growth

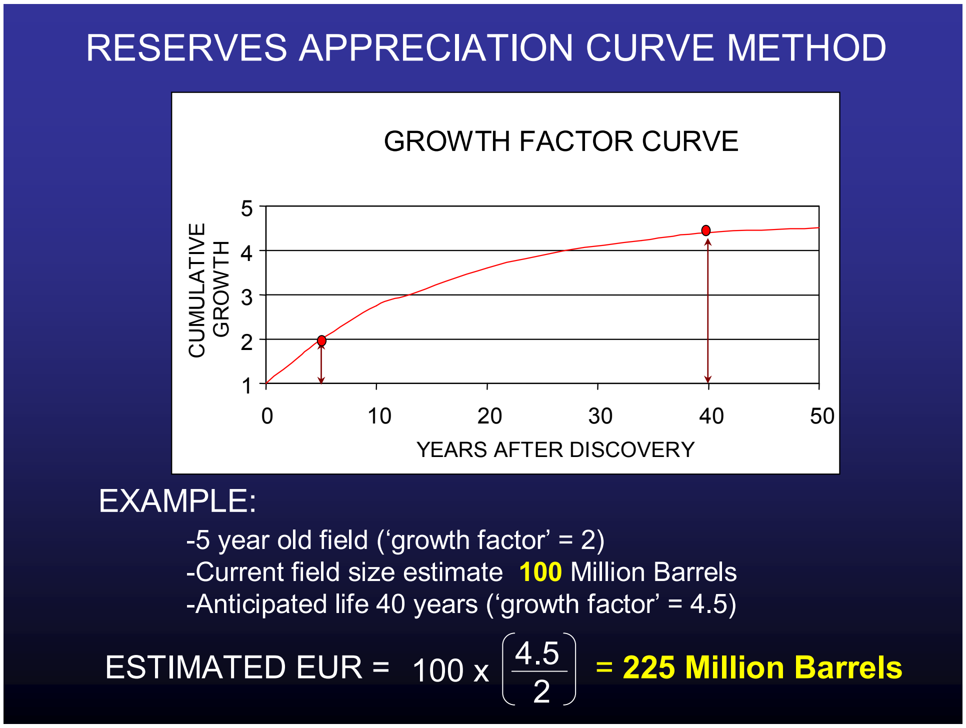
Reserves growth (also called 'Reserve Growth,' 'Field Growth,' 'Ultimate Recovery Appreciation,' and 'Reserves Appreciation') is the increase in the cumulative proved reserves of an existing field through time, as evidenced by an increase in successive estimates of its ultimately recoverable crude oil, natural gas, and natural gas liquids. reserves growth occurs in almost all petroleum provinces in the world and is considered the most important source for additional reserves in the United States. Reserves grow for a variety of reasons including extension of field boundaries internally by in-fill drilling and outwardly by satellite development, advances in drilling and/or production technology, advances in exploration technology (such as 3-D and 4-D seismic), and advances in our geologic and engineering understanding of the petroleum reservoirs (Figure 6). By studying the volume estimates at different points in time for mature fields, mathematicians can create 'growth factor curves' such as the one illustrated in Figure 7. These curves can be used to help predict the amount of oil that a field will ultimately produce over its lifetime.

Figure 6. Graphical representation of some causes of Reserve Growth (Gautier and others, 2005)



In the example below (Figure 7), a relatively new field is originally estimated to hold 100 million barrels of producible oil. Analysis of the Proved Reserves growth patterns of similar but older fields in the area has resulted in the generation of a ‘type’ cumulative growth curve which indicates that, when the field is fully exploited, it would eventually yield an additional 125 million barrels not recognized today if it behaves as the other older fields have. When these estimated reserves growth volumes are aggregated to a basin or country scale, they can be quite large.

Figure 7. Reserves appreciation estimation using growth factor curves (from Jeff Brown, 2007)



The concept and continued importance of Reserves Growth to estimating available future petroleum is the subject of considerable debate. One challenge stems from the fact that in some estimates only Proved (P1 or 1P) Reserves are considered, while in others the sum of Proved plus Probable Reserves (2P), or even Proved plus Probable plus Possible Reserves (3P) are taken to reflect 'Reserves.' Depending upon the reference point, the percentages and rates of conversion of reserves (and therefore the predicted amount of field 'growth') is substantially impacted. Another challenge in estimating ultimate recoverable reserves is that today's fields are generally (1) smaller, (2) developed more quickly, and (3) developed with better seismic data and completion technologies, than in the past, so there is some concern that using the growth patterns of older fields could overestimate ultimate Recoverable Reserves for today's and future discoveries. Studies are underway to try to determine the impact of Reserves Growth for 21st century fields.

1.24 Undiscovered Resources

Undiscovered petroleum resources are postulated to exist outside of known accumulations on the basis of geologic knowledge and theory. As explained above in

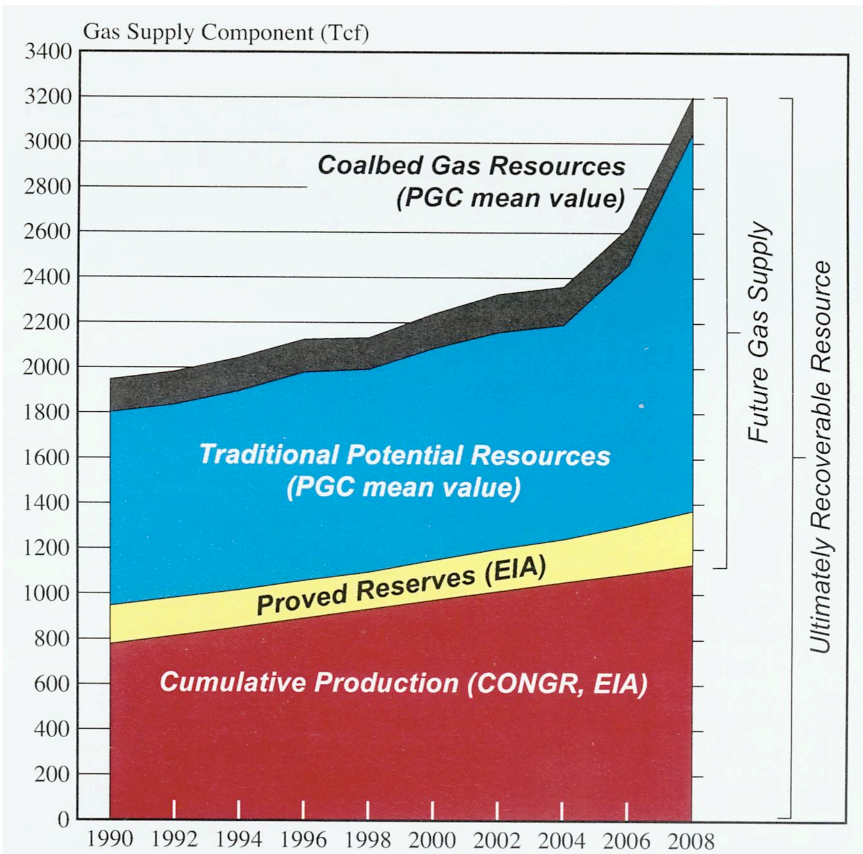
Section 1.11 (Hydrocarbon Formation), there are many aspects of resource endowment that must be present for hydrocarbons to form and be preserved. In a comprehensive resource assessment, each of these aspects is examined and measured by a variety of geological, geochemical, and geophysical means, yet a great deal of uncertainty remains. These uncertainties are expressed using statistical distributions, or ranges for possible outcomes, to capture a description of what future accumulations in a geologic play, basin, or country might look like. Construction of these distributions is guided by analysis of fields that have already been discovered, and by examining the geology of the region. Examination of size characteristics of *known accumulations*, together with an analysis of how many have already been discovered, is used to project numbers and sizes of those which may remain to be discovered. That is the general manner in which conventional, undiscovered resources are estimated or assessed. Often, when there are few or no data for the basin or region under study, *analogs* to known petroleum regions, including their characteristics and properties, are used to estimate the resources.

Industry continues to discover significant new resources. Yet every petroliferous basin is endowed with a finite population of potential traps that might hold accumulations. Historically, about 1 in 4 traps have proved to be viable (IHS, 2000) in the case of conventional reservoirs. This ratio has remained remarkably constant on a global scale since the 1960's (but may not be applicable to unconventional resources, discussed below). The exploration and production process therefore is one involving sampling this finite population without replacement. Once a structure is tested, it is removed from the population of potential future discoveries. Not surprisingly, the larger and more obvious potential traps are usually drilled first, and usually the largest discoveries are made early in the 'life' of a basin or play. This is the reason that the fields being discovered today are smaller, in general, than those discovered and developed in the past. However, there are significant exceptions to this generality and very large fields continue to be found, especially where acreage availability was restricted in the past or in frontier areas where there has been little exploration.

The predicted volumes to be found in the undrilled population of potential accumulations reflect estimated *undiscovered resources*. These estimates must take into account the average prospecting success rate, number of undrilled remaining prospects, and the predicted size characteristics for the future discoveries. The results of such analyses carry a much greater uncertainty (wider range of volumetric outcomes) than the uncertainty associated with remaining reserves in existing fields because there are fewer and less detailed data on which to base the estimate.

It must always be kept in mind that resource estimates are snapshots in time. Since the earth has a finite endowment of liquid hydrocarbons, from which we produce more and more each year, the logical conclusion would be that the estimates for what remains to be found should be going down, but this is not the case. Usually, resource estimates conducted by an individual organization tend to increase over time owing to some combination of the availability of more and better data, new acreage that was previously inaccessible or incorrectly considered non-prospective, or a new play type (such as shale gas or subsalt oil) made feasible by technological progress. The blue and black bands in Figure 8 provide a North American example of such an increase.

Figure 8. Temporal Increase Of Potential Gas Committee (PGC) Estimates of U.S. Natural Gas Resources (after Potential Supply of Natural Gas in the United States, December 31, 2008); EIA=U.S. Energy Information Administration, CONGR=the former American Gas Association Committee on Natural Gas Reserves)



1.25 Conventional versus Unconventional Reserves and Resources

Until the 1990's, virtually all estimates of hydrocarbon endowment focused on reserves and resources that were called 'conventional' – crude oils, NGLs (liquids that were extracted during production from gas fields) and natural gas that could be expected to be economically produced using state-of-the-art technology, and which were naturally distributed as discrete accumulations. "State-of-the-art" technology is, however, a moving target. For example, it was common practice as recently as the 1990's to exclude estimates for liquids located in water depths greater than 1000 meters, where significant production now exists.

Under most contemporary definitions, a primary delimiter between 'conventional' and 'unconventional' liquids is viscosity, that is, a fluid's resistance to flow. Enormous deposits of potentially productive liquid hydrocarbons exist in nature that cannot flow under either reservoir or surface conditions – an unconventional resource. This category includes huge deposits of low viscosity oil in Venezuela and western Canada, and bitumen deposits (tar-impregnated sands) in western Canada. The volumetric potential of these deposits may dwarf that of conventional accumulations. These resources in Canada are now economically produced and traded on the stock market. As a result of Canada's focus on their 'unconventional' resources, they now have the second largest reserves of oil in the world. Even though these resources are often difficult and expensive to produce (where such deposits are near the earth's surface, they are mined using techniques similar to those used for coal deposits; deeper deposits are subject to super-heated steam or solvent injection), their potential make them an attractive target to pursue.

The following definitions reflect these viscosity-based differences:

Conventional Oil: Petroleum found in liquid form flowing naturally or capable of being pumped without further processing or dilution.

Unconventional Oil: Heavy Oil, Very Heavy Oil, Oil Shale, and Oil Sands are all currently considered unconventional oil resources. These hydrocarbon mixtures have a high viscosity and flow very slowly (if at all) and require processing or dilution to be produced through a wellbore. Further, they may not be affected by hydrodynamic influences, such as the buoyancy of petroleum in water. Heavy and Very Heavy Oil are liquid resources, while Oil Shale and Oil Sands are solids that can be processed into synthetic crude oil.

> **Heavy Oil:** Heavy crude oils are understood to include only those liquid or semi-liquid hydrocarbons with a gravity of 20^o API or less. These include fuel oils remaining after the lighter oils have been distilled off during the refining process.
>
> **Very Heavy Oil:** On the production side, Very Heavy Oil is defined as having a gravity less than 10^o to 12^o API.
>
> **Oil Shale:** A fine-grained sedimentary rock containing *kerogen*, a solid organic material. The kerogen in oil shale can be converted to oil through the chemical process of pyrolysis. During pyrolysis, the oil shale is heated to 445^o-500^o C in the absence of air and the kerogen is converted to oil and separated out, a process called "retorting." Whether extracted by surface mining or underground in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). "Oil shale" is unrelated to liquid petroleum produced from wells drilled into more thermally mature shales that is sometimes called "shale oil."
>
>> *Kerogen***:** A complex mixture of compounds with large molecules containing mainly hydrogen and carbon but also oxygen, nitrogen, and sulfur. Kerogen is a precursor of petroleum and the organic component of

oil shales. It is waxy, insoluble in water, and upon heating, it breaks down into recoverable gaseous and liquid substances resembling petroleum.

Oil Sands: Also referred to as Tar Sands or Bituminous Sands, Oil Sands are a combination of sand, water, and *bitumen*.

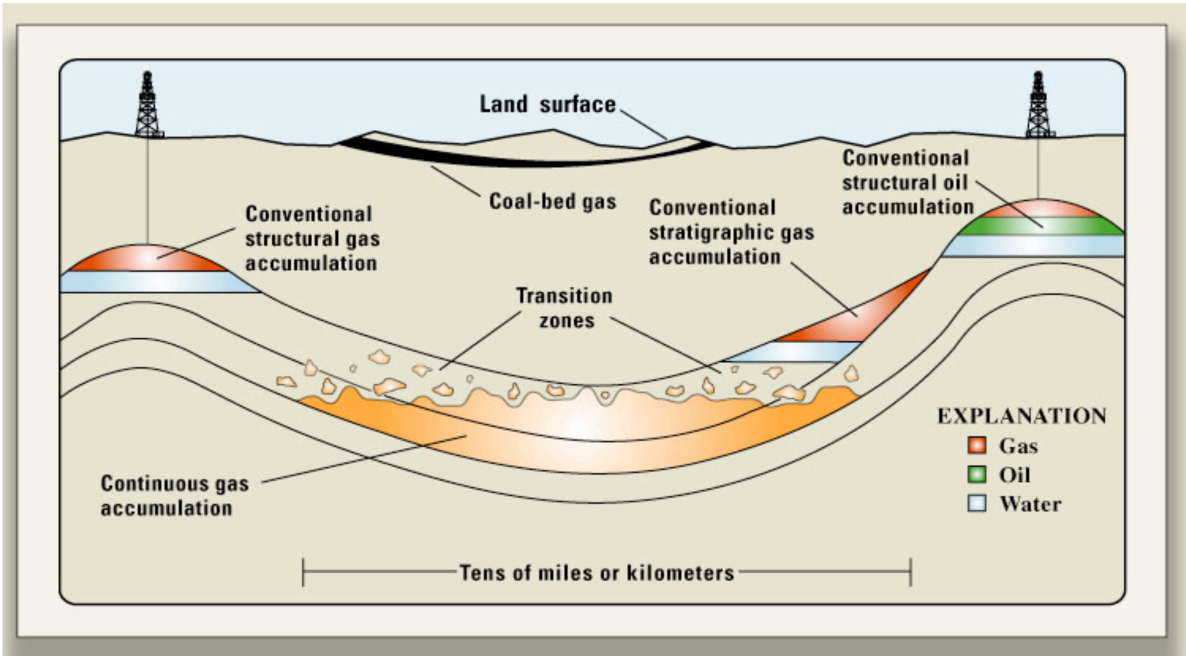
Bitumen is a semisolid, degraded form of oil that will not flow unless heated or diluted with lighter hydrocarbons. Bitumen is converted into synthetic crude oil or refined directly into petroleum products by specialized refineries.

Continuous Type or Unconventional Resources (shale gas, tight gas, coalbed methane): Unconventional oil or gas is another portion of the hydrocarbon endowment that has seen significant growth in recent years. Recent technical advances, especially in drilling and completion technologies, have allowed these resources to be produced economically from many North American basins.

Some organizations, such as the U.S. Geological Survey (USGS), use the term continuous accumulation to define those unconventional oil and gas resources that are economically produced but are not found in conventional reservoirs (see Figure 9) such as coalbed gas, tight gas sands, and shale gas. Conventional accumulations are described in terms of discrete fields or pools localized in structural or stratigraphic traps by the buoyancy of oil or gas in water. Conventional accumulations have a *trap and seal* which prevent the petroleum from escaping; they are confined to a *reservoir* horizon with defined thickness and lateral continuity; and they are limited down-dip by a horizontal contact zone with underlying water. This geologic setting means that the geometries, and therefore volumes, of each accumulation can be inferred with some precision.

Continuous accumulations are petroleum accumulations (oil or gas) that have large spatial dimensions and indistinctly defined boundaries, and which exist more or less independently of the subsurface water column. Continuous accumulations have two key geologic characteristics: (1) they consist of large volumes of rock pervasively charged with oil or gas, and (2) they do not appear to depend upon the buoyancy of oil or gas in water for their existence. Because they may cover hundreds, or even thousands, of square miles, the host rocks will have widely varying properties. The key in unconventional reservoirs is not just to find moveable oil or gas (which can be relatively easy), but to find those locations where these hydrocarbons can be produced at economic rates. Another key difference between conventional and unconventional accumulations is that some of these (shales and coals) are both source rock and reservoir rock.

Figure 9. Graphical representation of conventional and continuous petroleum accumulations (Schenk and Pollastro, 2002)



Uneconomic Unconventional Resources

As discussed above, there is a certain portion of the hydrocarbon endowment that has seen significant growth in recent years, specifically shale gas, tight sand, coalbed methane, and tight oil. Just as recent technical advances have allowed these resources to be produced economically in some basins, there are hydrocarbon resources that are currently unconventional and also uneconomic. But it is possible, though not assured, that technology might be developed that would some day allow production of these resources or that the economic parameters making these hydrocarbons currently uneconomic might change allowing for their development. Examples of these types of resources are natural gas hydrates and oil shale. Both of these resources, discussed elsewhere in the NPC study, are technically recoverable, at least from some types of reservoirs. Both of these resources bear keeping in mind as potential future resources, especially as research evolves related to their characterization and potential production.

1.3 Uncertainty

Significant uncertainties are an inherent part of resource estimation. The best-constructed methodologies have several important elements: (1) they directly address the resulting estimates' principal uncertainties; and (2) they are transparent in regards to the assessment methodology and assumptions underlying the estimates. These factors are critical for users to understand exactly what they represent.

What constitutes a resource has changed over time. Twenty years ago, coalbed methane was not a viable part of the U.S. energy mix. It now accounts for about 8% of the domestic natural gas production. Technological developments and developments in geologic and engineering understandings continually move the edge of what makes a resource a reserve.

The history of the petroleum industry is replete with instances of poor long term predictions and “good” resource-related surprises. Salient United States examples include:

- “Experts” predicted at the beginning of the last century that the modern domestic oil era, initiated in Pennsylvania during the mid-1800s, would soon end owing to lack of sufficient resources. Instead, major finds in other places soon proved them wrong, such as the 1901 discovery of Spindletop Field in the Texas’ Gulf Coast region, the 1930 discovery of East Texas Field in the Mid-Continent region, and the 1890-1920s discoveries of several large fields in California’s Los Angeles and San Joaquin basins.

- Many believed in the early 1940s that oil and gas either did not exist in, or could not be produced from, the open ocean. Until 1947 that is, when Kerr McGee used a platform-plus-barge combination to drill the first successful well out of sight of land in the Gulf of Mexico.

- Similarly pessimistic views that production from the large California oil fields would dwindle to a trickle owing to exhaustion of their resources have been repeatedly negated by technological advancements. They include the introduction of waterflooding prior to the 1960s and, more importantly, the application of thermal recovery methods to heavy oil reservoirs since the 1960s.

- Few “experts” held out hope that oil and gas could exist in deep water (over 5,000 feet) at great sub-seabed depths (on the order of 30,000 feet total vertical depth) until Shell’s 1986 Mensa prospect discovery proved they could and did.

- The late 1980’s advent of large-scale coalbed methane production was virtually unheralded, and therefore unanticipated.

- The late 1990’s advent of large-scale natural gas and natural gas liquids production from massively hydraulically fractured organic-rich shales, initiated in the Barnett Shale of Texas’ Fort Worth Basin, was also virtually unheralded and therefore unanticipated.

- Although small-scale hydraulic fracturing of oil-bearing “shale” formations such as California’s Monterrey Formation began in the 1980s, the adaptation of combined horizontal drilling and massive hydraulic fracturing as originally developed for gas in the Barnett Shale, to productive development of the oil-bearing Bakken Formation of Montana, North Dakota, Saskatchewan, and Manitoba was also unheralded and unanticipated until its rapid adoption and expansion began in 2001.

This long and presently continuing history of widely unanticipated "good" resource-related surprises clearly begs the question as to what currently ignored and currently discounted oil and gas resources might have the potential to provide similar surprises in the medium- and/or long term. Given the apt lesson about scientific and technological progress provided by history, perhaps consideration ought be given to establishment of a small but highly competent on-going effort dedicated and resourced specifically to (1) identify and characterize those oil and gas resources that are not yet being quantitatively estimated (using both open-source and disclosure-protected proprietary data and information), and (2) identify, analyze, summarize, and status-assess ongoing and/or needed R&D activities, basic or applied, that may hold promise for rendering these resources technically and then economically producible at some time well into the future. A few obvious possibilities include enhanced recovery of residual oil (both bypassed and diffuse) from old fields, oil shale conversion, and methane hydrate production, all of which are already being researched to varying degrees. Less obvious possibilities also undoubtedly exist.

1.4 Summary of Current North American Petroleum Resource Estimates

Resource assessments are conducted by government agencies, the private sector, and academic and professional organizations in the U.S. and Canada. Only publicly available (i.e. non proprietary) assessments were evaluated within the Resources Subgroup. Following is a description of each assessment and their findings. Most assessments evaluated were robust, transparent, and well documented. Each had a slightly different purpose or focus, and therefore provides a unique perspective on North American resources. Resource estimates for North America span the spectrum of resources and reserves. There are many differences among them, but there are often good reasons for those differences (e.g., different purposes). These differences can result from many factors such as use of different methodologies, inclusion versus exclusion of reserves growth, inclusion of only selected basins or reservoirs, inclusion of different types of hydrocarbons (crude oil only vs all liquids, for example), variations in technologic and economic assumptions (e.g., including current technology vs assuming future advances in exploration and completion technology), and differing minimum field sizes.

Organization: U.S. Geological Survey
What was assessed: The assessed products include conventional and continuous (unconventional) hydrocarbons - crude oil, natural gas liquids (condensates), and natural gas - of the

onshore U.S. and State waters. For the numbers below, oil and natural gas liquids were combined in the totals (per NPC instructions), but USGS assesses and reports them separately. Also for the numbers below, associated gas and non associated gas were combined for totals.
Methodology and system used to classify: The USGS reports undiscovered, technically recoverable resources. Technically recoverable means recoverable with today's technology and industry practice. The USGS assesses the potential for undiscovered oil and gas resources in geologic provinces in the United States and around the world. Two methodologies are used by the USGS; one for assessing conventional oil and gas resources and one for assessing unconventional (continuous) oil and gas resources (such as shale gas and coalbed gas). Both assessment methodologies are fully risked and based on a total petroleum systems approach and the development of a geologic model is key to all USGS assessments. The total petroleum systems are divided into Assessment Units (AU) (or mappable volumes of rock within the systems that encompass accumulations (discovered or undiscovered) which share similar geologic traits and socio-economic factors. In some cases, an AU may equate to a Total Petroleum system. For each basin assessed, the USGS evaluates both conventional and continuous (unconventional) accumulations. For conventional assessments, the sizes and numbers of potential accumulations are estimated based on the geologic model developed and these are run through a Monte Carlo analysis to determine the probability distributions of potential volumes of the resource. For continuous assessments, a distribution of well productivity based on decline-curve analysis is combined with geology-based estimates of what part of the AU is potentially productive.
Volumes reported: Undiscovered, technically recoverable oil -- in the following break downs, in accordance with the NPC data template requested: CONVENTIONAL: 18.08 billion barrels onshore + 28.57 billion barrels Arctic = 46.65 "grand total" conventional oil. UNCONVENTIONAL: 13.87 billion barrels onshore + 0.04 Arctic = 13.91 "grand total" unconventional oil. TOTAL CON + UNCON: 31.95 billion barrels onshore + 28.61 Arctic = 60.56 undiscovered, technically recoverable oil. Undiscovered, technically recoverable gas -- in the following break downs, in accordance with the NPC data template requested: CONVENTIONAL: 214.55 tcf onshore + 136.88 tcf Arctic = 351.43 total undiscovered, technically recoverable conventional gas in the U.S. UNCONVENTIONAL: 155.23 tcf tight gas onshore + 278.22 tcf shale gas onshore + 73.04 tcf coalbed methane onshore + 18.06 tcf coalbed methane Arctic (91.10 tcf coalbed methane total). Totals for unconventional -- 506.50 tcf onshore + 18.06 tcf Arctic = 524.55 tcf "grand total" continuous gas.

Organization: MMS (now BOEMRE): Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources: Energy Policy Act of 2005 -- Section 357 (by MMS)
What was assessed:

The assessed products include conventional hydrocarbons - crude oil, natural gas liquids (condensates), and natural gas - in the U.S. Outer Continental Shelf (OCS). However, the oil resources reported represent combined volumes of crude oil and condensate. Conventional resources only are assessed, those produced with purely conventional recovery techniques - no tight formations. Unconventional resources are not yet produced on the OCS.

Methodology and system used to classify:

The classification system that was used consists of technically recoverable resources, which they define as hydrocarbons potentially amenable to conventional production regardless of the size, accessibility, and economics of the accumulations assessed. They also report on total endowment which is comprised of known resources -- cumulative production and estimates of remaining proved and unproved reserves and reserves appreciation plus estimates of undiscovered resources. MMS also reports on reserves growth/appreciation -- the projected increase in current estimates of reserves within existing fields based on historical trends.

The method that was applied was the "MMS stochastic resource assessment methodology" for the undiscovered, technically recoverable resources. The methodology incorporates geologic risk and uncertainty at the prospect, play and basin level. The level of uncertainty is reflected in the frequency distributions for uncertain variables affecting the volume of hydrocarbons that may exist in a prospect and the number of accumulations that may exist in a play if technically recoverable hydrocarbons are present. Resource volumes are estimated conditional on recoverable hydrocarbons being present in a prospect and play. These conditional assessments are then weighted by a risk analysis which considers the probability that hydrocarbons may in fact not be present. Cumulative production is a measured quantity, and can be accurately determined. Reserves are estimates, and are estimated at different stages during the exploration and development cycle of a hydrocarbon accumulation, i.e., after exploration and delineation drilling, during development drilling, after some production and, finally, after production has been well established. Different methods of estimating the volume of reserves are used at each stage. Reserve estimating procedures generally progress from volumetric to performance-based techniques as the field matures, but the report does not say what those methods are. Reserve growth functions are modeled from empirical historical trends derived from the set of existing OCS fields having proved reserves at the end of 2002. They were used to develop an estimate of an existing field's size at a future date. Growth factors represent the ratio of the size of a field several years after discovery to the initial estimate of its size in the year of discovery. The assumptions central to this analysis are that:

the amount of growth in any year is proportional to the size of the field;

this proportionality varies inversely with the age of the field;

the age of the field is a reasonable proxy for the degree to which the factors causing appreciation have operated; and

the factors causing future appreciation will result in patterns and magnitudes of growth similar to that observed in the past.

The appreciation model used in this assessment projects no growth for fields more than 53 years of age.

Volumes reported:

Total endowment of technically recoverable oil and gas in the OCS, 2006

	Known Resources			Undiscovered	Total
	Cumulative	Reserves	Reserves	Resources	Endowment

Regions	Production		Apprec'tion	(mean estimate)	(mean estimate)
Oil (billion barrels)					
Alaska OCS	0.01	0.03	0.00	26.61	26.65
Atlantic OCS	0.00	0.00	0.00	3.82	3.82
Gulf of Mexico OCS	13.05	7.06	6.88	44.92	71.91
Pacific OCS	1.06	1.46	0.00	10.53	13.05
Total OCS	**14.12**	**8.55**	**6.88**	**85.88**	**115.43**
Natural Gas (trillion cubic feet)					
Alaska OCS	0.00	0.00	0.00	132.06	132.06
Atlantic OCS	0.00	0.00	0.00	36.99	36.99
Gulf of Mexico OCS	152.25	27.70	30.91	232.54	443.4
Pacific OCS	1.32	1.56	0.00	18.29	21.17
Total OCS	**153.57**	**29.26**	**30.91**	**419.88**	**633.62**

Undiscovered, Technically Recoverable Resources (range)

	Oil (BBO)			Gas (TCF)		
Regions	F5	F95	Mean	F5	F95	Mean
Alaska OCS	55.14	8.66	26.61	279.62	48.28	132.06
Atlantic OCS	7.57	1.12	3.82	66.46	14.3	36.99
GOM OCS	49.11	41.21	44.92	249.08	218.83	232.54
Pacific OCS	13.94	7.55	10.53	24.12	13.29	18.29
Total OCS	**115.13**	**66.60**	**85.88**	**565.87**	**326.4**	**419.88**

Organization: MMS (now BOEMRE) Report to Congress: Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2006 (MMS)

What was assessed:
The assessed products include conventional hydrocarbons - crude oil, natural gas liquids (condensates), and natural gas - in the Federal Outer Continental Shelf (OCS). Crude oil and condensate are reported jointly as oil. Associated and nonassociated gas are reported as gas.

Methodology and system used to classify:
85.9 billion barrels of undiscovered technically recoverable oil and 419.9 trillion cubic feet of undiscovered technically recoverable gas - same as that directly above. Also reported on economically recoverable oil and natural gas resources. These estimates are presented as price-supply curves for the entire OCS and individual regions (no tabular data). The price-supply curve for each region shows two curves and two price scales, one for oil and one for gas. The curves represent mean values at any specific price. They are not independent of each other; that is, one specific oil price cannot be used to obtain an oil resource and a separate gas price used to get a gas resource. The gas price is dependent on the oil price and must be used in conjunction with the oil price on the opposite axis to calculate resources. The reason for this condition is that oil and gas frequently occur together and the individual

pool economics are calculated using the coupled pricing. A different gas price associated with the oil price would result in a different resource number than that shown on the curve. The curves are found on the second tab of this spreadsheet. The two vertical lines (green for oil and red for natural gas) indicate the mean estimates of UTRR. At high prices, the economically recoverable resource volumes approach the conventionally recoverable volumes. These curves represent resources available with sufficient exploration and development efforts and do not imply an immediate response to price changes.

Volumes reported:

Total endowment of technically recoverable oil and gas in the OCS, 2006

	Known Resources				
Regions	Cumulative Production	Reserves	Reserves Apprec'tion	Undiscovered Resources (mean estimate)	Total Endowment (mean estimate)
Oil (billion barrels)					
Alaska OCS	0.01	0.03	0.00	26.61	26.65
Atlantic OCS	0.00	0.00	0.00	3.82	3.82
Gulf of Mexico OCS	13.05	7.06	6.88	44.92	71.91
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Undiscovered, Technically Recoverable Resources (range)

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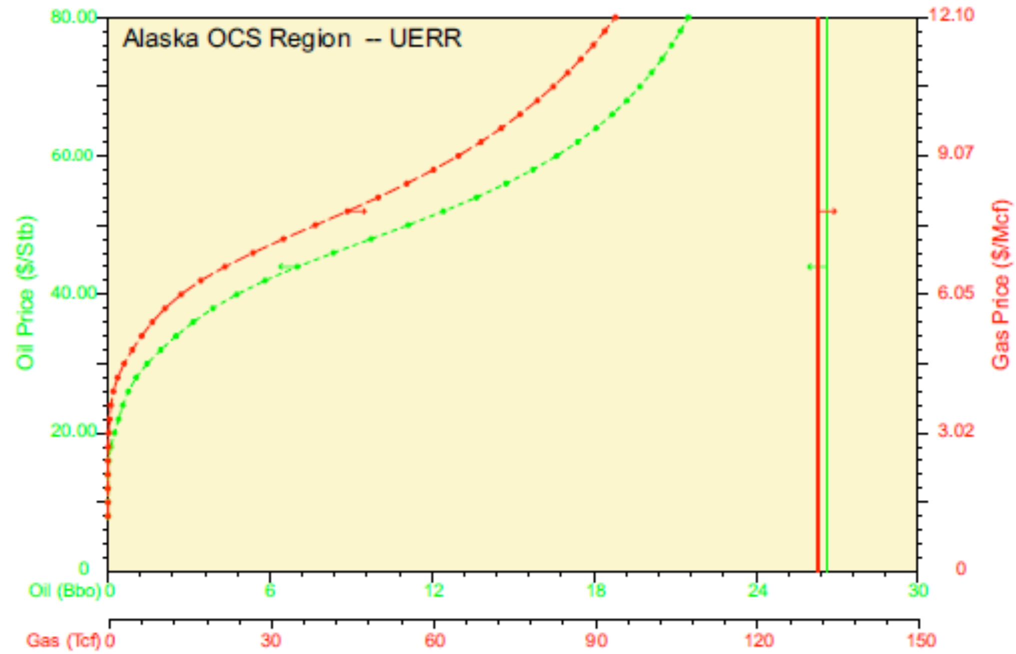
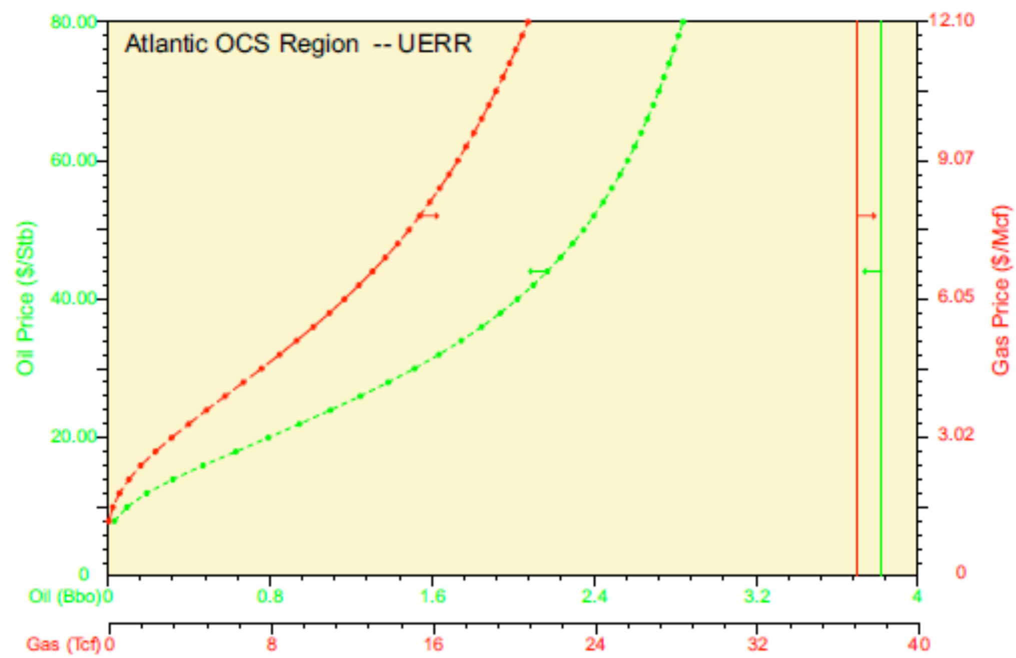
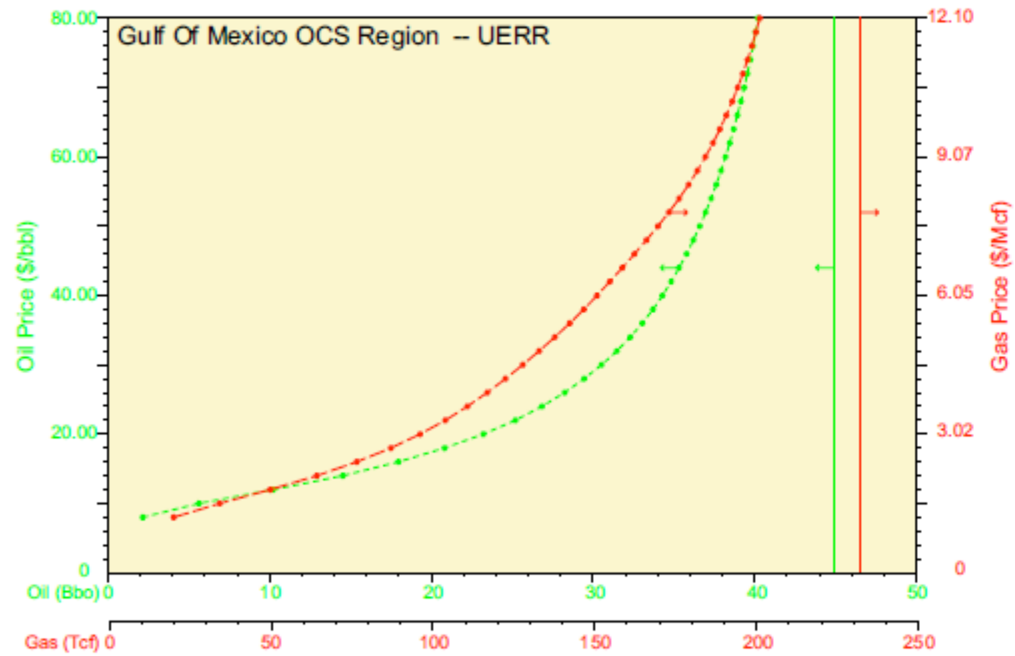
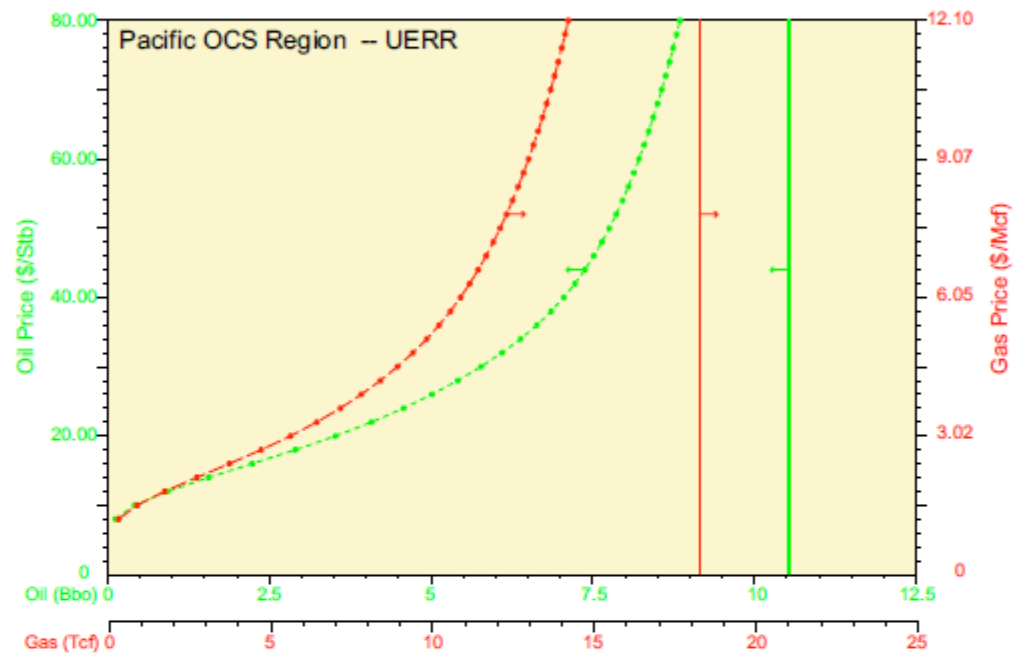
GOM OCS	49.11	41.21	44.92	249.08	218.83	232.54
Pacific OCS	13.94	7.55	10.53	24.12	13.29	18.29
Total OCS	**115.13**	**66.60**	**85.88**	**565.87**	**326.4**	**419.88**


Alaska OCS Region -- UERR
Oil Price ($/Stb)
Gas Price ($/Mcf)
80.00
60.00
40.00
20.00
0
12.10
9.07
6.05
3.02
0
Oil (Bbo) 0
6
12
18
24
30
Gas (Tcf) 0
30
60
90
120
150


Atlantic OCS Region -- UERR
Oil Price ($/Stb)
Gas Price ($/Mcf)
80.00
60.00
40.00
20.00
0
12.10
9.07
6.05
3.02
0
Oil (Bbo) 0
0.8
1.6
2.4
3.2
4
Gas (Tcf) 0
8
16
24
32
40


Gulf Of Mexico OCS Region -- UERR
Oil Price ($/bbl)
Gas Price ($/Mcf)
80.00
60.00
40.00
20.00
0
12.10
9.07
6.05
3.02
0
Oil (Bbo) 0 10 20 30 40 50
Gas (Tcf) 0 50 100 150 200 250


Pacific OCS Region -- UERR
Oil Price ($/Stb)
Gas Price ($/Mcf)
80.00
60.00
40.00
20.00
0
12.10
9.07
6.05
3.02
0
Oil (Bbo) 0 2.5 5 7.5 10 12.5
Gas (Tcf) 0 5 10 15 20 25

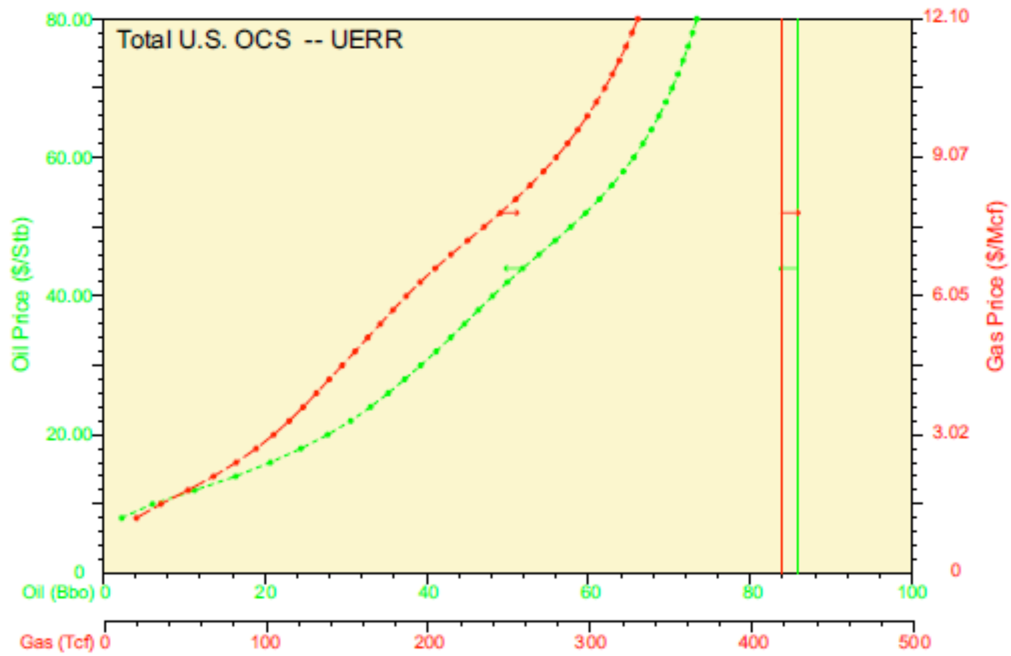


Figure 3. Price Supply Curves for Federal OCS Regions and Total Federal OCS.

Organization: IHS 2010	
What was assessed: Recoverable, unconventional gas and condensate in 11 primary unconventional gas plays in the U.S.	
Methodology and system used to classify: Based on cost/Mcf cutoffs of recoverable gas for each play and sub-play. Categories are high, medium, and low + technically recoverable. Well performance based analysis. Play and sub-play boundaries determined by geological and production mapping. Type curves for each play and sub-play were determined by evaluating fractile (probability) distribution of decline curves for all wells completed during six month periods over the past two years and annual periods for the prior eight years. Type curves were applied to the initial peak production rates for all wells in each sub-play to determine EURs for each producing gas well. Calculated EURs for all producing wells were mapped and fit to an artificial one square mile grid to determine the distribution of average EUR per square mile in each sub-play. Breakeven costs were per Mcf were used to define average EUR for high, medium, low commercial and technically recoverable compartments in each sub-play. The number of potential future wells that could be drilled was determined for each square mile within each sub-play. Estimated EURs for each sub-play were then determined for each square mile within each sub-play. Estimated EURs for each sub-play were then determined for four	

or more possible drilling densities for each of the established high, medium, low and technically recoverable compartments in each play.
Volumes reported: Shale: Commercial: High 278 tcf Medium 384 tcf Low 234 tcf Sum 895 tcf Technically Recoverable: 264 tcf Total: 1159 tcf Tight sandstone: Commercial: High 36 tcf Medium 29 tcf Low 27 tcf Sum 92 tcf Technically Recoverable: 108 tcf Total: 200 tcf Resource Sum: Commercial: High 314 tcf Medium 413 tcf Low 261 tcf Sum 987 tcf Technically Recoverable: 371 tcf Total: 1353 tcf

Organization: Potential Gas Committee 2008
What was assessed: Technically recoverable U.S. natural gas resources
Methodology and system used to classify: PGC's potential resources classification system consists of: (1) probable resources, corresponding to extensions of, and new reservoir discoveries in, already discovered fields; (2) possible resources, corresponding to new field discoveries in an already productive formation and geologic province; and (3) speculative resources, corresponding to new field and new pool discoveries in a formation not previously

productive in a geologic province or to new field discoveries in a previously unproductive province. In the report, the estimates for these categories are divided both geographically and geologically in several ways. Separate estimates are made for traditional gas resources, coalbed methane and, as of 2008, shale gas resources (which have always been considered a part of traditional resources by the PGC). The estimates are made in the form of triangular distributions for 90 provinces, which are then statistically aggregated to area and national totals. For each distribution the minimum point represents a 100% probability that at least that much gas exists in the province, the most likely point is the highest probability volume representing "the most reasonable assessment," and the maximum point has an effective probability of zero that that much or more gas is present in the province.

The PGC coalbed methane resource estimates for 27 coal regions, basins, and selected fields are based (1) on gas-in-place estimates volumetrically calculated as the product of net coal thickness of prospective seams, seam area, coal density, and gas content in standard cubic feet per ton which is subsequently converted to minimum, maximum, and most likely values by multiplying the in-place estimate by a range of recovery factors and in some instances imposing a maximum producible depth limit, or (2) in instances where a sufficiently long production history is available, an estimated ultimate recovery is statistically generated. The PGC hasn't yet formally reported its shale gas estimation methodology, possibly because it is still undergoing final refinement; owing to the nature of these resources its likely to be somewhat similar to their coalbed gas approach while accommodating a few differences between the two self-sourced reservoirs.

Volumes reported:

Mean estimate of U.S. potential gas resources = 1,836Tcf

Of this,

- 616 Tcf is shale gas resources
- 163 Tcf is coalbed gas resources
- 238 Tcf is offshore
- 194 Tcf is in Alaska (on- and offshore; no shale gas estimated for Alaska)

Organization: USGS Circum Arctic Resource Appraisal

What was assessed:

The assessed products include conventional crude oil, natural gas liquids (condensates), and natural gas - of all areas north of the Arctic Circle – the entire Circum Arctic area.

Methodology and system used to classify:

USGS assessed undiscovered, technically recoverable resources (technically recoverable = technically recoverable with today's technology and industry practice). One caveat – technically recoverable defined herein is without regard to sea ice and water depth. A full cycle analysis of this resource estimate is forthcoming, which does incorporate those factors.

The U.S. Geological Survey assesses the potential for undiscovered oil and gas resources in priority geologic provinces in the United States and around the world. The assessment methodology is fully risked and based on a total petroleum systems

approach and the development of a geologic model is key to all USGS assessments. The total petroleum systems are divided into Assessment Units (AU) (or mappable volumes of rock within the systems that encompass accumulations (discovered or undiscovered) which share similar geologic traits and socio-economic factors. In some cases, an AU may equate to a Total Petroleum system. For conventional assessments, the sizes and numbers of potential accumulations are estimated based on the geologic model developed and these undergo a Monte Carlo analysis to determine the probability distributions of potential volumes of the resource.
Volumes reported:

Table 1. Summary of Results of the Circum-Arctic Resource Appraisal

[MMBO, million barrels of oil; BCFG, billion cubic feet of natural gas; MMBNGL, million barrels of natural gas liquids; NQA, not quantitatively assessed. Results shown are fully risked mean estimates. For gas accumulations, all liquids are included as NGL (natural gas liquids). Provinces are listed in ranked order of total barrels of oil and oil-equivalent natural gas (BOE).]

Province Code	Province	Oil (MMBO)	Total Gas (BCFG)	NGL (MMBNGL)	BOE (MMBOE)
WSB	West Siberian Basin	3,659.88	651,498.56	20,328.69	132,571.66
AA	Arctic Alaska	29,960.94	221,397.60	5,904.97	72,765.52
EBB	East Barents Basin	7,406.49	317,557.97	1,422.28	61,755.10
EGR	East Greenland Rift Basins	8,902.13	86,180.06	8,121.57	31,387.04
YK	Yenisey-Khatanga Basin	5,583.74	99,964.26	2,675.15	24,919.61
AM	Amerasia Basin	9,723.58	56,891.21	541.69	19,747.14
WGEC	West Greenland-East Canada	7,274.40	51,818.16	1,152.59	17,063.35
LSS	Laptev Sea Shelf	3,115.57	32,562.84	867.16	9,409.87
NM	Norwegian Margin	1,437.29	32,281.01	504.73	7,322.19
BP	Barents Platform	2,055.51	26,218.67	278.71	6,704.00
EB	Eurasia Basin	1,342.15	19,475.43	520.26	5,108.31
NKB	North Kara Basins and Platforms	1,807.26	14,973.58	390.22	4,693.07
TPB	Timan-Pechora Basin	1,667.21	9,062.59	202.80	3,380.44
NGS	North Greenland Sheared Margin	1,349.80	10,207.24	273.09	3,324.09
LM	Lomonosov-Makarov	1,106.78	7,156.25	191.55	2,491.04
SB	Sverdrup Basin	851.11	8,596.36	191.20	2,475.04
LA	Lena-Anabar Basin	1,912.89	2,106.75	56.41	2,320.43
NCWF	North Chukchi-Wrangel Foreland Basin	85.99	6,065.76	106.57	1,203.52
VLK	Vilkitskii Basin	98.03	5,741.87	101.63	1,156.63
NWLS	Northwest Laptev Sea Shelf	172.24	4,488.12	119.63	1,039.90
LV	Lena-Vilyui Basin	376.86	1,335.20	35.66	635.06
ZB	Zyryanka Basin	47.82	1,505.99	40.14	338.95
ESS	East Siberian Sea Basin	19.73	618.83	10.91	133.78
HB	Hope Basin	2.47	648.17	11.37	121.87
NWC	Northwest Canada Interior Basins	23.34	305.34	15.24	89.47
MZB	Mezen' Basin	NQA	NQA	NQA	NQA
NZAA	Novaya Zemlya Basins and Admiralty Arch	NQA	NQA	NQA	NQA
TUN	Tunguska Basin	NQA	NQA	NQA	NQA
CB	Chuckhi Borderland	NQA	NQA	NQA	NQA
YF	Yukon Flats (part of Central Alaska Province)	NQA	NQA	NQA	NQA
LS	Long Strait	NQA	NQA	NQA	NQA
JMM	Jan Mayen Microcontinent	NQA	NQA	NQA	NQA
FS	Franklinian Shelf	NQA	NQA	NQA	NQA
Total		**89,983.21**	**1,668,657.84**	**44,064.24**	**412,157.09**

Assessment unit level results and basin level results are also available, but not reproduced here.

Organization: Geological Survey of Canada (GSC)	
What was assessed:	

Natural gas and crude oil in the Queen Charlotte Basin, Georgia Basin, and Tofino-Winona-Juan de Fuca basin area in Neogene and Cretaceous sediments offshore the province of British Columbia. GSC uses the word "potential" to designate in-place resources not yet discovered but inferred to exist.
Methodology and system used to classify: These regional quantitative assessments were derived using the GSC's probabilistic assessment methodology and PETRIMES software, based on subjective analyses of 10 conceptual plays that consider field size parametric data (reflecting distributions of reservoir parameters such as prospect area, reservoir thickness, porosity, trap fill, hydrocarbon fraction, oil shrinkage, and gas expansion), numbers of prospects, and exploration risks such as reservoir, seal, and source rock presence, timing of hyrocarbon migration and trap closure, and trap preservation).
Volumes reported: The volume of oil reported is a median "resource potential" estimate of 9.8 billion barrels for the Queen Charlotte Basin. The volumes of gas reported are median "resource potential" estimates of 25.9 Tcf for the Queen Charlotte Basin, 9.4 Tcf for the Tofino Basin, and 6.5 Tcf for the Georgia Basin, totalling to 41.8 Tcf. Proved reserves are nil; just shows to-date.

Organization: CNSOPB (Canada Nova Scotia Offshore Petroleum Board)
What was assessed: Conventional oil and gas resources of offshore Nova Scotia
Methodology and system used to classify: The methodology and classification system is unknown – not contained in the publication. All that was available to us was the spreadsheet, which did not detail either assessment methodology or classification criteria.
Volumes Reported: Oil: 188 MMBO discovered recoverable 2.36 BBO risked undiscovered recoverable Gas: 6.5 Tcf discovered recoverable 29 Tcf risked undiscovered recoverable (Includes 44.5 MMBO produced oil and 1.32 Tcf produced gas)

Organization: CNLOPB (Canada Newfoundland and Labrador Offshore Petroleum Board)
What was assessed: Oil, including NGLs, and gas volumes offshore Newfoundland, Canada (Grand Banks and Labrador Shelf). Some of the notable discovered accumulations include Hibernia, Hebron, Terra Nova, and White Rose fields.
Methodology and system used to classify: It is unclear what classification system was used. The volumes are described as a

combination of Reserves and Resources with the following characteristics: 'reserves' are defined as volumes of hydrocarbons proven by drilling, testing and interpreting geological, geophysical and engineering data, and that are considered to be recoverable using current technology and under present and anticipated economic conditions. "Resources" are volumes of hydrocarbons, expressed at 50% probability of occurrence, assessed to be technically recoverable, and that have not been delineated and have unknown economic viability. The report references economic analysis based on volumes developed using the criteria above, but an example of the actual methodology is not given.
In addition to the comments above this is essentially an Annual Report (2008-2009) and as is common with annual reports of Regulatory Boards, provides little description of evaluation methodologies, as the primary focus is regulatory communication, which is not necessarily focused on the technical description of analytical methods. The main role of the Board in this case is to interpret provisions of the Atlantic Accord and oversee Operator compliance.

Volumes reported:
1.818 BBO
478 MMBO NGLs
10,850 BCF gas
All characterized as remaining resources.

Organization: CAPP (Canadian Association of Petroleum Producers)

What was assessed:
Conventional oil and oil sands (bitumen and upgraded crude oil) located in both the Atlantic and Western Canada.

Methodology and system used to classify:
The reported produced volumes are included in the two accompanying worksheets (below). The first, called "Operating and In Construction" reports volumes only from projects that are currently producing or in construction. The "Growth Forecast" includes these volumes plus expected production from new projects. Both of these cases forecast oil production from 2010 to 2025 in thousands of barrels per day.
The primary basis of this production forecast is a survey conducted each year of all oil sands producers. Estimates based on publicly available information were used to include oil sands projects by non-members which the survey did not cover. From these data, adjustments are made to the startup date and production profile for each project or expansion phase, as necessary. The forecasted year over year growth took into account the availability of capital and labor and the experience of the project operators. Producers were requested to use their own expectations for future crude oil prices in determining the production profile from their projects. With regard to conventional production, a production forecast was generated based on internal analyses and a series of informal discussions with various provincial government departments and agencies.

Volumes reported:
Operating and In Construction:

APPENDIX B.2

CAPP Canadian Crude Oil Production Forecast 2010 – 2025

Operating & In Construction
June 2010

thousand barrels per day	Actuals					Forecast															
CONVENTIONAL	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Light & Medium																					
Alberta	374	360	347	347	316	304	294	284	276	268	260	252	245	237	230	225	221	217	212	208	204
B.C.	30	29	26	23	22	20	19	18	17	16	16	15	14	13	13	12	11	11	10	10	9
Saskatchewan [1,2]	148	155	162	183	184	185	185	185	185	185	181	177	174	169	164	158	154	149	145	140	135
Manitoba	14	19	22	23	26	27	27	27	26	26	25	25	24	24	23	23	22	22	21	21	21
N.W.T.	19	19	18	16	16	15	14	13	12	12	11	11	10	10	9	9	8	8	7	7	7
Total Conv. Light and Medium	**585**	**581**	**575**	**593**	**563**	**550**	**538**	**527**	**517**	**507**	**493**	**479**	**467**	**453**	**439**	**427**	**417**	**407**	**396**	**385**	**375**
Heavy																					
Alberta Conv. Heavy	197	183	178	156	145	138	131	124	118	112	107	101	96	91	87	82	78	74	71	67	64
Saskatchewan Conv. Heavy [1,2]	271	273	264	255	237	228	217	211	208	203	199	195	191	188	184	180	177	173	170	166	163
Total Conventional Heavy	**468**	**456**	**442**	**411**	**382**	**366**	**348**	**335**	**326**	**316**	**306**	**296**	**288**	**279**	**271**	**262**	**255**	**247**	**240**	**233**	**227**
TOTAL CONVENTIONAL	**1,053**	**1,037**	**1,017**	**1,004**	**946**	**916**	**886**	**862**	**843**	**822**	**799**	**775**	**755**	**732**	**710**	**689**	**672**	**654**	**637**	**618**	**602**
PENTANES/CONDENSATE	**160**	**166**	**173**	**169**	**161**	**157**	**154**	**151**	**148**	**145**	**142**	**141**	**140**	**138**	**137**	**135**	**134**	**133**	**131**	**130**	**129**
OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)																					
Oil Sands Mining	534	623	647	610	690	767	856	924	1,015	1,039	1,051	1,063	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068
Oil Sands *In Situ*	439	494	536	584	657	716	793	888	945	984	1,020	1,069	1,070	1,077	1,086	1,079	1,071	1,064	1,055	1,047	1,032
TOTAL OIL SANDS	**972**	**1,117**	**1,183**	**1,193**	**1,348**	**1,483**	**1,650**	**1,812**	**1,959**	**2,024**	**2,071**	**2,131**	**2,137**	**2,144**	**2,153**	**2,147**	**2,138**	**2,131**	**2,122**	**2,114**	**2,100**
WESTERN CANADA OIL PRODUCTION	**2,185**	**2,319**	**2,373**	**2,366**	**2,454**	**2,556**	**2,690**	**2,825**	**2,950**	**2,991**	**3,012**	**3,047**	**3,032**	**3,014**	**3,000**	**2,970**	**2,944**	**2,918**	**2,890**	**2,862**	**2,830**
ATLANTIC CANADA OIL PRODUCTION	**304**	**304**	**369**	**342**	**268**	**250**	**265**	**240**	**220**	**195**	**190**	**175**	**225**	**255**	**225**	**190**	**190**	**180**	**170**	**155**	**145**
TOTAL CANADIAN OIL PRODUCTION	**2,489**	**2,623**	**2,742**	**2,709**	**2,722**	**2,806**	**2,955**	**3,065**	**3,170**	**3,186**	**3,202**	**3,222**	**3,257**	**3,269**	**3,225**	**3,160**	**3,134**	**3,098**	**3,060**	**3,017**	**2,975**
OIL SANDS RAW BITUMEN**																					
Oil Sands Mining	626	769	784	724	825	912	1,008	1,079	1,172	1,200	1,212	1,223	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228
Oil Sands *In Situ*	439	494	536	584	665	721	805	900	957	997	1,032	1,081	1,083	1,090	1,098	1,092	1,083	1,077	1,067	1,059	1,045
TOTAL OIL SANDS	**1,065**	**1,263**	**1,320**	**1,307**	**1,490**	**1,632**	**1,813**	**1,979**	**2,130**	**2,197**	**2,244**	**2,304**	**2,311**	**2,318**	**2,326**	**2,320**	**2,311**	**2,305**	**2,295**	**2,287**	**2,273**

Notes:

1. *CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.*
2. *CAPP has revised from the June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.*

*** Raw bitumen numbers are highlighted. The oil sands production numbers (as historically published) are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.*

Table 2.1 Canadian Crude Oil Production

million b/d	2009	2015	2020	2025
Growth	2.72	3.29	3.88	4.34
Operating & In Construction	2.72	3.20	3.16	2.98

<u>Growth Forecast:</u>

APPENDIX B.1

CAPP Canadian Crude Oil Production Forecast 2010 – 2025

Growth
June 2010

thousand barrels per day — *Actuals* (2005–2009) — *Forecast* (2010–2025)

CONVENTIONAL	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Light & Medium																					
Alberta	374	360	347	347	316	304	294	284	276	268	260	252	245	237	230	225	221	217	212	208	204
B.C.	30	29	26	23	22	20	19	18	17	16	16	15	14	13	13	12	11	11	10	10	9
Saskatchewan [1,2]	148	155	162	183	184	185	185	185	185	185	181	177	174	169	164	158	154	149	145	140	135
Manitoba	14	19	22	23	26	27	27	27	26	26	25	25	24	24	23	23	22	22	21	21	21
N.W.T.	19	19	18	16	16	15	14	13	12	12	11	11	10	10	9	9	8	8	7	7	7
Total Conv. Light and Medium	**585**	**581**	**575**	**593**	**563**	**550**	**538**	**527**	**517**	**507**	**493**	**479**	**467**	**453**	**439**	**427**	**417**	**407**	**396**	**385**	**375**
Heavy																					
Alberta Conv. Heavy	197	183	178	156	145	138	131	124	118	112	107	101	96	91	87	82	78	74	71	67	64
Saskatchewan Conv. Heavy [1,2]	271	273	264	255	237	228	217	211	208	203	199	195	191	188	184	180	177	173	170	166	163
Total Conventional Heavy	**468**	**456**	**442**	**411**	**382**	**366**	**348**	**335**	**326**	**316**	**306**	**296**	**288**	**279**	**271**	**262**	**255**	**247**	**240**	**233**	**227**
TOTAL CONVENTIONAL	**1,053**	**1,037**	**1,017**	**1,004**	**946**	**916**	**886**	**862**	**843**	**822**	**799**	**775**	**755**	**732**	**710**	**689**	**672**	**654**	**637**	**618**	**602**
PENTANES/CONDENSATE	**160**	**166**	**173**	**169**	**161**	**157**	**154**	**151**	**148**	**145**	**142**	**141**	**140**	**138**	**137**	**135**	**134**	**133**	**131**	**130**	**129**
OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)																					
Oil Sands Mining	534	623	647	610	690	767	856	924	1,015	1,043	1,056	1,070	1,079	1,111	1,159	1,229	1,277	1,327	1,436	1,514	1,529
Oil Sands *In Situ*	439	494	536	584	657	716	793	888	952	1,022	1,106	1,221	1,311	1,442	1,551	1,640	1,724	1,772	1,830	1,891	1,931
TOTAL OIL SANDS	**972**	**1,117**	**1,183**	**1,193**	**1,348**	**1,483**	**1,650**	**1,813**	**1,966**	**2,064**	**2,162**	**2,291**	**2,390**	**2,553**	**2,710**	**2,868**	**3,000**	**3,099**	**3,266**	**3,405**	**3,461**
WESTERN CANADA OIL PRODUCTION	**2,185**	**2,319**	**2,373**	**2,366**	**2,454**	**2,556**	**2,690**	**2,826**	**2,957**	**3,032**	**3,104**	**3,207**	**3,284**	**3,422**	**3,556**	**3,692**	**3,806**	**3,886**	**4,034**	**4,153**	**4,191**
ATLANTIC CANADA OIL PRODUCTION	**304**	**304**	**369**	**342**	**268**	**250**	**265**	**240**	**220**	**195**	**190**	**175**	**225**	**255**	**225**	**190**	**190**	**180**	**170**	**155**	**145**
TOTAL CANADIAN OIL PRODUCTION	**2,489**	**2,623**	**2,742**	**2,709**	**2,722**	**2,806**	**2,955**	**3,066**	**3,177**	**3,227**	**3,294**	**3,382**	**3,509**	**3,677**	**3,781**	**3,882**	**3,996**	**4,066**	**4,204**	**4,308**	**4,336**
OIL SANDS RAW BITUMEN**																					
Oil Sands Mining	626	769	784	724	825	912	1,008	1,079	1,172	1,204	1,217	1,233	1,287	1,373	1,436	1,518	1,572	1,626	1,735	1,814	1,830
Oil Sands *In Situ*	439	494	536	584	665	721	805	901	964	1,034	1,119	1,235	1,328	1,461	1,574	1,665	1,750	1,798	1,857	1,918	1,958
TOTAL OIL SANDS	**1,065**	**1,263**	**1,320**	**1,307**	**1,490**	**1,632**	**1,813**	**1,980**	**2,137**	**2,238**	**2,336**	**2,468**	**2,615**	**2,834**	**3,010**	**3,183**	**3,322**	**3,424**	**3,592**	**3,732**	**3,788**

Notes:

1. *CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.*
2. *CAPP has revised from the June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.*

*** Raw bitumen numbers are highlighted. The oil sands production numbers (as historically published) are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.*

Table 2.1 Canadian Crude Oil Production

million b/d	2009	2015	2020	2025
Growth	2.72	3.29	3.88	4.34
Operating & In Construction	2.72	3.20	3.16	2.98

Organization: Alberta's Energy Utilization Board Report 2005-A, Alberta's Ultimate Potential for Conventional Natural Gas	

What was assessed:

The assessed product is conventional natural gas located in Alberta (Western Canadian Sedimentary Basin). This gas is from clastic and carbonate reservoirs where recovery is possible and is based on technological improvements and prices that can be reasonably anticipated.

Methodology and system used to classify:

Gas in place is the volume of gas in the reservoir, *recoverable gas* is the volume that can be produced, and *marketable gas* is the volume that remains after processing. Although this report focuses on gas in place (GIP), it also includes estimates of recoverable and marketable gas using parameters from existing pools. Gas that has been produced and estimates of gas yet to be produced are also shown. *Remaining gas* (ultimate potential minus cumulative production) represents the volume available to meet future market demands.

Terminology summary:

<table>
<tr><th colspan="4">Terms</th><th>Level of Uncertainty</th></tr>
<tr><td rowspan="4">Ultimate Potential</td><td rowspan="2">Undiscovered</td><td colspan="2">Future</td><td rowspan="2">High
↑
Medium</td></tr>
<tr><td colspan="2">Unbooked/Unconfirmed/Bypassed</td></tr>
<tr><td rowspan="2">Discovered</td><td rowspan="2">Booked</td><td>Reserves</td><td>Low</td></tr>
<tr><td>Cumulative Production</td><td>None</td></tr>
</table>

For the purpose of this report, the term *ultimate potential* refers to an estimate of the volume of marketable gas reserves that will be proven to exist in a geological basin or in a specific area after exploration has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. At any point in time, ultimate potential is the sum of resources that have been discovered and resources that are still undiscovered. Discovered resources have been confirmed by wells drilled, while undiscovered resources are expected to be discovered by future drilling.

The study uses data (tops, well tests, etc) from 320,000 wells drilled by December 2004. Forty-two stratigraphic intervals were identified and each was divided into one to nine play areas. These were then further divided into single sections (256 hectares). Thus, a play area tract is a 3D cell that is 256 hectares in area and one stratigraphic interval in thickness. Each tract was assigned a designation as booked, unbooked, unconfirmed, bypassed, drilled, no potential, or future in a hierarchical fashion. The data from these tracts were used to generate maps, summaries, graphs, and statistical analyses which were, in turn, used to estimate GIP and marketable gas by play area. The methodology was developed and implemented by a collaborative team. A number of companies that are actively exploring in the foothills area were consulted, as were staff in other governmental agencies. Several external peer reviews were also held. While the report does not provide sufficient detail to rigorously check the methodology, the involvement of multiple individuals and agencies provides a measure of confidence.

Volumes reported:
The reported volumes are included in the following "Resources Summary" worksheet. The volumes are reported as marketable conventional natural gas in units of Billions of Cubic Meters and Trillions of Cubic Feet at standard conditions. Volumes are shown with no adjustment for heating values.

Table A. Alberta's ultimate potential for marketable conventional natural gas

	Gas in place		Marketable gas	
Case	10^9 m^3	Tcf	10^9 m^3	Tcf
Low	9731	345	5765	205
Medium	10583	376	6276	223
High	12012	426	7134	253

Table B shows a breakdown of ultimate potential for natural gas into its components as of early December 2004 (production to end of October 2004).

Table B. Categorization of ultimate potential—medium case

	Gas in place		Marketable gas	
Category	10^9 m^3	Tcf	10^9 m^3	Tcf
Discovered	7744	275	4542	161
Cumulative production	5863	208	3438	122
Remaining discovered	1882	67	1104	39
Undiscovered	2838	101	1734	62
Ultimate potential	10583	376	6276	223
Remaining ultimate potential	4720	168	2838	101

The best estimate of "ultimate potential for marketable conventional natural gas" is 6276 billion cubic meters.
The remaining ultimate potential of "marketable conventional natural gas" is 2838 billion cubic meters.

Organization: U.S. Geological Survey

What was assessed: Technically recoverable gas resources from natural gas hydrates on the North Slope of Alaska

Methodology and system used to classify: For the first time, the USGS assessed gas hydrates as a producible resource occurring in discrete hydrocarbon traps and structures. The approach used followed standard geology-based USGS assessment methodologies developed to assess conventional oil and gas resources (described above). Analysis of 3-D seismic data was used to delineate limited, discrete volumes of

rock bounded by faults and downdip water contacts. The USGS conventional assessment approach also assumes that the hydrocarbon resource being assessed can be produced by existing conventional technology. The production potential of known and seismically inferred gas hydrate accumulations in northern Alaska still needs additional field testing, but limited field testing and numerical production models of these reservoirs suggest that gas can be produced from gas hydrate with existing conventional technology, with depressurization being the most promising method.
Volumes reported: 85 trillion cubic feet of technically recoverable gas within gas hydrates in northern Alaska Total undiscovered resources in three total petroleum systems: F95 – 25,233 bcfg F50 – 81,030 bcfg F5 – 157,831 bcfg Mean – 85,427 bcfg

Organization: USGS
What was assessed: In-place estimates of the potential liquid hydrocarbons produced from the oil shale for the Piceance and Uinta Basins. (An assessment of the Greater Green River Basin is imminent)
Methodology and system used to classify: The assessed products are liquid hydrocarbons produced by heating oil shale to 500° C and holding it there for 40 minutes while volatiles pyrolytically generated from the oil shale's kerogen are released as vapor and then condensed for measurement (the Fisher assay procedure), as estimated on an in-place basis for the Eocene Green River Formation located in the Uinta and Piceance basins. A cutoff depth of 6,000 feet was applied in the Uinta Basin. The classic ore body assessment method was applied, substituting data on pyrolytic yield per ton of oil shale for ore grade and multiplying by the estimated oil shale tonnage to yield an in-place liquid hydrocarbon estimate. Spatial variation of these factors was dealt with using GIS software and a deterministic spatial interpolation method (radial basis function) to generate isopach and isoresource models, the spatial statistics of which could be computed in the GIS using a zonal statistics function to yield the volumetric estimates. A strong statistical relationship between weighted-average liquids yield in gallons per ton for each zone was used to convert the borehole yield data to barrels per acre.
Volumes reported: The estimated in-place volumes of liquid hydrocarbons are: 2.85 trillion barrels – 1.32 trillion barrels in the Uinta Basin 1.53 trillion barrels in the Piceance Basin.

Organization: ERBC (Alberta Energy Resources Conservation Board)

What was assessed:

Bitumen, crude oil, and natural gas; not clear if the NGLs are captured with the crude oil, but assumed to be so.

Methodology and system used to classify:

Note that the original recoverable conventional crude oil volumes are based on the 1988 ERCB study, and have not been changed. The classification system that was used consists of estimates of initial established reserves (recoverable quantities estimated to be in the ground before any production), remaining established reserves (recoverable quantities known to be left), and ultimate potential (recoverable quantities that have already been discovered plus those that have yet to be discovered).

The method that was applied included the use of specific evaluation methodologies for each product type. It is not clear if volumes quoted are stochastically derived, or are from deterministic/empirical calculation. Also, it is not clear if summation included aggregation considerations. References are made to prior reports regarding such items as petrophysical parameters, reservoir data, cutoffs and Recovery Factor for some of the product types, and it is expected that calculation methodologies are well documented, although these additional data sources were not reviewed for the purpose of evaluating this report.

Volumes reported:

Reserves and Production Summary, 2009

	Crude bitumen		Crude oil		Natural gas[a]	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)
Initial in place	286,627	1,804	10, 851	68.3	9,308	330
Initial established	28,092	177	2,795	17.6	5,221	185
Cumulative production	1,099	6.9	2,567	16.2	4,101	146
Remaining established	26,992	170	228	1.4	1120[b]	39.8[b]
Annual production	86.4	0.544	26.8	0.169	123	4.4
Ultimate potential (recoverable)	50,000	315	3,130	19.7	6276[c]	223[c]

[a] Expressed as "as is" gas, except for annual production, which is at 37.4 Mj/m$^{3.}$ Includes unconventional natural gas.

[b] Measured at field gate (or 36.4 trillion cubic feet downstream of straddle plant).

[c] Does not include CBM.

[d] Annual Production is marketable.

Organization: NARUC (National Association of Regulatory Utility Commissioners)

What was assessed:

U.S. onshore and offshore oil and gas in both moratoria and non moratoria areas. But exactly what is covered is unclear because resources are not defined. Much of the work was based on studies using undiscovered technically recoverable resources, but it would not be reasonable to define these resource estimates by the same definition.

Methodology and system used to classify: The methodology can be characterized as not robust to any statistical forecasting techniques or reservoir modeling or even geologic based assessments. The volumetric assessment rationale is unknown, specifically it has not been compared to other sources or methodologies. This work was focused primarily on assessing the possible economic, socio-economic, and environmental impacts of possible moratorium severity and duration. It would be unfair to describe this work as a resource assessment as that portion of the research was not intended to be rigorous, but rather a necessary first step to answer other research questions. This report uses Gas Technology Institute numbers as its base. To the base case, the OCS additional resource is increased based on new technology being developed for deep water resources (greater than 5000 feet); onshore gas resources are increased based on technology development and geologic understanding of the gas shale resource; Alaska is increased in oil for ANWR.
Volumes reported: GTI base case: Oil – 229 Bbo Gas – 2,034 Tcf PLUS: OCS Adds – 154 Tcf of gas 37 Bbo of oil Onshore Lower-48 Adds – 122 Tcf of gas Onshore Alaska Adds – 10 Tcf of gas 6 Bbo of oil

Organization: Advanced Resources International Game Changer CO_2
What was assessed: Oil volumes in the U.S., including Alaska, extrapolated from studies performed on select areas in California, Gulf Coast, Illinois, Alaska, Oklahoma and Louisiana Offshore (shelf), associated with discovered/known accumulations.
Methodology and system used to classify: The classification system that was used in this DOE-sponsored report is unclear. The method that was applied included the use of a technical and economic evaluation of the processes currently employed for CO_2 (enhanced oil recovery (EOR)), extrapolated to the application of then-untested CO_2 technologies (some of which have been subsequently tested ex: high rate CO2 injection and closer well spacing).The methodology can be characterized as an extrapolation of successful CO_2 pilots/field applications to higher volume CO_2 projects, based on original test results. The methodology is based on successful laboratory and pilot trials, scaled up using reservoir simulation (PROPHET stream tube simulator) and other analytic techniques, though additional R&D work would be necessary to validate some of the processes.
The volumes of oil reported are 83.7 BBO (2006) technically recoverable for the above areas, extrapolated to total domestic technical recovery of 160 BBO (2006). This is double the amount estimated to be recoverable from application of existing CO_2

technologies (based on the February 2006 DOE Report "U.S. Department of Energy/Fossil Energy: "Undeveloped Oil Resources: The Foundation for Increased Oil Production and a Viable Domestic Oil Industry"). The ARI report goes on to assume economic recovery of half these volumes with an oil price of $40. The report also estimates that similar CO_2 application would provide 380 BBO (including primary and secondary) from undiscovered accumulations (source of undiscovered accumulation volume estimate unknown).

Organization: ARI 2010 update of above
What was assessed: Oil volumes in U.S., including Alaska, extrapolated from studies performed on select areas of California, Gulf Coast, Illinois/Michigan, Mid-continent, Permian, Rockies, East/Central Texas, Williston, Appalachia, Alaska and Louisiana Offshore (shelf), associated with discovered/known accumulations.
Methodology and system used to classify: The classification system that was used in this DOE-sponsored report is unclear. The method that was applied included the use of a technical and economic evaluation of the processes currently employed for CO_2 injection, extrapolated to the application of "Next Generation" CO_2 technologies. "Next Generation" in this assessment, assumes technology characteristics used in previous DOE/NETL studies. Specifically, it assumes: (1) Increasing the volume of CO_2 injected into the oil reservoir; (2) optimizing well design and placement, including adding infill wells, to achieve increased contact between the injected CO_2 and the oil reservoir; (3) improving the mobility ratio between the injected CO_2/water and the residual oil; and, (4) extending the miscibility range, thus helping more reservoirs achieve higher oil recovery efficiency. The models used to develop the production volumes included National Energy Market Model (NEMS) runs by the Natural Resources Defense Council (NRDC) and the Energy Information Administration (EIA). In addition, NRDC modeled carbon capture and storage deployment and CO_2-EOR production at the aggregate national level in MARKAL (acronym for MARKet ALlocation).
Volumes reported: The volumes of oil reported are 84.8 BBO (2010) technically recoverable, 48.0 BBO economically recoverable, for the above areas using current CO_2 Best Practices, which increases to 119 BBO technically recoverable, 66.0 BBO economically recoverable, if "Next Generation " CO_2 processes are employed. The report goes on to assume economic recovery at $70/BBl and a CO_2 cost of $2.38/mcf.

1.5 Study Observations

Resource estimates for North America span the spectrum of resources and reserves. There are many differences among them, but there are often good reasons for those differences (e.g., different purposes). These differences can result from several factors such as use of different methodologies, inclusion versus exclusion of reserves growth, inclusion of only selected basins or reservoirs, inclusion of different types of hydrocarbons (crude oil only vs all liquids, for example), variations in *technologic and economic assumptions (e.g., including current technology vs assuming future advances in exploration and completion technology), and differing minimum field sizes.*

Resource assessments are conducted by government agencies, the private sector, academic, and professional organizations in the U.S. and Canada (Mexico is covered in another section of the NPC report). Only the government agencies provide a comprehensive set of assessments, covering oil and gas, onshore and offshore, conventional and unconventional, and so on

Significant uncertainties are inherent in resource estimation. The best-constructed methodologies directly address the resulting estimates' principal uncertainties, and transparency regarding the assessment methodology and assumptions underlying the estimates is critical for users to understand exactly what they represent.

A better understanding of reserves growth is required for all types of oil and gas resources, especially those that are newly emergent.

Small changes in recovery efficiency (percentage of oil in place that will ultimately be produced), individually and cumulatively, will continue to have a significant impact on the size of technically and economically recoverable resources. Present and future R&D could also result in additional production from old fields.

Mature onshore areas in the U.S. and Canada have some, but limited, conventional opportunities. CO_2 EOR, assuming anthropogenic sources are available, has the potential for substantial additional oil production. Offshore North America conventional resources still have significant potential, especially the Gulf of Mexico. There is potential, as well, offshore Atlantic and Pacific. The Arctic holds very large potential, undiscovered resources.

The role of unconventional resources in the North American energy budget will continue to grow and have a significant impact. Onshore unconventional resources, in particular, will be very important, Shale gas, Canadian oil sands, tight gas, tight oil, gas hydrates, and possibly oil shale are expected to provide further resources for additions to reserves.

While unconventional resources, especially shale gas, might be significant contributors to U.S. production, it should be recognized that currently these are expensive resources to produce, and there needs to be an appropriate balance between environmental impact and production of these resources.

There are many unknowns regarding unconventional, offshore, and Arctic sources, and additional data and information are required to make informed policy and commercial decisions about these potential resources.

1.6 References

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