

# Incorporating International Petroleum Reserves and Resource Estimates into Projections of Production

U.S. Energy Information Administration

June 7, 2011

*This paper is released to encourage discussion and critical comment. The analysis and conclusions expressed here are those of the authors and not necessarily those of the U. S. Energy Information Administration.*

---

Authors: Lauren Mayne and John Staub

Direct all questions to John Staub, [john.staub@eia.gov](mailto:john.staub@eia.gov), (202) 586-6344

Disclaimer: Views not necessarily those of the U.S. Energy Information Administration

## ***Introduction***

The Energy Information Administration (EIA) receives periodic requests for our assessment of international oil reserves estimates and explanations of how our long-term oil production projections link to them. EIA recognizes the need for reliable international reserves estimates that reflect a uniform application of consistent standards for reserves reporting. Unfortunately, the diversity and complexity of the existing reserves estimates and varied application of reporting standards across countries present significant barriers to meaningful representation of international reserves estimates. Because existing reserves estimates and their associated terminology can be quite confusing, EIA strives to ensure that its long-term oil production projections are supported by careful assessment of the best reserves – and resource – information available to us.

Analyses of specific oil field production profiles and decline rates – and related graphical representations of future production from different distinct resource categories – have been developed by other organizations using energy data and analytical resources of the company IHS. EIA periodically purchases access to the IHS database to update our near-term projections and resource assumptions, but budget limitations preclude buying continuous access and we do not currently have an active subscription. Given the 25-year horizon of EIA’s oil production and consumption scenarios, the reserves data and projections available from such sources must also be supplemented with estimates of geologically expected resources that are not directly associated with discovered fields. Provision must also be made for future technological advancement leading to enhanced resource accessibility.

The following discussion provides information on our assessment methodology, comparable long-term outlooks’ approaches to resource uncertainties, production decline rates, resource terminology, and the available estimates.

## ***EIA’s Assessment Approach***

The future of world oil supply and demand is inherently uncertain. Recognizing that a multitude of different oil market conditions are possible in both the near and distant future, EIA develops a variety of projection scenarios covering a wide range of possible future market balances and supply and demand environments. While we don’t label any one of our cases as “most likely” or “most accurate,” we do ensure that each case is internally consistent and supported by oil resource estimates. EIA’s sources and use of oil resource estimates are similar to that of several well-respected and comparable efforts,

including long-term projections developed by IHS Cambridge Energy Research Associates (CERA) and the International Energy Agency (IEA).

EIA's, CERA's and IEA's projections all recognize that some resources that have yet to be discovered and/or classified as proved reserves will be developed and brought online to satisfy a significant portion of future oil demand, especially during the latter part of a 20- to 25-year projection period. Existing producing fields and known projects under development together provide the inventory of productive capacity from which world oil markets will be primarily supplied in the near term. Known projects alone provide a measure of current development activity and investment by producers. Long-term projections incorporate the understanding that producers will continue to identify and develop as-yet unknown fields and pursue additions to reserves through exploration of new basins and types of resources, extensions of existing fields, and the application of improved or new technology to increase recovery factors in mature areas.

EIA reviews known projects and their completion status to develop a fairly detailed view of the production capacity that will be available to supply oil over the near-term – roughly the next three to five years. Major upstream oil investment projects typically take several years to plan and execute, with a gestation period ranging from three years to ten years or more. However, we do not limit our projections of oil supply over a longer period of time to currently known resources or projects, since future projects that are as yet unknown will also contribute to supply. Production projections over a longer time interval must be based on an assessment of estimated resources, field production profiles and declines, supply economics, anticipated product demand, and investment conditions in each country where oil resources are located. The methodology that underlies our long-term international liquids production projections is summarized in the section entitled “Liquids production modeling approach” on pages 27-29 of the *International Energy Outlook 2010 (IEO2010)* (see the attached documents at the end of this discussion paper).

At EIA's April 2009 annual energy conference, EIA hosted a roundtable discussion of future oil production focused on “known but yet to be developed” and “yet to be found” resources. One of the charts presented (**Figure 1**) showed future production from existing projects and known projects under development, which together must be relied upon for most near-term production. While the chart deliberately omitted EIA's projections of additional projects and investments needed to meet demand in each of our projection cases over a longer time horizon, in order to allow the conference panel to openly discuss multiple scenarios and possibilities, this should not be misconstrued as suggesting that the consumption path depicted in the chart is infeasible or unsupported by economic resources. The white area labeled “Unidentified Projects” (located between future production from existing and identified supply projects and the projected consumption of liquids) reflects resources converted to production in EIA's *Annual Energy*

*Outlook 2009 (AEO2009)* Reference case that are referred to as “known but yet to be developed” and “yet to be found” resources in the IEA’s “*World Energy Outlook 2010 (WEO2010)*” (**Figure 2**) and as “fields under appraisal” and “yet to find resources” in CERA’s long-term outlook.

Focusing on the first three to five years of the “World’s Liquid Fuel Supply” graph in “Announced Projects Typically Meet Majority of Production Replacement and Growth Needs During Next Three Years” (**Figure 3**), the yellow and red areas represent expected future production volumes derived from projects that are known to be planned or under development. The known projects do not include all planned projects because many mid-size and small projects are not mentioned in the news or trade press. The gaps between the shaded areas and the three AEO2009 price case demand lines represent the volumes of oil production that would need to be provided by presently unknown, perhaps presently unplanned, projects or fields yet to be found. Over time the gaps are typically filled in as additional information becomes public. Sometimes a gap is even temporarily “over filled” as production exceeds consumption and the resulting excess production is put into storage. The gap does not represent an expected production shortfall, rather it logically reflects lack of firm information about the future because investment decisions are less certain and more flexible the further out in the future they are.

In the *IEO2010*, “World Liquids Production” (**Figure 4**) depicts the source regions of liquids production that we expect will satisfy demand in the Reference Case. Because EIA does not currently have an active subscription to the proprietary IHS database of supply projects, an update of the “World’s Liquid Fuels Supply” graphic has not been issued. “Comparing the recent world outlooks from EIA (IEO) and IEA (WEO)” (**Figure 5**) provides an apples-to-apples comparison of three EIA and three IEA scenarios. EIA is precluded from disseminating the relevant CERA projections<sup>1</sup> under the terms of its contract with CERA.

### ***Rate of Decline of Existing Production***

The rate at which existing production is expected to decline is a very significant factor in assessing what volumes of resources will need to be developed in the future to meet projected liquids demand. At any given time some fields are just beginning to produce, some are maintaining their production rates, and others are declining. EIA used a 4.5 percent global annual average decline rate for all fields in the *AEO2009*. This rate was estimated by CERA based on its assessment of IHS data for the production profiles of over

---

<sup>1</sup> IHS CERA, Private Report “Pausing for Breath: Liquids Production Capacity to 2030” Parts 1 and 2, published respectively in October and November 2009, and Special Report “The Future of Global Oil Supply: Understanding the Building Blocks” published in November 2009.

800 of the worlds' oil fields.<sup>2</sup> In ongoing EIA modeling efforts existing projects decline at a rate that is specific to each project.

The need for new projects and their ability to meet demand at a given price are heavily determined by the decline in existing production. As CERA's research indicated, a field's production profile and decline rate are shaped by a variety of factors including "the field size, [physical characteristics of the] reservoir, technology, investment patterns, and government decisions." A change in any one of these factors could change the production profile designed by the company or country governing the field's development. For example, a field's decline can be slowed by application of new production technology, the discovery and development of a new reservoir in the field, or a change in the market that makes further investment in the field economically viable.

Reservoir characteristics are much less likely to drive rapid or dramatic changes in a given field's expected production and decline rate profiles than are so-called "above ground" factors, ranging from economics to technology to politics. Due to the significance these factors have for the world's future oil supply and their exposure to unanticipated changes, no responsible analyst would claim to precisely predict future global oil production. EIA's assessment of future production possibilities are therefore based on scenarios structured on a specified set of aboveground factors from which EIA can develop projections of what resources might be economically developed in a given timeframe, taking account of timelines for development of oil projects as well as supporting infrastructure (e.g. pipeline systems and terminals). Taken together, the scenarios depict a range (although not an all-inclusive one) of possible future world oil markets and country production profiles.

### ***Estimates of Resources and Reserves***

EIA's country-level resource estimates are identical across all scenarios, which are presented as alternative oil price cases with differing resultant demand paths and supply mixes. All of the supply mixes are based on EIA's published proved reserves estimates and the U.S. Geological Survey's (USGS) World Petroleum Assessment 2000 estimate of both undiscovered conventional resources and the growth of known conventional resources.

Unfortunately, the estimation and reporting of resources and reserves (which are a small subset of resources; see the McKelvey classification scheme of **Figure 6**) is far from standardized or transparent internationally. Estimates of resources and reserves are functions of the knowledge of physical quantities originally in place, the availability of technology to convert the in-place resources to producible reserves, the economic

---

<sup>2</sup> CERA's research and findings were published in "Finding the Critical Numbers" in September 2007.

feasibility of producing them, and the uncertainties associated with these factors. All of these factors can and do change over time. Unfortunately, “resources” and “reserves” are often ambiguously or incorrectly used terms. The Society of Petroleum Engineers (SPE) (see attached document SPE 2005, *Comparison of Selected Reserves and Resource Classifications and Associated Definitions*) and Securities and Exchange Commission (SEC) convention for describing confidence in reserves estimates (not yet used internationally by all estimators) is as follows:

- “proved” reserves have the highest probability of eventual production (when properly estimated, a recovery probability of 90 percent or more, often referred to as a P90 or a “1P” estimate)
- “probable” reserves are the next most likely to be producible
- “possible” reserves have the lowest probability of eventual production
- the sum of “proved” + “probable” reserves yields a median, P50 or “2P” estimate of reserves with a recovery probability of 50 percent
- the sum of “proved” + “probable” + “possible” reserves yields a higher volume P10 or “3P” estimate with a recovery probability of 10 percent or less.

It is important to remember that the three reserves classes – proved, probable and possible – encompass “discovered commercial” resources. Reserves are a subset of resources.

“All systems define major resource categories that can be mapped directly to the SPE categories: undiscovered (prospective resources), discovered unrecoverable, discovered sub-commercial (contingent resources) and discovered commercial (reserves).” – SPE 2005, *Comparison of Selected Reserves and Resource Classifications and Associated Definitions*, page 3. (see attached document)

The P90, P50, and P10 terminology applies to estimated volumes at three particular confidence levels distributed along a continuous probability distribution of estimated volumes, whereas the 1P, 2P 3P notation is typically used in business settings when discussing discrete estimates of reserves irrespective of how they were estimated. The McKelvey box diagram developed in the early 1970’s stylistically captures both the geologic certainty and the economic feasibility of oil resources and reserves (**Figure 6**).

EIA is able to construct a rather thorough and well-informed assessment of the United States’ oil resources owing to the resource assessment efforts of the USGS and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), as well as EIA’s own estimation of United States proved reserves. That, however, is not the case outside of U.S. borders. With no universally applicable reporting requirements, the measurement and classification of oil reserves and resources still varies by country, and not all of the world’s reserves are being developed by the publicly-traded companies that

are held to SEC reporting standards. As noted in IEA's *World Energy Outlook 2008* (WEO2008) "there is no internationally agreed benchmark or legal standard as to how much proof is needed to demonstrate the existence of a discovery, nor about the assumptions to be used to determine whether discovered oil can be produced profitably." IEA also noted that progress on developing a set of universal rules is hampered by the different existing standards in each country.

The attached SPE paper addresses the variety of reporting standards internationally as well as SPE's efforts to harmonize and cross reference these standards. The National Petroleum Council's (NPC) 2007 report "Facing the Hard Truths about Energy" (see "Helpful Links" below) provides a further discussion of the variation in reserves reporting standards across countries. While EIA supports efforts to develop a universal system and standardized regulations for reserves reporting, we do not have the resources, access, or mandate to independently verify the resources or reserves reported by other nations. To put the level of effort in context, EIA has about 10 employees dedicated to gathering and analyzing oil and natural gas reserves and resources for the United States--where EIA has authority to require reporting of proved reserves and publicly traded companies are subject to SEC rules. In support of previous research on field reserves growth and recovery, EIA has in the past used IHS's EDIN database on oil and gas fields' reserves reporting history. This database is the only source of information of which we are aware that provides proved, probable, and possible reserves estimates by field for countries outside the United States.

As of 2007, only seven percent of the world's proved reserves were owned by firms subject to SEC reporting requirements, and well over ninety percent of the world's proved reserves were held by countries that limit or prohibit others' access to their resources. That, in turn, impacts the reporting and validation of reserves estimates. Sovereignty issues and secrecy surrounding reserves estimates severely limit the sources available for estimate verification. As more attention is given to the reliability and accuracy of international reserves estimates, it is possible other nations will eventually be more willing to share reserves data with EIA, USGS, and SPE through the Joint Oil Data Initiative (JODI)<sup>3</sup>.

Even the IHS database of historic and current reserves estimates is heavily populated by estimates either taken directly from or derived from government sources (about one-sixth and two-thirds of the estimates, respectively). The IHS database also provides some estimates from field operators (about one-eighth of the estimates) and from

---

<sup>3</sup> JODI is an international effort to improve the availability and reliability of monthly oil production and consumption data. It was conceived by Ministers at the seventh International Energy Forum (April 2001) and launched by six international organizations – Asia-Pacific Economic Cooperation (APEC), Eurostat, IEA, Latin American Energy Organization (OLADE), Organization of the Petroleum Exporting Countries (OPEC) and United Nations Statistics Division (UNSD) – and their member countries.

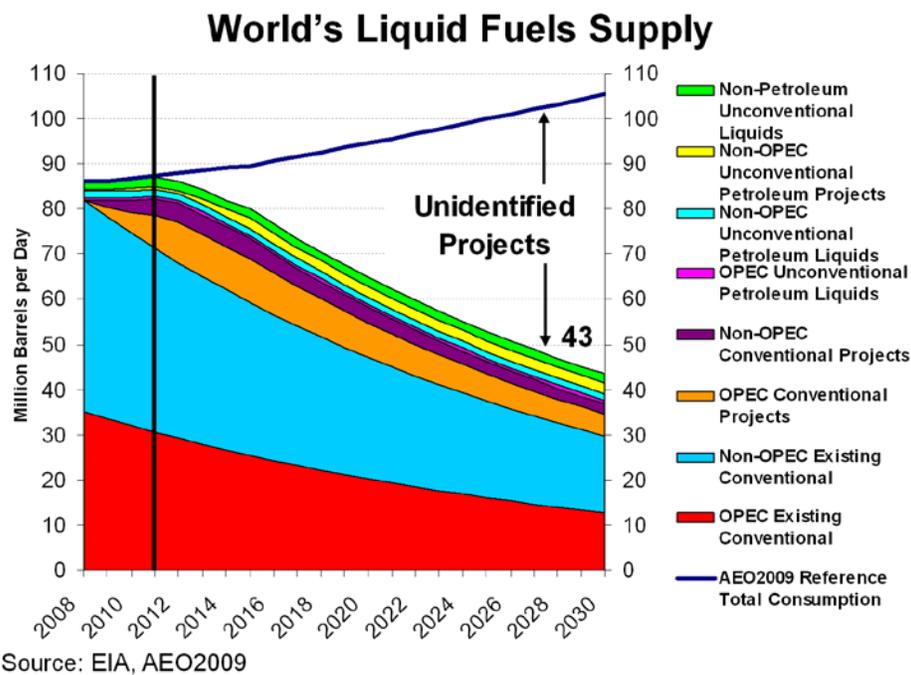
miscellaneous sources (less than one-tenth of the estimates). While the IHS database does not necessarily contain estimates for every field in every country, it does generally have enough field-level information to provide insight on an individual country's reserves estimates.

Notwithstanding its limitations, the USGS relied on the IHS database to support its World Petroleum Assessment 2000 (see "Estimates of Ultimately Recoverable Resources from Conventional Global Oil and Natural Gas Liquids", **Figure 7**). EIA has also used the IHS database to research probable reserves and initial-in-place (IIP) estimates in the past.

IIP is the total of all expected recoverable and unrecoverable resources, sometimes also referred to as original-oil-in-place (OOIP). Current estimates of global IIP range from 14 to 24 trillion barrels. Comparatively, the world has produced about 1.1 trillion barrels of petroleum as of 2010. The smaller IIP estimates often do not include all types of petroleum; for example, source rocks and oil shales are sometimes omitted. The most thoroughly documented IIP estimates point to over 20 trillion barrels of oil. The table of IIP estimates provided (**Figure 8**) is for a base case scenario with the data divided into six categories of petroleum and four regions. What portion of the remaining 14 to 24 trillion barrels of IIP petroleum will be produced in the future will depend on technology, economics and policy.

**Cited Figures**

**Figure 1**

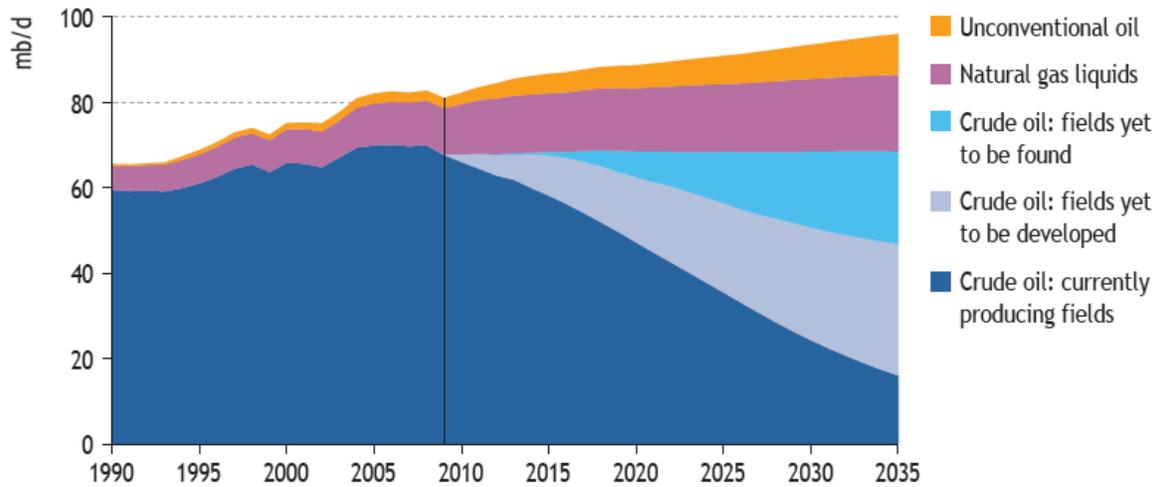


8

(Source: EIA Energy Conference, April 7, 2009)

Figure 2

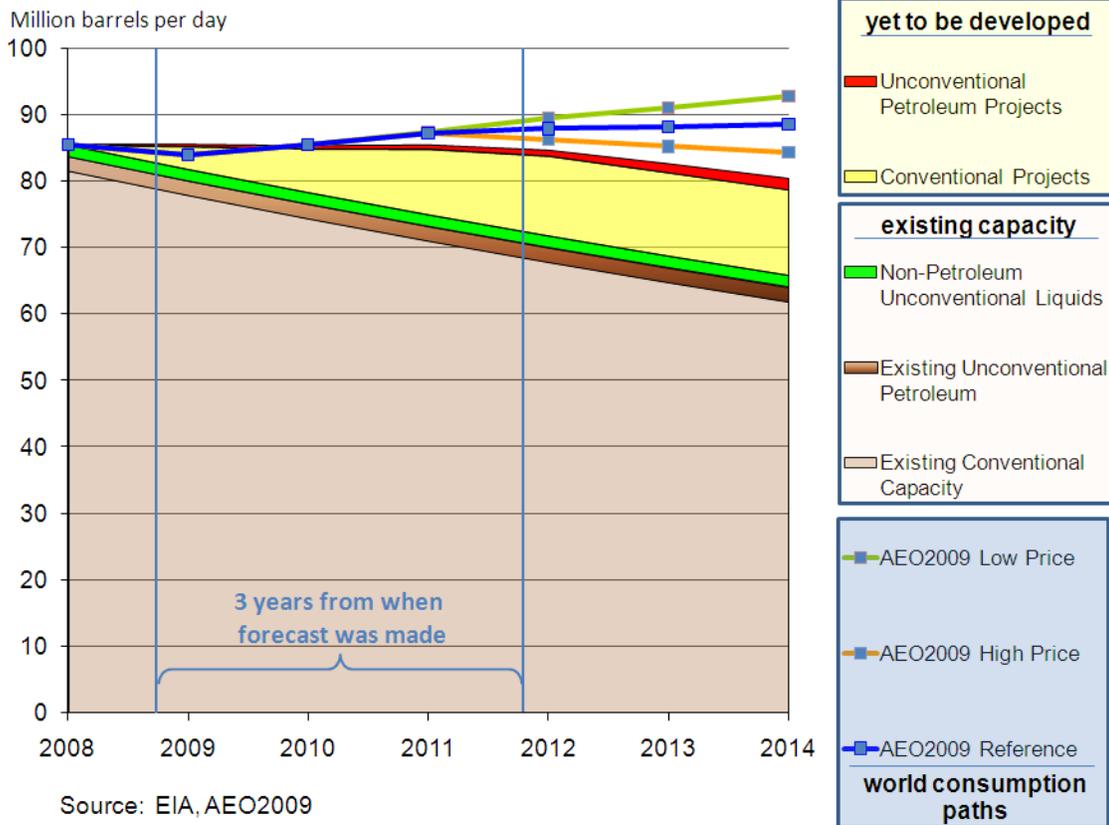
**Figure 3.19 • World oil production by type in the New Policies Scenario**



(Source: IEA World Energy Outlook 2010, page 122, Figure 3.19)

Figure 3

Announced projects (yellow and red areas) typically meet majority of production replacement and growth needs during next three years

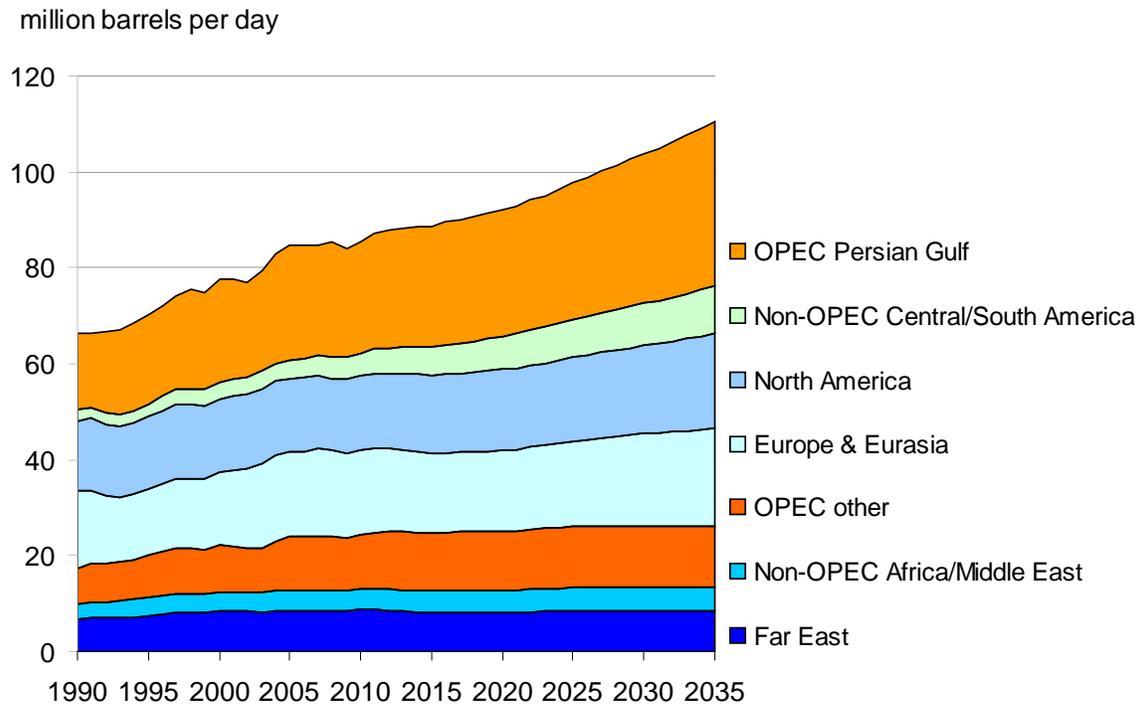


Notes:

- This analysis was done in late 2008 / early 2009 for the AEO2009. It shows that as of October 1, 2008 announced projects were expected to meet almost all replacement and new production volumes for the following three years through September 2011.
- Brown areas show petroleum production capacity declining at 4.5 percent
- Green area is non petroleum production (not changing here)
- **YELLOW** area shows announced projects as scheduled to come online
- **RED** area is for unconventional productions (oil sands mainly)
- LINES = world demand trajectories
- Area between RED area and the three AEO2009 world consumption paths include smaller projects not tracked (because of limited data) and projects not yet identified.

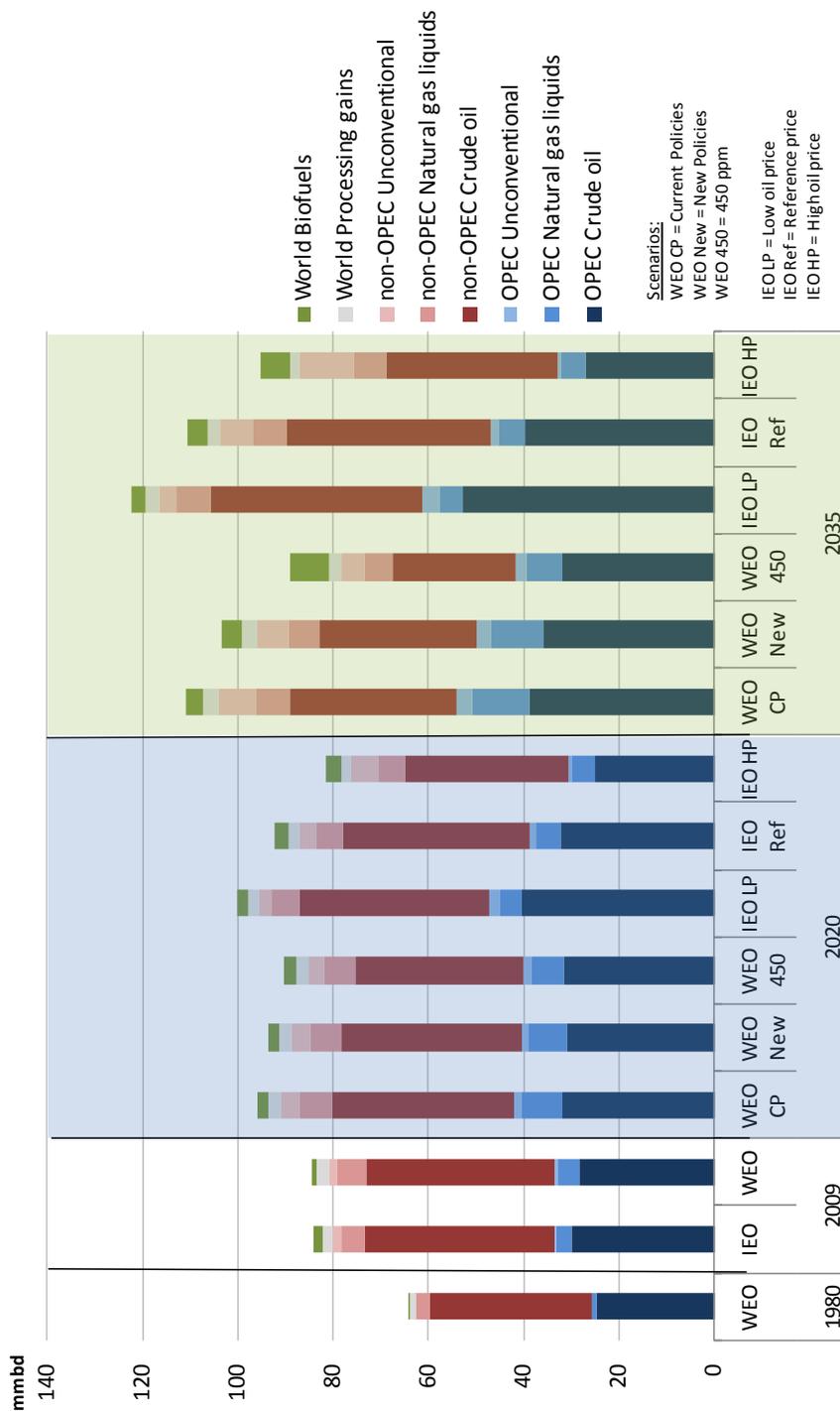
Figure 4

### World liquids production



Source: EIA IEO 2010 (July 2010)

**Figure 5**  
**Comparing the recent world outlooks from EIA (IEO) and IEA (WEO)**



Sources: WEO2010 table 3.3 and IEO2010

Figure 6

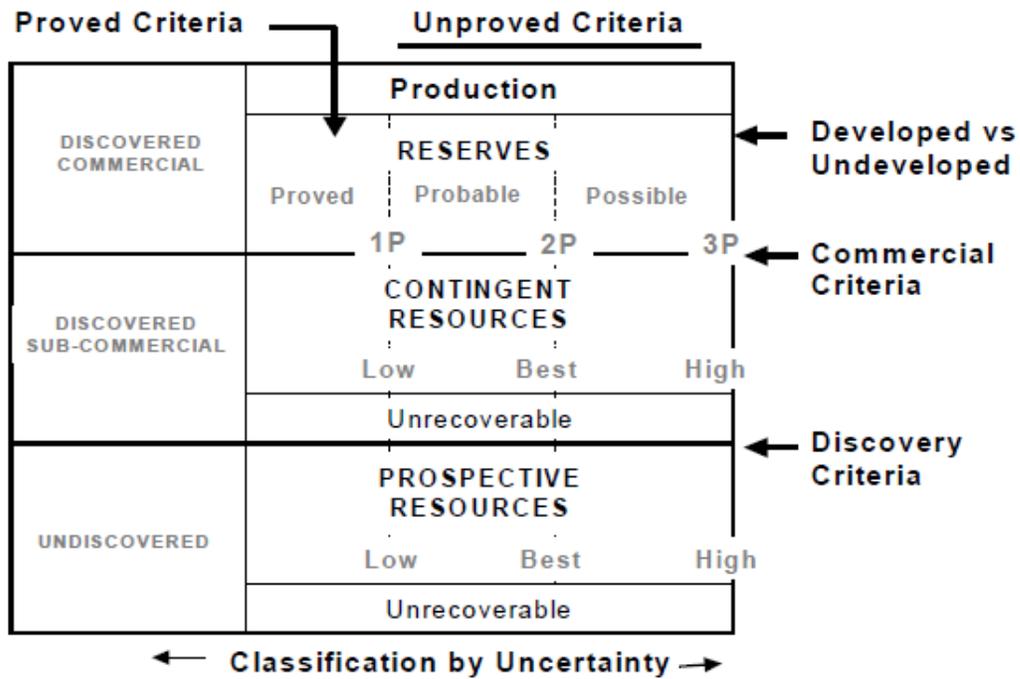
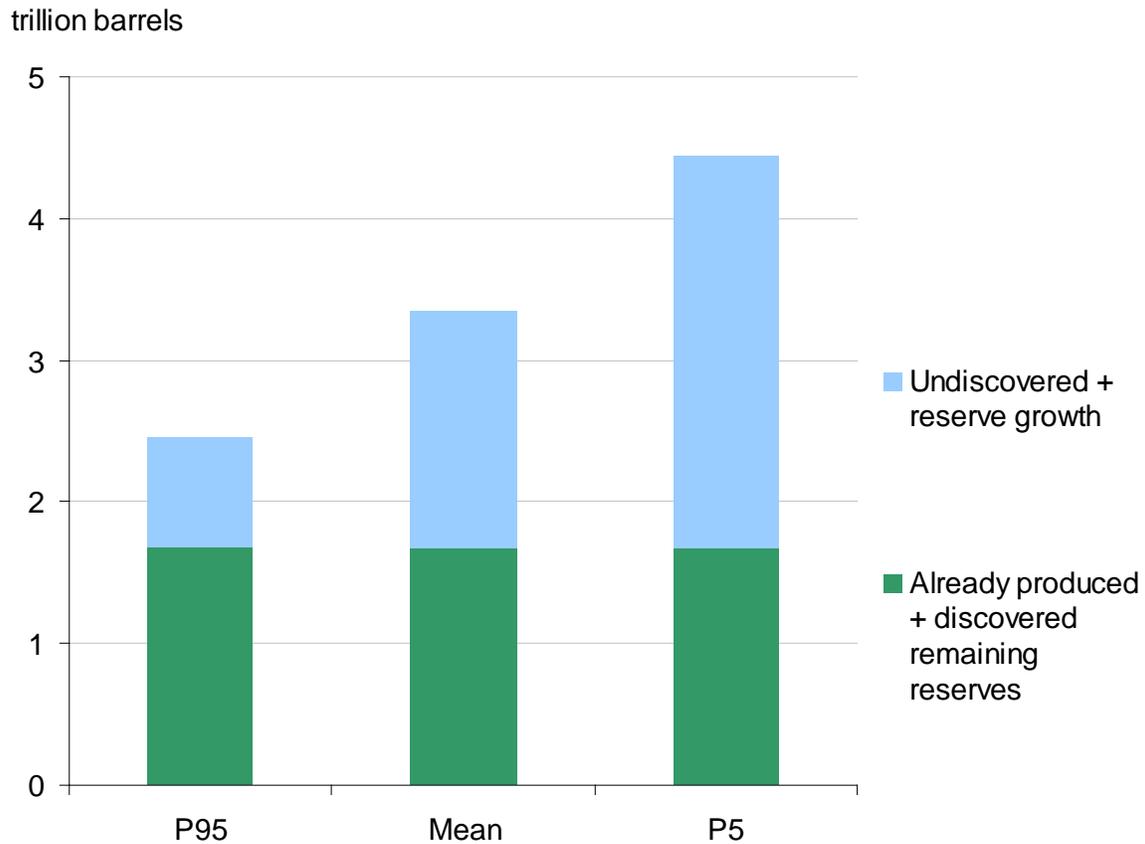


Figure 3: Decision Points in Resource Classification

Source: SPE 2005 Comparison of Selected Reserves and Resource Classifications and Associated Definitions, Figure 3, page 25

Figure 7

### Estimates of ultimately recoverable resources from conventional global oil and natural gas liquids



Note: P95 represents a 95 percent chance that the resource size will equal or exceed the estimate, while P5 indicates a 5 percent chance that the probability will equal or exceed the estimate.

(Source: USGS World Petroleum Assessment 2000, Table 1)

Figure 8

### Global Initial-in-Place estimate for petroleum liquids

(trillion barrels)	Mid. East OPEC	Other OPEC	United States	Other Non-OPEC
Conv. Crude and Condensate	2.6	2.6	0.9	2.9
Natural Gas Plant Liquids	0.3	0.3	0.2	0.4
Extra Heavy Crude (<10° API)	0.0	2.3	0.0	0.0
Bitumen	0.0	0.0	0.0	2.4
Oil Shale	0.0	0.0	2.1	0.7
Source Rock	0.9	0.9	0.3	1.0
<b>Total Liquids</b>	<b>3.8</b>	<b>6.0</b>	<b>3.4</b>	<b>7.4</b>

Note: Estimates of global IIP for petroleum liquids vary from 14 to 24 trillion barrels. This table shows 20.6 trillion barrels.

Sources: I.H.S. Energy, World Energy Council, USGS, Nehring Associates, EIA analysis April 2008

## ***Helpful Links***

U.S. Energy Information Administration

<http://www.eia.gov>

U.S. Energy Information Administration, *International Energy Outlook 2010*

<http://www.eia.gov/oiaf/ieo/index.html>

Society of Petroleum Engineers, reserves and resources information

<http://www.spe.org/industry/reserves/>

Society of Petroleum Engineers, "Comparison of Selected Reserves and Resource Classifications and Associated Definitions" (see pages 23 & 29 in particular)

[http://www.spe.org/industry/reserves/docs/OGR\\_Mapping\\_Final\\_Report.pdf](http://www.spe.org/industry/reserves/docs/OGR_Mapping_Final_Report.pdf)

National Petroleum Council, 2007 report *Facing the Hard Truths about Energy*

<http://www.npchardtruthsreport.org/download.php>

National Petroleum Council, Hard Truths report, Chapter 2 (see page 96)

[http://downloadcenter.connectlive.com/events/npc071807/pdf-downloads/NPC-Hard\\_Truths-Ch2-Supply.pdf](http://downloadcenter.connectlive.com/events/npc071807/pdf-downloads/NPC-Hard_Truths-Ch2-Supply.pdf)

International Energy Agency, *World Energy Outlook 2008* (see Chapters 9-15)

[http://www.iea.org/publications/free\\_new\\_Desc.asp?PUBS\\_ID=2056](http://www.iea.org/publications/free_new_Desc.asp?PUBS_ID=2056)

USGS *World Petroleum Assessment 2000*

<http://energy.cr.usgs.gov/WEcont/WEToC.pdf>

Joint Oil Data Initiative (JODI)

<http://www.ioidata.org/>

### ***Attached Documents***

EIA *IEO2010* "Liquids production modeling approach," pages 27-29

SPE 2005 report "Comparison of Selected Reserves and Resource Classifications and Associated Definitions"

# International Energy Outlook

---

## 2010

July 2010

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

---

**This publication is on the WEB at:**  
**[www.eia.gov/oiaf/ieo/index.html](http://www.eia.gov/oiaf/ieo/index.html)**

---

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Since June 2009, Iraq—the only OPEC member not currently assigned a quota—has held two bid rounds. The sum of the targeted production increase from the awarded fields is about 9.5 million barrels per day, or almost four times the country's current production. Although most industry analysts do not expect Iraq to achieve the production targets in full, especially not in the near to mid-term, the likely increase still could cause changes in OPEC's quota allocation and long-term production decisions.

The year also held significant challenges and surprises for non-OPEC supply, some with potentially long-lasting implications. Although prices rose throughout 2009, many of the supply projects delayed during the price slump that started in 2008 have not been revived. Given the time needed for project development, there is a lag between the time of investment decision and the eventual arrival of the projects in the market. Consequently, mid-term supply growth may be constrained if delayed projects are not restarted in the short term.

A related trend that began in 2008 and continued in 2009 was the decline in costs for materials, labor, and equipment ("factor inputs") necessary to develop supply projects. The decline may have encouraged delays in some projects as investors waited to secure contracts at the lowest possible cost; however, the trend appears to have bottomed out at the end of 2009 after only a slight overall reduction in costs [4]. Before the recent reduction in production costs, an industry research group estimated that costs had approximately doubled since 2000 [5]. Higher costs serve to raise the breakeven oil price at which a project would be considered economical, thus affecting decisions as to which supply projects are likely to move forward in the future.

Also starting in 2008 and continuing into 2009 was a crisis in the global credit market, which made it difficult to finance some exploration and production projects. It will take several years to realize the full effect of limits on credit availability for oil supply projects, because the projects stalled by the lack of financing, particularly exploration projects, would not have brought supply to the market for years. In addition, the recent credit crisis may also have led to an overall and possibly lasting change in risk appetite on the part of both lenders and investors. Ironically, while credit terms were being tightened and financial risk was being trimmed, ongoing exploration efforts in Africa resulted in a wave of discoveries and new hope for unexplored and underexplored non-OPEC frontiers (see box on page 28). It remains unknown whether those exploration efforts will continue to bear fruit, and whether future efforts will be hampered by credit conditions. At present these are important uncertainties to be considered in the projections of future oil supply and demand balance.

## World liquids production

In the *IEO2010* Reference case, world liquids production in 2035 exceeds the 2007 level by 26 million barrels per day. Increases in production are expected for both OPEC and non-OPEC producers. Overall, 51 percent of the total increase is expected to come from non-OPEC areas, including 33 percent from non-OPEC unconventional liquids production alone. OPEC produces 47 million barrels per day in 2035 in the Reference case, and non-OPEC producers provide 64 million barrels per day.

The Reference case assumes that OPEC producers will choose to maintain their market share of world liquids supply and will invest in incremental production capacity so that their liquids production represents approximately 40 percent of total global liquids production throughout the projection. Increasing volumes of conventional liquids (crude oil and lease condensate, natural gas plant liquids [NGPL], and refinery gain) from OPEC members contribute 10.3 million barrels per day to the total increase in world liquids production from 2007 to 2035, and conventional liquids supplied from non-OPEC nations contribute 4.8 million barrels per day.

Unconventional liquids production increases by about 5 percent annually on average over the projection period, because sustained high oil prices make unconventional liquids more competitive, and above-ground factors limit the production of economically competitive conventional liquids. Unconventional fuels account for 37 percent (9.5 million barrels per day) of the increase in total liquids production in the Reference case, and 8.4 million barrels per day of the increase in unconventional supply comes from non-OPEC sources. High oil prices, improvements in exploration and extraction technologies, emphasis on recovery efficiency, and the emergence and continued growth of unconventional resource production are the primary factors supporting the growth of non-OPEC liquids production in the *IEO2010* Reference case.

### Liquids production modeling approach

The *IEO2010* projections are based on a two-stage analytical approach. Projections of liquids production before 2015 are based largely on a project-by-project assessment of production volumes and associated scheduling timelines, with consideration given to the decline rates of active projects, planned exploration and development activity, and country-specific geopolitical situations and fiscal regimes. There are often lengthy delays between the point at which supply projects are announced and when they begin producing. The extensive and detailed information available about such projects, including project scheduling and the investment

## Is offshore West Africa the world's next frontier for oil?

The development of non-OPEC oil supply centers has grown and diversified widely over time. North America dominated non-OPEC supply in the early 1970s, the North Sea and Mexico evolved as major sources in the 1980s, and much of the new production in the 1990s and into the 2000s came from developing countries in Central and South America, the non-OPEC Middle East, and China. Now industry has shifted its attention to offshore resources along Africa's western coast, suggesting that Africa may become an important non-OPEC oil-producing region within a decade.

Between 2007 and 2009, oil discoveries off the West African coast resulted in a flurry of exploration and production activity, with a number of companies showing active interest in obtaining exploration blocks. In June 2007, the Jubilee field was discovered by the United Kingdom's Tullow Oil in the deep coastal waters of Ghana.<sup>a</sup> Initial estimates suggest that the Jubilee field contains approximately 490 million barrels of proven reserves and may have as much as 1.8 billion barrels of potential reserves.<sup>b</sup> Work on the Jubilee field began in 2009. Initial production is expected to begin at the end of 2010, increasing to 120,000 barrels per day in 2011.

The discovery of Jubilee spurred interest in oil exploration along the coast of several other West African nations, notably, Côte d'Ivoire, Liberia, and Sierra Leone. In September 2009, Anadarko Petroleum discovered oil off the coast of Sierra Leone at the Venus-B1 exploratory well—the first deepwater discovery in the Sierra Leone-Liberian Basin. Although its commercial viability has not yet been confirmed, the discovery serves to frame a "new oil frontier" area of the West African coast, extending from Ghana to Sierra Leone, with significant resource potential.<sup>c</sup>

A 2010 assessment by the U.S. Geological Survey (USGS) of two West African provinces, the Senegal Province and the Gulf of Guinea Province, estimated mean undiscovered resources of 2.4 billion barrels and 4.1 billion barrels, respectively.<sup>d</sup> This represents a significant increase in the undiscovered potential of the

two provinces since the 2000 USGS *World Petroleum Assessment*. In 2000, the Senegal Province was estimated to hold a mere 157 million barrels of oil. The Gulf of Guinea Province estimate has grown from 1.0 billion barrels of oil resource in 2000 to 4.1 billion barrels in 2010.

While the potential resource base offshore West Africa appears to be ample, there are other important considerations that may deter the region's oil development. Investment climates vary among countries, and there are risks that must be evaluated before foreign companies commit to investing in oil production. Foreign investors attempt to limit their risks, including but not limited to political, economic, operational, and geopolitical risks.

Many West African nations have only recently recovered from civil war or other periods of political instability, and they may still be dealing with inexperienced governments, potentially suffering from corruption and mismanagement. Companies can be dissuaded from investing if they believe that business operations might be hampered by government interference. For example, the recent dispute between Kosmos Energy and the government of Ghana concerning the proposed sale of Kosmos's stake in the Jubilee field to ExxonMobil signaled potential problems for companies operating in offshore Ghana.<sup>e</sup> Although the dispute was resolved—at least temporarily—when Kosmos agreed to remain a partner until the field begins first production, the issue over transfer of assets could have negative impacts on future international investment.

Because this is the first time that oil production has been a consideration for many West African countries, they may have little or no legislation concerning hydrocarbon resources. Côte d'Ivoire introduced a new Oil and Gas Development Code in 1996 in an attempt to increase foreign direct investment, and the Ghanaian government is scheduled to draft legislation establishing an independent regulator to manage oil revenues before production begins at the Jubilee field  
(continued on page 29)

<sup>a</sup>"Ghana: 'World-class' Jubilee Oilfield Larger Than Expected," *Petroleum Economist* (January 27, 2009), web site [www.petroleum-economist.com](http://www.petroleum-economist.com) (subscription site).

<sup>b</sup>"Africa: Jubilee Field: Ghana's Oil Industry Takes Off," *iStockAnalyst.com* (April 5, 2010), web site [www.istockanalyst.com/article/viewiStockNews/articleid/4006121](http://www.istockanalyst.com/article/viewiStockNews/articleid/4006121); and "Exxon's Ghana Move Raises Hopes, Tensions," *Petroleum Intelligence Weekly*, Vol. 48, No. 42 (October 19, 2009), pp. 2-3, web site [www.energyintel.com/publicationhomepage.asp](http://www.energyintel.com/publicationhomepage.asp) (subscription site).

<sup>c</sup>J. Collin, "Anadarko: West Africa Find Opens New Frontier," *Oil Daily* (September 17, 2009), web site [www.energyintel.com](http://www.energyintel.com) (subscription site).

<sup>d</sup>U.S. Geological Survey, World Petroleum Resources Project, "Assessment of Undiscovered Oil and Gas Resources of Four West Africa Geologic Provinces," Fact Sheet 2010-3006 (February 2010), web site <http://pubs.usgs.gov/fs/2010/3006/pdf/FS10-3006.pdf>.

<sup>e</sup>E. Gismatullin and T. Patel, "Tullow Says Kosmos to Stay in Ghana Until Production Starts" (April 22, 2010), web site [www.bloomberg.com/apps/news?sid=aigcwbvWOSCE&pid=20601087](http://www.bloomberg.com/apps/news?sid=aigcwbvWOSCE&pid=20601087).

### Is offshore West Africa the world's next frontier for oil? (continued)

later this year.<sup>f</sup> The legislation aims to create an independent regulatory body and revenue management procedures to avoid the mismanagement and corruption that have arisen elsewhere on the continent. It remains to be seen how Sierra Leone and Liberia, both still recovering from recent civil wars, will manage this task.

<sup>f</sup>C. Hunter, IHS Global Insight, "Ghana: Oil & Gas: Government Policy," *Energy Country Profiles* (April 5, 2010), web site [www.ihsglobalinsight.com](http://www.ihsglobalinsight.com) (subscription site).

The coast of West Africa represents a new frontier for the petroleum industry, but how and when the resources will be brought to market remains uncertain. Although there has been healthy exploratory activity, production from the region is still in its infancy.

and development plans of companies and countries, make it possible to take a detailed approach to modeling mid-term supply.

Although some projects are publicized more than 7 to 10 years before their first production, others can come on line within 3 years. For that reason, project-by-project analyses are unlikely to provide a complete representation of company or country production plans and achievable production volumes beyond 3 years into the future. Instead, production decisions made after the mid-term, or 2015, are assumed to be based predominantly on resource availability and the resulting economic viability of production.

In view of the residual effects of previous government policies and the unavoidable lag time between changes in policy and any potential production changes, however, most country-level changes in production trends are noticeable only in 2020 and beyond. Geopolitical and other "above-ground" constraints<sup>14</sup> are not assumed to disappear entirely after 2015, however. Longstanding above-ground factors for which there are no indications of significant future changes—for instance, the government-imposed investment conditions currently in place in Iran, or OPEC adherence to production quotas—are expected to continue affecting world supplies long after 2015. Even if above-ground constraints were relaxed, the expansion of production capacity could be delayed, depending on the technical difficulty and typical development schedule of the projects likely to be developed in a particular country.

For some resource-rich countries it is assumed that current political barriers to production increases will not continue after 2015. For instance, both Mexico and Venezuela currently have laws that restrict foreign ownership of hydrocarbon resources. Their resource policies have discouraged investment—both foreign and domestic—and hindered their ability to increase or even maintain historical production levels. In the Reference

case, both Mexico and Venezuela ease restrictions at some point after 2015, allowing some additional foreign involvement in their oil sectors that facilitates increases in liquids production, including from deepwater prospects in Mexico and extra-heavy oils in Venezuela's Orinoco belt.

Iraq is another resource-rich country where currently there are significant impediments to investment in the upstream hydrocarbon sector. Liquids production in Iraq dropped substantially after the U.S.-led invasion in 2003. From 2002 to 2003 production declined from 2.0 million barrels per day to 1.3 million barrels per day, and since then it has achieved only inconsistent and slow growth. Although Iraq's production levels are not expected to increase substantially in the near term, it is assumed that political and legal uncertainty subsides, and that renewed investment and development activity ensue, resulting in significant growth in production from 2015 to 2035.

#### Non-OPEC production

The return to sustained high oil prices projected in the *IEO2010* Reference case encourages producers in non-OPEC nations to continue investment in conventional liquids production capacity and increase investment in enhanced oil recovery (EOR) projects and unconventional liquids production. Non-OPEC production increases steadily in the projection, from 50 million barrels per day in 2007 to 64 million barrels per day in 2035, as high prices attract investment in areas previously considered uneconomical, and fears of supply restrictions encourage some net consuming nations to expand unconventional liquids production from domestic resources, such as coal and crops.

Despite the maturity of most non-OPEC producing basins, conventional liquids production in the Reference case increases from 48 million barrels per day in 2007 to 52 million barrels per day in 2035. The overall increase results primarily from production increases in four

<sup>14</sup>"Above-ground" constraints refer to those nongeological factors that could affect supply, including but not limited to government policies that limit access to resources; conflict; terrorist activity; lack of technological advances or access to technology; price constraints on the economic development of resources; labor shortages; materials shortages; weather; environmental protection actions; and short- and long-term geopolitical considerations.

# Society of Petroleum Engineers



## **Oil and Gas Reserves Committee (OGRC)**

### **“Mapping” Subcommittee Final Report – December 2005**

### **Comparison of Selected Reserves and Resource Classifications and Associated Definitions**

Mapping Subcommittee:  
John Etherington  
Torbjorn Pollen  
Luca Zuccolo

# Table of Contents

	Page
<b>Executive Summary</b>	3
<b>Introduction</b>	5
<b>Classifications/Definitions Studied</b>	6
<b>Method of Study</b>	8
<b>Summary Comparison by issuing Agency</b>	
○ Overview of Category and Class “Mapping”	9
○ US Security and Exchange Commission (SEC-1978)	11
○ UK Statement of Recommended Practices (SORP-2001)	12
○ Canadian Security Administrators (CSA -2002)	13
○ Russian Ministry of Natural Resources (RF-2005)	14
○ China Petroleum Reserves Office (PRO–2005)	16
○ Norwegian Petroleum Directorate (NPD–2001)	18
○ United States Geological Survey (USGS-1980)	20
○ United Nations Framework Classification (UNFC-2004)	22
<b>Findings and Analysis</b>	
<b>Overview - Classification Approach</b>	24
<b>Comparison by Major Issue</b>	25
○ Classification by Discovery Criteria	25
○ Classification by Commercial Criteria	27
○ What is Commercial?	
○ Project Status Categories	
○ Classification by Uncertainty	29
○ Deterministic vs Probabilistic Methods	
/Aggregations Issues	
○ Proved Reserves Criteria	31
○ Unproved Reserves Definitions	32
○ Improved Recovery (IR)	33
○ Developed vs Undeveloped Reserves	34
○ Other Issues	34
○ Proved without Probable	
○ Lease Fuel	
○ Reserves Reference Point	
○ Unconventional Hydrocarbons	
○ Resource Entities	
<b>Conclusions and Recommendations</b>	37

## **Appendix A**

(attached separately)

Detailed Descriptions of Agencies' Classifications/Definitions  
Summary and Detailed (tables) Comparison to SPE Reserves Definitions

- US Security and Exchange Commission (SEC-1978)
- UK Statement of Recommended Practices (SORP-2001)
- Canadian Security Administrators (CSA -2002)
- Russian Ministry of Natural Resources (RF-2005)
- China Petroleum Reserves Office (PRO-2005)
- Norwegian Petroleum Directorate (NPD-2001)
- United States Geological Survey (USGS-1980)
- United Nations Framework Classification (UNFC-2004)

## Executive Summary

In October 2005, the “Mapping” subcommittee of the SPE Oil and Gas Reserves Committee (OGRC) completed a study of reserve/resource classification systems published by the following eight international “agencies”:

1. US Security and Exchange Commission (SEC - 1978)
2. UK Statement of Recommended Practices (SORP -2001)
3. Canadian Security Administrators (CSA -2002)
4. Russian Ministry of Natural Resources (RF-2005)
5. China Petroleum Reserves Office (PRO – 2005)
6. Norwegian Petroleum Directorate (NPD – 2001)
7. United States Geological Survey (USGS - 1980)
8. United Nations Framework Classification (UNFC- 2004)

The overall structure of, and reserves definitions within, each system were compared to the 1997 SPE/WPC reserves definitions, the 2000 SPE/WPC/AAPG classification, the 2001 supplemental guidelines, and the 2004 glossary (hereafter referred to as the “SPE definitions”).

Although the terminology varies, there is a high degree of commonality:

- All systems define major resource categories that can be mapped directly to the SPE categories: undiscovered (prospective resources), discovered unrecoverable, discovered sub-commercial (contingent resources) and discovered commercial (reserves).
- Most classifications recognize three deterministic scenarios with decreasing technical certainty: a low estimate, best estimate and high estimate. While probabilistic assessments are not commonly applied, it is generally accepted that the equivalent estimates on a cumulative probability distribution would be greater than or equal to P90, P50 and P10 respectively. For discovered and commercial volume estimates, the discrete (incremental) volumes within these bounds are generally referred to as proved, probable and possible reserves. The Russian, UNFC and USGS recognize similar certainty classes but use alternative terminology.

The regulatory agencies typically define a subset of the total classification for disclosure to investors and further impose specific rules around technical and commercial certainty. The SEC guidance is the most restrictive while the Canadian and UK regulations allow disclosures more closely aligned with assessments used for internal resource management.

The UNFC uniquely provides a high-level classification system that can be applied to all extractive industries including energy minerals (petroleum, coal and uranium).

Based on analysis of each agency’s classification system, the subcommittee collated the following potential “best practices” for review by the OGRC subcommittee charged to recommend revisions to current SPE reserves and resource definitions:

- Utilize a consistent set of criteria to segregate discovered from undiscovered without reference to ultimate commerciality. All such discovered volumes should be initially categorized as contingent resources.
- Estimates of recoverable quantities must clearly identify the development project(s) applied to a specific accumulation (reservoir) and its in-place hydrocarbons. The “project-reservoir” intersect becomes the resource entity for which an uncertainty distribution of recoverable quantities is defined. The project maturity/chance of reaching production status is used to segregate reserves from contingent resources.
- To maintain consistency, the same class confidence hurdles (P90/P50/P10) should be applied to estimates whether assessed using deterministic or probabilistic methods. Although the assessment should support either arithmetic summation or probabilistic aggregation, the guidelines should clearly identify that these certainty guidelines apply to the project-reservoir entity.
- From a business perspective, the inclusion of additional deterministic technical and commercial criteria for reserves classes (proved, probable, possible) or discrete estimates (1P, 2P, 3P) may have value in providing increased consistency in assessments. However, these should be provided as guidelines and not imbedded in the class definitions. The definitions should be broad enough to accommodate such criteria as imposed by regulatory agencies.
- Apply developed/undeveloped status to all reserves classes. Reserves that remain undeveloped beyond a reasonable period demonstrate lack of commitment and should be reclassified as contingent resources.
- The definitions should encompass all hydrocarbons whether conventional or unconventional (gas, liquid or solid phases) irrespective of the extraction method and processing applied.
- The total system should provide for accounting of all components to support mass balance; that is, the sum of produced, recoverable, production/processing losses and unrecoverable quantities should equal the estimated initially-in-place hydrocarbons. The guidelines should provide the option, subject to regulatory rules, of including hydrocarbons to be consumed as fuel in production and processing as reserves and contingent resources.

Documentation regarding reserves and resources is best presented in a more structured manner consisting of:

- Overall Resource Classification – chart and resource category definitions
- Reserves Definitions – high level, principle-based
- Application Guidelines – detailed guidance, subject to periodic revisions
- Application Examples – illustrations of both common and exceptional issues

The format used by the Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum in their 2002 definitions provides a useful template.

## Introduction

The goal of resource classifications is to provide a common framework for estimating quantities of oil and gas, both discovered and undiscovered, associated with reservoirs, properties and projects. The classification should cover volumes originally in-place, technically and/or commercially recoverable, on production or already produced. Ideally, subsets of a single classification system could be used by regulatory agencies, government departments, and internally by the operating companies.

In 2000, the Society of Petroleum Engineers (SPE) jointly with the World Petroleum Council (WPC) and the American Association of Petroleum Geologists (AAPG) published a Reserve and Resource Classification to address the requirement for an international standard. The underlying Reserves Definitions were unchanged from those published by the SPE/WPC in 1997. Additionally, in 2001 the SPE/WPC/AAPG jointly published “Guidelines for the Evaluation of Petroleum Reserves and Resources” as clarifications for the application of the 2001 and 1997 documents. Further clarification was provided in the Glossary of 2005, in particular by the definition of the term commercial, and thereby reserves. The total information contained in these four documents is referred to hereafter as the current “SPE definitions”.

At the September 2004 Annual Technical Conference and Exhibition, the leadership of the SPE and the OGRC jointly developed a “grand vision” that reads:

” To have a set of reserves & resource definitions (and an associated set of estimating guidelines, which are current best practices) universally adopted by the oil industry, international financial organization and regulatory reporting bodies”.

In order to achieve this “vision”, the OGRC discussed several key options to “clarify and/or revise existing SPE Reserves and Resource Definitions”. In December 2004, two subcommittees were established to progress this project:

- the **Definitions Subcommittee** was charged with reviewing the current SPE “definitions” documents in detail to identify internal inconsistencies and ambiguities, identify key issues not addressed, examine improved presentation formats, and ultimately draft a revised set of documents.
- the **Mapping Subcommittee** was charged with examining key alternative classification and definitions that are, or have the potential to be, broadly applied to reserves and resources reporting and prepare a detailed comparison of each to the current SPE definitions.

This document contains the results of the Mapping Subcommittee’s findings. The survey of each agency provides the OGRC with a useful summary of major classifications currently being applied. The focus of this report is to identify those features that deserve further study by the Definitions Subcommittee in their task to clarify/revise the existing SPE definitions.

The Mapping Subcommittee consisted of: John Etherington (Consultant – Canada), Torbjorn Pollen (Statoil - Norway) and Luca Zuccolo (ENI- Italy) and was chaired by John Etherington.

## Classifications/Definitions Studied

The subcommittee reviewed and compared eight sets of classifications and definitions as published by the following agencies:

1. US Security and Exchange Commission (SEC-1978)
2. UK Statement of Recommended Practices (SORP-2001)
3. Canadian Security Administrators (CSA -2002)
4. Russian Ministry of Natural Resources (RF-2005)
5. China Petroleum Reserves Office (PRO-2005)
6. Norwegian Petroleum Directorate (NPD-2001)
7. United States Geological Survey (USGS-1980)
8. United Nations Framework Classification (UNFC-2004)

While there are several other major classifications/definitions that may be examined in the future, these eight represent an appropriately diverse mix used in securities regulations, government reporting, and/or for companies' internal resource/asset management. The eight agencies selected can be categorized as follows with additional reference to the depth of associated documentation (see figure 1):

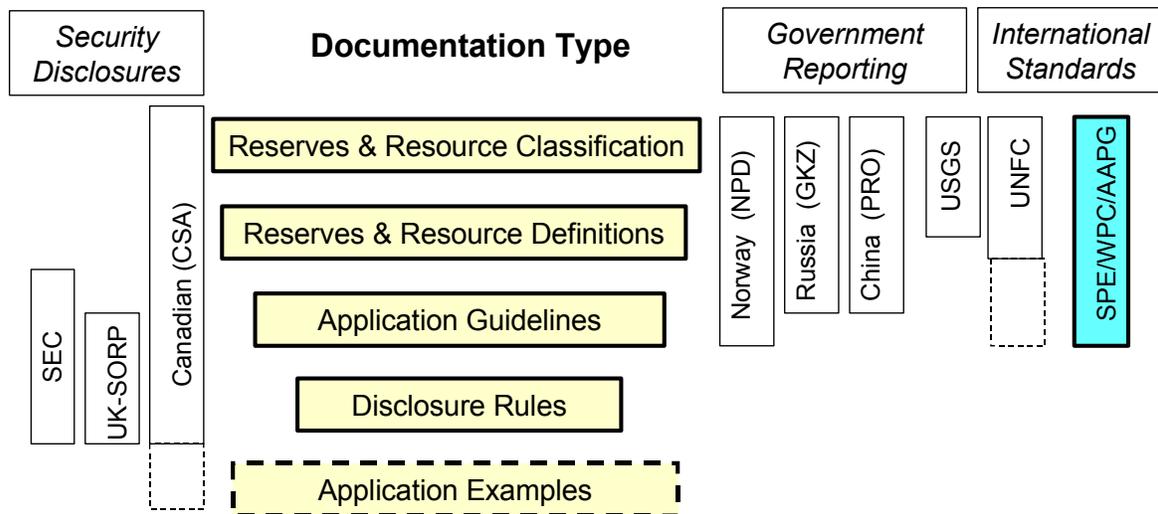


Figure 1: Categorization of Agencies Surveyed

- Securities Disclosures: SEC, Canadian (CSA), UK SORP.
 

These agencies define rules for defining proved and/or 2P reserves estimates to be disclosed to security investors for publicly traded oil and gas companies. The primary objective is to provide consistent volume and associated value assessments such that investors may compare financial performance. The estimation guidelines are imbedded in their financial accounting regulations. Typically no overall reserve and resource classification context is supplied and the application guidelines take on the format of “rules”. Canada’s approach is unique in that the security regulations reference a full classification, definitions and detailed assessment guidelines that are maintained by professional societies, not by the regulatory agency.

- Government and industry reporting: Norway, the Russian Federation, China, USGS. These agencies attempt to capture the full resource base in order to project future production potential for the country and are not primarily concerned to show recoverable volumes and values accruing to individual companies. Governments need this information regarding production and reserves to implement and modify legislation and policy (fiscal terms, licensing incentives, etc.) on resource development to manage energy supply. In the case of Norway, the government's classification is also used internally by the Norwegian companies to manage their oil and gas portfolios (*for those listed on U.S. stock exchanges, they must also estimate proved reserves under SEC guidelines*). The USGS conducts "future potential of the world" studies based on geological-based assessment units that cut across political boundaries to support long-range global energy supply analyses.
  
- Technical Standards: United Nations Framework Classification (UNFC), SPE. The SPE and UNFC definitions are presented as independent standards to promote international consistency in total resource assessment processes and terminology. The SPE classification and definitions are the current de facto standard and most oil and gas companies have adapted it into their internal systems. The UNFC incorporates the SPE standards for petroleum within an overall classification system applicable to all the energy minerals (including coal and uranium). The UNFC is endorsed by the UN Economic and Social Council, a top level body in the UN, equivalent to the Security Council, but for economic and social affairs. SPE and UNFC committees are currently coordinating to ensure their classifications are synchronous and have a common set of application guidelines.

Given the diversity of oil and gas accumulations and development projects, there can be significant interpretation latitude, not only in the estimation of recoverable quantities, but also in their logical classification. Thus, to promote consistency in application, it is beneficial to have a comprehensive set of application examples that cover the key issues. None of the agencies currently have such examples. The professional societies that maintain the Canadian technical guidelines are in the process of publishing an extensive set of such examples showing the recommended interpretations for each.

## Method of Study

The subcommittee made extensive use of websites and published papers to gather information on the reserves and resources classifications and associated definitions utilized by the identified agencies. The committee established a contact person within the Canadian, Russian, Chinese, USGS and UNFC agencies to act as an advisor and to validate comparisons to their definitions. For the SEC, UK-SORP and Norwegian agencies, the committee sought advice from SPE members experienced in applying these systems.

The selected definitions are published by international organizations such as the United Nations or are part of reporting requirements defined by government agencies. In some cases the definitions are extracted from regulatory reporting requirement documents including legislation to prescribe company disclosures to securities investors of oil and gas reserves and associated financial data.

In order to achieve consistency for analyses, a standard template was developed to document the classification/definitions of each agency surveyed and consists of:

- Overview of the Agency issuing the classification.
- A summary description of the classification.
- A comparison to the SPE/WPC/AAPG 2000 (SPE) classification with a discussion of key differences.
- A table detailing a comparison to the SPE reserves definitions.

In order to consolidate the definitions into a manageable-sized table, it was necessary to summarize lengthy sections of text. This often involved rewording sections and eliminating other sections. A complete documentation of each agency's classification is included in Appendix A. An abbreviated summary of the classifications and a comparison to the SPE system is included herein under the heading "**Summary Comparisons by issuing Agency**".

*It must be emphasized that the SPE does not claim that the classification and definitions as documented in this study represent the authoritative version of these agencies' guidelines; users should obtain official copies of the guidelines directly from the issuing agencies. Readers are referred to the agencies' publications (in many cases these are available on websites) that are the official source of technical and commercial criteria.*

Based on their review of these classifications, the subcommittee identified the underlying key principals of a hydrocarbon classification scheme and critically evaluated the varying approaches herein under the heading "**Findings and Analysis**". The focus was on identifying those features that, if adopted and adapted, have the potential to strengthen a revised SPE reserves and resource classification and associated definitions.

## Summary Comparisons by Issuing Agency

### Overview of Category and Class “Mapping”

Based on reviews of the agencies’ documentation and discussions with experts in each classification, the subcommittee constructed a series of correlation tables to identify categories and classes that are generally equivalent but use different terminology.

Table 1 correlates the major status categories. All the major classifications define 3 major categories: undiscovered, discovered sub-commercial and discovered commercial.

		SPE 2001	SEC 1978	UK-SORP 2001	CSA 2002	RF 2005	PRO 2005	NPD 2001	USGS 1980	UNFC 2003
<b>In-Place</b>										
Total Petroleum Initially-In-Place	Total PIIIP				Total PIIIP	Total PIIIP	Total PIIIP	**	Total PIIIP	Total PIIIP
Discovered Petroleum Initially-In-Place	Discovered PIIIP				Discovered PIIIP	Geological Reserves	Geological Reserves	**	Discovered PIIIP	Discovered PIIIP
Undiscovered Petroleum Initially-In-Place	Undiscovered PIIIP				Undiscovered PIIIP	Geological Resources	Undiscovered PIIIP	**	Undiscovered PIIIP	Undiscovered PIIIP
<b>Recoverable</b>										
Discovered + Undiscovered	Resources				Resources			Recoverable Resources		Remaining Recoverable
Produced	Production	Production	Production	Production	Production	Produced Reserves	Production	Historical Production	Cumulative Production	Produced
Discovered	Discovered	Discovered	Discovered	Discovered	Discovered	Recoverable Reserves	Recoverable Reserves	**	Identified Resources	
Discovered Commercial	Reserves	Reserves	Reserves	Reserves	Reserves	Economic - Normally Profitable Reserves	Economical Initially Recoverable Reserves*	Reserves	(Economic) Reserves	Reserves
Discovered Sub-commercial	Contingent Resources				Contingent Resources	Contingently Profitable & Subeconomic Reserves	*	Contingent Resources	Marginal Reserves	Contingent Resources
Discovered Unrecoverable	(Discovered) Unrecoverable				(Discovered) Unrecoverable	Unrecoverable Reserves	Residual Unrecoverable Volumes	**	Demonstrated Subeconomic Resources	Unrecoverable
Undiscovered	Prospective Resources				Prospective Resources	Recoverable Resources	Recoverable Resources	Undiscovered Resources	Undiscovered Resources	Prospective Resources
Undiscovered Unrecoverable	(Undiscovered) Unrecoverable				(Undiscovered) Unrecoverable	Unrecoverable Resources	Residual Unrecoverable Volumes	**		Unrecoverable

\* Chinese classification is EUR-based - includes production. Contingent Resources equivalent is technically recoverable minus economically recoverable  
 \*\* The NPD classification is for recoverable quantities only based on development projects.

Table 1: Correlation of Status Categories

There is general consensus to apply the term “reserves” or “economic reserves” to the discovered commercial category. The term “geological reserves” is applied to discovered in-place volumes in China and Russia. The undiscovered category is variously referred to as prospective, recoverable or undiscovered resources; the common denominator is the term “resources” as opposed to reserves. “Resources” is also commonly used as a general term for all discovered and undiscovered volumes. The discovered sub-commercial category is variously termed contingent resources or contingent (or marginal) reserves. The regulatory agencies typically define a subset of the total reserves and resources for public disclosures; the SEC and UK-SORP rules cover only a portion of reserves while the Canadian (CSA) guidelines allow the option to also report contingent and/or prospective resources. The Norwegian Petroleum

Directorate’s classification does not include in-place categories; it applies only to volumes recovered by development projects.

Table 2 compares terminology used for discovered volumes based on technical certainty classes. Most classifications recognize three cumulative estimates or scenarios based on decreasing technical certainty: low/best/high estimate. Many agencies apply specific terms to the associated incremental volumes; the SPE terms in the discovered commercial category are proved, probable and possible. While the same low/best/high estimates are applied to contingent and prospective resources, only the Chinese, USGS, and UNFC provide terms for the incremental estimates.

	SPE 2001	SEC 1978	UK-SORP 2001	CSA 2002	RF* 2005	PRO ** 2005	NPD 2001	USGS 1980	UNFC*** 2003
<b>In-Place</b>									
Low Estimate	Increment					Measured			
Best Estimate	Increment					Indicated			
High Estimate	Increment					Inferred			
<b>Recoverable</b>									
Commercial Low Estimate	Increment	Proved	Proved	Proven	Proved	A+B+C1	PVEIRR	Measured	111
	Cumulative	Proved (1P)		Proven	Proved	A+B+C1	PVEIRR	Low Est	Low Est
Commercial Best Estimate	Increment	Probable		Probable	Probable	C2	PBEIRR	Indicated	112
	Cumulative	Proved + Probable (2P)		Proven + Probable	Proved + Probable			Base Est	Best Est
Commercial High Estimate	Increment	Possible			Possible	C2	PSTEUR	Inferred	113
	Cumulative	Proved + Probable + Possible (3P)			Proved + Probable + Possible			High Est	High Est
Sub-commercial Low Estimate	Increment						PVSEIRR	Measured	121, 231
	Cumulative	Low Est				Low Est	Low Est	Low Est	Low Est
Sub-commercial Best Estimate	Increment						PBSEIRR	Indicated	122, 232
	Cumulative	Best Est				Best Est	Best Est	Base Est	Best Est
Sub-commercial High Estimate	Increment						PSTEUR	Inferred	123, 233
	Cumulative	High Est				High Est	High Est	High Est	High Est

Table 2: Correlation of Certainty Classes for Discovered Volumes

\*The Russian classes A–Reasonable Assured, B–Identified, and C1–Estimated are roughly equivalent to proved developed producing, proved developed non-producing and proved undeveloped. C2 is generally equivalent to probable and possible combined.

\*\*The Chinese make an initial certainty classification based on in-place volumes (measured, indicated, inferred) that carry through to technically recoverable and ultimately to economically recoverable. All recoverable estimates are EUR-based (before production). Production is separated from proved developed leaving PDRER - proved developed remaining economic reserves. PVEIRR is proved economic initially recoverable; PBEIRR is probable economic initially recoverable; PVSEIRR is proved sub-economic initially recoverable reserves; PBSEIRR is probable sub-economic initially recoverable. PSTEUR is possible technical EUR and is not divided into commercial and sub-commercial.

\*\*\* UNFC numeric codes refer sequentially to the level of Economic, Feasibility (project status) and Geological certainty.

The SPE and CSA use the terms low/best/high estimates for prospective resources, with the understanding that these recoveries are conditional on discovery. There are no terms supplied for incremental volumes. Others treat undiscovered as a completely separate category in which the same technical certainties may not apply; for example, UNFC codes all undiscovered as 334 where 4 refers to potential geological conditions.

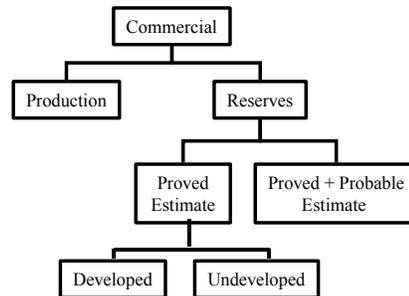
## US Security and Exchange Commission (SEC-1978)

The SEC rules and guidelines address proved reserves only. The SEC prohibits additional disclosure of unproved reserves, i.e. probable and possible, as well as Contingent and Prospective Resources. While SPE and SEC proved reserve definitions are quite similar, SEC regulations are generally considered to be slightly more restrictive. Key differences between SEC and SPE systems are:

- While both proved definitions apply “current economic conditions”, the SEC specifically requires use of year-end prices and costs while the SPE will, in some circumstances, allow use of average prices and costs.
- SPE allows use of either deterministic or probabilistic methodologies. While the SEC does not forbid probabilistic analyses, the disclosed quantities must be demonstrated to meet the defined deterministic criteria.
- SPE generally requires a well test to classify reserves as proved but can be waived if the estimate is fully supported by wireline formation tests, logs and cores. The SEC states that a well test is mandatory and can be only avoided in the Gulf of Mexico (GOM) deep water if the estimate is fully supported by seismic, wire line conveyed sampling, logs and cores.
- Both the SPE and the SEC limit proved reserves to those recovered above the lowest known occurrence of hydrocarbons. In the absence of data on fluid contacts, SPE states that the lowest known structural occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data. In contrast, the SEC effectively rules out the use of conclusive technical data other than direct well observations and incremental proved below LKH can only be based on performance history.
- Regarding unconventional hydrocarbons, the SEC allows coal bed methane to be classified as proved reserves if the recovery is shown to be economic. While the SEC has ruled that bitumen recovered by mining is not petroleum reserves, there are no published guidelines for bitumen produced by in situ methods. The SPE reserve definitions apply to both conventional and unconventional hydrocarbons.
- The SPE guidelines define developed producing and non-producing status while SEC defines developed with no sub-categories.
- Both SEC and SPE guidelines set similar criteria around commerciality to include not only economics but also some evidence of a commitment to proceed with development projects within a reasonable time frame. This includes confirmation of market, production and transportation facilities, and the required lease extensions. Neither set of definitions specifies the documentation to support these claims. Neither definition requires “absolute certainty” in terms of approvals, contracts, market, etc.
- The SEC requires a reasonable certainty of procurement of project financing; the SPE does not specifically address financing requirements although all proved reserves must be “reasonably certain” to be produced.

## UK Statement of Recommended Practices (SORP-2001)

*Note: Initial offerings in the UK employ guidelines of the London Stock Exchange (which have different reserves guidelines) while annual reporting thereafter utilize SORP.*



SORP is primarily an accounting standards document. It does not discuss the full reserves and resource classification system (no possible reserves, no contingent or prospective resources) nor does it supply detailed guidance on the recommended evaluation practices. Under SORP, reserves may be disclosed, at company's choice, as either "Proven developed and undeveloped oil and gas reserves" (option 1) or "Proven and Probable oil and gas reserves" (2P- option 2). These alternatives are mutually exclusive.

Its 2P definitions clearly require that "there should be a 50% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50% statistical probability that it will be less". Further "the equivalent statistical probabilities for the proven component of proven and probable reserves are 90% (*probability actual =>than estimated*) and 10% (*!=< than*) respectively".

The commercial and technical criteria for the 2P case are very similar to those set by the SPE definitions. Specific criteria include:

- Reserves may only be considered proven and probable if producibility is supported by either actual production or conclusive formation test. (*SPE probable does not require a flowing well test.*)
- 2P includes immediately adjoining undrilled portions beyond proved which can be reasonably judged as economically productive based on available geophysical, geological and engineering data.
- improved recovery 2P reserves can be included on the basis of successful pilots or operation of an installed program in the reservoir or other reasonable evidence (successful analogs or reservoir simulation studies).
- reserves may be considered commercially producible if management has the intention of developing and producing them.

The Proven Developed and Undeveloped definitions in Option 1 duplicate those of the basic SEC guidance, thus SORP does not subdivide Proven Developed into Producing and Non-Producing. (*It is noted that some issuers interpret that while the words duplicate the SEC proved definitions, there is no obligation to consider the supplemental guidance issued by SEC staff and thus the reported proved reserves under SORP may not equal those estimated for SEC disclosures*).

Regarding non-conventional hydrocarbons, the Proven definition is taken from the SEC and the 2P definition does not address the issue.

## Canadian Security Administrators (CSA- 2002)

*The disclosure rules for Canadian registered companies are contained in CSA's National Instrument (NI) 51-101 which references resource definitions and application guidelines contained in the Canadian Oil and Gas Evaluation Handbook Volume 1 authored by the Canadian chapter of the Society of Petroleum Evaluation Engineers. The underlying reserve definitions are those published by the Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum in 2002 and referred to hereafter as the "CIM definitions".*

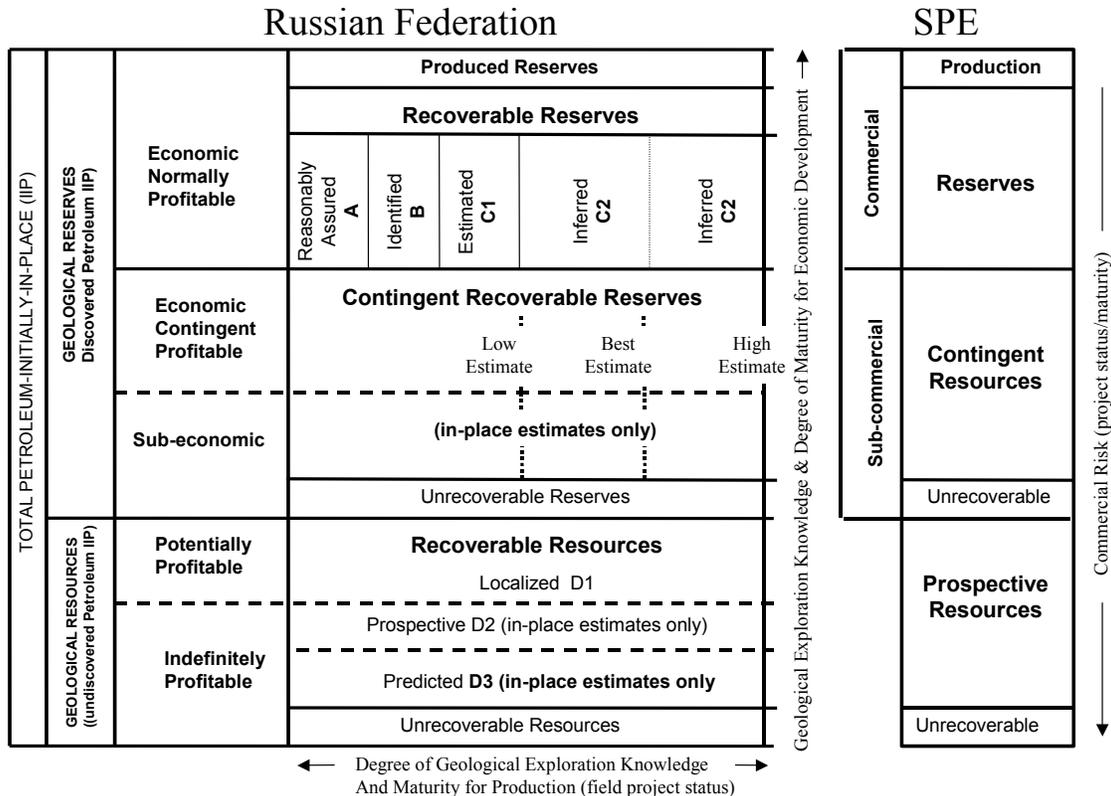
NI 51-101 requires two sets of disclosures: Proved plus Probable using a defined forecast of costs and prices (2P forecast case) and Proved using prices as of the effective date of the assessment (1P constant case, similar to SEC Proved). Reserves impairment is based on the 2P forecast case. Issuers have the option of also disclosing one or all of: possible reserves, contingent resources and prospective resources.

The overall classification is identical and the reserves definitions are very similar to those of the SPE; however, the following issues are noted:

- The CIM definitions state that "the qualitative certainty levels are applicable to both individual Reserve Entities and to Reported Reserves being the sum of entity level estimates used in disclosures. While defining the same probability hurdles (P90, P50, P10) as the SPE, the CIM apply these at the reporting level (country or corporation) while the SPE applies them at the entity level (field, property or project). In large portfolios the central limit theorem would allow lower confidence targets at the entity level. *(although COGEH still requires a "high degree of certainty" at the entity level)*. Both SPE and CIM guidance discourages fully probabilistic aggregation beyond the field/project level. However, since the CIM claims that even deterministic estimates have an inferred confidence level, the same portfolio effect may potentially be reflected in their deterministic estimates.
- Although NI 51-101 does specifically include bitumen (including mined bitumen) as reserves, the CIM definitions do not address the issue and COGEH guidelines do not include bitumen or synthetic oil as product types. SPE guidelines are designed to incorporate both conventional and unconventional reserves but do not specifically address in situ recovery versus mining extraction methods.
- The CIM classification allows the subdivision into Developed (separated into Developed Producing and Developed Non-producing) and Undeveloped at all reserves certainty levels whereas the current SPE definitions apply these status categories only to proved reserves.
- The CIM reserves definitions state that, "the fiscal conditions under which reserve estimates are prepared should generally be those which are considered to be a reasonable outlook on the future. Security regulators or other agencies may require that constant or other prices and costs be used in the determination of reserves and value. In any event, the fiscal assumptions used in the preparation of reserves estimates must be disclosed".

## Russian Federation Classification Scheme (RF-2005)

Comparisons of the new Russian Federation and SPE/WPC/AAPG classifications can be best approached by first examining separation into categories based on the “commercial axis”:



There is overall alignment at major boundaries. The Russians split the undiscovered into 3 categories that can be roughly described as prospects (D1), leads (D2), and plays (D3). The SPE and other organizations such as the NPD apply a project maturity axis to describe a similar approach.

While the SPE classification refers to recoverable volume throughout, the Russians estimate only in-place volumes for their D3 and D2 classes and the sub-economic portion of their Contingent Recoverable Reserves. The logic is that lacking sufficient definition for computing development plan economics, it is not feasible to forecast recovery to an economic limit. In the SPE approach, analogous developments would be used to estimate recovery efficiency.

The overall intent of the Contingent Recoverable Reserves category is similar to the SPE's Contingent Resources, that is, these are discovered volumes that because of some contingency (economics and/or technology), it is not currently feasible to proceed with development. Those volumes categorized as sub-economic by RF-2005 due to access constraints such as under parks, cities, or in water protection zones (environmental) or lack of local pipelines and/or infrastructure may still have economic potential and would not be segregated in the SPE classification unless project status categories were also applied. The RF-2005 proposal also includes shut-in wells in the Sub-economic

Contingent category; without further clarification it is not obvious why this is not classified as developed but non-producing.

The Russians use the term “reserves” for all types of discovered volumes (in-place, economic, sub-economic) whereas the SPE uses the term reserves only for the remaining, commercially recoverable portions of discovered volumes. *(This may be typical of linguistic difficulties that are encountered internationally when technical terms are translated using their general meaning.)*

The Russian reserves classes A, B, and C1 grossly correlate to SPE Proved Developed Producing (PDP), Proved Developed Non-Producing (PNP) and Proved Undeveloped (PUD) respectively (see above comparison graphic). Recoverable estimates in their category B have all the certainty of Category A but are not on production for some reason. Category C1 correlates to SPE PUD in areas one drainage unit offset to Proved Developed but does not specifically address proved reserves in deeper reservoirs or the case where a relatively large expenditure is required to a) re-complete an existing well or b) install production or transportation facilities for primary or improved recovery projects.

Category C2 encompasses SPE probable and possible (unproven) and can only be dissected by detailed examination of the information available. Although probabilistic methods are rarely applied in Russia, this could be used as a basis for defining a 2P (best) versus 3P (high) estimate. The RF 2005 requires reporting by field/reservoir and thereafter aggregations to various levels and ultimately total Russia; aggregation is arithmetic by category based on the deterministic method.

RF-2005 does not address treatment of unconventional hydrocarbons (tight gas, coal bed methane, bitumen). The only reference to unconventional hydrocarbons is that heavy oils should be classified as “very complicated” accumulations.

Significant differences versus SPE guidelines include:

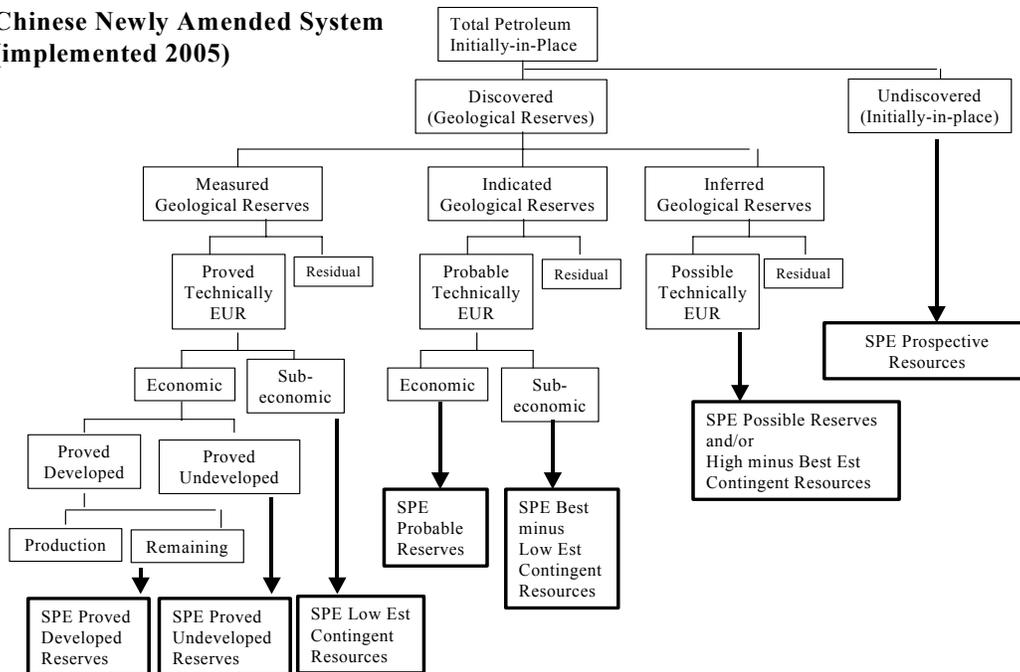
- RF 2005 includes incremental reserves due to application of “established” improved recovery methods and infill drilling in Category A (equivalent to SPE PDP) without the requirement for a successful pilot in the subject reservoir or a commitment to proceed with the incremental development.
- In historical Russian classifications, one value of recovery ratio was established in the original development plan and there was no provision to forecast a range of resulting recovery efficiencies. To some extent, this is still true, although incremental reserves from forecast application of a new recovery method can be included in category C1.
- The Russian classification does not provide for using more conservative commercial criteria for proved versus unproved reserves. All reserves are evaluated using the criteria “commercially recoverable if brought to production under competitive market conditions, with use of equipment and technology of recovery and treatment ensuring that the requirements for rational use of the subsoil and environmental protection are observed”.

Since the Russian classification is based on geologic certainty of in-place volumes, there is a much greater emphasis on volumetric analysis in all categories whereas most Western analysts would focus on production performance-based estimates (decline, material balance) in Proved and Probable estimations for mature properties.

## China Petroleum Reserves Office (PRO-2005)

There is a broad general agreement between the new Chinese (PRO-2005) and the SPE classification systems. However, there are some interpretational differences:

### Chinese Newly Amended System (implemented 2005)



a) It is key to remember that under the Chinese classification system:

- 1) the term “reserves” is used for both discovered in-place volumes and technically recoverable volumes in addition to economically recoverable volumes.
- 2) Further all certainty criteria are assigned to estimated in-place volumes and ultimate recoverable volumes, not restricted to remaining volumes. Thus, the Chinese Proved and subset Proved Developed Estimated Initially Recoverable Reserves must be reduced by prior cumulative production before comparison to SPE reserves.

b) The Chinese have retained their industrial flows criteria by completion depth as a reference to define a commercial discovery but staff are encouraged to estimate local or field-wide criteria as well. In general, a commercial rate would allow recovery of the cost of drilling a producing well (excluding abandonment costs).

c) For Proved Technical Estimated Ultimate Recovery (PTEUR), the feasibility studies assume recent average prices and costs but for Proved Economic Initially Recoverable Reserves (PVEIRR), more stringent criteria include use of prices and costs as of the assessment date. *(In practice, Chinese companies may apply their internal forecast prices in feasibility studies to define PTEUR.)*

d) For PBEIRR/Probable, Chinese guidelines allow use of either historical average or forecast costs and prices whereas the SPE Probable and Possible apply forecast costs and prices.

e) The Chinese subdivide the undiscovered resources (comparable to SPE/WPC/AAPG Prospective Resource) into two categories: Petroleum Initially-in-place in Prospects at early stages of exploration and Unmapped Petroleum Initially-in-place that is based on regional reconnaissance mapping only.

f) While the China classification makes reference to probability targets, their post-discovery assessments are usually based on deterministic scenarios and it is rare that probabilistic analyses are used. While 2P and 3P match SPE guidance at P50 and P10, the Chinese definitions for Proved reference a hurdle of P80 versus the SPE P90. The Chinese documents include phrases such as “indicated geological reserves are estimates with a moderate level of confidence with a relative error not more than +/- 50%”. This does not relate to actual probabilistic targets and is supplied as a general guide. It would appear that this implies a higher degree of uncertainty than normally associated with SPE probable estimates.

g) In the detailed definition of LKH, the Chinese specifically state that they would accept reliable pressure data as a primary criteria; the SPE requires a lowest penetration “unless otherwise indicated by definitive geological, engineering or performance data”.

The Chinese expect that there should be no material difference between SPE Proved Ultimate and their PVEIRR. However, it should be noted that it is common for the feasibility studies to include waterflood in the initial plans for oil reservoir development and improved recovery volumes may not be uniquely identified.

The issue of combining a range of recovery efficiencies with in-place uncertainties to define proved versus probable and possible recoverable volumes is problematical in the Chinese system. In many cases, the assessment focuses on “geological uncertainty” and an analog recovery factor is applied.

Regarding non-conventional hydrocarbons, the same classification is applied to Coal Bed Methane reserves; the Chinese have not yet developed regulations for bitumen or oil sands.

## Norwegian Petroleum Directorate (NPD-2001)

The Norwegian Petroleum Directorate classification (NPD-2001) is based on the SPE/WPC/AAPG 2000 classification but expanded to utilize categories that differentiate projects based on their commerciality, that is, their maturity towards full producing status. These categories can also be viewed as qualitative measures of commercial risk or chance of commerciality.

		SPE/WPC/AAPG	NPD		
TOTAL PETROLEUM-INITIALLY-IN-PLACE	DISCOVERED PETROLEUM-INITIALLY-IN-PLACE	COMMERCIAL	PRODUCTION	0	Sold and Delivered
			P90      P50      P10	1	On Production
			RESERVES	2 F/A	Under Development
		SUB-COMMERCIAL	1P      2P      3P	3 F/A	Development Committed
			CONTINGENT RESOURCES	4 F/A	Resources in Planning
			.....	5 F/A	Development Likely
			.....	6	Development Unlikely
	UNRECOVERABLE		7F/A	Being Evaluated	
	UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE	PROSPECTIVE RESOURCES		8	Prospect
		.....		9	Play and Lead
UNRECOVERABLE					

← Range of Uncertainty →

F= First recovery  
A = Advanced recovery

The horizontal axis relates to the uncertainty in recoverable hydrocarbon quantities associated with each development project. There may be several projects recovering oil and gas from the same accumulation, and these may be in different stages of maturity, and thus in different categories. The NPD has found it to be convenient to distinguish between the first project (F) and additional projects (A). For example, the incremental recovery associated with an Enhanced Oil Recovery (EOR) project would be tracked using the "A" attribute and the quantities associated with primary recovery project use the "F" modifier while the estimate of original oil in-place may remain constant.

Probabilistic hurdles are similar to the SPE guidance, that is, low estimate/P90 or P80 and high estimate/P10 or P20. The P80/P20 option is rarely used and was included to accommodate major issuers who used that convention in earlier times. The NPD substitutes the term "base estimate" for best estimate. It reflects the current understanding of the extension, characteristics and recovery factor of the reservoir. The base estimate can be calculated deterministically or stochastically. If calculated by a stochastic method, it should correspond to the mean value (not the median/P50).

As the NPD classification is developed for the resource management needs of the Norwegian Government and the business process management needs of the Norwegian companies, emphasis has been more on reflecting changes in ultimate recoverable estimates than on annual financial reporting. The concept of proved reserves according to deterministic criteria is not recognized as we know it from the SEC or SPE definitions. P90 reserves are however both a reasonable and simple, well defined substitute,

remembering that future, uncommitted projects are not allowed to contribute to the 2P nor 3P reserves as this would distort the P90 of the distribution.

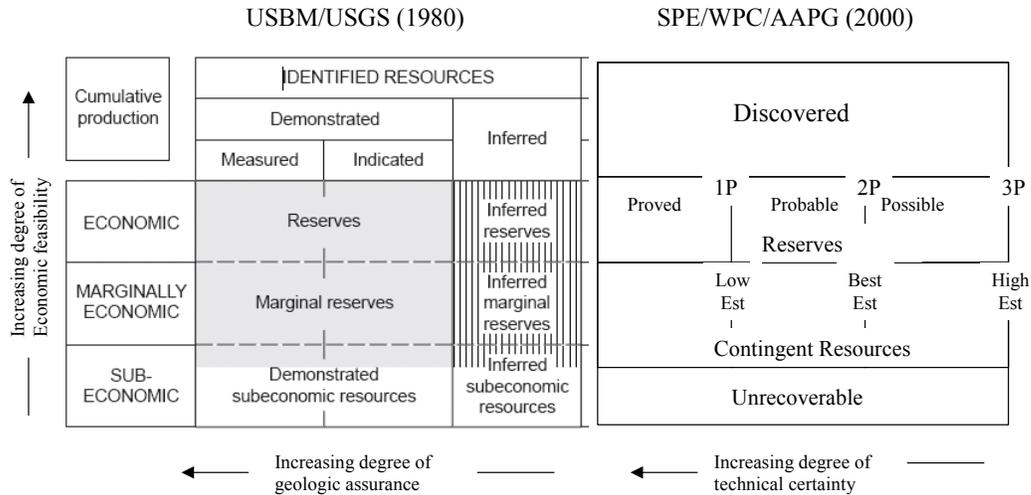
While the terms Proved, Probable and Possible are not utilized, the definitions of low/1P, base/2P, and high/3P estimated quantities allow derivation of these entities if required (notwithstanding that the base is the mean and not P50).

The NPD defines a discovery as one petroleum deposit, or several petroleum deposits collectively, which have been discovered in the same wildcat well, in which through testing, sampling, or logging there has been established a probability of the existence of mobile hydrocarbons (includes both a commercial and a technical discovery).

The NPD does not give definitions of commercial/economic or sub-commercial/sub-economic but depends on the status categories to segregate Reserves from Contingent Resources. Contingent Resources are defined as petroleum resources that have been discovered but no decision has yet been taken regarding their (development for) production. It is noted that their category 3 (reserves which the licensees have decided to recover) may include projects for which the authorities have not yet approved a Plan of Development (PDO) or granted exemption therefrom. Thus the differentiation of Reserves from Contingent resources may seem to rest solely on the licensees' internal commitment to proceed with development. Under the petroleum law, the licensees are however given the right to produce the petroleum. The government approval of the PDO is an occasion to align interests in the way development will take place and not an occasion to remove a right already granted.

## US Geological Survey (USGS-1980)

The following graphic illustrates the overall comparison of the USBM/USGS (1980) and the SPE/WPC/AAPG (2000) classifications for the discovered portion of total resources.



The USGS classification is based on two parameters whereby resources are classified by feasibility of economic recovery and degree of geologic certainty. The SPE classification classifies resources based on 3 parameters: feasibility of economic recovery (commerciality) in the y-axis and a combination of degree of geologic assurance and degree of recovery efficiency termed technical uncertainty on the x-axis. Although some differences exist, the classification schemes are comparable.

The USGS hypothetical and speculative undiscovered resources combined correlate to SPE Prospective Resources; they can be classified by technical uncertainty (low/best/high estimate or a probability distribution) but there is no attempt to segregate undiscovered volumes according to commercial certainty.

Although the USGS measured, indicated, and inferred classes of reserves are assigned to reflect geologic assurance, these classes have been loosely interchanged with, respectively, the proved, probable, and possible classes. While measured and proved are comparable, probable and possible may not be directly interchangeable with indicated and inferred. Some earlier publications suggest that USGS inferred is not a high side estimate of indicated but refers to only unexplored deposits for which estimates of the quality and quantity are based on geologic evidence and projections and may not have any direct sampling or measurements. Later publications indicate closer alignment with SPE possible reserves that may be a combination of high-side estimates of drilled (sampled) areas and adjacent undrilled areas (fault blocks and satellite features).

The shaded area in USGS classification is termed the “reserves base”; “it may encompass those parts of the resources that have a reasonable potential for becoming economical within the planning horizons (30 years) beyond those that assume proven technology and current economics”. Thus, it appears that inferred reserves may be based on forecast conditions while demonstrated (measured and indicated) are based on

current conditions. This contrasts with SPE guidance that only proved is based on current conditions while probable and possible may be based on forecast conditions.

Users should be aware of the “reserves” terminology used in current USGS reports as illustrated in this chart based on results information in the USGS World Petroleum Assessment 2000.

World Excluding United States (conventional)

	Oil - billion barrels			
	<u>F95</u>	<u>F50</u>	<u>F5</u>	<u>Mean</u>
1- Cumulative Production				539
2 – Remaining Reserves				859
3 – Known Reserves (1+2)				1398
4 – Reserves Growth	192	612	1031	612
5 - Undiscovered	334	607	1107	649
6 – Future Volumes (2+5)				1508
7 – Future Grown Volumes (2+4+5)				2120
8 – Total Endowment (1+2+4+5)				2659

“Remaining reserves” are taken from NRG Associates and Petroconsultants (IHS) reports and may represent proved or proved plus probable reserves as defined in their data sources (typically using SPE definitions). “Reserves Growth” as discussed above is based on USGS projections of future (30 year) additions from new recovery methods, improved prices, satellite development, etc. using proprietary algorithms derived from analog fields of similar maturity. The volumes may include what would be currently classified under SPE guidelines as possible, contingent resources and even some portions of unrecoverable and speculative potential (for satellite accumulations). The USGS does not quote reserve growth for individual fields, it is only statistically meaningful for large aggregations; the 2000 report only quotes reserves growth on a total world basis. The SPE term “estimated ultimate recovery” may be applied to either USGS terms “known reserves” or “future endowment”.

The reserves growth and undiscovered resource aggregations use probabilistic models and will have portfolio effects. The USGS uses P95 for the lowside and P05 for the upside with two measures of central tendency being the median (P50) and the mean. Cumulative production and remaining reserves are aggregated arithmetically.

The 2000 USGS world assessment does not include unconventional hydrocarbons (continuous accumulations) from tight gas, coal bed methane, heavy oil (<15<sup>0</sup> API), and tar sands but do recognize their potential. As extraction and processing technology develops, the geologic descriptions are matured and their recovery becomes economically feasible, they will be assessed in the same manner as conventional hydrocarbons.

USGS “economic” implies that profitable extraction or production under defined investment assumptions has been established, analytically demonstrated, or assumed with reasonable certainty. This would not conflict with SPE guidance. The USGS definitions do not include more detailed guidance on such issues as pricing, discovery criteria and proved (measured) limits (e.g. LKH, DSU offsets).

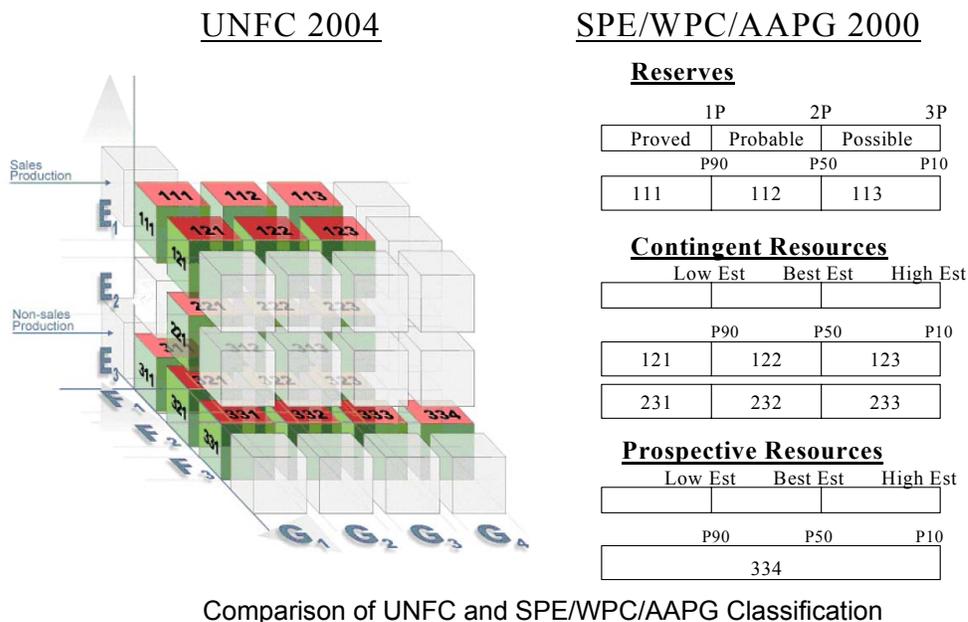
## United Nations Framework Classification (UNFC-2004)

The UNFC was originally developed to support consistent reporting of coal resources but was later extended to apply to all minerals. The classification was developed under the auspices the United Nations Economic Commission for Europe (UNECE) and subsequently endorsed by the UN Economic and Social Council (ECOSOC) in 1997 and recommended for worldwide implementation. In 2000, it was proposed to study its application to all energy resources including uranium and petroleum. The study was carried out by the UNECE Ad Hoc Group of Experts on the Harmonization of Energy Reserves/Resources Terminology; it included broad representation from governments and industry including prior members of the SPE Oil and Gas Reserves Committee. The result was the UN Framework Classification for Energy and Mineral Resources (UNFC), published in 2004 and subsequently endorsed for worldwide implementation by the ECOSOC.

The study teams built on existing standards; in the case of petroleum, the primary reference standard was the 2000 SPE/WPC/AAPG classification but care was taken to accommodate other systems such as that used in the Russian Federation. The classification is based on three key attributes:

- Economic (E)
- Field Project Status/Feasibility (F)
- Geological (G)

Subdividing each attribute results in a 3-dimensional matrix composed of 36 potential categories, 19 of which are applied to petroleum. An alpha-numeric numbering system bridges the language barrier for international communication (by adopting the standard sequence “EFG”, it is further reduced to a pure numeric system). The following figure illustrates mapping of the UNFC and SPE classifications.



The category boundary conditions are sufficiently similar to allow detailed correlations between the two systems.

The economic and feasibility axes are combined in the SPE 2-dimensional system where the single vertical axis is the degree of commerciality or the chance of reaching producing status within a reasonable time frame.

The G-Axis is correlative to the horizontal axis in the SPE classification that represents the range of uncertainty in quantities to be recovered. It is recognized that the recoverable quantities reflect uncertainties both on the quantities initially-in-place and also on the efficiency of the development project applied.

UNFC introduces the principle of non-sales quantities both to make the material balance complete and to allow for the use of the UNFC in the management of important economical resources that are not traded commercially. In oil and gas, this will typically be fuel, flare, and processing losses.

The UNFC uses field status categories to effectively separate reserves and contingent resources. UNFC has introduced the concept of justified, but not committed projects to define reserves, but excluded such projects from contributing to committed reserves. Committed reserves are foreseen as the primary basis for supplementing financial reports. This allows the continued communication of large recoverable quantities, such as those reported from the Middle East, as reserves and not as a high grade of contingent resources.

The UNFC introduced a sub-category (E1.2 – Exceptional Economic) to accommodate projects that are not normally economic but production is supported by government subsidies based on strategic requirements.

The UNFC geologic (technical) uncertainty categories are similarly based on low/best/high estimates with the same probability hurdles (P90/P50/P10) as recommended in the SPE system. Estimates may be based on either deterministic or probabilistic methods in both systems.

The SPE classification maintains the same technical uncertainty classes (low/best/high estimates) from pre- to post-discovery with the only change being in field status or discovery risk. The UNFC classifies all undrilled resources as G4; any subdivision by technical uncertainty is given by non-numeric qualifications.

The UNFC is a high level set of principles and definitions but currently lacks the detailed application guidelines (e.g. LKH constrains on proved) to fully implement the system. The Ad Hoc Group of Experts has been charged with developing application guidelines and that project is ongoing in liaison with the SPE Oil and Gas Reserves Committee.

# Findings and Analysis

## Overview – Classification & Assessment Approach

For those agencies that assess the total hydrocarbon resources, there is a high degree of commonality in classification approach.

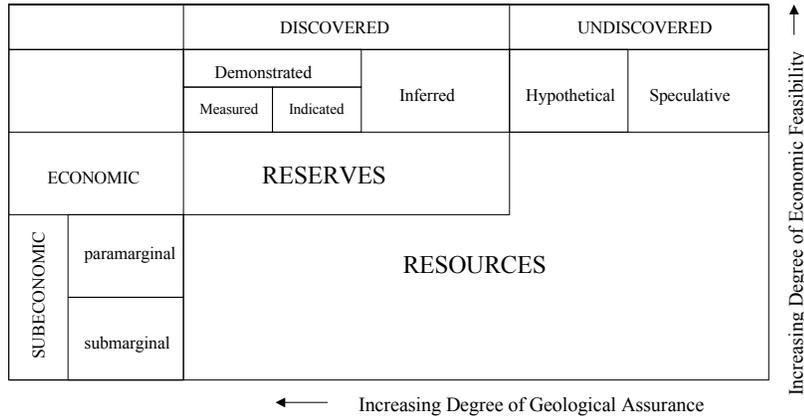


Figure 2: McKelvey Box (unmodified)

Most of these systems, including the current SPE definitions, are based on the classification approach recommended by V.E. McKelvey in the early 1970's and captured graphically in the McKelvey box diagram (figure 2). In this classical diagram, the horizontal axis denotes geological certainty while the vertical axis denotes the degree of economic feasibility. Thus, all of the agencies recognize three major categories: undiscovered, discovered economic and discovered sub-economic.

The following simplistic description of an exploration to production/abandonment life cycle provides background to address key differences in reserves and resource classification and definitions used by individual agencies.

In the initial phase, a potential accumulation is identified, the hydrocarbon type(s) is forecast, a range of in-place volumes assessed, and a chance of discovery is estimated. Assuming a discovery, a high-level development plan is applied to estimate a production rate versus time profile and associated cash flow schedule. Integration over time to a defined economic limit yields an Estimated Ultimate Recoverable (EUR) and associated Future Net Revenue (FNR). These undiscovered volumes are termed Prospective Resources.

Based on results of an exploratory well, all or a portion of the recoverable volumes in the accumulation may be re-categorized as discovered based on defined criteria. These discoveries may be economic or sub-economic depending on the development plan and costs/prices assumed. The sub-economic include Contingent Resources (and unrecoverable) while the economic are "provisionally" categorized as Reserves.

Additional analysis and potentially appraisal drilling may be required to fully define the detailed development plan, associated recoverable volume estimates, and project economics to justify the investment commitment to move into a development phase leading to commercial production. Once such a project commitment is confirmed, the

time integration of the product delivery schedule defines quantities to be finally classified as Reserves. Based on these analyses and by applying additional guidelines, the recoverable volumes scenarios can be separated into low estimate (proved), best estimate (proved plus probable or 2P) and a high estimate (proved plus probable plus possible or 3P).

Most agencies prescribe additional rules to define the low estimate or proved class. Reserves may be further classified as developed and undeveloped based on the status of the wells and associated production facilities required to implement production.

*In the following analysis the terms “proved” and “proven” reserves are considered synonymous. Also, most definitions use the generic term “quantities” to describe the amount of product recovered from a reservoir although the measurements are typically in terms of volumes at defined surface conditions (temperature and pressure). For purposes of this discussion, the terms quantities and volumes are considered synonymous.*

**Comparison by Major Issue**

Using the above activity flow, the resulting classification process can be related to a series of key decision points (Figure 3).

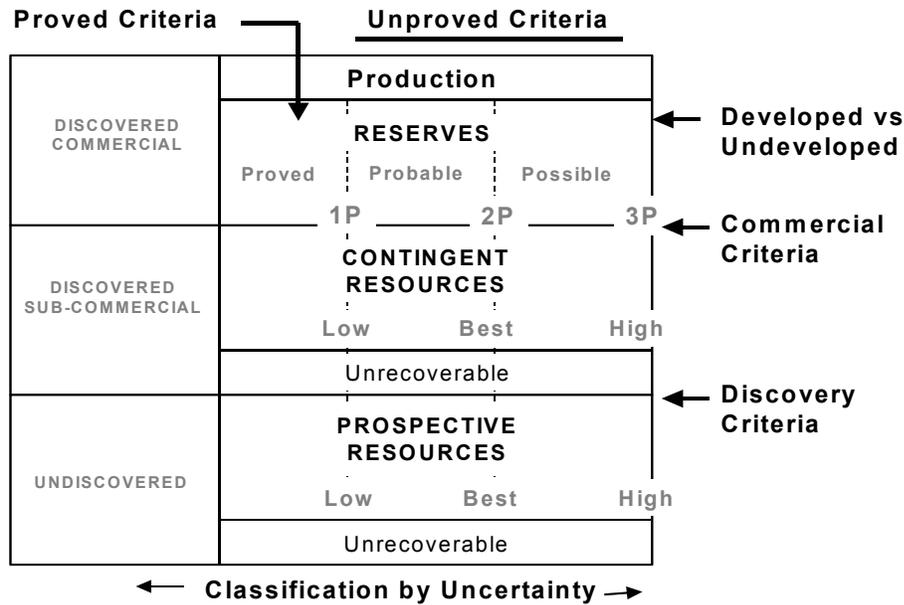


Figure 3: Decision Points in Resource Classification

The following issues regarding decision criteria are identified for further consideration by the Definitions subcommittee:

**Classification by Discovery Criteria**

The initial step in the assessment process is to clearly identify those accumulations that have met the criteria to be classified as “discovered” based on the results of one or more exploratory wells. The principle is well documented in the SPE glossary definition of Know Accumulation: “The term accumulation is used to identify an individual body of moveable petroleum. The key requirement to consider an accumulation as known, and

*hence contain reserves or contingent resources, is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice, provided there is a good analogy to a nearby and geologically comparable known accumulation”.*

While at this junction, we need not segregate reserves and contingent resources, most of the agencies’ guidelines require actual production or a conclusive flowing well test at “commercial rates” as indicative that a reservoir has been “discovered” and there is the potential to ultimately define “proved reserves”. There is some latitude in definition of “commercial rates” as this obviously varies by location, existing infrastructure, hydrocarbon type/quality, price/cost and fiscal terms. For example, China issues a table of completion depth versus flow rate as a minimum guidance.

In some cases, the productivity can be based on alternate testing methods that record short duration drawdowns and capture fluid/gas samples (wireline formation tests) but typically require additional supporting evidence (logs, cores, seismic). This appears to be the intent in SPE definitions but is accepted by the SEC only in deep water Gulf of Mexico wells. The level of evidence is based on production or a conclusive test in neighboring wells completed in the same or analogous reservoirs when supported by logs and cores in the subject reservoir. The appropriateness of the analog based on similarities of the reservoir and the distance of offset are interpretations that must be individually justified.

Thus, most of the definitions, including those of the SPE, focus on the well rates related to proved reserves but are more circumspect regarding establishing discovery criteria for unproved reserves and contingent resources. The China definitions allow recognition of “geological reserves” in “known reservoirs after the oil and gas is found by drilling”.

SPE probable reserves can be based on well logs but lack core data or definitive tests and are not analogous to producing or proved reservoirs in the area. In the SPE 1997 definitions, possible reserves can be assigned in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates. *(Clearly this appears to be closer to contingent resources in their 2000 classification).*

The Canadian CIM definitions are explicit in that “potential accumulations that have not been penetrated by a wellbore may (only) be classified as Prospective Resources”. “Confirmation of commercial production of an accumulation by production or a formation test is required for classification of reserves as proved”. However, in the absence of production or formation testing, probable and /or possible reserves may be assigned based on well logs/cores which indicate analogy to proved reservoirs in the immediate area.

*Notwithstanding the requirement for a well penetration, users typically assign unproven reserves to adjacent fault blocks without conclusive evidence that faults are non-sealing allowing pressure communication.*

The Norwegian Petroleum Directorate (NPD) defines a discovery as one petroleum deposit, or several petroleum deposits collectively, which have been discovered in the same wildcat well, in which through testing, sampling, or logging there has been

established a probability of the existence of mobile hydrocarbons (includes both commercial and a technical discoveries).

*The flow rate and mobile hydrocarbon criteria in the current definitions clearly refer to conventional petroleum and would be difficult to apply to non-conventional hydrocarbon deposits such as bitumen that is immobile under natural conditions.*

#### Classification by Commercial Criteria

Not all accumulations that meet the criteria of a “discovery” can be commercially developed in a timely manner. Even where the discovered accumulation is large and flow rates are substantial, there may be some contingency that prevents development and hence classification as “reserves”. Example contingencies include: lack of available market, lack of current producing or transportation infrastructure, environmental or legal constraints. In many cases the reservoirs are not economically producible with current technology and the contingency is a combination of technology development and/or product sales price.

Some reservoirs have tested oil or gas but at rates too low to meet current economic criteria, thus the conflict with the “*commercial flow rate*” requirement in the above discovery criteria.

For agencies publishing a full reserves and resource classification, there is always a category equivalent to contingent resources (SPE, Canada, Norway); synonyms are sub-economic (China), marginally economic (USGS), or sub-commercial (Russia). All classifications, excepting China’s, recognize full geological/or technical uncertainty classes (low/best/high estimate or equivalent) within the contingent resources category.

#### ○ What is Commercial?

Three aspects that arise throughout the various classifications as criteria for reserves versus contingent resources are: economic, commercial and commitment (or intent). There is general agreement that economic means the project income will cover the cost of development and operations (at zero discount rate). There is not enough detail supplied to judge whether cash flows are uniformly computed (before/after tax?, what pricing assumptions?). The Canadians recommend using a reasonable outlook; the Chinese use current market conditions, the Russian reserves can be brought to production under competitive market conditions. In most definitions commercial is used synonymously with economic.

Interestingly the current SPE definition of commercial makes no reference to economics but focuses on demonstrated intent to bring to production status within a reasonable time frame. “Intent may be demonstrated with firm funding/financial plans, declarations of commerciality, regulatory approvals and satisfaction of other conditions that would otherwise prevent the project from being developed and brought to production”. The Russian and Chinese do not directly address “intent” but refer to an approved development plan that will be carried out in the near future. Similar to the SPE approach, under the CIM guidelines undeveloped recoverable volumes must have a sufficient return on investment to justify the associated capital expenditure in order to be classified as reserves as opposed to Contingent Resources.

Thus most agencies require intent to develop and some element of positive economics for a development project to be commercial. *There is some latitude in whether proved*

reserve must be economic standalone, and whether a standalone project must be economic – in some cases the economics are defined on a multi-project business level.

○ Project Status Categories

Project status categorization links the geologic endowment with the industrial and the financial resources deployed to exploit it. In the 2000 classification, when referring to their classification graphic, the SPE states “the vertical axis represents the level of status/maturity of the accumulation. Many organizations choose to further subdivide each resource category using the vertical axis to classify accumulations on the basis of the commercial decisions required to move the accumulation towards production”.

The Norwegian Petroleum Directorate (NPD) states that: “Originally recoverable resources in a field or discovery are classified according to their position in the development chain from a discovery being identified until production of the resources is complete. The system is designed to allow a single field or discovery being able to contain resources classified in different project status categories”.

The NPD focuses on the “project” being applied to convert in-place hydrocarbons into recoverable sales products. Their model allows several development projects, both primary and secondary (additional) to be applied to the same accumulation. In this approach, reserves and contingent resources are separated by the project maturity that is based on commitment by the owners and does not specifically address economics.

The SPE 2001 supplemental guidance notes that project status can be viewed as related to development risk (figure 4); that is, higher levels of maturity reflect higher probability (lower risk) that the accumulation will achieve commercial production. While some users suggest that reserves should have 90% probability of reaching producing status, neither the SPE of NPD directly associate quantitative risk factors with their project status categories.

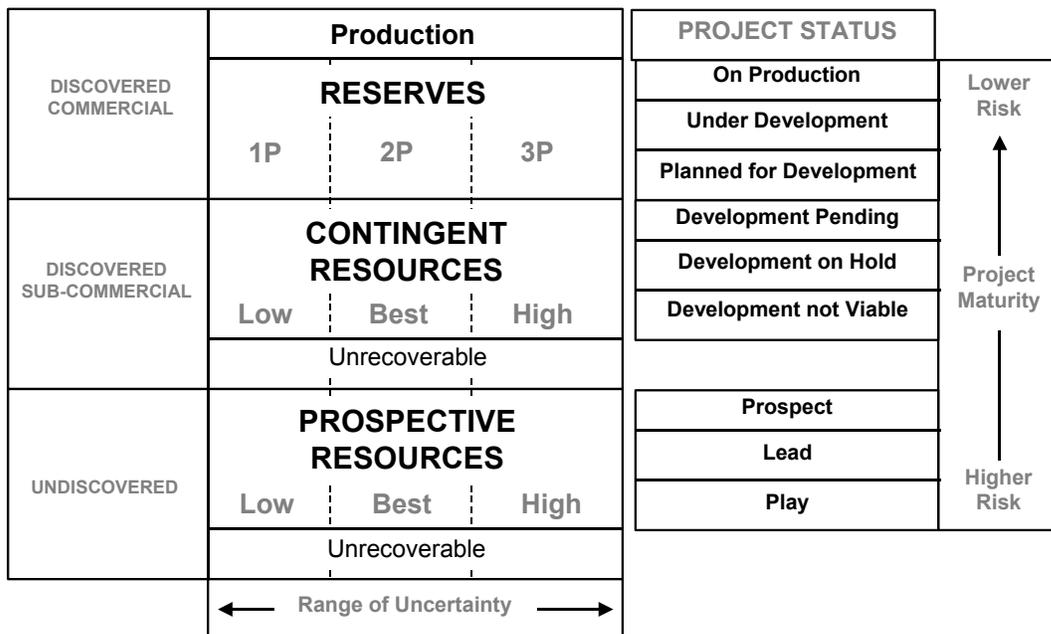


Figure 4: Project Status Categories/Commercial Risk

The UNFC addresses this issue using two axes within their 3-d cube system: E = Economic and commercial viability and F= Field project status and feasibility. The highest assurance category is a project that is both economic and is either on production or a firm commitment to develop has been documented. By using the two axes an explicit description of both economic and project status can be designated. Note that UNFC “reserves” may include SPE reserves plus other recoverable quantities through justified but not committed projects. Both NPD and current SPE guidelines allow some latitude in defining commitment to qualify as reserves (for example partner concurrence but lacking final government approvals).

#### Classification by Uncertainty

All classifications use the horizontal axis to describe an uncertainty range of volume outcomes and identify three subdivisions: proved/low estimate, 2P /best estimate, and 3P/high estimate. In all cases, except for the China classification, these same subdivisions are used in contingent resources. The USGS terms measured, identified, and inferred are generally correlative to proved, probable, possible although the boundaries may not exactly align. The NPD refers to the intermediate scenario as the “base estimate”.

The Russian, Chinese, and USGS classifications appear to retain more of the original McKelvey approach in which the horizontal axis is indeed “geological uncertainty” related to in-place volumes and the characteristics of the reservoir. This certainty is based on the phase of exploitation and well density. It appears that recovery efficiency is often defined as somewhat fixed based on analogs and is taken as the optimum rate associated with an approved development plan. Quite often this includes incremental recoveries associated with established improved recovery processes routinely applied in these types of accumulations. It is difficult for these classifications to accommodate combinations of in-place volume uncertainty and recovery efficiency uncertainty; these combined uncertainties are central to the SPE classification.

This approach is best illustrated in the Chinese classification. Their term “reserves” includes both geological reserves (in-place) and recoverable reserves. The initial uncertainty classification (measured, indicated, inferred) is based on in-place volumes and the phase of exploitation; for example measured geological reserves are estimated with a high level of confidence, have been proved economically recoverable by appraisal drilling, fluid contacts or LKH established, and limits are delineated by reasonable well spacing. In-place volumes in each of these certainty classes are then subdivided into technically recoverable and economically recoverable. Despite this different approach, the Chinese economically recoverable reserves categories (PVEIRR and PBEIRR) are very comparable to the SPE proved and probable before production.

All agencies identify a “grey area” between possible reserves and contingent resources. It is noted that the Chinese inferred/possible category does not differentiate economic versus uneconomic as the volumes are not sufficiently defined to make that distinction.

*Clarifications may be required to explain how uncertainty distributions and/or scenarios underlying the reserves and resource classes may address a combination of in-place volumes uncertainty and recovery efficiency uncertainty as regards the development project(s) applied. In addition, there will be uncertainty associated with the realization of uncommitted projects.*

○ Deterministic versus Probabilistic Methods and Aggregation Issues

While each of the agencies can accommodate either deterministic or probabilistic methods for uncertainty analysis, only in Western Europe is probabilistic analysis routinely applied to discovered volume assessments. The standard targets in probabilistic assessments are set at low estimate/proved  $\Rightarrow$  P90, best estimate/2P  $\Rightarrow$  P50, and high estimate/3P  $\Rightarrow$  P10. *There are two exceptions: China guidelines specify proved  $\Rightarrow$  P80; NPD guidelines allow either P90 or P80 for low estimates, P10 or P20 for high estimates and if the best estimate (= their base estimate) is calculated by stochastic methods, it should correspond to the mean value (not P50).*

There is not universal agreement on the entity level to which these targets apply; this is commonly referred to as the “aggregation issue”. The SPE specifies the guidance applies to the field or property level (pre-aggregation) whereas Canadian (CIM) guidance specifies the reporting level (post-aggregation). Given the effect of the central limit theorem, the arithmetic summation of field Proved volumes in a large portfolio of properties would typically be much less than the P90 of the probabilistic aggregation of the distributions associated with these same properties. This same portfolio effect will cause the arithmetic sum of P10 volumes to be much greater than the P10 of the probabilistic aggregate. *(The actual variance is a function of the dependencies defined in the probabilistic aggregation model; the mean of the aggregate is not impacted by dependency variations.)*. Note that both the CIM and SPE recommend that probabilistic aggregation be confined to the field, property or project level.

Comparisons of SPE and CIM proved volumes may still be problematical since the CIM suggests that even deterministic estimates have an “inferred confidence level” that would approximate the probability targets. The original Canadian guidance included examples in which reporting level P90 can be achieved where the inferred proved confidence level of individual properties in the portfolio is significantly less than P75. However, the NI 51-101 regulations also require that proved estimates at the entity level should reflect a high degree of confidence.

The SEC supplemental guidance requires that proved reserves be defined at the field level and then arithmetically summed to the reporting level. *(While UK-SORP option 1 duplicates SEC definitions, some issuers do not interpret that the SEC’s supplemental guidance applies)*. None of the other classifications directly address the aggregation issue. While they do not clearly identify the entity level being assessed, it is inferred that it is at the reservoir or field level.

Many users interpret that the current SPE definitions consider deterministic and probabilistic methods as distinct and thus the criteria (e.g. the proved estimate should have high degree of confidence and at least P90 probability) are not necessarily synchronized. Consideration should be given to clarification using the Canadian logic that deterministic scenarios have an inferred confidence level and the same quantitative probability targets should apply. The guiding principle is that the reserve volumes assigned to each uncertainty class should be similar despite the method applied.

The aggregation approach may depend on what the results are being used for. For internal portfolio management fully probabilistic aggregation that preserves the beneficial “portfolio effect” may be appropriate. For 2P reserve disclosures, probabilistic aggregation and arithmetic summation may yield similar results. Regarding proved reserves disclosures, arithmetic aggregation may be the only method that preserves the

entity level high degree of certainty. *The ideal solution would be to disclose both the arithmetic and probabilistic aggregate Proved to demonstrate the benefits of a large, diversified portfolio in protecting against negative corporate Proved revisions.*

#### Proved Reserves Criteria

All the agencies give specific guidance that limit quantities assigned to their low estimate case (proved, measured) including:

- LKH – most are similar to SPE guidance, that is, if a hydrocarbon/water contact is not penetrated in a wellbore, volumetric calculations of proved reserves should be restricted by the lowest known structural elevation of occurrence of hydrocarbons as defined by well logs, core analysis or formation testing (*in the same reservoir*). China guidelines allow use of reliable pressure data to define the fluid contact. The SEC allows that “upon obtaining performance history sufficient to reasonably conclude that more (proved) reserves will be recovered than those estimated volumetrically down to LKH, positive reserve revisions should be made”. The SPE allows the use of definitive geological, engineering or performance data, which would include pressure data, but in general only if supported by other data confirming the existence of a single pressure system.
- Lateral Extent – in addition to the drilling spacing unit (DSU) (or drainage area) of the productive well, proved reserves are limited to immediate offset locations (8 offset DSU's including diagonals) assuming they are within the productive limits of the reservoir, appear to have lateral continuity to the productive wells based on geological and engineering data and thus can be reasonable judged as economically productive. Geophysical data is specifically listed in addition to geological and engineering data used in judging proved limits in UK SORP proven plus probable disclosure option 2. The SEC rules that seismic data and/or pressure analysis cannot be the sole indicator(s) of lateral continuity. Where legal drilling units have not been defined, the SEC will accept “technically justified drainage area”.
- Existing Conditions – There is similar language in most classifications that proved reserves are those quantities with reasonable certainty to be commercially recoverable under current economic conditions, operating conditions and government regulations including prices and costs as of the evaluation date. While the SPE allows that current conditions may be based on average historical prices and costs, SORP option 1, and China use costs/prices on the date of assessment except as stipulated in contracts or agreements. The SEC specifies pricing determined by the market on the last day of the reporting company's fiscal year (typically December 31). The Russian definitions are less prescriptive; they require that all reserves be commercially efficient for recovery under competitive market conditions, with up-to-date equipment and technologies. Under Canadian regulations, the proved (developed producing and non-producing, undeveloped, and total) reserves are defined under both evaluation date (that is, year-end/constant) and defined forecast cost/price scenarios; the proved plus probable estimates use forecast cost/prices schedules only. Reserve impairment [ceiling test and depletion] is calculated using the 2P/forecast case. UNFC and USGS definitions do not address specific pricing criteria. In the case of the UNFC, this is not considered a functional criterion to be included in the classification itself, but a prescriptive one, to be fixed, when required in regulatory specifications or guidelines. This allows, for instance, the

use of historical or forecast prices based on “futures markets” or some other standard reference.

- Discovery Criteria – As previously discussed, many agencies, including the SPE, require more rigorous discovery criteria for proved (e.g. a flowing well test) than for unproved reserves (well log indications of productivity). This leads to assessments that may have unproven reserves without associated proved reserves; this is problematical for reserves defined using probabilistic methods.

The potential result of applying these special proved reserves criteria is to distort the underlying classification system; as shown in figure 5; in many cases the resulting Proved reserve quantities may be less than the low estimate whether derived by deterministic or probabilistic methods.

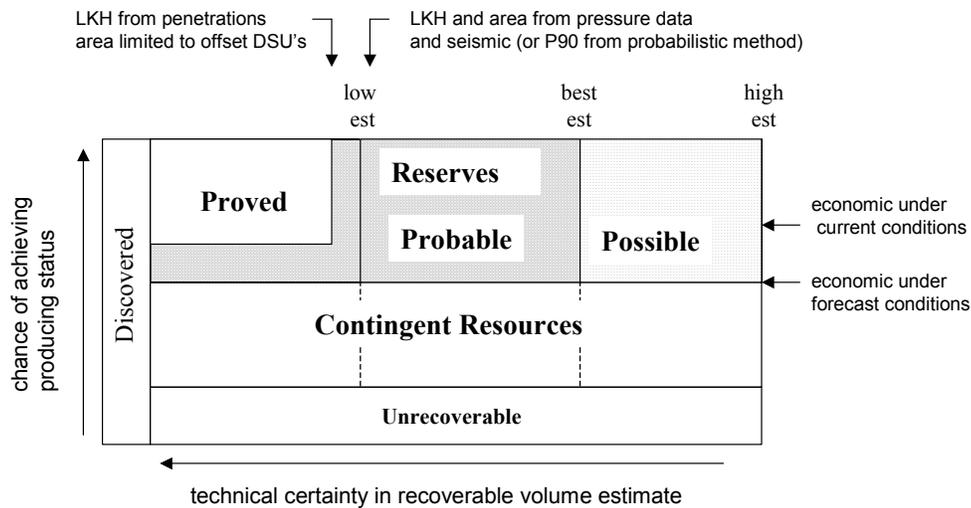


Figure 5: Impact of Proved Reserves “Special Criteria”

The practical solution may be to admit that there are two processes involved in reserves classification. First reserves are defined as commercial or non-commercial based on a 2P/forecast case and then a distribution of recoverable quantities is based on a defined development plan. Even where the probabilistic method is used, a separate deterministic, conservative case for proved may be required to incorporate specific regulatory downside cost/pricing estimates and technical criteria that limit the portions of the reservoir considered. The full suite of modern acquisition and analysis tools (3-d seismic, pressure gradient analysis, wireline formation tests, reservoir simulation, etc.) should be accommodated. The drilling spacing unit/drainage area criteria become difficult to apply in offshore operations, horizontal wells and complex multi-lateral completions.

#### Unproved Reserves Criteria

All classifications (excluding SEC) recognize lower certainty levels of reserves based on distance from producing wells, more limited availability of geological (and geophysical) and engineering data. Most define a best estimate (2P) and high estimate (3P) case. The Russian class C2 (inferred) includes probable and possible combined. While most classifications have the same general requirements for commerciality, there is variation.

- the SPE, China, UK SORP (option 2) allow use of forecast conditions different from proved. Canada uses forecast conditions for their base case but also require a constant case for proved. The Russians use the same conditions (commercially efficient under competitive market conditions) for all classes.
- the Canadian and SPE guidelines do not require a flowing well test to define probable and possible reserves.
- the Chinese state that it is not possible to separate possible from high estimate Contingent Resources due to lack of information.
- it is likely that the Russian C2 and the USGS inferred categories also includes some Contingent Resources
- the UNFC does not explicitly describe probable and possible criteria but refer to their best and high estimate cases based on geologic certainty. It furthermore allows all quantities to be described in terms of a probability distribution or a range using the SPE standards (P90, P50 and P10).

The SPE is the only classification that attempts to describe probable and possible reserves with specific deterministic criteria (e.g. updip/down dip fault blocks).

There certainly is ambiguity in the current SPE definitions (and others) between unproven reserves and contingent resources. Again use of a logical assessment sequence that first segregates reserves and contingent resource based on commercial criteria may be the key. This model needs to have a central reference point suggested by the Canadians as being the 2P/forecast case. Thereafter, 3P is an upside version (both of in-place and recovery efficiency) of the 2P case but uses the same commercial conditions. The option of including alternative development scenarios (including improved recovery or infill drilling) in the upside 3P case needs careful consideration and is difficult to synchronize with investments to yield valid associated values. Use of the NPD project-based model may be the practical solution.

#### Improved Recovery (IR) Reserves

“Improved Recovery is the extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes water-flooding, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes”.

For attribution of incremental proved reserves through application on new improved recovery methods, both the SPE and SEC require that there be successful testing by a pilot project or favorable response from an installed program in the subject reservoir. For established IR methods, proved reserves can be booked based on successful projects in analogous reservoirs with similar rock and fluid properties. The SEC has slightly more rigorous criteria for analogous reservoirs. UK and Canadian guidelines are similar to those of the SPE.

Historically Russian and Chinese classifications did not require a successful pilot for established IR methods; in fact the recovery efficiency derived for most oil development plans includes waterfloods. The current Russian classification retains this approach but the new Chinese proved definitions require that the IR technology be demonstrated by a successful pilot or successful response in an analogous field. All require some level of commitment to proceed with facilities installation prior to booking proved reserves.

SPE and Canadian classifications use similar criteria for unproved. Probable reserves can be assigned based on analogs when rock and fluid are favorable but no pilot has yet been implemented: Possible reserves can be assigned when success is less completely assured. There should be a reasonable certainty that the IR project will be implemented for reserves attribution. IR volumes can be assigned as contingent resources when the project results are risky due to poor economics, lack of technology, or lack of commitment.

For both internal project assessments and regulatory disclosures, the incremental recoveries and costs associated with improved recovery methods must be specifically identified.

The Canadian NI 51-101 reconciliation guidelines include infill drilling and compression under improved recovery processes.

#### Developed/Undeveloped

All classifications except the USGS provide for segregating proved reserves into Developed and Undeveloped based on the status of production facilities. Most criteria are similar to those stated under SPE guidelines: “developed reserves are expected to be recovered from existing wells including reserves behind pipe that can be brought to production with minimal cost. Improved recovery reserves are considered developed only after the necessary equipment has been installed.” The Canadian system similarly defines Proved develop producing and non-producing and these categories are roughly equivalent to Russian A and B categories.

Undeveloped reserves are expected to be recovered from new wells on undrilled acreage, from deepening existing wells to a different reservoir; or where a relatively large expenditure is required to re-complete an existing well. While not using these same terms, all agencies generally recognize that new capital is required to bring undeveloped reserves to developed status.

The Canadian guidance proposes that it is logical to distinguish developed versus undeveloped reserves in all uncertainty categories. Under this logic, even a proved developed reservoir has upside geologic extent and recovery efficiency that should be captured in the probable and possible categories. Canadian NI 51-101 rules also require that any undeveloped reserve should have a documented plan for development within two years to retain its reserves classification.

#### Other Issues

- Probable Without Proved – Because of the split criteria for proved versus reserves in general (pricing, technology), it is theoretically possible to have probable and possible reserves but no part of reserves meet the proved criteria. This is compounded if one applies the two tiered discovery criteria within the SPE and Canadian systems. This becomes somewhat difficult to envisage if one is using the probabilistic methods that define volumes exceeding P90 as proved. The option is to require that, if no part of the reservoir/project meet the proved criteria, then the total volumes should be reclassified as contingent resources. None of the agencies, including the SPE, directly address this issue in current guidelines.

- Lease Fuel – An underlying principle in the UNFC is the conservation of mass in reserves and resource classifications and tracking, that is, all quantities need to be estimated whether produced, consumed, flared, lost, remaining recoverable (reserves or contingent resources) or unrecoverable such that the total adds back to the original in-place discovered resources in the subject accumulation. The key issue is whether to include gas (or oil) consumed as fuel to support production (and lease processing) operations in reserves disclosures. The Canadian guidelines treat lease fuel as part of shrinkage. The SPE and SEC allow issuers the option to include lease fuel consumed as part of reserves as long as an appropriate operating expense is allocated. UK-SORP requires issuers to consistently include or exclude such volumes for production and reserves. The issue is not specifically addressed in other classifications. This can become a major issue in LNG and bitumen upgrader projects as the volume of gas or bitumen consumed relative to the marketable product quantities can be significant (*if the reserves reference point is at the plant outlet – see below*).
- Reserves Reference Point – (also called measurement or custody transfer point). Most agencies support the principle that the quantities used in reserves estimations are based on measurements, product specification, and pricing at the initial custody transfer point. Typically in a gas project the measurement is of the marketed product in its condition as delivered to a sales pipeline. In some cases, the sales quantity may include minor non-hydrocarbons such as CO<sub>2</sub>. Custody transfer can be obscured by varying ownerships or sharing of processing facilities. For example, in integrated extra-heavy oil or bitumen production and processing projects, it is not clear if the quantity for reserves estimates is the quantity at the upgrader inlet or synthetic crude oil measured at the upgrader outlet.
- Unconventional Hydrocarbons – Figure 6 illustrates the total spectrum of hydrocarbon types and accumulations.

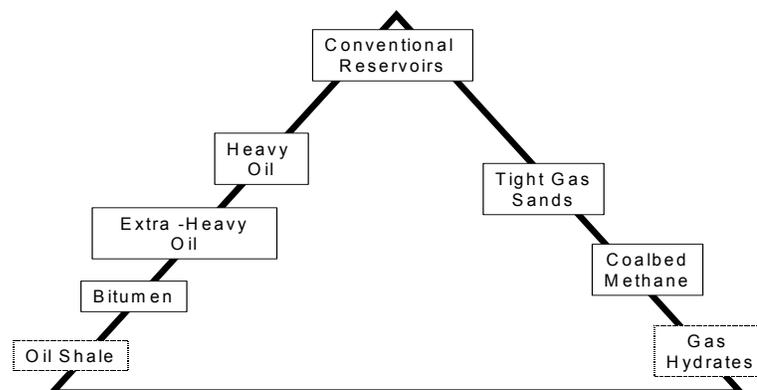


Figure 6: Conventional vs Unconventional Hydrocarbons

The SEC has accepted “down to” coalbed methane and extra-heavy oil as being part of conventional oil and gas operations, excludes oil shales, does not address gas hydrates and is currently ambivalent on bitumen. They exclude mined bitumen, provisionally include bitumen recovered by in situ methods and are currently studying whether upgraded synthetic oil can be defined as the sales product. The Canadian regulations include all bitumen as petroleum reserves

whether extracted by in situ or mining methods and define the custody transfer point for integrated operations at the upgrader outlet. Most classifications now accept coal bed methane but do not address the bitumen issue. The current SPE position is that their classification and definitions apply to all hydrocarbons, conventional and unconventional. Moreover the glossary definition of petroleum includes solid forms. However, the SPE gives no specific guidance around such issues as mined bitumen or upgrader processing. *Bitumen and oil shale may be excluded by discovery criteria that reference identification of “moveable” hydrocarbons; certainly these resources may not support a flowing well test.*

- Resource Entities - Historically North American operators used the “lease-well-reservoir” as the smallest reserve entity, that is, reserves were computed on a drilling spacing unit basis by completion interval. This was the level at which ownership and royalties could be allocated. In foreign operations where leases covered broad areas, the reservoir (or zone of a reservoir) became the reserve entity. Many European operators identify the project as operational unit and lease zones are aggregated to the project level to allocate costs versus volumes to establish economic criteria.

It is not always clear in the various definitions which reserve entity is being assessed for risk and uncertainty analysis. Figure 7 illustrates the relationship between the reservoir, lease (property) and project entity. In-place volumes are estimated for reservoirs. Projects have associated cash flow attributes. The intersection of reservoir and project (through a well completion) defines a specific development project applied to a specific reservoir and attributes would be recoverable quantities and associated cash flows. Ownership and fiscal terms are typically defined for a lease. Thus aggregation or allocation of a reservoir–project to a lease would form the basic entity for resource assessment. By careful design of a data model, quantities and value can be associated with individual reservoirs, leases and projects (and wells).

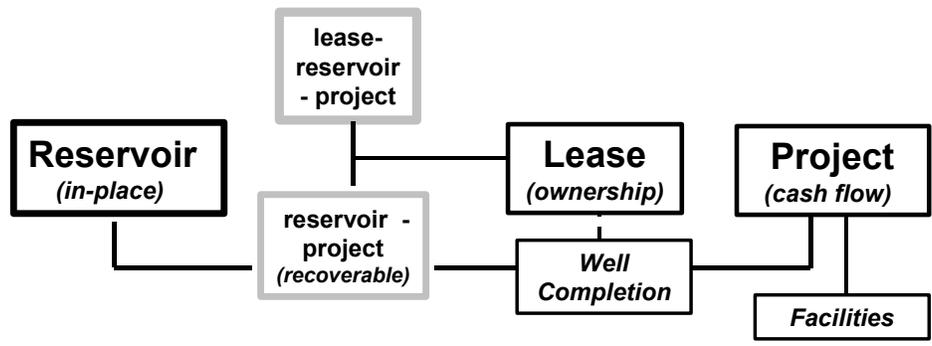


Figure 7: Resource Data Entities and Entity Relationships

The entity level defined for reserves disclosures varies between securities agencies and may be total corporate or by country; however issuers must maintain detailed accounting by lease and reservoir subject to audits. The SEC requires separate disclosures for PSC/PSA’s. While the SEC requires products categorized as crude oil (includes condensate), gas and natural gas liquids, other agencies require a more detailed accounting by product type. The SPE does not address tracking resources by product or type of lease.

## Conclusions and Recommendations

The following observations are based on an analysis of the reserves and resource classifications and associated definitions and guidelines as published by the eight agencies surveyed in this report.

There is general international agreement on a classification system for petroleum resources that defines three broad categories of recoverable quantities: undiscovered, discovered sub-commercial, and discovered commercial.

All classifications incorporate classes of resources within each category to describe uncertainty in estimating the quantities of hydrocarbons that may be recovered by applying development projects. The assessments accommodate uncertainty in both the in-place hydrocarbon volumes and a range of recovery efficiencies associated with projects being applied. All classifications define 3 scenarios to define this uncertainty range: a low, intermediate (termed “best”) and high estimate. Most classifications agree that if these uncertainty distributions were derived stochastically, the associated cumulative probability hurdles would be P90/P50/P10. There is some variation in the deterministic qualitative criteria that define these scenarios.

To achieve greater consistency among project assessments, many of the classifications apply additional deterministic criteria to the low estimate of “discovered commercial”, typically defined as “proved reserves”. All classifications recognize that a portion of these discovered commercial volumes may be recovered with existing facilities (developed) while the remaining portion requires additional investment (undeveloped).

While there is variation in the terminology used to describe the resource categories and uncertainty classes, it is quite feasible to identify correlative terms. There is lack of clarity in the detailed definitions of boundary conditions between categories.

Based on this analysis, revisions to the current SPE resource classification, definitions and guidelines may consider the following as potential “best practices” to provide increased clarity and better align with business processes:

- Utilize a consistent set of criteria to segregate discovered from undiscovered without reference to ultimate commerciality. A discovery is a known accumulation(s). It has been penetrated by a wellbore and the resulting analysis of well logs, cores or formation tests indicates that significant hydrocarbons exist and are potentially recoverable. All such discovered volumes should be initially categorized as contingent resources.
- The guidelines should emphasize that recoverable quantities must clearly identify the development project applied to a specific accumulation and its in-place hydrocarbons. Without an associated development project, in-place volumes must be designated as unrecoverable. Economics and feasibility attributes are associated with development projects. The remaining quantities associated with projects categorized as “commercial” are assigned the term “reserves”. The boundary between contingent resource and reserves thus rests on the term commercial as applied to a development project. It has two components: economics and feasibility or “intent”. The most practical approach is to use the project maturity/chance of reaching production status to clarify reserves versus contingent resources. An appropriate chance may be 90% (i.e. 10% risk).

- Definitions and guidelines should accommodate both deterministic and probabilistic assessment methods. To maintain consistency, the same class confidence hurdles (P90/P50/P10) should be applied to estimates whether assessed using deterministic or probabilistic methods. While inherently qualitative, all deterministic estimates have an inferred probability. *Calibration tests utilizing both assessment methods are recommended.* Although the assessment should support either arithmetic summation or probabilistic aggregation, the guidelines should clearly identify the entity to which these certainty guidelines apply and the preferred entity is the project level.
- Guidelines around economics/intent should focus on the “best estimate”, being the equivalent of proved plus probable (2P), of recoverable quantities associated with a project. While companies certainly evaluate upside and downside cases or the complete probabilistic distribution to make investment decisions, the most representative single estimate is generally accepted as 2P. (While there are valid arguments to use the mean as the preferred measure of central tendency, this may not be practical to maintain comparability to deterministic assessments.)
- From a business perspective, the inclusion of additional deterministic technical and commercial criteria for reserves classes (proved, probable, possible) or discrete estimates (1P,2P, 3P) may have value in providing increased consistency in assessments. The definitions should be broad enough to accommodate such criteria as imposed by regulatory agencies.
- Apply developed/undeveloped status to all reserves classes. Logically there is a range of recoveries associated with developed reserves. Reserves that remain undeveloped beyond a reasonable period demonstrate lack of commitment and should be reclassified as contingent resources.
- The definitions should encompass all hydrocarbons whether conventional or non-conventional (gas, liquid or solid phases). Supplemental guidelines may be required to address issues pertaining to extraction (mining, in situ) and processing (upgrading) that is required to yield a marketable product.
- The total system should provide for accounting of all components to support mass balance; that is, the sum of quantities sold, production and processing losses (including hydrocarbons consumed as fuel) and unrecoverable quantities should equal the estimate of initially-in-place hydrocarbons.

Documentation regards reserves and resources is best presented in a more structured manner consisting of:

- Overall Resource Classification – chart and resource category definitions
- Reserves Definitions - high level, principal-based
- Application Guidelines – detailed guidance, subject to periodic revisions
- Application Examples - illustrations of both common and exceptional issues

While not necessarily endorsing its content, the format used by the Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum provides a useful template.