Guidelines for the Evaluation of Petroleum Reserves and Resources

A Supplement to the SPE/WPC Petroleum Reserves Definitions and the SPE/WPC/AAPG Petroleum Resources Definitions

SPE International

WORLD PETROLEUM CONGRESSES

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS AAPG 1917

Guidelines for the Evaluation of Petroleum Reserves and Resources

A Supplement to the SPE/WPC Petroleum Reserves Definitions and the SPE/WPC/AAPG Petroleum Resources Definitions

SOCIETY OF PETROLEUM ENGINEERS

Printed in the United States of America.

ISBN 978-1-55563-105-5

05 06 07 08 09 10 11 12 13 / 9 8 7 6 5 4 3 2

Society of Petroleum Engineers
222 Palisades Creek Drive
Richardson, TX 75080-2040 USA

http://www.spe.org/web/store/index.shtml
service@spe.org
1.972.952.9393

Table of Contents

Chapter 1 Summary

Introduction

Claude L. McMichael

Over the past 60 years, numerous technical organizations, regulatory bodies, and financial institutions have introduced nomenclatures for the classification of petroleum reserves. In 1987, the Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC), working independently, developed sets of reserves definitions that were strikingly similar in most key aspects. Both gained wide acceptance and have become the standards for reserves classification across much of the industry. Soon after their introduction, it became apparent to both organizations that these two sets of definitions could be combined into a single text and that such a development would improve consistency in reserves evaluation and reporting. Contacts between representatives of the two organizations started shortly after the publication of the original sets of definitions and were increased in June 1994. A joint task force was established between SPE, under the guidance of the Oil and Gas Reserves Committee, and WPC with the assignment of drafting the joint definitions. This effort was completed in March 1997 with the approval of the "SPE/WPC Petroleum Reserves Definitions." These are included in this document as Appendix A.

From the outset of the SPE/WPC effort it was recognized that a major shift in the current conventions used in evaluating and reporting reserves could have a significant and disruptive impact on the industry business environment. A re-evaluation of the current reserves base would require a considerable commitment of both human and financial resources. In addition, a major increase or decrease in the reported reserves would have a significant impact on the industry asset base, with implications within the financial and regulatory communities. It was imperative that the new definitions recognize current technical trends in reserves evaluation and reporting conventions but, at the same time, retain full compatibility with as much of the current common usage as possible. This was essential to minimize impact on previously reported quantities and changes required to bring about industry acceptance. Further, it was essential that the definitions provide sufficient flexibility for countries and companies to adapt their internal systems to meet their regulatory or business needs. The basic principles on which these definitions were developed were published in the January 1996 issue of the *Journal of Petroleum Technology* and the June 1996 issue of the *WPC Newsletter.*

While one of the key objectives was to retain continuity with past reserve evaluations, the "SPE/WPC Petroleum Reserves Definitions" extended previous definitions in three very important areas. The revised definitions provided for the use of both probabilistic and deterministic methods in the evaluation of all categories of reserves, including proved reserves; they allowed the use of average prices in the evaluation of all reserve categories; and they recognized the use of analog reservoirs in evaluating the effectiveness of recovery processes. In each case, use of these definitions is dependent on them being consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting the reserves.

While these definitions represented a major step forward in both the reporting of reserves and the inclusion of current technology, they were limited by several significant omissions. As an example, they failed to:

- recognize the benefits to be gained by expanding the definitions to include the entire resource base, including those quantities of petroleum contained in known accumulations that are not currently commercial and quantities that are yet to be discovered
- provide insight into the practical application of price averaging and the stabilizing impact this would have on project economics and reserves
- give guidance on the application of the probabilistic methodology to the evaluation of petroleum reserves and resources, as well as the influence that proper aggregation could have on a company's asset base
- present common industry practices for reporting gas volumes, including fuel and flare usage, transfer of injection volumes between projects, conversions from gas volumes to oil equivalents, and booking practices for international fiscal systems such as production sharing and service contracts
- highlight the varying international regulations that play a critical role in the evaluation and reporting of petroleum reserves and resources on a worldwide basis

In 1999, the SPE Oil and Gas Reserves Committee, in conjunction with WPC, undertook the development of a resource classification system that would include the 1997 reserves definitions. This effort was joined by the American Association of Petroleum Geologists (AAPG) later that year and was approved by the three organizations in February 2000. With these new definitions, SPE, WPC, and AAPG are attempting to rectify, at least partially, some of the omissions while retaining the spirit of their reserve definition principles. Chapter 2 presents an analysis of the recently adopted "SPE/WPC/AAPG Petroleum Resources Classification and Definitions," which are included in Appendix B. This new system in no way changes the "SPE/WPC Petroleum Reserves Definitions." Instead, it expands the system to include the total resource base, including those volumes that might be sub-economic or might be contained in accumulations yet to be discovered.

Chapter 3 addresses operational issues, and Chapter 4 covers current economic conditions and includes a discussion on application of average pricing and the implications this would have under existing regulations. Chapters 5 and 6 address the use of probabilistic methodologies in petroleum reserves and resources evaluations; Chapter 5 reviews some of the approaches used in the industry today, while Chapter 6 covers the approaches as well as the implications of aggregation both across projects and within an individual project. Chapter 7 discusses geostatistics, which is being used throughout the industry to attempt to characterize the spatial variation in rock properties and reservoir connectivity. Chapter 8 reviews the application of seismic data to reserves and resources evaluations; it highlights how the technology can be used, its reliability, and additional data that are needed to support the conclusions from seismic data. Finally, in Chapter 9, the issues associated with reserves reporting under production-sharing and risk-based contracts are discussed.

Petroleum reserves and resources are important to both companies and countries. Numerous regulatory bodies around the world have developed regulations relating to the evaluation and external reporting of reserves. The individual evaluator continues to be responsible for ensuring that the rules are fully met within a specific region or country.

Chapter 1
Introduction

Claude L. McMichael

Introduction

Over the past 60 years, numerous technical organizations, regulatory bodies, and financial institutions have introduced nomenclatures for the classification of petroleum reserves. In 1987, the Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC), working independently, developed sets of reserves definitions that were strikingly similar in most key aspects. Both gained wide acceptance and have become the standards for reserves classification across much of the industry. Soon after their introduction, it became apparent to both organizations that these two could be combined into a single set and that such a development would improve consistency in reserves evaluation and reporting. Contacts between representatives of the two organizations started shortly after the publication of the initial sets of definitions and were increased in June 1994. A joint task force was established between SPE, under the guidance of the Oil and Gas Reserves Committee, and WPC with the assignment of drafting the joint definitions. This effort was completed in March 1997 with the approval of the "SPE/WPC Petroleum Reserves Definitions." These are included in this document as Appendix A.

From the outset of the SPE/WPC effort, it was recognized that a major shift in the current conventions used in evaluating and reporting reserves could have a significant and disruptive impact on the industry business environment. A re-evaluation of the current reserves base would require a considerable commitment of both human and financial resources. In addition, a major increase or decrease in the reported reserves would have a significant impact on the industry asset base, with implications within the financial and regulatory communities. It was imperative that the new definitions recognize current technical trends in reserves evaluation and reporting conventions but, at the same time, retain full compatibility with as much of the current common usage as possible. This was essential to minimize impact on previously reported quantities and changes required to bring about industry acceptance. Further, it was essential that the definitions provide sufficient flexibility for countries and companies to adapt their internal systems to meet their regulatory or business needs. The basic principles on which these definitions were developed were published in the January 1996 issue of the *Journal of Petroleum Technology* and the June 1996 issue of the *WPC Newsletter* and included in the following paragraphs.

> *There is a growing awareness worldwide of the need for a consistent set of reserves definitions for use by governments and industry in the classification of petroleum reserves. Since their*

introduction in 1987, the Society of Petroleum Engineers and the World Petroleum Congresses reserves definitions have been standards for reserves classification and evaluation worldwide.

SPE and WPC have begun efforts toward achieving consistency in the classification of reserves. As a first step in this process, SPE and WPC issue the following joint statement of principles.

The SPE and the WPC recognize that both organizations have developed a widely accepted and simple nomenclature of petroleum reserves.

The SPE and the WPC emphasize that the definitions are intended as standard, general guidelines for petroleum reserves classification which should allow for the proper comparison of quantities on a worldwide basis.

The SPE and the WPC emphasize that, although the definition of petroleum reserves should not in any manner be construed to be compulsory or obligatory, countries and organizations should be encouraged to use the core definitions as defined in these principles and also to expand on these definitions according to special local conditions and circumstances.

The SPE and the WPC recognize that suitable mathematical techniques can be used as required and that it is left to the country to fix the exact criteria for reasonable certainty of existence of petroleum reserves. No methods of calculation are excluded, however, if probabilistic methods are used, the chosen percentages should be unequivocally stated.

The SPE and the WPC agree that the petroleum nomenclature as proposed applies only to known discovered hydrocarbon accumulations and their associated potential deposits.

The SPE and the WPC stress that petroleum proved reserves should be based on current economic conditions, including all factors affecting the viability of the projects. The SPE and the WPC recognize that the term is general and not restricted to costs and price only. Probable and possible reserves could be based on anticipated developments and/or the extrapolation of current economic conditions.

The SPE and the WPC accept that petroleum reserves definitions are not static and will evolve.

While one of the key objectives was to retain continuity with past reserve evaluations, the "SPE/WPC Petroleum Reserves Definitions" extended previous definitions in three very important areas. They provided for the use of both probabilistic and deterministic methods in the evaluation of all categories of reserves, including proved reserves; they allowed the use of average prices in the evaluation of all reserve categories; and they recognized the use of analog reservoirs in evaluating the effectiveness of recovery processes. In each case, use of these definitions is dependent on them being consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting the reserves.

While these definitions represented a major step forward in both the reporting of reserves and the inclusion of current technology, they were limited by several significant omissions. As an example, they failed to:

- recognize the benefits to be gained by expanding the definitions to include the entire resource base, including those quantities of petroleum contained in accumulations that are not commercial under the present economic conditions and quantities that are yet to be discovered
- provide insight into the practical application of price averaging and the stabilizing impact this would have on project economics and reserves
- give guidance on the application of the probabilistic methodology to the evaluation of petroleum reserves, as well as the influence that proper aggregation of reserves could have on a company's asset base
- present common industry practices for report gas volumes. This includes fuel and flare usage, transfer of injection volumes between projects, conversions from gas volumes to oil equivalents, and booking practices for international fiscal systems such as production sharing and service contracts
- highlight the varying international regulations that play a critical role in the evaluation and reporting of petroleum reserves on a worldwide basis.

In 1999, the SPE Oil and Gas Reserves Committee, in conjunction with WPC, undertook the development of a resource classification system that would include and complement the 1997 reserves definitions. This effort was joined by the American Association of Petroleum Geologists (AAPG) later that year and was approved by the three organizations in February 2000. With these new definitions, SPE, WPC, and AAPG are attempting to rectify, at least partially, some of the omissions while retaining the spirit of their reserve definition principles Chapter 2 presents an analysis of the recently adopted SPE/WPC/AAPG "Petroleum Resources Classification and Definitions," which are included in Appendix B. This new system in no way changes the "SPE/WPC Petroleum Reserves Definitions." Instead, it expands the system to include the total resource base, including those volumes that might be sub-economic or might be contained in accumulations yet to be discovered.

Chapter 3 addresses operational issues, and Chapter 4 covers current economic conditions and includes a discussion on application of average pricing and the implications this would have under existing regulations. Chapters 5 and 6 address the use of probabilistic methodologies in petroleum reserves and resources evaluations; Chapter 5 reviews some of the approaches used in the industry today, while Chapter 6 covers the approaches as well as the implications of aggregation both across projects and within an individual project. Chapter 7 discusses geostatistics, which is being used throughout the industry to attempt to characterize the spatial variation in rock properties and reservoir connectivity. Chapter 8 reviews the application of seismic data to reserves and resources evaluations; it highlights how the technology's use and its reliability, as well as additional data that are needed to support the conclusions from seismic data. Finally, in Chapter 9, the issues associated with reserves reporting under production-sharing and risk-based contracts are discussed.

Chapter 2 Summary

Petroleum Resources Classification and Definitions

James G. Ross

Resource Definitions

In February 2000, SPE, WPC, and AAPG approved a "Petroleum Resources Classification and Definitions" system (Appendix B). These resource definitions were developed as a supplement to the existing "SPE/WPC Petroleum Reserves Definitions" (1997) and did not modify those definitions in any way. The two sets of definitions should be viewed as companion documents.

The key part of the resource definitions relates to the classification of estimated recoverable quantities from accumulations that have been discovered but are currently considered as sub-commercial, and from those accumulations that have yet to be discovered. These are termed Contingent Resources and Prospective Resources, respectively.

While reference should be made to the full definitions contained in Appendices A and B, they may be summarized as follows:

Reserves—Those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward.

Contingent Resources—Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

Prospective Resources—Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

The basis for the fundamental subdivisions of the system—i.e., what constitutes a known accumulation and what criteria may be relevant for commerciality—is discussed in the following section.

Related Definitions

Resource volume estimates are derived for an *accumulation*, and reserves may only be quoted for a *known accumulation*; thus, it is important to define these terms. Further, it is recognized that decisions on commerciality, and hence on the likelihood of development, are based on specific *projects*. First, however, it is beneficial to define *reservoir* and *field*. There are various definitions already in use for these terms; where possible, these existing definitions have been used as a basis for the following:

Reservoir—A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rock or by water barriers and is characterized by a single-pressure system.

Field—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both.

Known Accumulation—The term *accumulation* is used to identify an individual body of moveable petroleum in a reservoir. However, the key requirement is that in order to be considered as *known,* and hence contain reserves or contingent resources, 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.

Two types of accumulations have been defined that may require different approaches for their evaluations:

Conventional Deposit—A discrete accumulation related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down-dip contact with an aquifer, and which is significantly affected by hydrodynamic influences, such as the buoyancy of petroleum in water.

Continuous-Type Deposit—A petroleum accumulation that is pervasive throughout a large area and which is not significantly affected by hydrodynamic influences. Examples of such deposits include “basin-center” gas and gas hydrate accumulations.

It is intended that the resources and reserves definitions, together with the classification system, will be appropriate for all types of petroleum accumulations. However, it is recognized that continuous-type deposits provide additional challenges in their evaluation and that generally accepted methods have yet to be established.

Project—This represents the link between the petroleum accumulation and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of a group of several fields. In general, an individual project will represent the level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimated recoverable volumes for that project.

Note that there are no commercial connotations associated with the terms *reservoir*, *known accumulation*, and *field.*

Commerciality

The distinction between commercial and sub-commercial known accumulations (and hence between reserves and contingent resources) is of key importance in ensuring a reasonable level of consistency in reserves reporting. On the basis of the SPE/WPC/AAPG classification system, it is clear that the accumulation must be assessed as commercial before any reserves should be assigned. It is recognized that some ambiguity may exist between the definitions of contingent resources and unproved reserves. This is a reflection of variations in current industry practice.

It is recommended that, if the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable time frame, the estimated recoverable volumes for the accumulation be classified as contingent resources. A reasonable time frame for the initiation of development depends on the specific circumstances but, in general, should be limited to around 5 years. A longer time frame could be applied where, for example, a group of gas fields are committed to a sales contract (and are therefore clearly commercial), but some of them will not be developed until actually required to meet contractual obligations. In general, in order to assign reserves of any category, a *project* needs to be defined in the form of a commercially viable development plan, and there should be evidence of a firm intent to proceed with that plan. Reserve quantities would then represent the estimated recovery resulting from the implementation of that plan.

Resource Uncertainty Categories

Any estimation of resource quantities for an accumulation or group of accumulations (a *project*) is subject to uncertainty and should, in general, be expressed as a range. The function of the three primary categories of reserves (proved, probable, possible) in the “SPE/WPC Petroleum Reserves Definitions” is to illustrate the range of uncertainty in the estimate of the potentially recoverable volume of petroleum from a known accumulation. Such estimates, which are done initially for each well or reservoir, may be made deterministically or probabilistically and are then aggregated for the accumulation/project as a whole. Provided a similar logic is applied for all volumetric estimates (including contingent and prospective resources), the estimate of uncertainty for each accumulation can be tracked over time from exploration through discovery, development, and production. This approach provides an extremely effective basis for evaluating the validity of the methodology used for the estimate of potentially recoverable volumes.

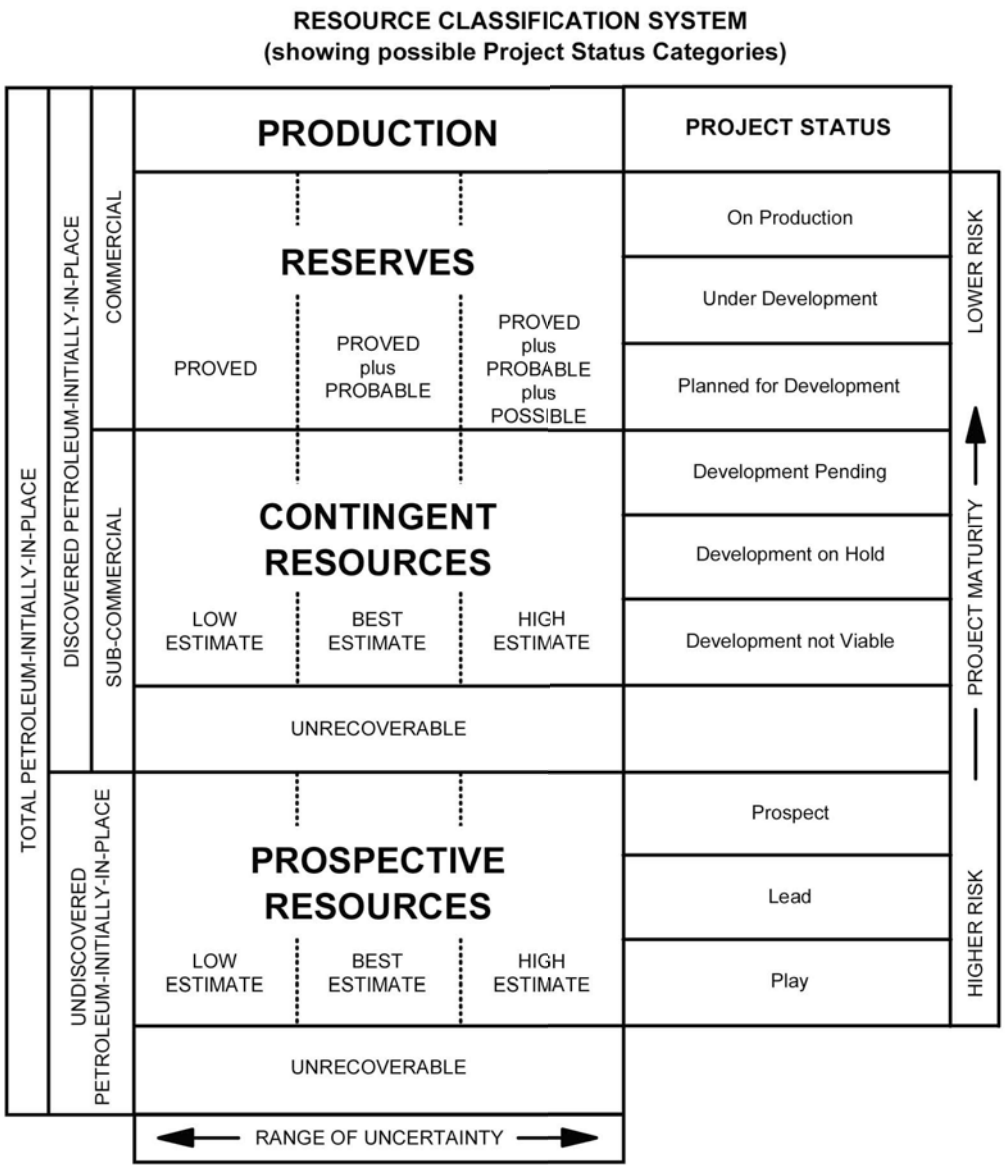
The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes for an individual accumulation or a project. In the case of reserves, and where appropriate, this range of uncertainty can be reflected in estimates for proved reserves (1P), proved plus probable reserves (2P), and proved plus probable plus possible reserves (3P) scenarios. For other resource categories, the equivalent terms low estimate, best estimate, and high estimate are recommended.

Project Status Categories

To establish a more detailed resource reporting system that can provide the basis for portfolio management, many countries and companies subdivide resource categories further on the basis of project status or maturity. This reflects the principle that, as an accumulation moves to a higher level of maturity, there will be a higher probability (lower risk) that the accumulation will achieve commercial production. The project status categories are independent of the uncertainty associated with the range of potentially recoverable volumes; however, for an individual accumulation, it would be expected that uncertainty would decrease as maturity increases.

The following project status categories are provided for illustrative purposes only. SPE, WPC, and AAPG are not endorsing the use of any specific subdivision of reserves, contingent resources, or prospective resources because it is recognized that countries and companies will wish to establish their own categories consistent with the objectives of their own classification systems. In the classification system shown in Figure 2.1, each accumulation is categorized according to its project status/maturity, which reflects the actions (business/budget decisions) required to move it toward commercial production.

Figure 2.1



Note: For illustrative purposes only. Not to scale.

The categories used as examples reflect the following concepts:

Reserves

On Production—The project is currently producing and selling petroleum to market.
Under Development—All necessary approvals have been obtained, and development of the project is underway.
Planned for Development—Satisfies all the criteria for reserves, and there is a firm intent to develop, but detailed development planning and/or necessary approvals/contracts have yet to be finalized.

Contingent Resources

Development Pending—Requires further data acquisition and/or evaluation in order to confirm commerciality.
Development on Hold—Of significant size, but awaiting development of a market or removal of other constraints to development, which may be technical, environmental, or political, for example.
Development not Viable—No current plans to develop or to acquire additional data at this time due to limited production potential.

Prospective Resources

Prospect—Potential accumulation is sufficiently well-defined to represent a viable drilling target.
Lead—Potential accumulation is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.
Play—Recognized prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific leads or prospects.

This example system provides a basis for resource classification and therefore portfolio management, the objective being to balance the resource base over the various categories while focusing on moving individual accumulations from low maturity (such as lead) through to projects that are on production and generating revenue. Contingent resources are particularly important in that they should be minimized; resources in this category are highlighted as requiring specific action in order to realize value despite being discovered. Budget decisions should focus on increasing project maturity.

Chapter 2

Petroleum Resources Classification and Definitions

James G. Ross

2.1 Introduction

The "SPE/WPC Petroleum Reserves Definitions" (see Chapter 1 and Appendix A) have been developed over many years, starting with definitions for proved reserves only and subsequently expanding to encompass probable and possible reserves. However, the definitions are specifically for reserves; because these constitute only a subset of the whole resource base, it was considered worthwhile to provide some additional definitions and guidelines that would help illustrate the context of reserves and facilitate consistency among professionals using such terms. This effort was also supported and endorsed by the American Association of Petroleum Geologists (AAPG), and the new petroleum resources classification system and definitions were approved by all three organizations in February 2000. The approved document is reproduced in Appendix B. These resource definitions were developed as a supplement to the existing "SPE/WPC Petroleum Reserves Definitions" (1997) and did not modify those definitions in any way. The two sets of definitions should be viewed as companion documents.

Establishing an integrated petroleum resource reporting system is a fundamental requirement of any country or company wishing to document fully its resource base and/or adopt portfolio management practices. Therefore, a generally accepted framework of resource definitions has significant potential value. Further, with a resource framework established, it is hoped that improved consistency of reserves reporting will also be achieved.

The fundamental principles of resource subdivision were established by McKelvey[1] in 1972, and these remain the basis for the new system (Figure 2.1).

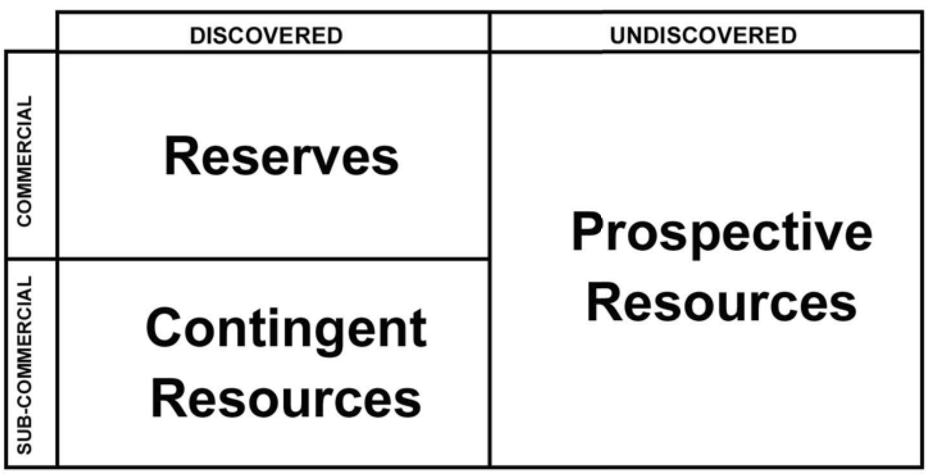


Figure 2.1—Modified McKelvey Box Showing Terminology for Recoverable Resources

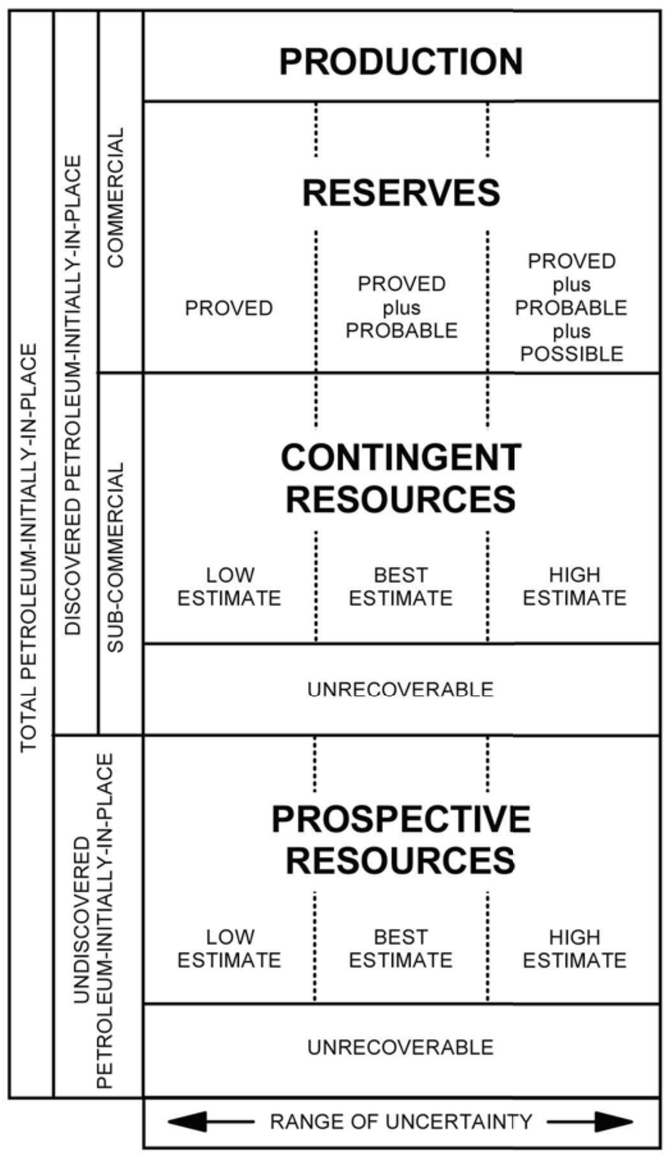
In 1987, the WPC published its report "Classification and Nomenclature Systems for Petroleum and Petroleum Reserves," which included definitions for all categories of resources. The WPC report,[2] together with definitions by other industry organizations and recognition of current industry practice, provided the basis for the SPE/WPC/AAPG system outlined here. A graphical representation of the definitions and resource classification system is reproduced in Figure 2.2.

2.2 Reserves and Resources

Because reserves are a subset of resources, it is necessary to define resources first in order to place reserves in context. The entire resource base (defined here as Total Petroleum-initially-in-place) is generally accepted to be all those estimated quantities of petroleum contained in the sub-surface, as well as those quantities already produced. This was defined previously by the WPC as "Petroleum-in-place" and has been termed "Resource Base" by others. However, some users consider only the estimated recoverable portion to constitute a resource. To avoid possible confusion, the approved classification system includes specific definitions both for those quantities estimated to be initially-in-place and for those quantities estimated to be recoverable.

It is recognized that all Petroleum-initially-in-place quantities may constitute *potentially* recoverable resources because the estimation of the proportion that may be recoverable can be subject to significant uncertainty and will change with time. Those quantities classified as Unrecoverable may become recoverable resources in the future as commercial circumstances change and technological developments occur. Such quantities would include, for example, volumes left in the ground when a field is abandoned.

FIGURE 2.2—RESOURCE CLASSIFICATION SYSTEM



Not to scale

Total Petroleum-initially-in-place is subdivided into Discovered and Undiscovered Petroleum-initially-in-place, reflecting whether or not the quantities are contained in “known accumulations” (discussed in the next section). Discovered Petroleum-initially-in-place may be classified as Commercial or Sub-Commercial, based on the criteria for commerciality discussed later.

Estimated recoverable volumes are further subsets of these in-place categories and are defined as Reserves, Contingent Resources, and Prospective Resources.

Reserves are defined by SPE/WPC as follows (refer to Appendix A for full definitions):

> *Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward.*

Thus, reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining.

Despite this clarity, misuse of the term *reserves* is widespread, and it is strongly urged that the following expressions are not used:

- Geologic reserves—sometimes used to denote petroleum-initially-in-place
- Technical reserves—sometimes used to classify sub-commercial discovered volumes, defined here as Contingent Resources
- Prospective or speculative reserves—sometimes used for undiscovered volumes, defined here as Prospective Resources
- Initial or ultimate reserves—sometimes used instead of Estimated Ultimate Recovery (EUR), defined here as estimated remaining recoverable quantities plus cumulative production

Contingent Resources are those discovered and potentially recoverable quantities that are, currently, not considered to satisfy the criteria for commerciality and are defined as follows:

> *Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.*

Prospective Resources are those potentially recoverable quantities in accumulations yet to be discovered and are defined as follows:

> *Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.*

The basis for the fundamental subdivisions of the system (i.e., what constitutes a known accumulation and what criteria may be relevant for commerciality) is discussed in the following two sections.

2.3 Related Definitions

Resource volume estimates are derived for an *accumulation*, and reserves may only be quoted for a *known accumulation*; thus, it is important to define these terms. Further, it is recognized that decisions on commerciality, and hence on the likelihood of development, are based on specific *projects*. First, however, it is beneficial to define *reservoir* and *field*. There are various definitions already in use for these terms; where possible, these existing definitions have been used as a basis for the following:

Reservoir—A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rock or by water barriers and is characterized by a single-pressure system.

Field—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both.

Known Accumulation—The term *accumulation* is used to identify an individual body of moveable petroleum in a reservoir. However, the key requirement is that in order to be considered as *known,* and hence contain reserves or contingent resources, 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.

Two types of accumulations have been defined that may require different approaches for their evaluations:

Conventional Deposit—A discrete accumulation related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down-dip contact with an aquifer, and which is significantly affected by hydrodynamic influences, such as the buoyancy of petroleum in water.

Continuous-Type Deposit—A petroleum accumulation that is pervasive throughout a large area and is not significantly affected by hydrodynamic influences. Examples of such deposits include “basin-center” gas and gas hydrate accumulations.

It is intended that the resources and reserves definitions, together with the classification system, will be appropriate for all types of petroleum accumulations. However, it is recognized that continuous-type deposits provide additional challenges in their evaluation and that generally accepted methods have yet to be established.

Project—This represents the link between the petroleum accumulation and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of a group of several fields. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend money), and there should be an associated range of estimated recoverable volumes for that project.

Note that there are no commercial connotations associated with the terms *reservoir*, *known accumulation*, and *field*.

In general, there will be a range of uncertainty in the estimated recoverable volume for each well or reservoir in a project (see Section 2.5), though such uncertainty may be relatively minor for mature accumulations where there is substantial production history. These estimates must then be aggregated for the project as a whole (see Chapter 5).

2.4 Commerciality

The distinction between commercial and sub-commercial known accumulations (and hence between reserves and contingent resources) is of key importance in ensuring a reasonable level of consistency in reserves reporting. On the basis of the above classification system, it is clear that the accumulation must be assessed as commercial before any reserves should be assigned. Even though the "SPE/WPC Petroleum Reserves Definitions" do allow for some uncertainty in commercial criteria to be reflected in the reserve categories (Proved, Probable, and Possible), it is also clearly stated that reserves (of all categories) must be commercial. Thus, contingent resources may include, for example, quantities estimated to be recoverable from accumulations for which there is currently no viable market or where commercial recovery is dependent on the development of new technology. In addition, it would be appropriate to classify a new discovery as containing contingent resources rather than reserves where the evaluation is at an early stage and commerciality has yet to be confirmed.

Where an accumulation has been assessed as commercial, reserves may be assigned. However, reserves still must be categorized according to the specific criteria of the SPE/WPC definitions; therefore, proved reserves will be limited to those quantities that are commercial under current economic conditions (see Chapter 3), while probable and possible reserves may be based on future economic conditions.

The assessment of commerciality of an accumulation is generally the responsibility of the country or company concerned with the possible development of the accumulation and will vary according to local conditions and circumstances. However, some guidelines may be established that should help to achieve some consistency in practice. It is recommended that, if the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable time frame, the estimated recoverable volumes for the accumulation be classified as contingent resources. A reasonable time frame for the initiation of development depends on the specific circumstances but, in general, should be limited to around 5 years. A longer time frame could be applied where, for example, a group of gas fields are committed to a sales contract (and are therefore clearly commercial), but some of them will not be developed until actually required to meet contractual obligations. In general, in order to assign reserves of any category, a *project* needs to be defined in the form of a commercially viable development plan, and there should be evidence of a firm intent to proceed with that plan. Reserve quantities would then represent the estimated recovery resulting from the implementation of that plan.

Within individual countries and companies it would be expected that some more specific guidelines would be established and applied. In general, these would be based primarily on an economic evaluation of the development, but they should also include considerations of political, environmental, and market risks that could delay or preclude development. The underlying economic evaluation usually would be based on the country's or company's own perception (best estimate) of future costs and prices, together with a best-estimate production profile that, in an offshore environment at least, would be expected to equate to a "proved plus probable" scenario for the field. Onshore, the decision may be based simply on the viability of completing the discovery well.

Even where the "proved plus probable" case appears to be commercially viable, if the uncertainty in the estimate is large it still may not be prudent to classify the volumes as reserves. Generally, there will be a check to ensure that there is limited downside exposure; this may be done by ensuring that a "low" case scenario is at least "break-even," which is consistent with the requirement that proved reserves are viable "under current economic conditions" (see Chapter 3). In practice, this means that, in general, if no proved reserves may be assigned to any reservoirs in a field, then all estimated recoverable quantities would be classified as contingent resources (rather than probable or possible reserves).

If an accumulation is considered to be commercial, then reserves of all categories may be assigned provided that the quantities in each category satisfy all the relevant criteria of the "SPE/WPC Petroleum Reserves Definitions." It is recognized that some countries and companies choose not to assign any proved reserves until the development plan has received all the relevant formal approvals. Under the SPE/WPC definitions, this is not strictly necessary because proved reserves may be booked provided that there is "a reasonable expectation" that the necessary facilities to process and transport those reserves will be installed.

2.5 Resource Uncertainty Categories

Any estimation of resource quantities for an accumulation or group of accumulations (a project) is subject to uncertainty and should, in general, be quoted as a range. The function of the three primary categories of reserves (Proved, Probable, and Possible) in the SPE/WPC reserves definitions is to illustrate the range of uncertainty in the estimate of the potentially recoverable volume of petroleum from a known accumulation. Such estimates, which are done initially for each well or reservoir, may be made deterministically or probabilistically (Chapter 4) and then aggregated for the accumulation/project as a whole (Chapter 5). Provided that a similar logic is applied for all volumetric estimates (including contingent and prospective resources), the estimate of uncertainty for each accumulation can be tracked over time from exploration through discovery, development, and production. This approach provides an extremely effective basis for evaluating the validity of the methodology used for the estimate of potentially recoverable volumes.

The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes for an individual accumulation or a project. In the case of reserves, and where appropriate, this range of uncertainty can be reflected in estimates for proved reserves (1P), proved plus probable reserves (2P), and proved plus probable plus possible reserves (3P) scenarios. For other resource categories, the equivalent terms Low Estimate, Best Estimate, and High Estimate are recommended.

Two fundamentally different philosophies have developed in applying a deterministic approach to reserves estimation. One is a risk-based or "incremental" approach, while the other is based on uncertainty and is sometimes referred to as a "cumulative" approach. *Risk* is defined here as the probability that a discrete event will or will not occur, whereas *uncertainty* is defined as the range of possible outcomes in an estimate. Whenever a numeric estimate is made of a parameter that is not known exactly, there is uncertainty associated with the estimate. An obvious example is the estimate of the recoverable volume of petroleum for an accumulation; it is not possible to estimate this volume exactly as a result of both technical and commercial uncertainties. In the exploration side of the business, this distinction between risk and uncertainty has long been appreciated and utilized. Undrilled prospects are assessed on the basis of the risk of a dry hole and the uncertainty of the potentially recoverable volume if a discovery is made.

Despite the early recognition of the problem of uncertainty in reserve estimation[3] and the references to uncertainty ("progressively increasing uncertainty") in the "SPE/WPC Petroleum Reserves Definitions," North American practice has been based largely on risk as the determinant for classifying reserves as Proved, Probable, or Possible. In contrast, in many other parts of the world, uncertainty-based systems have been used for many years. The reasons behind this parallel development can been traced back to the way the industry itself has developed, reflecting differences between onshore and offshore environments, the size of properties/leases and discoveries, the reporting regulations, and many other factors. It is clear that in each case, the approach fulfilled the needs of the users and both are equally valid; they are simply different ways of thinking about the same problem. However, because the system based on uncertainty permits both deterministic and probabilistic methods to be used and directly compared, as well as allowing the application of uncertainty tracking over time, there are some significant benefits with this approach.

Risk-Based Philosophy

In this approach, the reserve quantity for each category (Proved, Probable, and Possible) is estimated deterministically as a *discrete* volume. No uncertainty (as defined above) is implicit in the actual reserve quantity assigned as probable or possible. Rather, there is a risk (at least for the probable and possible cases) of that volume not being present and/or being recovered. Under the "SPE/WPC Petroleum Reserves Definitions," the probable reserves (not the proved plus probable reserves) must be "more likely than not to be recoverable"; in other words, there is a risk of less than 50% that the probable reserves will not be produced. Possible reserves have a greater risk of not being produced, being "less likely to be recoverable than probable reserves." This risk may apply to the presence of the petroleum, the likelihood of the necessary development proceeding, or both. Thus, possible reserves could refer to the upside potential in an existing, producing field or to the potentially recoverable volume from a known accumulation where commercial development is subject to some doubt.

For example, if there is a large gas accumulation in an area where there is currently no identifiable gas market, the likelihood of development proceeding in the foreseeable future may be very small. In this situation, some countries/companies will assign the entire accumulation as Possible Reserves, reflecting the significant risk that development will not occur (although development is considered to be "possible"). Because all quantities are classified in a single category (i.e., Possible Reserves), this approach precludes the classification of any uncertainty in the recoverable volume (which must be substantial because the accumulation is, as yet, undeveloped).

The risk-based logic attempts to capture both volumetric uncertainty (range of possible recoverable volumes from a development) and project maturity (risk of no development) in a single system. Industry practice and guidelines commonly recommend that quantities in different reserve categories should not be aggregated (e.g., as in Proved plus Probable Reserves) or, if they are to be combined, they should be "adjusted for risk." Consequently, this approach does not permit the tracking of uncertainty over time (as discussed next), nor is it easily reconcilable with the probabilistic method. Nevertheless, it represents a valid interpretation and application of the current "SPE/WPC Petroleum Reserves Definitions."

Uncertainty-Based Philosophy

The probabilistic evaluation method is, by its very nature, an uncertainty-based approach. However, it can be (and is) also applied using deterministic methods; in such cases, a more appropriate term is the scenario approach because it is based on three specific scenarios for the accumulation rather than on a single deterministic estimate. Project maturity is handled completely separately (see Section 2.6).

In this approach, the objective is, first, to make a "best estimate" of the recoverable volume, which represents the estimate considered to be the closest to the quantity that actually will be recovered from the accumulation. Next, an estimate of an upside and a downside case of recoverable volumes is made, which provides a measure of the range of uncertainty in the best estimate. With the scenario approach, therefore, three different scenarios are established for the accumulation that are consistent with the Proved category (downside case), the Proved plus Probable category (the best estimate), and the Proved plus Probable plus Possible category (upside case). Each scenario is chosen to represent a realistic combination of parameters, consistent with the relevant definitions and taking into account potential dependencies between parameters. Thus, the downside case is not simply a matter of combining the low estimate of every input parameter; if two parameters are unlikely to occur together, that must be taken into account (dependencies are discussed further in Chapter 4). The scenarios may incorporate both technical and commercial uncertainty.

This approach is directly comparable to the probabilistic method. However, instead of trying to estimate the complete range of possible outcomes (which includes making assumptions with regard to probability distributions and levels of dependency/correlation), the required three reserve values are estimated by selecting three representative scenarios. Although not as mathematically rigorous as the probabilistic method, this approach has the advantage that each assumption can be identified specifically (e.g., this particular value of average porosity was used for the proved scenario); hence, reserve auditing is facilitated. Perhaps the most important aspect in this regard is the relationship between the development plan (and hence recovery factor) and the geological model (and hence the petroleum-initially-in-place). This potential dependency is frequently overlooked when applying the probabilistic method and may be easier to accommodate with the scenario approach.

Where an uncertainty-based philosophy has been applied (whether done deterministically or probabilistically), resource uncertainty categories can be used to relate the estimates of uncertainty over the life of an accumulation. Where deterministic methods are used, the degree of confidence associated with the low, best, and high estimates should be consistent with the technical criteria for the equivalent category of reserves. For example, if an accumulation is currently not commercial solely because of the lack of a market, then, where a market is subsequently developed and in the absence of any new technical data, the proved reserve estimate would be expected to approximate the previous low estimate. Similarly, where probabilistic methods are used, the probabilities associated with the low, best, and high case scenarios should be consistent with those values appropriate for the equivalent category of reserves. Thus, there should be at least a 90% probability that the estimated potentially recoverable quantity (from a technical standpoint) will equal or exceed the low estimate, on the assumption that development did proceed. Equivalent probability values of 50% and 10% should be used for the best and high estimates respectively. These resource uncertainty categories of Low Estimate, Best Estimate, and High Estimate may be related to the reserve categories as shown in Figure 2.3.

RESOURCE UNCERTAINTY CATEGORY	RESERVES		OTHER RESOURCES
	Scenario	Probabilistic	Scenario
LOW ESTIMATE	Proved (1P)	P90	Low
BEST ESTIMATE	Proved plus Probable (2P)	P50	Most Likely
HIGH ESTIMATE	Proved plus Probable plus Possible (3P)	P10	High

Figure 2.3—Resource Uncertainty Categories

A consistent approach to estimating the volumetric uncertainty in an accumulation (of any status/maturity), as described above, allows the use of the very powerful tool of tracking volumetric uncertainty in EUR over time (Figure 2.4). This approach is based on the fact that, with more information, uncertainty should be reduced.[3] Often, actual estimates of uncertainty will not reflect this theoretical trend, which indicates that the previous estimate was inappropriate and therefore provides a basis for reviewing and improving methodologies used to estimate uncertainty.

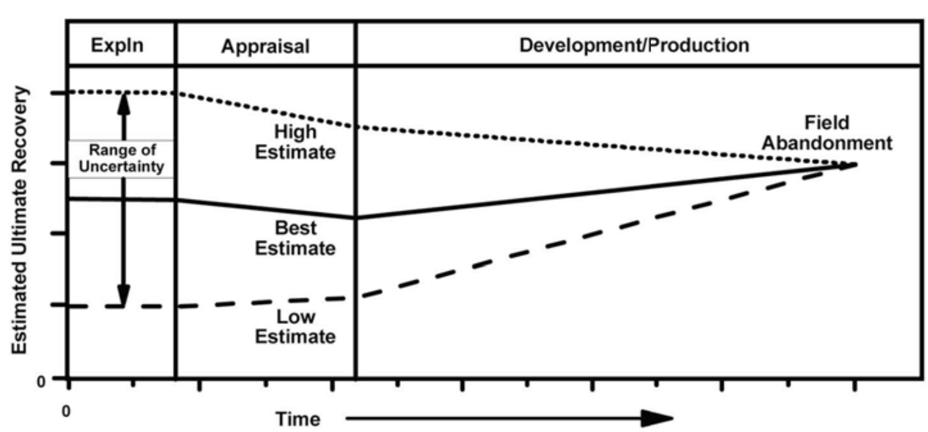


Figure 2.4—Uncertainty in Resource Estimation

2.6 Project Status Categories

The "SPE/WPC Petroleum Reserves Definitions" contain definitions for reserve status categories that relate to "the development and producing status of wells and reservoirs." These status categories, which may be used to subdivide proved reserves, reflect the fact that, because additional expenditures are required to upgrade the quantities between categories, actual production may not be achieved in the event that such an investment is not made. However, it is important to recognize that all proved reserves, regardless of reserve status category, must satisfy all the criteria under the SPE/WPC definitions for the Proved classification. On a probabilistic basis, this may be seen as requiring at least a 90% probability (i.e., a risk of less than or equal to 10%) that such financial commitments will be made and will be successful.

However, in order to establish a more detailed resource reporting system that can provide the basis for portfolio management, many countries and companies subdivide resource categories further on the basis of project status or maturity.[4] This reflects the principle that, as an accumulation moves to a higher level of maturity, there will be a higher probability (lower risk) that the accumulation will achieve commercial production. The project status categories are independent of the uncertainty associated with the range of potentially recoverable volumes; however, for an individual accumulation, it would be expected that uncertainty would decrease as maturity increases (as discussed in Section 2.5).

The following project status categories are provided for illustrative purposes only. SPE, WPC, and AAPG do not endorse the use of any specific subdivision of reserves, contingent resources, or prospective resources because it is recognized that countries and companies may wish to establish their own categories consistent with the objectives of their own classification system. In the classification system shown (Figure 2.5), each accumulation (or group of accumulations) is categorized according to its project status/maturity, which reflects the actions (business/budget decisions) required to move it towards commercial production. The categories used as examples reflect the following concepts.

RESERVES

On Production—The project is currently producing and selling petroleum to market.
Under Development—All necessary approvals have been obtained, and development of the project is underway.
Planned for Development—Satisfies all the criteria for reserves, and there is a firm intent to develop, but detailed development planning and/or necessary approvals/contracts have yet to be finalized.

CONTINGENT RESOURCES

Development Pending—Requires further data acquisition and/or evaluation in order to confirm commerciality.

Development on Hold—Of significant size, but awaiting development of a market or removal of other constraints to development, which may be technical, environmental, or political, for example.
Development not Viable—No current plans to develop or to acquire additional data at this time due to limited production potential.

PROSPECTIVE RESOURCES

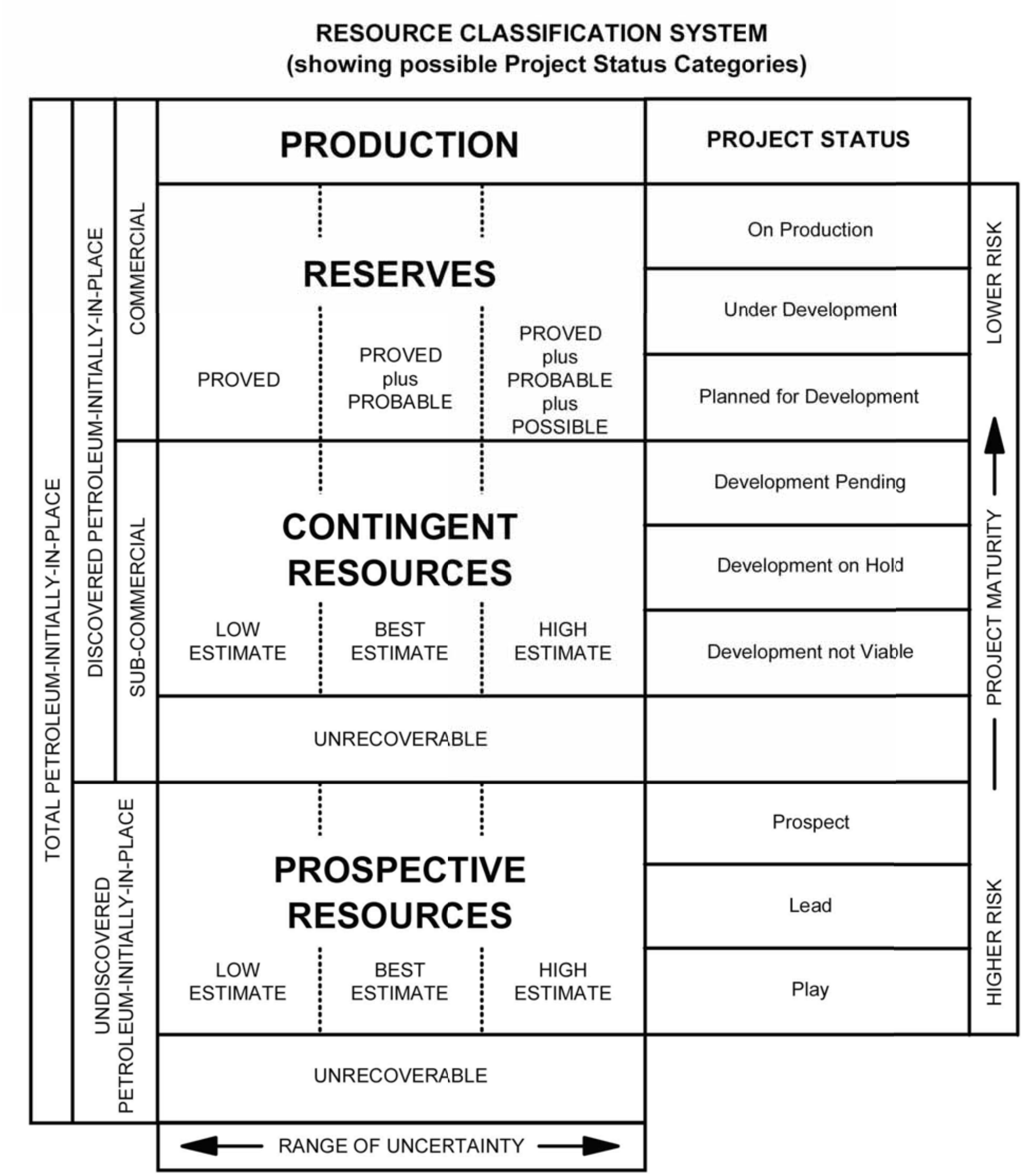
Prospect—Potential accumulation is sufficiently well-defined to represent a viable drilling target.
Lead—Potential accumulation is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.
Play—Recognized prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific leads or prospects.

This example system provides a basis for resource classification and hence portfolio management, the objective being to balance the resource base over the various categories while focusing on moving individual accumulations from the low maturity (such as lead) through to projects that are on production and generating revenue. Contingent resources are particularly important in that they should be minimized; resources in this category are highlighted as requiring specific action in order to realize value despite being discovered. Budget decisions should focus on increasing project maturity. As a specific accumulation moves up the system to higher levels of maturity it will, in general, correspond to an increase in the probability of reaching commercial production. However, when comparing accumulations, the respective probabilities may not correspond in precisely the order shown.

References

1. McKelvey, V.E.: "Mineral Resource Estimates and Public Policy," *American Scientist* (January–February 1972) **60**, No. 1, 32.
2. "Classification and Nomenclature Systems for Petroleum and Petroleum Reserves," Study Group Report, 1987 World Petroleum Congress, Houston.
3. Arps, J.J.: "Estimation of Primary Oil Reserves," paper presented at the 1956 Petroleum Conference—Economics and Valuation, Dallas, 29–30 March.
4. "Classification of Petroleum Resources on the Norwegian Continental Shelf," *Norwegian Petroleum Directorate,* Stavanger (July 1997).

Figure 2.5



Note: For illustrative purposes only. Not to scale.

Chapter 3 Summary
Operational Issues

Claude L. McMichael and Allan Spencer

Fuel, Flare, Operational Usage, and Third-Party Natural Gas

Records of natural gas and crude oil consumption for fuel, flare, and other operational requirements need to be kept for operational and reservoir monitoring purposes.

In general, gas consumed in operations is excluded from reported production. In some cases, however, produced gas consumed in operations may be included in production and reserves when the volumes replace fuel purchases. The value of the fuel used is considered as offsetting revenue and operating costs and therefore does not enter into either category. Flared gas is not included in either production or reserves. Gas purchased off-the-lease for use in operations should be treated as a purchase and should not be included in production or reserves. If gas consumed in operations is included as production or reserves, it is recommended that a footnote be used to indicate the volume of gas.

Third-party gas obtained under a long-term purchase, supply, or similar agreement for whatever purpose is excluded from reserves.

Wet and Dry Gas

The reserves for wet or dry gas should be considered in the context of the condition of the gas at the point of sale. Thus, for gas that is sold as wet gas, the volume of the wet gas would be reported, and associated/extracted liquids would not be reported separately. It could be expected that the corresponding enhanced value as a result of the sale of wet gas would be reflected in the sale price achieved for such gas.

Non-Hydrocarbon Gases and Other Substances

In the event that non-hydrocarbon gases are present, the reported volumes should reflect the condition of the natural gas at the point of sale. Thus, the accounts will reflect the value of the gas product at the point of sale. If the sale gas includes the impurity, the reserves and production should also include that impurity. If the impurity is extracted before sale and the sales gas contains only hydrocarbon gases, then the reserves and production should reflect only the hydrocarbon gases.

Natural Gas Injection

To include injection gas in the reserves, the volumes would have to meet the normal criteria in the definitions. In particular, they would need to be demonstrably economic to produce once available for production. In addition, the existence of a firm market for the gas needs to be assured; the proximity of a gas pipeline distribution system or other export option should be in evidence; and production and sale of these gas reserves should be part of the established development plan for the field.

If third-party gas is utilized, then for the originator of the gas, gas reserves, production, and sales are reported in the normal way; for the recipient, the gas normally would be treated as a purchase and is unlikely to be considered as a reserve. It should be accounted for as inventory. When reproduced, the gas would not contribute toward field production or sales. On commencing gas production from the field, the last-in/first-out principle is recommended; hence, the inventory gas would be produced first and would not count toward field production.

There may be occasion for the transfer of gas from one lease to another free of charge. In such a case, injected gas could be considered a transfer of mineral rights, and the associated gas reserves and subsequent production can be accounted for by the receiving field.

Liquid Conversion to Crude Oil Equivalent

Regulatory reporting usually stipulates that liquid and gas hydrocarbon reserves volumes are reported separately, with liquids being the sum of the crude oil, condensate, and natural gas liquids (NGL). For internal company reporting purposes and for intercompany analysis, the combined volumes for crude oil, condensate, NGL, and gas as an oil-equivalent value offer a convenient method for comparison.

Often the combination of crude oil, condensate, and NGL reserves volumes are simply added arithmetically to provide an oil-equivalent volume. A more correct method in terms of value involves taking account of the different densities of the fluids. Further improvement in combining crude oil, condensate, and NGL can be achieved by considering the heating equivalent of the three fluids and combining accordingly.

Gas Conversion to Oil Equivalent

Converting gas volumes to the oil equivalent is customarily done on the basis of the heating content or calorific value of the fuel. There are a number of methodologies in common use.
Before aggregating, the gas volumes first must be converted to the same temperature and pressure. Common industry gas conversion factors usually range between 1 barrel of oil equivalent (boe) = 5.8 thousand standard cubic feet of gas (mscf) to 1 boe = 6.0 mscf.

The conversion factor of 5.8 mscf/boe is a reasonable approximation and is recommended for gases where the condition of the gas is dry at the point of sale. If a conversion factor is to be applied to one field or a portfolio of fields where a material proportion of the gas is wet or has a calorific value materially different to 1,000 Btu/scf, it is necessary to calculate a conversion factor based on the actual calorific value.

Royalty

Royalty refers to payments that may be due to the host government, mineral owner, or landowner, in return for the producer having access to the petroleum. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. A few agreements provide for the royalty to be taken only in kind by the royalty owner.

Within the U.S., royalty volumes are strictly omitted from reported reserves because of the specifics of local reporting requirements. Outside the U.S., and where permitted by local regulations, the distinction is made between royalty paid in cash and royalty taken in kind. When paid in cash, the cash flow from the royalty is reflected in the company's accounts, and the corresponding reserves are included. Conversely, royalty that may be taken in kind is generally excluded from the reserves.

Crude Overlift/Underlift, Gas Balancing

Production overlift or underlift can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes. At any given financial year-end, a company may be in overlift or underlift. In general, reported production should be equal to the liftings actually made by the company during the year and not the production entitlement for the year. For companies where liftings occur at infrequent intervals, however, the option remains to record production as entitlement on an accrual basis.

In gas-production operations involving multiple working-interest owners, an imbalance in gas deliveries can occur. These imbalances must be monitored over time and eventually balanced in accordance with accepted accounting procedures.

There are two methods of recording revenue to the owners' accounts. The entitlement basis of accounting credits each owner with a working-interest share of the total production rather than his actual sales; the sales basis of accounting credits each owner with his actual gas sales, and an account is maintained of the over- and under-produced volumes. The production volumes recorded by the owners will be different in the two cases. The reserves estimator must consider the method of accounting used, the current imbalances, and the manner of balancing the accounts when determining reserves for an individual owner.

Chapter 3
Operational Issues

Claude L. McMichael and Allan Spencer

3.1 Fuel, Flare, Operational Usage, and Third-Party Gas

Gas (as the lower valued of the two principal oilfield production components, crude oil and natural gas) is often utilized for plant operation, most significantly in power generation. Substantial saving can be achieved to the operating cost of a project by avoiding the purchase of alternative supplies of gas or refined fuels such as diesel. Gas flaring to the atmosphere for plant balancing and similar reasons has been substantially reduced in recent years and eliminated in many fields, except in the case of emergency depressurization of facilities. This operational development has followed from the continuing and increasing environmental lobby, government regulations, and common-sense economics.

Records of gas and oil consumption for fuel, flare, and other operational requirements need to be kept for operational and reservoir monitoring purposes.

Gases volumes consumed in operations are, in some cases, included in production and reserves inasmuch as they replace alternative sources of fuel that would be required to be purchased in their absence. The value of the fuel used is considered as offsetting on the revenue and operating costs side, and hence does not go into either category. Flared gas is not included in production or reserves. Gas that is utilized in operations and has been purchased off-the-lease is treated as a purchase and is not included in production or reserves. If gas consumed in operations is included in production or reserves, it is recommended that a footnote be used to indicate the volume of gas consumed in operations included.

Generally, however, it is customary to exclude gas consumed in operations from production.

Third-party gas obtained under a long-term purchase, supply, or similar agreement for whatever purpose is excluded from reserves.

3.2 Wet and Dry Gas

The reserves for wet or dry gas should be considered in the context of the condition of the gas at the point of sale. Thus, for gas that is sold as wet gas, the volume of the wet gas would be reported, and there would be no associated or extracted liquids reported separately. It would be expected that the corresponding enhanced value as a result of the sale of wet gas would be reflected in the sale price achieved for such gas.

In the alternative case, when the liquids are extracted from the gas prior to sale and the gas is sold in the dry condition, then the dry-gas volume and the extracted liquid volumes, be they condensates and/or natural gas liquids (NGL), should be accounted for separately.

3.3 Non-Hydrocarbon Gases

As an extension of the previous paragraph, in the event that non-hydrocarbon gases are present, the reported volumes should reflect the condition of the gas at the point of sale. Correspondingly, the accounts will reflect the value of the gas product at the point of sale.

Hence, if gas sold as produced includes a proportion of carbon dioxide, for example, the reserves and production should also include that CO_2. In the case of the CO_2 being extracted before sale and the sales gas containing only hydrocarbon gases, the reserves and production should reflect only the hydrocarbon gases that will be sold.

3.4 Other Substances—Sulphur

The treatment of gas containing hydrogen sulphide is generally handled in a similar fashion. For gases containing small quantities, the H_2S may be included in the reserves where the gas is sold (e.g., for power generation) and the levels are low enough not to require separation. Whereas for liquefied natural gas (LNG), and processes involving compression where the dangers following stress cracking embrittlement are paramount, the H_2S must always be removed and therefore should be excluded from reserves.

For high concentrations of H_2S, however (concentrations as high as 90% have been known), the H_2S gas may be separated and converted to sulphur, which can then be sold. In such cases, the natural gas reserves exclude the H_2S volumes, and the sulphur volumes may be quoted separately as a reserve volume, if appropriate. At times, prices for sulphur can be low, and stockpiling for future sale is not uncommon.

3.5 Gas Re-Injection

Gas can be injected into a reservoir for a number of reasons and under a variety of conditions. It can be gas re-injected into the same reservoir for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. In such cases, assuming that the gas eventually will be produced and sold, then the gas volume estimated as eventually recoverable can be included in the field reserves. If gas volumes are to be included in the reserves, they must meet the normal criteria laid down in the definitions. In particular, they need to be demonstrably economic to produce once available for production; the existence of a firm market for the gas needs to be assured; the proximity of a gas pipeline distribution system or other export option should be in evidence; and production and sale of these gas reserves should be part of the established development plan for the field. In the case of miscible injection or other enhanced recovery processes, due allowance needs to be made for any gas not available for eventual recovery as a result of losses associated with the efficiencies inherent in the corresponding process. In some cases, the objective of gas injection in a reservoir can be efficient disposal of the gas; in such cases, no gas reserves should be allocated to reserves.

Surplus gas may be sold to a third party, who may utilize the gas in a different reservoir similarly for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. In such cases, for the originator of the gas, gas reserves, production, and sales are reported in the normal way; for the recipient, however, even if the gas eventually will be sold, the gas normally would be a purchase of gas, presumably under a long-term purchase agreement, and such a gas purchase is unlikely to be considered as a reserve. It should be accounted for as inventory. When reproduced, the gas would not contribute towards field production or sales. Typically, under such circumstances the field would then contain gas that is part of the original in-place volumes as well as injected gas held in inventory. On commencing gas production from the field, the last-in/first-out principle is recommended; hence, the inventory gas would be produced first and not count towards field production. Once the inventory gas has been re-produced, further gas production would be drawn against the original field reserve and recorded as production. The above methodology ensures that the uncertainty with respect to the original field volumes remains with the gas reserves and not the inventory.

An exception to this could occur if the gas is acquired through a production payment. In this situation, the volumes acquired could be considered as a reserve.

There may be occasion for the transfer of gas from one lease to another, as described in the previous paragraph, to be free of charge. In such a case, the re-injected gas could be considered to be a transfer of mineral rights, and as such the associated gas reserves and subsequent production when reproduced may be accounted for by the receiving field.

Alternative gas reserves acquisition strategies are explored in Chapter 9, to which reference should be made.

3.6 Liquid Conversion to Oil Equivalent

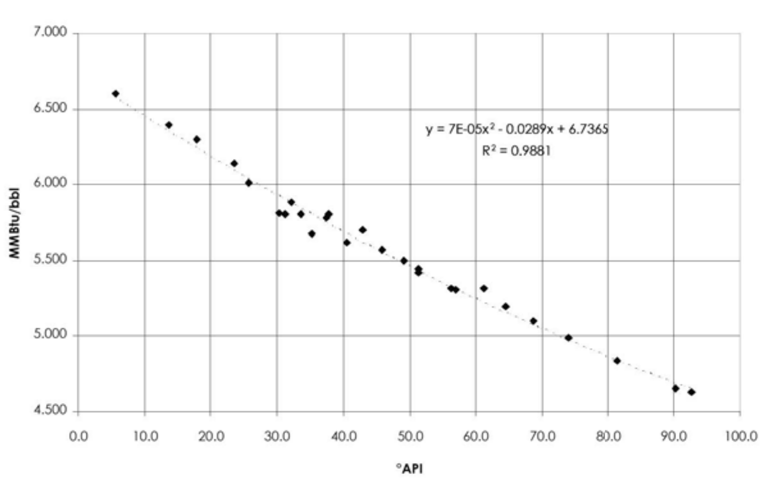
Regulatory reporting usually stipulates that liquid and gas hydrocarbon reserves volumes are reported separately, liquids being the sum of the crude oil, condensate, and NGL. For internal company reporting purposes and often for intercompany analysis, the combined volumes for crude oil, condensate, NGL, and gas as an oil equivalent value offer a convenient method for comparison.

Often, the combination of crude oil, condensate, and NGL reserves volumes are simply added arithmetically to provide an oil equivalent volume. This is normally satisfactory when one product dominates and the other two streams are not material in comparison. A more correct, but imperfect method in terms of value, involves taking account of the different densities of the fluids.

Further improvement in combining crude oil, condensate and NGL can be achieved by considering the heating equivalent of the three fluids and combining accordingly.

The following correlation between the Btu heat content of crudes, condensates, fuel oils, and paraffins is based on a combination of data from a number of sources: Katz, Table A-1, Basic data for compounds; EIA/International Energy Annual (1995); and Alaska Dept. of Natural Resources (April 1997).

Figure 3.1—Btu Content of Crudes, Condensates, Fuel Oils, and Paraffins



Graph provided through personal communication by Chapman Cronquist.

3.7 Gas Conversion to Oil Equivalent

Converting gas volumes to an oil equivalent is customarily done on the basis of the heating content or calorific value of the fuel. There are a number of methodologies in common use.

Before aggregating, the gas volumes first must be converted to the same temperature and pressure. It is customary to convert to standard conditions of temperature and pressure associated with the system of units being used.

In those parts of the industry that report gas volumes in typical oilfield units of millions of standard cubic feet (MMscf), Imperial Unit standard conditions are 14.7 psi and 60°F. Standard conditions in the metric system are 15°C and 1 atmosphere (atm). Normal conditions used in part of continental Europe are 0°C and 1 atm. Note that care needs to be taken in converting from Sm^3 and Nm^3 to scf or vice versa, as the conversion factors are different depending on the temperature and gas composition. For Sm^3, the factor is generally 35.3xxx, and for Nm^3 the conversion factor is normally 37.xxx (the last three places vary according to the gas composition).

A common gas conversion factor for intercompany comparison purposes is 1 barrel of oil equivalent (boe) = 5.8 thousand standard cubic feet of gas (mscf) at standard conditions of temperature and pressure (STP) viz. 15°C and 1 atm.
Another factor in use, presumably rounded from above, is 1 boe = 6 mscf.

Derivation of the Conversion Factor. First, some facts:

$$
\begin{aligned}
\text{1 Btu} &= \text{1,055.06 J} \\
\text{1,000 Btu/scf} &= \text{1.055 MJ/scf} \\
&= \text{1.055 MJ/scf} * 35.3147\ \text{m}^3/\text{ft}^3 \\
&= 37.257\ \text{MJ/m}^3 \text{ (at STP viz. 15°C and 1 atm)}
\end{aligned}
$$

From that list, an approximate 35°API oil has a heat content of some 5.8 million Btu/bbl.

$$
\begin{aligned}
\text{Thus, 1 boe} &= \text{5.8MBtu} \\
&= 5.8 * 10^6 * \text{1,055.06 J} \\
&= \text{6,119 MJ} \\
&= 164.238\ \text{m}^3 \text{ (at } 37.257\ \text{MJ/m}^3\text{)} \\
&= 5{,}800\ \text{ft}^3 \text{ (at STP viz. 15°C and 1 atm)}
\end{aligned}
$$

Hence, the conversion factor 5.8 mscf/boe is based on the heat content of approximately a 35°API crude and a gas with a calorific value of 1000 Btu/scf (37.3 MJ/m^3) at standard conditions of temperature and pressure, namely 15°C and 1 atm.

A reasonable approximation of 5.8 mscf/boe is recommended for gases where the condition of the gas is dry at the point of sale. Where one field is being converted (or, in the case of a portfolio of fields where a material proportion of the gas in the portfolio is wet or has a calorific value materially different to 1000 Btu/scf), it is necessary to calculate a conversion factor for all fields in the portfolio based on the actual calorific value of each gas at its point of sale. For convenience, a weighted average conversion factor, based for example on the remaining proved reserves, could be calculated and utilized for a company with a large number of holdings.

An alternative conversion factor of 5.62 mscf/boe is used by some companies reporting in the metric system of units. It is based on 1000 Sm^3 of gas per 1 Sm^3 of oil. This different factor can possibly be justified by the observation that price parities tend to weigh up oil energy relative to gas energy, or by picking a lighter gravity oil as a reference—but what has carried weight in practice for the users is that 1000 is a round and extremely convenient number to use as long as boe remains a measurement quantity with no market or customer.

A useful formula for changing calorific value from Imperial to metric units (at STP viz. 15°C and 1 atm.) is $MJ/m^3 = Btu/scf * 35.3\ scf/m^3 * 1\ kJ / 0.948\ Btu * 1\ MJ/1000\ kJ$.

TABLE 3.1—ABBREVIATIONS

atm	atmosphere= 1.01325 bar = 101 325 Pa
boe	barrel of oil equivalent
Btu	British thermal unit
ft^3	cubic feet
m^3	cubic meter
Sm^3	Standard cubic meter at 15°C and 1 atm
Nm^3	Normal cubic meter at 0°C and 1 atm
J	Joule
kJ	kilo (10^3) Joule
MJ	Mega (10^6) Joule
mscf	thousand standard cubic feet
mmscf	million standard cubic feet
scf	standard cubic feet

For further details on the units and conversion factors refer to *The SI Metric System of Units and SPE Metric Standard,* SPE, Richardson, Texas (1984), and Chapter 6, Section 6.6 of this document.

3.8 Royalty

Royalty is the payment by that name defined in the agreements and paid to the host government or landowner. Many agreements allow for the oil company, usually at the government's or landowner's option, to lift the royalty oil, sell the oil on the government's behalf, and pay the proceeds to the government in cash.

A few agreements provide for the royalty to be taken only in kind by the government.

Within the United States, royalty volumes are strictly omitted from reported reserves owing to the specifics of local reporting requirements. Overseas, where permitted by local regulations, the distinction is made between those volumes where royalty is paid in cash, and those volumes where the royalty is taken in kind. On the basis that the cash flow from the royalty taken in cash is reflected in the company's accounts, the corresponding reserves are included where the Royalty is paid in cash. Conversely, royalty taken in kind is excluded from the reserves. Please refer to Chapter 1 for the commercial background of the regulations.

3.9 Overlift/Underlift

Production overlift or underlift can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed among the parties. At any given financial year end, a company will be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year, and not on the production entitlement for the year.

For companies with small equity interests, where liftings occur at infrequent intervals (perhaps greater than 1 year), the option remains to record production as entitlement on an accrual basis.

3.10 Gas Balancing

In gas-production operations involving multiple working interest owners, an imbalance in gas deliveries can occur that must be accounted for. Such imbalances result from the owners having different operating or marketing arrangements that prevent the gas volumes sold from being equal to the ownership share. One or more parties then become over- or underproduced. For example, one owner may be selling gas to a different purchaser from the others and may be waiting on a gas contract or pipeline installation. That owner will become underproduced, while the other owners sell their gas and become overproduced. These imbalances must be monitored over time and eventually balanced in accordance with accepted accounting procedures.

There are two methods of recording revenue to the owners' accounts. The "entitlement" basis of accounting credits each owner with a working interest share of the total production rather than the actual sales. An account is maintained of the revenue due the owner from the overproduced owners. The sales basis of accounting credits each owner with actual gas sales, and an account is maintained of the over- and underproduced volumes (relative to the actual ownership). The production volumes recorded by the owners will be different in the two cases. The reserves estimator must consider the method of accounting used, the current imbalances, and the manner of balancing the accounts when determining reserves for an individual owner.

Chapter 4 Summary
Current Economic Conditions

H. David Crossley

Trends in market conditions have demonstrated significant volatility in product prices and associated costs. Provided that it is permissible under relevant reporting regulations and in the absence of firm contractual arrangements, it is recommended that, in general, a 12-month average of product prices, immediately prior to the effective date of the evaluation, should be used (without escalation) to determine proved reserves. Escalation of product prices and costs is allowed for unproved reserve volumes.

The determination of operating and net abandonment costs under current economic conditions should be based on the same time frame as that used for determining average pricing. Consistent types of cost items should be used to determine operating and net abandonment costs.

Chapter 4
Current Economic Conditions

H. David Crossley

4.1 Introduction—History and Background/Interpretation of Current Economic Conditions

As early as the 1930s, the American Petroleum Institute (API) introduced terminology such as "existing technical and economic conditions" that has been a major element of all subsequent proved reserves definitions. In 1964, the API definition of proved reserves was "…quantities…which… geological and engineering data demonstrate with reasonable certainty to be recoverable…from known reservoirs under existing economic and operating conditions." In 1965, the Society of Petroleum Engineers (SPE) published its proved reserves definitions using the terms "reasonable certainty" and "existing economic and operating conditions."

In December 1978, the U.S. Securities and Exchange Commission (SEC) adopted guidelines and definitions for proved reserves. These definitions used the terms "reasonable certainty" and "existing economic and operating conditions"—i.e., "prices and costs as of the date the estimate is made" (usually inferred to mean the effective date of the reserve report, not the date the calculations were performed).

The 1981 SPE definitions, originally proposed in September 1980 by SPE, API, and the American Association of Petroleum Geologists (AAPG) used the terms "reasonable certainty" and "existing economic conditions." In 1987, SPE published a set of reserves definitions, which included Probable and Possible categories. Proved reserves were to be commercially recoverable with "prices and costs prevailing at the time of the estimate." That year, the World Petroleum Congresses (WPC) published its "Classification and Nomenclature Systems for Petroleum and Petroleum Reserves." These definitions were very similar to the SPE definitions. The WPC document used the terms "reasonable certainty" and "economic and operation conditions at the same date." In 1991, SPE submitted proposed changes to the 1987 definitions that would have permitted "specified" rather than "existing" prices and costs in making the reserve estimates. Also included was a redefinition of the analogous conditions to be used in the assignment of proved reserves to improved recovery projects. Those proposed changes, after much debate, were withdrawn in 1994.

In March 1997, the SPE and WPC boards of directors approved a single set of reserves definitions jointly assembled and agreed upon by SPE and WPC. This was the result of several years of dedicated effort by individuals from both groups and recognized the urgent need for greater consistency and understanding in industry application of existing reserve definitions. The SPE/WPC agreed definitions state that proved petroleum reserves should be based on current economic conditions, and these conditions should not be restricted to costs and prices but should include all factors affecting a project's viability. Probable and possible reserves, as defined by the new SPE/WPC rules, could be based on future expected economic conditions (generally meaning anticipated escalated prices and costs where appropriate) and future anticipated technical developments.[1]

4.2 Current Economic Conditions Defined

The new SPE/WPC guidelines defined proved reserves as "those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations."

The definition of current economic conditions was listed as follows and represents a significant departure from past definitions and/or interpretations:

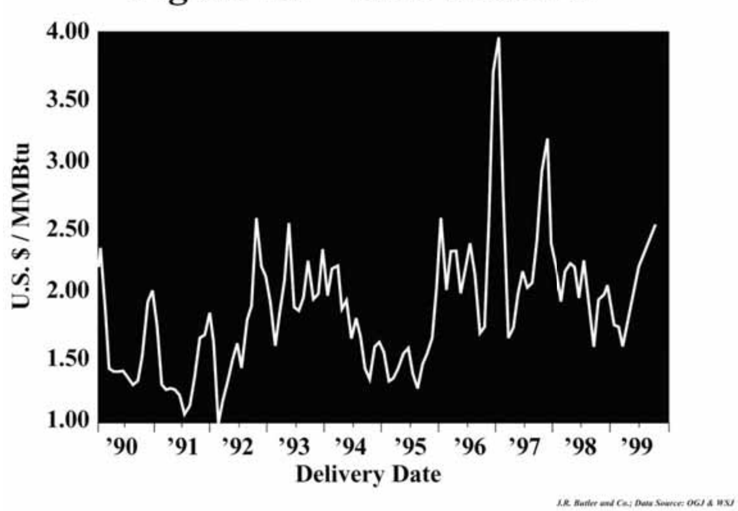
> *"Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves."*

The industry standard practice recommended and approved by SPE and WPC boards recognizes "recent" price and cost volatility, which did not exist when the first concepts of "existing economic conditions" were developed. Earlier attempts to redefine current economic conditions to fit "modern" conditions, such as the 1991 attempt described earlier, were hampered by the obvious, significant potential change in both procedure of calculation and value amount of remaining proved reserves with any change in definition.

Ultimately, SPE and WPC recognized that a change in definition to reflect modern economic conditions was imperative to avoid somewhat bizarre situations. An example of such a situation would be continued production with no proved reserves (by an ultra-strict interpretation of the existing “one single-day price” economic conditions definition). This situation could occur during a temporary product price downturn that happened to coincide with the date of calculation or effective date of the reserve report. Additional examples of results from the application of the old “stable price” rules to the calculation of proved reserves in various situations are discussed later and in detail in the references shown at the end of this chapter.

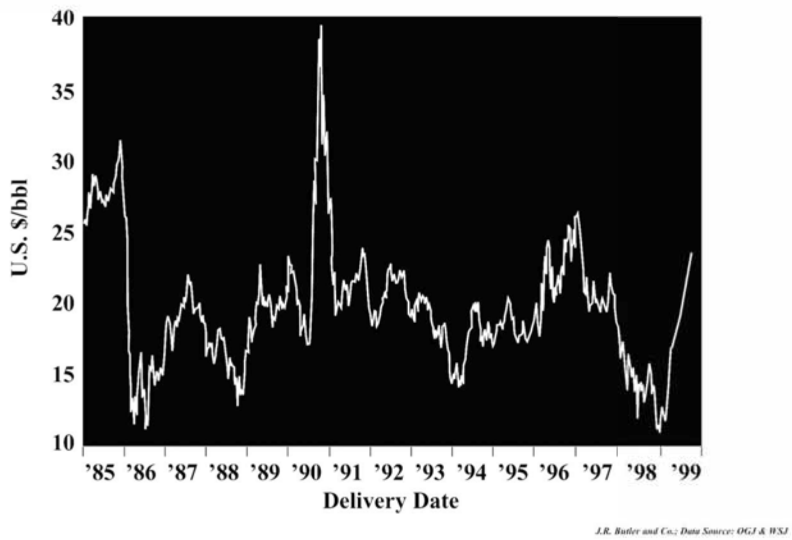
Modern industry standard practice dictates that in conditions of relatively short-term price fluctuation, a corresponding “knee-jerk” reaction to reduce or temporarily increase proved reserves is not practical or efficient. This “one day” analysis attempt at long range reserve recovery under modern price fluctuations is confusing to both the financial community and to those attempting to apply the rules within the industry. From 1986 to 2000, WTI oil prices fluctuated from about U.S. $12/bbl to a high of U.S. $39/bbl in the third quarter of 1990, and back to roughly the U.S. $12/bbl level at year end 1998. By the end of the first quarter of 1999, the West Texas Intermediate (WTI) price had already increased back to U.S. $16.64/bbl. (Please refer to the product price graph, Figure 4.1.[2]) This represents a 39% increase in 90 days. By comparison, the Dow Jones Industrial Average, which was very volatile during that time, increased only 0.5% over the same period. Toward the end of the first quarter of 2000, WTI prices had again rebounded dramatically to about U.S. $28/bbl.

Figure 4.1—GAS PRICES



While WTI prices demonstrate the price volatility over time, heavy crude grades demonstrate the lower extreme of the temporary dip at year-end 1998 with prices as low as the U.S. $7/bbl range. These prices also rebounded in percent increase terms in a manner similar to WTI in the first quarter of 1999 and the first quarter of 2000. In contrast to the approximate U.S. $12/bbl WTI year-end 1998 price, an average 12-month 1998 price for WTI was approximately U.S. $14.50/bbl. Other recent comparisons of year-end and 12-month average prices show large differences on a U.S. $/bbl basis. Both crude and natural gas prices show wide fluctuation over the past 15 years (please refer to Figures 4.1 and 4.2). The fluctuation in product prices in recent years is compared to the long-term, relatively constant product price in effect when many of the original “existing prices” proved definitions were developed. The wide changes in price in recent years now require special consideration to obtain industry consistency and avoid confusion in the investor and financial communities.

Figure 4.2—WTI SPOT PRICES



As an industry standard guideline, the "averaging period" that is consistent with the purpose of the reserve estimate could be different for various types of industry projects, and should in general be left to the judgment of those responsible for representing the country or company concerned (but should be well-documented). Thus, proved reserve booking decisions may be made without overemphasis on temporary "one day," "year end," or "date of estimate" prices that temporarily deviate from historical averages caused by transitory world events or crises. If, however, the price fluctuation circumstances decrease the certainty of future development or action to less than 90% certainty, the reserve volumes should be shifted to one of the Unproved Reserve or Contingent Resources categories as appropriate.

There are many documented examples in the recent technical literature that support the logic of using 12 months as the time period for estimating product prices and operating costs. As a guideline for the "averaging period" for estimating proved reserves, the specified time period would normally be a prior 12-month average determined at the date of the reserve estimate, provided it is permissible under relevant reporting regulations.

4.3 Operating Costs and Abandonment in Current Economic Calculations for Proved Reserves

The economic limit calculation based on economic conditions can significantly affect the estimate of proved reserve volumes. The following are recommended industry standard guidelines for calculating operating and abandonment costs. Economic limit is defined as the production rate at which net income from a property (which may be an individual well, lease, or entire field) equals "out of pocket" cost to operate that property (the cost to maintain the operation). In the case of offshore operations, the evaluator should take care to ensure that the estimated life of individual proved reserve entities (as in well or reservoir entities) does not exceed the economic life of a platform in the area capable of ensuring economic production of all calculated volumes.

Operating costs should be based on a time frame consistent with that used to develop product prices (see discussion in the previous section regarding use of a 12-month averaging period). Operating costs for most situations should include material and supply costs, labor and power costs, and chemical costs, as well as any fixed overhead charges (e.g., to leases/fields operated by others) and any severance and ad valorem taxes. Operating costs should exclude DD&A and P&A costs, as well as any overhead above that required to operate the property itself. When calculating abandonment cost for economic analysis, the estimate should, for consistency, be based on costs determined during the same time period that was used to determine operating costs. Reuse of producing structures and equipment (such as offshore platforms) and/or the import of adjacent production to existing facilities can extend the point at which operating costs would normally exceed net income from the property and thus extend the life of the property.

4.4 Production-Sharing Contract Reserves/Contract Extensions and Current Economic Conditions

A production-sharing contract is a contractual agreement between a contractor and a host government under which the contractor typically bears all risk and costs for exploration, development, and production. In return, the contractor is given the opportunity to recover the investment from production (cost hydrocarbons), subject to specific limits and terms. The contractor also receives a stipulated share of the production remaining after cost recovery (profit hydrocarbons). Unlike concessions, the host government retains ownership; however, the contractor normally receives title to the prescribed share of the volumes as they are produced. Reported reserves are based on the economic interest held subject to the specific terms and time frame of the agreement (as discussed extensively in Chapter 9 of this volume).

The remaining reserves and/or resources in production-sharing contracts are often re-calculated annually (depending on the agreement) based on current economic conditions related to product price and operating costs. In these instances, the current economic conditions that determine the annually changing remaining reserves are agreed upon in the contract between the operating company or companies and the government or other entity. In times of product price volatility as in recent years, the annually calculated volumes of proved reserves associated with these production-sharing contracts could fluctuate quite widely depending on annual year-end product prices. If there are no specific contracts or other prohibitions, an alternate approach can be used based on the SPE/WPC definition of current economic conditions. It states that current economic conditions "…may involve an averaging period that is consistent with the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves." A price could therefore be selected based on an average lifetime price associated with the contract life. In agreements of this type, the volumes would be a function of the average price or contracted price over the life of the project rather than the prevailing price at the time of the estimate. The reserves calculated with this price could then be considered Proved Reserves within the guidelines of the SPE/WPC definitions.[3]

As production-sharing or other types of agreements approach maturity, they can be extended by negotiation of renewed contract terms, by the exercise of options to extend, or by other means. In such an event where a firm right to extend exists, and if there is reasonable certainty that the right to exercise the option to extend will be completed, the additional reserves realized through the extension of the contract terms may be added. These may be reserves resulting from primary recovery, or reserves that fall within existing and operating secondary or tertiary recovery projects. Terms affecting the current economic condition calculations that determine annual production volumes are normally agreed upon by contract with the local government or other entity. But booked reserve amounts for total life can sometimes be determined by using an average price over the life of the project, as described earlier. This technique reduces or eliminates what can be tremendously large annual negative or positive reserve revisions using single-day year-end pricing. Volume calculations using single-day year-end prices are frequently in the opposite direction in successive years as a result of large temporary product price fluctuations.

A production payment is frequently used to finance producing property acquisitions or facilities expansion. This type of loan is essentially a sale of reserves (or possibly resources in some cases) whose future production is used to repay the principal of the loan and interest thereon. The producers' booked volumes should be reduced from the total ultimate working interest recoverable volume by the amount required to extinguish the loan. In this situation, the volume of such reserves will be dependent upon the currently established price of hydrocarbons during the period of principal and interest payments. Therefore, the price used for calculating reserves and resources to be booked should be the agreed forecast of hydrocarbon prices over the payment period. Similarly, any situation in which a future options contract price has been established as the current agreed product price for future production of reserves or resources should use the established contract price for volume booking amounts. Because probable and possible reserves and contingent resources are specifically defined by SPE/WPC guidelines as allowing "future expected economic conditions," futures market prices could also be considered as a basis for volume calculation in those categories.

Contracts where average project lifetime prices are not appropriate for calculating reserves should use the prior 12-month average price as opposed to a single-day year-end price. Either of these techniques reduces or eliminates the very large remaining volume swings that are possible with determinations made from single-day prices that can fluctuate widely from year to year.

It should also be noted that the phrase "current economic conditions" also applies to the term of the existing agreement to produce from a property. Therefore, in the absence of a firm right or option to extend the agreement, reserves expected to be produced after contract termination will not, in general, be classified as Proved. Such quantities may be classified as Probable or Possible reserves or resources, depending on the level of certainty and commercial viability associated with contract extension.

References

1. Caldwell, R.H. and Heather, D.I.: "Why Our Reserves Definitions Don't Work Anymore," paper SPE 30041 presented at the 1995 SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, 26–28 March.
2. Ausburn, B.E.: "Comparison of Reserves Estimates Using Different Definitions," J.R. Butler and Co., Houston (September 1996). Product price variation graphs by J.R. Butler and Co., B.E. Ausburn (April 1999).
3. McMichael, C.L.: "Effect of Different International Fiscal Systems on Reserves Reporting," McMichael and Assocs., Plano, Texas (February 1996); McMichael, C.L. and Young, E.D.: "Effect of Production Sharing and Service Contracts on Reserves Reporting," paper SPE 37959 presented at the 1997 SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, 16–17 March.

Chapter 5 Summary
Probabilistic Estimation Procedures

Sigurd Heiberg and Wim J.A.M. Swinkels

Probabilistic methods of reserve and resource estimation provide a structured approach to account for uncertainty. Probabilistic methods help ensure that quoted quantities are appropriate relative to the requirements of certainty.

Probabilistic methods do not introduce new information, nor do they introduce radical changes. They bring clarity to the expressions of certainty or uncertainty. The change that they facilitate is an evolutionary enhancement of the methods used previously, and not a break with the traditions they represent.

Deterministic methods do not address uncertainties in terms of probabilities. They require that reserve/resource volumes be described in terms of discrete estimates. In theory and practice, there is no difference between a deterministic method and a probabilistic one when the probabilistic method addresses the expected (mean) value only. The expected values behave like deterministic values in the sense that the expected value of a sum is equal to the sum of the expected values (and likewise for products of uncorrelated factors).

Probabilistic methods of reserves estimation start by identifying the project for which reserves are to be quantified. Intuitively, this is the (uncertain) amount of petroleum to be recovered from one or more petroleum accumulations. More specifically, a reserve quantity is the amount of petroleum to be recovered in response to a given effort to get it (i.e., from a specific development plan or project). Thus, a field may have petroleum resources in several resource categories simultaneously. A field with oil reserves may, for instance, have associated or free gas (or potential for improved recovery) that does not meet the requirements that the resource definitions set for quoting it as reserves, but which could be contingent resources. The field also may have prospective (undiscovered) resources.

The probabilistic quantification of proved reserves must ensure that quantities are not affected by upside potentials that it would be unreasonable to include, or that would be in conflict with the requirements of the definitions.

The following guidelines accomplish this:

- Those estimated recoverable quantities that are fully consistent with the criteria for proved reserves are identified and their expected value (EV) determined (or a single deterministic analysis undertaken).

- All estimated recoverable quantities that are fully consistent with the criteria for discovered resources of any category (including proved) are identified and the value that has at least a 90% probability of being exceeded (i.e., at least the P90 value) determined for the complete inventory of those discovered resource quantities. The value selected as the proved reserves quantity should be the lower of the EV of the proved reserves quantities (or deterministically assessed proved value) or the P90 value for the complete inventory of discovered resources quantities.

These guidelines are illustrated by the following example:

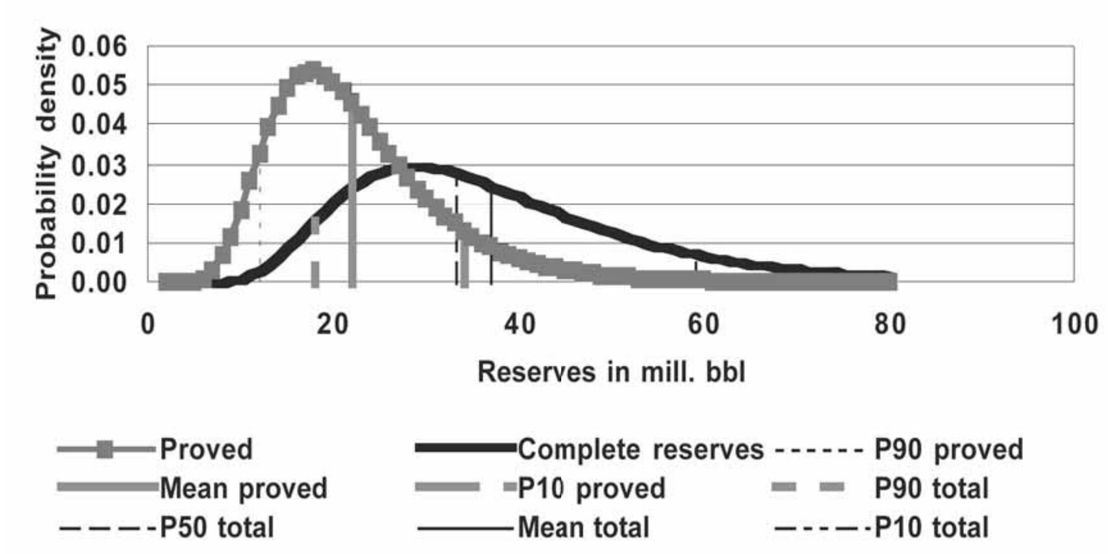


Figure 5.1—Probability density functions of reserves of a proved quantity and of a complete discovered resource.

The mean (expected) value of the proved quantity is 22 million, whereas the P90 of the complete discovered resource is 18 million. The guidelines state that 18 million should be chosen as the proved number. If the upside potential of the complete scenario were higher, the proved value could be increased up to the mean value of the proved scenario, or 22 million bbl. At the other extreme, where there is no upside beyond what has been identified as proved, then the proved reserve would be the common P90 value of the proved and complete resource quantity, or 12 million.

When probabilistic methods are used to quantify contingent and prospective resources, the low estimate is assessed as the P90 of the quantities included in the relevant category. The best estimate is a measure of central tendency such as the expected value, and the high estimate is the P10 value. This assumes that discoveries will be made and developed. The probability that this will in fact happen is assessed and expressed separately.

Probabilistic reserves quantification may be the result of a static analysis, or of an analysis of forecasts in time of the quantities to be produced (and sold) from one or more projects, and to which the company reporting such volumes is entitled. In both cases, probabilistic assessments of the following parameters are required: structural control (gross rock volume, or GRV), reservoir parameters, recovery from the reservoirs, recovery of sales products from the well streams, and entitlement to sales. A probabilistic quantification involves both probabilistic assessments of the parameters and assessment of the dependencies and correlation between parameters and between the entities being aggregated. The same applies in fact when a deterministic quantification is made, although it is not explicitly expressed.

In the static analysis, reserves are calculated as the product of gross rock volume, net-to-gross volume ratio, porosity, hydrocarbon saturation, volume conversion from reservoir to standard conditions and the recovery factor. The probability density function (pdf) for the resulting reserves is often asymmetrical with a high upside.

The GRV is often seen as the quantity that contributes the most to uncertainties in reserves. Normally, the volume of the reservoir prism is proportional to the cube of the column height. Consequently, uncertainty in GRV will often tend towards a log-normal pdf, and this also highlights the sensitivity of reserves estimates to the depth of the lowest known hydrocarbons.

Measurements of rock properties (porosity, saturation, and flow characteristics) are generally insufficient to fully characterize the reservoir and hence to fully define the range or shape of the appropriate pdf. The observed or calculated data help to condition uncertain (alternative) interpretations. Measurements of fluid properties are generally more representative provided they are made on virgin accumulations that are in chemical and physical equilibrium.

Uncertainty in recovery efficiency is critically dependent on both the characteristics of the reservoir and the specifics of the scheme for recovery and processing of the oil and gas. Realistic (alternative) reservoir interpretations should be considered, conditioned by available observations, and consistent with the definitions. The sophistication of the modeling algorithms should be tailored to the completeness and quality of the available data.

The pdfs selected should reflect available observations and interpretations. Particular care is required to ensure that an appropriate (and realistic) range is chosen. For example, it is frequently overlooked that the pdf for a reservoir property such as porosity defines the uncertainty in the estimate of the average porosity, which is not the same as the actual range of porosity values encountered in the reservoir. The complete distribution from P100 (minimum) to P0 (maximum) should always be viewed to ensure that it represents a valid range of uncertainty for that parameter.

Probabilistic reserve estimates developed as a sum of production forecasts in time may benefit from the following:

- Determining the factors on which uncertainty in production forecasts depend and ranking them in order of importance.
- Identifying dependencies between factors and developing, where possible, aggregated descriptions to replace strongly dependent factors.
- Developing key alternative realizations of production forecasts by varying the factors that have sufficient impact on uncertainties, and correlating the forecasts to the factors varied.
- Using the correlations together with information on the pdfs of the factors varied to develop large sets of forecasts with associated probabilities or a large set of representative equiprobable forecasts.
- Applying the formulas of commercial agreements and fiscal frameworks to determine entitlement to each forecast and summing them up over time to get the appropriate entitlement volumes.
- Producing the pdfs for the scalar quantities of interest.

Chapter 5
Probabilistic Estimation Procedures

Sigurd Heiberg and Wim J.A.M. Swinkels

5.1 Quoting Reserve and Resource Quantities Using Probabilistic Methods

Only the remaining commercially recoverable petroleum from known accumulations qualifies for classification as a reserve. Other quantities are classified as Contingent Resources or Undiscovered Resources. All have value, directly as current producing assets, or as future development opportunities. In either case, they must be measured and managed.

Reserves are typically more sharply defined than resources because of their more advanced position in the development life cycle and the greater amount of technical data that tends to be available to describe them. Even so, reserve numbers are generally defined within a range, not as one fixed quantity. The range may be described qualitatively by deterministic methods or quantitatively by probabilistic methods.

Probabilistic methods provide a structured approach that accounts for both the uncertainty in each of the parameters that impact reserves of individual development and production projects and the residual uncertainty in reserves in a portfolio of projects. Probabilistic methods help ensure that quoted quantities are appropriate relative to the requirements of certainty.

Probabilistic methods do not introduce new information, nor do they introduce radical changes. They bring clarity to the expressions of certainty or uncertainty. The change that they facilitate is an evolutionary enhancement of the methods used previously, not a break with the traditions they represent.

5.1.1 Reserves and Resources

Resource estimation starts by identifying the project for which reserves are to be quantified. Intuitively, this is the (uncertain) amount of petroleum to be recovered from one or more petroleum accumulations. More specifically, a reserve or resource quantity is the amount of petroleum to be recovered in response to a given effort to get it (i.e., from a specific development plan or project). Thus, a field may have petroleum resources in several resource categories simultaneously. A field with oil reserves may, for instance, have associated or free gas, or potential for improved recovery, that does not meet the requirements that the resource definitions set for quoting them as reserves, but which could be contingent resources. The field also may have prospective (undiscovered) resources.

When the new resource classification was introduced in 2000, it allowed a clearer distinction between uncertain recoverable quantities from a project of a given maturity and projects of different maturities. As this was not facilitated when the reserves definitions stood alone, the definitions allow the inclusion of commercially less mature resources in the probable and possible reserves. Today, these would be better classified as Contingent Resources. To ensure continuity, the procedure outlined in the “Proved Reserves” section therefore allows contingent resources to influence (the reasonable certainty of) proved reserves to the same extent that would have been done before. In practicing this, judgment is clearly required. Caution must be used to avoid taking into account contingent resources with little or no commercial potential. The risk that immature potentials may not be realized must also be taken into account.

Reserves are typically grouped in two fundamental ways:

- As Proved (1P) Reserve entities alone, from which Proved Reserves are calculated.
- On a cumulative basis, from which the Proved plus Probable (2P) or the Proved plus Probable plus Possible (3P) reserve is calculated.

Probabilistic methods start by identifying the entity for which reserves are to be quantified. The reserve entity that qualifies as Proved is included in the proved reserve scenario and can be fully described in terms of quantity and pdf, whereas all discovered resource entities, including proved reserves, are included in a complete and cumulative discovered resource category. A proved reserve entity may, for instance, be the oil estimated to be produced from a pool under a certain development scheme, ignoring any oil present below the lowest observed oil. The discovered resource entity considered may also include contributions from below the lowest observed oil, other less completely observed reserves, and certain contingent resources, provided sound judgment is applied in this respect.

Proved Reserves

The specific requirements to be met before a petroleum quantity can be considered a proved reserve are found in Section 5.4. When proved reserves are calculated, the requirement for certainty for a given quantity must be met by aggregating the probabilistic descriptions for each part that makes up the quantity of interest, whether it be for an individual project or for a portfolio of projects.

The definitions require that, when probabilistic methods are being used, there shall be at least a 90% probability (P90) that the quantity actually recovered will equal or exceed the estimate quoted. The definitions go on to state that there shall be at least a 50% probability that the quantities actually recovered will exceed the sum of the 2P reserves. Likewise, there shall be at least a 10% probability that the 3P reserves will be equalled or exceeded.

If P90 of all reserves were to be the only requirement with respect to certainty of proved reserves, then proved reserves would be influenced by estimates of upside potentials. For example, a P90 estimate could include a contribution from a quantity that the definitions specifically exclude from contributing towards a proved reserve, and which is classified as Probable or Possible. In the example mentioned above, the P90 value would be influenced by quantities below the lowest observed oil and by the quantities to be gained through an improved recovery project. Clearly, it would not be appropriate to permit proved reserves to be influenced by such upside potentials.

Conventional deterministic methods do not include more than the expected value of entities qualifying for the proved reserve scenario to qualify as proved reserves. This represents a natural upper limit, consistent with the definitions.

The following guidelines accomplish this:

- Those estimated recoverable quantities that are fully consistent with the criteria for proved reserves are identified and their EV determined (or single deterministic analysis undertaken).

- All estimated recoverable quantities that are fully consistent with the criteria for discovered resources of any category (including Proved) are identified, and the P90 value is determined for the complete inventory of those discovered resource quantities.
- The value selected as the proved reserve quantity should be the lower of the EV of the proved reserve quantities (or deterministically assessed proved value) or the P90 value for the complete inventory of discovered resources quantities.

These guidelines are illustrated by Figure 5.1.

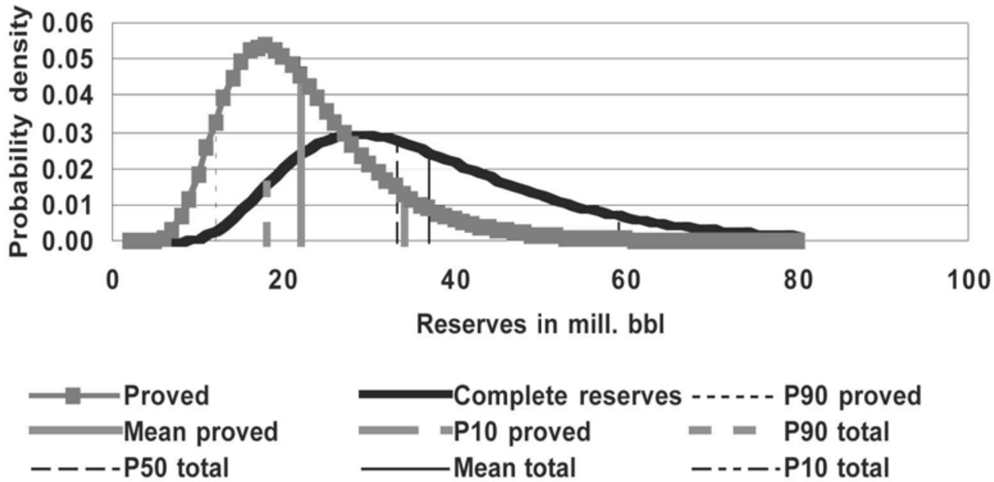


Figure 5.1—Probability density of reserves of a proved quantity and of a complete discovered resource.

The mean (expected) value of the proved reserve entity is 22 million bbl, whereas P90 of the complete discovered resource is 18 million bbl. The guidelines state that 18 million bbl should be chosen as the proven number. If the upside potential of the complete scenario were higher, the proven value could be increased up to the mean value of the proved scenario, or 22 million bbl. At the other extreme, where there is no upside beyond what has been identified as Proved, then the proved reserve would be the common P90 value of the proved and complete reserve quantity, or 12 million bbl.

In practice, the P90 value of the Proved group of quantities will be equal to or smaller than the P90 value of the complete discovered resource category (except in rare cases, for example where there is negative correlation between oil and gas reserves). When working with many quantities of comparable size, the P(90) and the expected values of the Proved group of quantities will approach each other. In such cases, the P(90) value of the Proved group of entities is a good approximation of the value calculated as the minimum of the expected value of the Proved group of quantities, and the P(90) value of all discovered resources. Whenever this approximation is acceptable, it is not necessary to consider the complete discovered resources when estimating proved reserves.

Unproved Reserves

The definitions do not restrict 2P and 3P reserves in the same way they restrict proved reserves. The wording used is: " In general, probable reserves may include..." Similar wording is used to define possible reserves. These statements are illustrative and not exhaustive. They are intended as guidelines when the probabilistic method is not adopted.

From a probabilistic point of view, the possible reserves will include entities that do not qualify as Proved or Probable reserves. This further emphasizes that quantities other than the ones mentioned in the definitions may be included as well.

When using probabilistic methods, the P50 and P10 values of the entities included in the complete and cumulative reserve category therefore give the 2P and 3P reserves. In Figure 5.1, the 2P value is 33 million bbl, and the 3P value is 59 million bbl.

If several independent entities of comparable size are aggregated, the expected values may, for all intents and purposes, be used instead of P50. Then, the conventional deterministic method and the probabilistic method will come together, as the expected value of the sum is equal to the sum of the expected values.

Contingent Resources and Undiscovered Resources
Scenarios are not considered for contingent recoverable quantities and undiscovered resources. When probabilistic methods are used, the low estimate is assessed as P90 of the quantities included in the relevant category. The best estimate is a measure of central tendency, such as the expected value, and the high estimate is the P10 value. The contingent resources are, as the name indicates, contingent upon the realization of development and production schemes. The likelihood that this will occur is expressed indirectly and qualitatively by using appropriate resource status categories, and quantitatively, when required, through the use of probabilities.

5.2 Reserve Description

Reserves are computed either through a static analysis, or through a forecast in time of quantities to be produced (and sold) that the reporter is entitled to receive.

5.2.1 Static Analysis of Reserves

In the static and volumetric reserve calculation, the GRV of a reservoir containing a petroleum accumulation is multiplied by net-to-gross rock volume ratio, porosity, hydrocarbon saturation, the volume conversion factor for going from reservoir to standard conditions, the recovery factor, and the entitlement factor.

In the probabilistic method, each factor in the reserves equation is described with a statistical distribution represented by a pdf. The factors are not all independent of each other, and correlations should be identified and represented in the probabilistic calculation of reserves. The resultant pdf for the reserve is often asymmetrical.

To express uncertainty (or certainty) in the form of a pdf is a refinement relative to describing the quantity or reserve with single numbers and the degree of confidence attached to them. The refinement is particularly useful when there is an observational basis for quantifying the pdf.

Sometimes, reservoir uncertainty is observed directly. Seismic data observes the entire reservoir, and the observations contain information with respect to resolution from which pdfs may be derived. In contrast, borehole data is only representative of a small part of the reservoir. The reserve estimator will have to draw on a vast body of knowledge in geosciences and technology to supplement such direct but incomplete observations in order to assess the reserves. Nevertheless, a probabilistic approach allows the application of a much broader information base than does a deterministic one. When this information is poor, a probabilistic method may be no better than a deterministic approach, but it will, unless abused, never be worse.

5.2.2 Reserves as the Sum of Sales Forecasts in Time

Reserves may be computed by summing up the sales forecasts in time. Information on uncertainty in future production has value in itself well beyond that which may be obtained through a quality reserve assessment. It does, for instance, allow a rational analysis of the value of information, of flexibility, and of other real options. These options may in turn be used to enhance the value of the project and improve on the quality of production forecasts and reserves.

Some guiding principles in producing production forecasts are:

- Determining the factors on which uncertainty in production forecasts depend and ranking them in order of importance.
- Identifying dependencies between factors and developing, where possible, aggregated descriptions to replace strongly dependent factors.
- Developing key alternative realizations of production forecasts by varying the factors that have sufficient impact on uncertainties, and correlating the forecasts to the factors varied.
- Using the correlations together with information on the pdfs of the factors varied to develop large sets of forecasts with associated probabilities or a large set of representative equiprobable forecasts.
- Applying the formulas of commercial agreements and fiscal frameworks to determine entitlement to each forecast and sum them up over time to get the appropriate entitlement volumes.
- Producing the pdfs for the scalar quantities of interest.

In the general case, there will neither be a unique P90 nor P10 forecast in time. This is seen when forecasts of different production capacities are made without varying reserves. High P10 production early will lead to low P90 production late, and vice versa. Only in special cases, as when Step 1 identifies that uncertainties depend on uncertainties in reserves only, will there be such unique relations. It is therefore recommended to refrain from assigning pdfs to vectors, such as forecasts in time, and to reserve them for scalars such as reserves.

Production forecasting reveals that produced volumes are dependent on information well beyond that used in reservoir characterization and reservoir engineering and management. Pdfs of short-term forecasts are typically obtained by observing past predictability of equipment performance, well performance trends, their predictability, and so on. Pdfs of long-term forecasts are more strongly dependent on reservoir uncertainty and the measures available to handle it through the production chain up to the sales point.

When estimating reserves on a probabilistic basis using production forecasts in time, it becomes very clear that reserves assessment requires a multidisciplinary analysis.

5.3 Parameters and Their Uncertainty Distribution

Uncertainty in the estimate of petroleum reserves and resources is associated with every term in the equations describing them. Parameters are divided in four major groups: structural controls, reservoir parameters, recovery factor (including surface facilities), and entitlement to reserves.

5.3.1 Reservoir Volume

Usually, the biggest contribution to overall uncertainty is in the GRV of the reservoir—just how big is it? The uncertainty may be related to lack of definition of reservoir limits from seismic data, of conversion from time in seismic observations to depth, of dips of the top of the formation, of the existence and position of faults, and of whether they are sealing to petroleum migration and production. Importantly, the GRV depends critically on the height of the hydrocarbon column. Normally, the volume of a reservoir prism increases proportionally with the cube of the column. The definition of proved reserves recognizes this sensitivity by excluding rock volumes below the lowest observed hydrocarbons.

5.3.2 Reservoir Parameters

Uncertainty associated with the properties of the reservoir rock also must be taken into consideration. While petrophysical logs and measurements in the laboratory may be quite accurate, the samples collected may be representative only for the most homogeneous of formations. A core 4 inches wide is not necessarily a representative sample of a buried and altered river delta, superimposed plains of meandering river channels, a suite of beach deposits, turbid marine landslides, or other geological formations. Only in rare instances can measurements of porosity, net-to-gross ratio, fluid saturation, and factors affecting fluid flow be applied directly and with confidence. For the most part, they help condition one or several alternative (uncertain) interpretations.

Fluid properties are different. The processes of convection and diffusion over geologic times have generally ensured a measure of chemical equilibrium within a virgin pool. While it is not uncommon to observe gradients in fluid composition, they often are both continuous and homogeneous in the way they vary. A few well-chosen samples may therefore provide a representative selection of the fluids. Sampling and analysis may, however, be a significant source of uncertainty. Pools with initial gradients in fluid composition or where phase changes have occurred will be disturbed by production. Here, samples risk being unrepresentative of the pool; they may be misinterpreted easily. Here, fluid definition is less certain than in virgin reservoirs.

5.3.3 Recovery From the Reservoirs

Recovery is affected by the shape of the reservoir, its properties and fluid contents, and its drainage strategy. When a reservoir is closely defined, the effects of well and drainage point density and location, fluid displacement, pressure depletion, and their associated production and injection profiles, may be modeled numerically. Realistic alternatives, conditioned by available information and consistent with the definitions, may be modeled to assess the uncertainties.

When a reservoir is poorly defined, detailed numerical modeling may give way to material-balance calculations, or even less precise methods. This may even be a direct assessment of uncertainty in recovery efficiency, based on characteristics of the reservoir and of the production facilities.

5.3.4 Recovery of Sales Products From the Well Streams

The reference point for reserves is commonly a sales point. Reserves quantification requires an assessment of recovery of crude oil and gas from the reservoir, and of the corresponding sales products manufactured from the crude streams through the use of process facilities. Consumption and losses must be accounted for.

5.3.5 Entitlement

To how much of the reserves may a reporter claim entitlement? The answer to this question is generally not thought of as uncertain but as clearly defined in fiscal and regulatory frameworks and in the commercial agreements in force.

Under certain agreements, the split of production and reserves between stakeholders is made to depend on production or profit. Examples are agreements of progressive royalty or government take and production-sharing agreements. The uncertainty in a party's entitlement is then influenced directly by costs, prices, and production rates and their variation in time. This is further explained in Chapter 9 of this volume.

5.3.6 Selecting Distribution Functions for Individual Parameters

In probabilistic reserve calculations, the estimator has to specify a pdf that fits the information available. Modern tools (such as commercially available add-ins and other statistical software) allow for a wide choice of pdfs (normal, log-normal, triangular, Poisson, etc.).

The following may give some practical guidance on the selection of the parameter distributions:

- The pdf of a sum of a large number of independent quantities of the same magnitude tends toward a normal distribution. Examples are the reserves of a large number of equally sized fields in a portfolio, and the porosity of a rock body. If they are not of the same magnitude, the sum and its pdf will be dominated by the largest ones.
- By the same token, the pdf of a sum of logarithms tends toward a normal distribution. As a result, a product of independent factors, whose logarithms are of the same magnitude, tend toward a log-normal distribution. Examples of entities that are strongly affected by products are the reserve of an accumulation and the permeability of a porous system.
- The normal, log-normal, or other appropriate distributions must only be applied to the extent that, and in the intervals for which, they usefully reflect the underlying uncertainty. For instance, when a distribution contains negative values or extends to infinity, and the quantity described definitely is positive and bounded, the distribution will have to be modified to fit reality.

The pdf is in practice often approximated with triangular distributions, particularly when data are limited. When a probability distribution cannot be determined, a uniform distribution is sometimes used. Locally, approximations like these are normally considered a poor fit to reality. However, aggregated quantities are more influenced by mean values and standard deviations than they are by the forms of the distributions of individual components in the aggregation. This justifies the use of simple approximations when information is aggregated. A common error when working with poorly defined quantities is to underestimate the possible uncertainty range of each parameter. Particular attention should therefore be paid to this, regardless of the distributions chosen.

The distribution of the raw data may give a better description of the uncertainty range than the distribution of averaged data when analyzed correctly in a geological perspective. The averaging process can filter out the high and low ends of the spectrum. However, the use of raw data distribution necessitates discretion, as some measurements may not be valid for a variety of reasons.

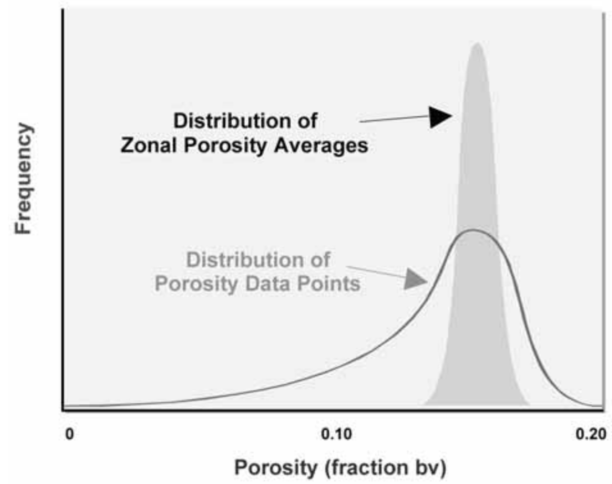


Figure 5.2—Frequency distributions of porosity.

Even if some of the core plugs have 0% porosity, we can't use 0% porosity as the low value in our distribution of average field-wide porosity. We have already established that there are some porous zones (i.e., average porosity must be greater than 0%).

We should consider the known distribution of available data. If abundant data are available (e.g., computer analyses of the porosity logs), and the geologic processes of sedimentation, deformation, and diagenesis are such that the variability along the hole is representative of the variability in the reservoir, then the actual distribution of these data can be used. If only scarce data are at hand, then the range should be defined and turned into a distribution.

TABLE 5.1—SOME RESERVOIR PARAMETERS AND TYPICAL RANGES OF UNCERTAINTY

	Range	Source
Gross Rock Volume (GRV)	+/–30%	3D Seismic
		2D Seismic
Net-to-Gross	+/–20%	Well Logs
Porosity	+/–15% of the measurement	Logs
	+/–10%	Cores
Hydrocarbon Saturation	+/–20%	Well Logs
Dip	+/–10%	Dipmeter
	+/–30%	Seismic
Formation Volume Factor (B_o)	+/–5%	PVT Test

These values assume that samples examined are representative of the reservoir.

Some Guidelines

- Make a conscious engineering decision on range and shape of the input distributions for the volumetric calculation.
- Do not confuse the three measures of centrality: expectation or mean, mode, and median.
- Avoid distributions that extend into infinity.

- Make sure the range of input parameters describes not more than the hydrocarbon resource category that you claim to describe.

5.4 Definitions and Rules

Probability	The extent to which an event is likely to occur measured by the ratio of the number of favorable cases to the whole number of cases possible.[1] Note that the probability used in reserves estimation is a subjective probability, quantifying the likelihood of a predicted outcome.
Probability Density Function (pdf)	Probability as a function of one or more variables, such as a hydrocarbon volume.
Cumulative Probability Distribution Function (Cdf); Survival Function (Sf)	To each possible value of a variable, a Cdf (Sf) assigns a probability that the variable does not exceed (does exceed) that value. The “SPE/WPC Petroleum Reserves Definitions” use survival function in the statement: *“If probabilistic methods are used, there should be at least 90% probability that the quantities actually recovered will equal or exceed the estimate.”*
Measures of Centrality	The different measures of centrality defined below coincide only when pdfs are symmetrical. This is seldom the case for reserves. In general, and for most practical purposes, they differ.
Mean, Expectation, or Expected Value	The mean is also known as the expectation or the expected value. It is the average value over the entire probability range, weighted with the probability of occurrence. $Mean = \sum_{i=1}^{n} x_i \cdot P(x_i) \text{ or } \int x \cdot P(x) \cdot d(x)$ where x = reserve value and $P(x)$ = probability of x. The mean is by far the most important measure of centrality. It behaves like a single deterministic measure of reserves in aggregation and would be the number to look for if reserves are to be reflected by a single neutral number with no optimism or conservatism.
Mode, or Most Probable Value	The mode is another name for the most probable value. It is the reserves quantity where the pdf. has its maximum value. Believing more strongly in this estimate than any other, a deterministic evaluation of reserves with no optimism or conservatism is likely to produce the mode.
Median (also known as P50)	The value for which the probability that the outcome will be higher is equal to the probability that it will be lower.
	Measures of Dispersion
Percentiles	The quantity for which there is a certain probability, quoted as a percentage, that the quantities actually recovered will equal or exceed the estimate.
P90	The quantity for which there is a 90% probability that the quantities actually recovered will equal or exceed the estimate. In reserves estimation, this is the number quoted as the proven value.
P50, or Median	The quantity for which there is a 50% probability that the quantities actually recovered will equal or exceed the estimate.
P10	The quantity for which there is a 10% probability that the quantities actually recovered will equal or exceed the estimate.
Variance	The variance is calculated by adding the square of the difference between values in the distribution and the mean value and calculating the arithmetic average. $s^2 = \frac{\sum_{i=1}^{n} (x_i - \mu_i)}{n} = \int_a^b (x - \mu)^2 f(x) dx$ where x = reserve, = mean, and $f(x)$ = pdf. It is convenient to square the differences, as this avoids that positive and negative values cancel. The same effect may be obtained by taking absolute values of the difference, but the mathematical properties of such a measure are not as elegant as those of the variance.
Standard Deviation	The square root of the variance.

[1]New Concise Oxford Dictionary

Chapter 6 Summary

Aggregation of Reserves

Wim J.A.M. Swinkels

Introduction: Issues in Reserves Aggregation

Oil and gas volumes are usually reported for individual reservoirs or for fields. These estimates are based on performance evaluations and volumetric calculations for reservoirs or groups of reservoirs. The estimates are then added up to arrive at estimates for fields, areas, and companies. The uncertainty of the individual estimates at each of these levels may differ widely, depending on geological setting and maturity of the resource.

Adding up estimates with different levels of uncertainty is complicated by the following:

- The purpose for which the estimate is required.
- The fact that discount factors may be applied for high-risk volumes.
- Use of production-performance estimates to determine estimated ultimate recovery.
- Quality differences in the fluids, such as the gross heating value of gas reservoirs.

Aggregating Over Reserves Levels (Wells, Reservoirs, Fields, Companies, and Countries)

Reservoir Behavior From Performance Plots

Estimated ultimate recovery (EUR) can be estimated from performance plots at different reserves levels (e.g. blocks, reservoirs, and fields).

If we derive the EUR through extrapolation of performance in mature fields, we may run into complications. It is often observed that performance extrapolation at the reservoir level leads to a higher EUR than the sum of extrapolated well decline curves for that reservoir. One effect that is not captured by extrapolation methods is that closed-in wells may extend field life beyond that indicated by the producing wells in the reservoir. Another problem specific to gas fields is that the *p/z* plot on an individual well basis usually does not properly reflect the overall reservoir pressure decline. In such situations, it is good practice to check with an overall reservoir performance extrapolation.

Dependencies Between Estimates

One of the main complications in the aggregation of reserves, particularly with proved reserves, is the correlation between parameters in the reserves calculation. This leads to dependencies between individual reserves estimates for fault blocks, reservoirs, or sub-units of reservoirs, such that low reserves in one reservoir element naturally will be associated with low reserves in another one, or just the opposite. There are numerous causes of dependency between reserve estimates, including geological (e.g., fault location), methodological (similar interpretation methods), or personal (same geologist for a number of reservoirs).

Levels of Aggregation

In practice, a boundary is emerging for the statistical addition of proved reserves. Many companies and organizations now appear comfortable with the idea of adding probabilistically up to the field level, provided dependencies are properly handled. However, there is much less industry-wide acceptance for statistical treatment of aggregation above the field level and up to regional or company level. In some cases, it may be acceptable to aggregate probabilistically up to a project level where the project includes several fields. In such cases, the project should have a common sales point and be subject to depreciation as a single unit.

Adding Proved Reserves

Difference Between Dependent and Independent Addition

In quoting proved reserves, volumes are "estimated with reasonable certainty to be commercially recoverable" in the development of the field or project. In applying probabilistic reserves estimation methods, SPE/WPC defines proved reserves as having at least 90% probability (P90) of exceeding the quoted value. The proved reserves generally represent a conservative estimate of the recoverable volumes; for this reason, they are widely used by investors and bankers. In dealing with only a single asset, this makes sense because it allows for the risk that the development will result in much less than the expected hydrocarbon recovery. However, if we add proved reserves of several assets, this may lead to an overly conservative estimate, particularly if the estimates of the volumes are largely independent of each other.

Methods to aggregate volumes independently (assuming no correlation between possible high and low outcomes) are as follows:

- Scenario trees, representing the possible outcomes as branches of a tree and calculating the overall outcome.
- Monte Carlo methods.
- Treating the volume estimates as a physical measurement with an associated error and then using error propagation methods. This method is an approximation that only holds for symmetric distributions. Volumetric estimates, being the product of a number of parameters, tend towards a log-normal distribution (i.e., asymmetrical and with a tail of high values).

Use of Correlations

In many practical situations, we will be in between fully dependent or arithmetic addition and fully independent or probabilistic addition of proved reserves. The reason for this is that some parameters of our estimates will be correlated, while others will be completely independent of each other. Ignoring correlations in these cases will lead to overestimation of proved reserves. The rigorous solution in this situation is to calculate probability distributions, specify the correlation between them, and generate the resulting probability distribution for the aggregate. Monte Carlo simulation is one method of achieving this. The overriding problem in this approach is the proper specification of the correlation matrix. Various measures can make this process practical to apply.

Aggregating Resource Categories

Hydrocarbon volumes may be classified into various categories, depending on the risk and uncertainty associated with these volumes.

The volumes, which are thus identified, may or may not be ultimately produced, depending on the success of the project. For this reason it is important not to aggregate reserves, contingent resources, and speculative resources without due consideration of the risk of accumulations not achieving commercial production.

In adding up such volumes a meaningful total can be defined only by adding up the risked mean volumes (or complete distributions that incorporate the risk) resulting in a statistical expectation of the recovery. This will be no problem for a large portfolio of opportunities or for a smaller portfolio where the discounted (risked) volumes do not add significantly to the total.

Scenario Methods

A powerful method is the use of scenario methods. In such methods, we draw up scenario trees, of which the branches reflect various subsurface outcomes. Dependencies between various parameters can be represented easily in such trees.

The fully independent evaluations will usually result in a narrower range of uncertainty than the low-dependency or dependent evaluations. Experience suggests that we only need to apply a fully dependent method if we can identify sizeable correlations.

Normalization and Standardization of Volumes

Hydrocarbon volumes can be added and properly interpreted only if there is no doubt as to their meaning. Volumes are usually reported at surface pressure and temperature, for which convenient values are used. This leads to differences between reported volumes in different unit systems.

Chapter 6

Aggregation of Reserves

Wim J.A.M. Swinkels

6.1—Introduction: Issues in Reserves Aggregation

The petroleum engineer usually reports oil and gas volumes for reservoirs and fields. Each estimate is based on performance evaluations and volumetric calculations on reservoir blocks or sub-blocks. The reserves evaluator then adds up these estimates for the basic elements to arrive at estimates for reservoirs, fields, areas, and companies. The uncertainty of the individual estimates at each of these aggregation levels may differ widely, depending on geological setting and maturity of the resource.

Typically, the confidence in a reserves estimate will increase when a multidiscipline team of engineers and earth scientists matures the resource from an undrilled prospect to a drilled volume that can be defined volumetrically. Maturation then goes on to a stage of development that has sufficient production and pressure information to allow reliable production performance evaluation.

Adding up estimates with such different levels of uncertainty, can be further complicated by several factors:

- The purpose for which the estimate is required.
  Oil companies, considering long-term performance of their assets, will use the expectation (often interpreted as Proven + Probable) or best estimate of the volumes for investment purposes. They work on the assumption that in the long run the sum of their expectation values will be realized, with the downside in one case compensated for by the upside in another situation.
  Bankers, accountants, and utilities will go for a high level of certainty and concentrate on the proved volumes. Gas contracts are typically based on proved reserves, which adds a strong business incentive to the accurate determination (and addition) of proved reserves.
  Accountants use the ratio of production to proved reserves as the basis for depreciation of investments. This in turn has a definite impact on such business indicators as Return on Average Capital Employed (ROACE). For these calculations, they require proved reserves at the level at which the investments apply, which is often the field level or higher.
- The fact that engineers and geologists use discount factors for high-risk volumes.
- Production performance estimates are used to extrapolate the life of mature fields to determine Ultimate Recovery (UR). From reservoir dynamics, it follows that we have to take care in adding estimates of reserves established by these methods from well level to a reliable reservoir estimate.
- Differences in quality of the gas or liquid, which make up the reserves (e.g., the gross heating value of gas reservoirs).

In Section 6.2, we treat some general technical issues in reserves aggregation. In a discussion on the aggregation of reserves, we also address the issue that the uncertainty of the sum of volumes will be less than the sum of the uncertainties of the individual volumes. In other words, the certainty increases with the number of independent units available. The implications of the resulting uncertainty reduction in a diverse portfolio will be discussed in Section 6.3.

In Section 6.4, we discuss aggregation over reserves categories, and we show the use of scenario methods for reserves aggregation in Section 6.5, followed in Section 6.6 by a few notes on normalization and standardization of volumes. Section 7 summarizes the chapter in a few simple guidelines.

6.2 Aggregating Over Reserves Levels (Wells, Reservoirs, Fields, Companies, Countries)

6.2.1 Reservoir Behavior

Adding up volume-derived expectation values is relatively straightforward. This is true for situations where expectation values are interpreted as Proved plus Probable, and also for the probabilistic method because, from a statistical point of view, the expectations of distributions can be arithmetically added.

We can also derive the expectation of UR through extrapolation of performance behavior in mature fields. If we do this by aggregating from estimates for individual wells to totals for reservoirs or even fields, we may run into complications. It is often found that performance extrapolation at the reservoir level leads to a higher UR than the sum of the extrapolated well decline curves for that reservoir.

One reason for this may be that aggregating from individual well decline curves does not capture the effect that closing in a well can give an extra lease on life to the surviving wells in the reservoir. Another problem, which is specific to gas fields, is that the *p/z* plot per well usually does not properly reflect the overall reservoir pressure decline. In such situations, it is good practice to use an overall reservoir performance extrapolation if possible.

Decline-curve methods for groups of wells generally have a weak theoretical basis. Ross Purvis provides a good overview of these issues in the chapter on decline-curve methods in Ref. 1.

6.2.2 Dependencies Between Estimates

One of the major reasons why the addition of reserves, particularly proved reserves, sometimes leads to complications is that many parameters in the reserves calculation are correlated. This leads to further dependencies between individual reserves estimates for reservoir blocks, reservoirs, or sub-reservoirs, such that low reserves in one reservoir element will naturally be associated with low reserves in another one, or just the opposite. There are numerous causes of dependence between reservoirs of a geological (fault location), methodological (similar interpretation methods), or personal (same optimistic geologist for a number of reservoirs) nature, as classified in Table 6.1.

TABLE 6.1—CAUSES OF DEPENDENCE BETWEEN RESERVES ESTIMATES OF FIELDS OR RESERVOIRS

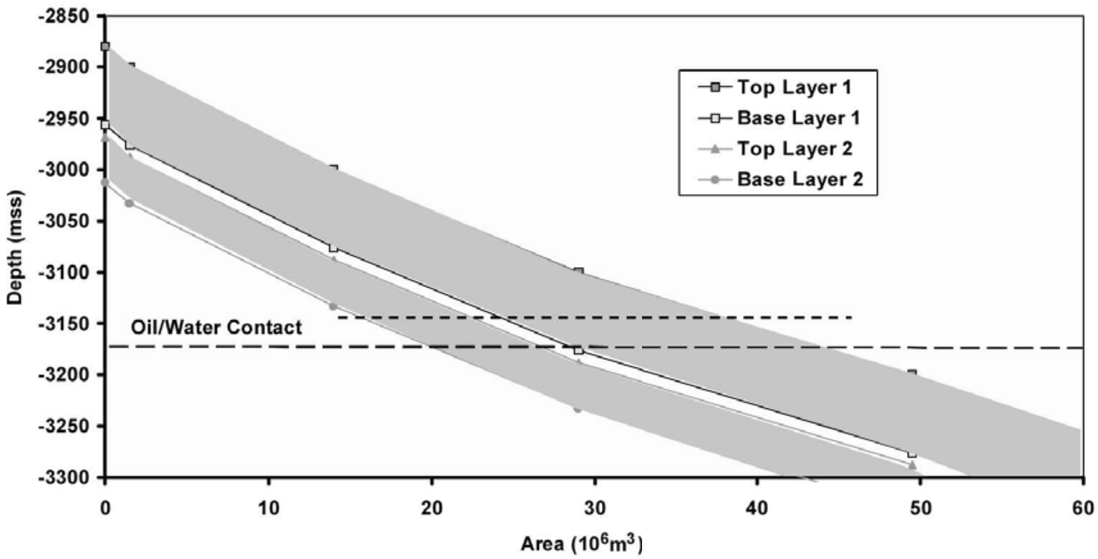
Type of Dependence	Example of Situation/Parameter
None No shared risk identified (fully independent).	Local, independent pressure systems
Weak A shared risk is not considered to be important when compared to other, known, independent risks.	Common seismic survey or seismic interpreter Common source of recovery factor estimates, tools (e.g., reservoir simulator), and ranges Saturation-calculation method (e.g., Waxman Smits, Archie) Saturation-height function (e.g., using capillary-pressure data from other fields)
Medium The shared risks could be real and significant.	The success of a low-pressure compression project in one field is a pre-requisite of success in another, and hence the recovery factor estimates are potentially linked. However, the major components of the uncertainties in reserves of the two fields (structure, etc.) remain independent.
Strong The shared risks are known to be real and significant.	The aquifer and pressure systems between two adjacent fields are likely to be common, and actions in one field will affect recovery in the others.
Total The shared risks are absolute.	Two adjacent oil accumulations have commonality assumed in all essential risks (reservoir unit, velocity model, aquifer drive); thus, their reserves estimates should be added arithmetically.
Negative The shared risks are absolute and inverse.	An oil field is developed in a core area only. Additional upside in stock-tank oil initially in place (STOIIP) in flank areas will result in a reduction in the average recovery factor. Uncertainty in fault location works in the opposite direction for gross rock volume (GRV) in two adjacent blocks.

Modified from Carter and Morales, 1998.

An example of a positive relation between two estimates can be illustrated with the following area depth plot of a field, which consists of two reservoir sands divided by a shale layer. The sands have a common oil/water contact (OWC).

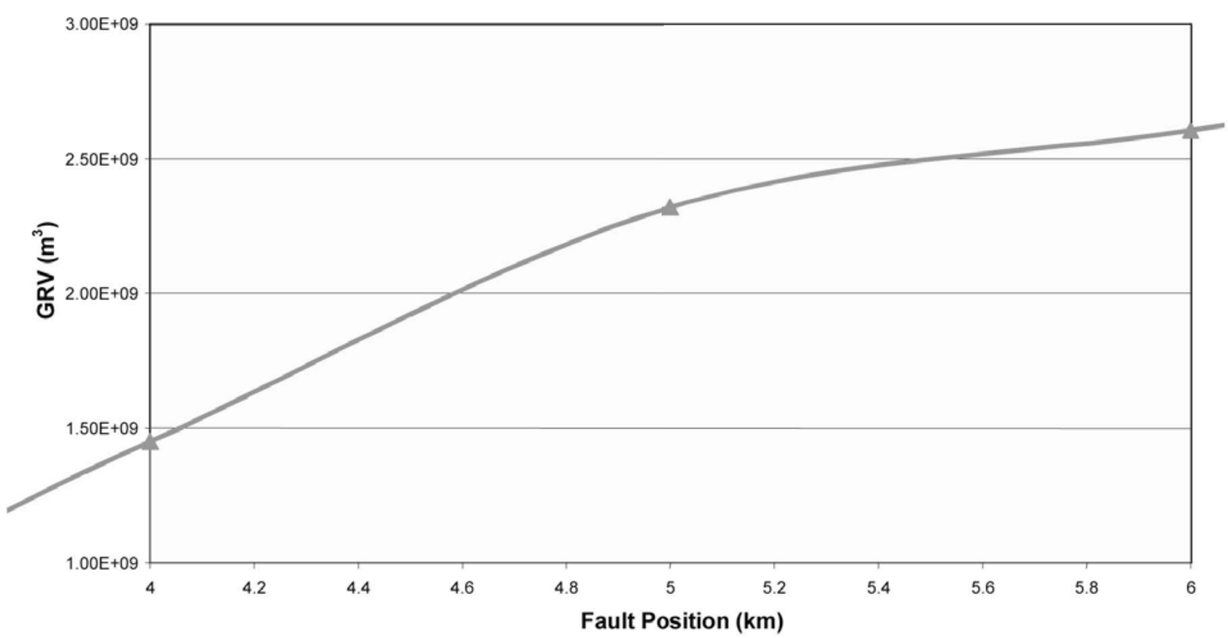
Obviously, in this case the reserves for both sands will change in the same direction if an exploration well finds the OWC somewhat shallower or if a new seismic interpretation lifts the flank of the structure. Adding up the low or proved values for the two sands is justified to arrive at an estimate for a low reserves case for the field.

Figure 6.1—West Star Field—Area vs. Depth



A negative correlation occurs when there is uncertainty about the location of a fault between two non-communicating reservoir blocks. An example is a reservoir with two blocks, A and B, separated by a fault. There is an uncertainty of several hundreds of meters on the fault location. The impact of this uncertainty can be represented by a relation between the fault position and the GRV of the largest block, Block A, as illustrated in Figure 6.2.

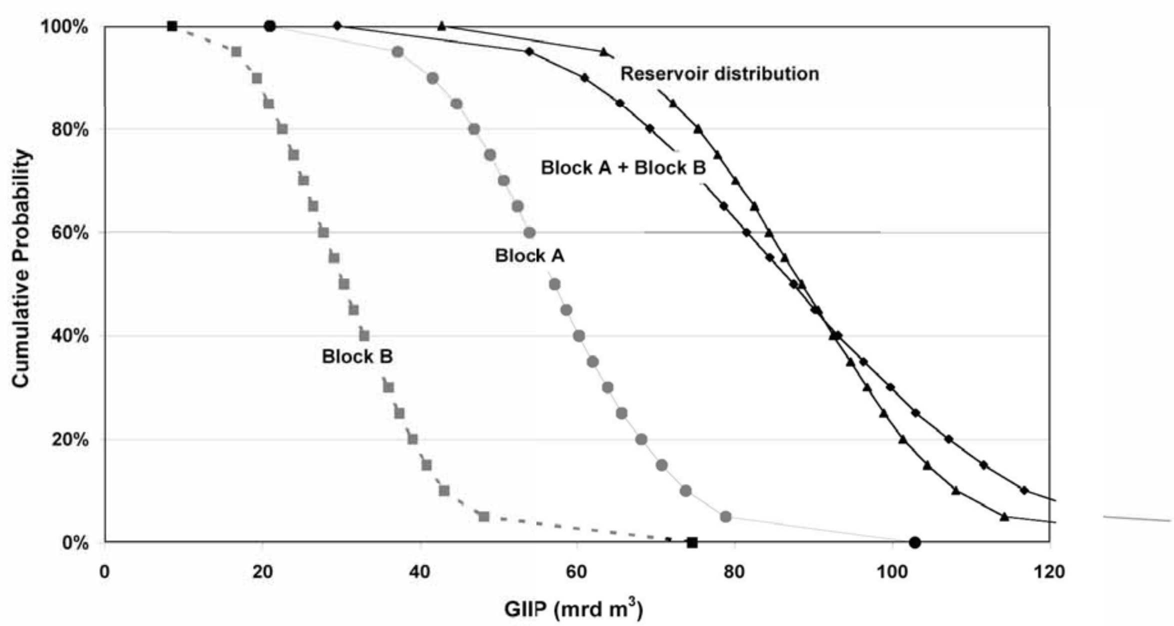
Figure 6.2—GRV of Fault Block A as a Function of Fault Position



It is now possible to calculate the Gas Initially In Place (GIIP) in both blocks; obviously, there is a negative correlation between the volume in one block and the volume in the other. If we now add up the proven values in each of the two blocks, we are adding two low cases, which in reality will never occur simultaneously. It is clear that in this case the proved value of the two blocks combined will be larger than the arithmetic sum of the two proved values.

A probabilistic picture of this situation is given in Figure 6.3, which shows the cumulative probability curves of Blocks A and B. The figure also shows the arithmetic sum of the two blocks compared with the actual distribution of the full reservoir. The sum of the proved values of the two blocks at the 90% level is some 7×10^9 m^3 (0.245 Tcf), or 11% less than the proved value derived for the full reservoir.

Figure 6.3—Probability Distribution—Reservoir Blocks A and B



Another commonly encountered negative correlation is the situation in a gas-capped oil reservoir, where gas below the gas/oil contact (GOC) is carried as a separate entity, with its own recovery factors. If there is an uncertainty in the GOC depth, then there is a negative correlation between the gas reserves, which are carried above and below the GOC.

Adding up the expectation values makes good sense to arrive at the combined expectation of total GIIP, being the sum of free gas and solution gas. Obviously, this is not the case for the proved reserves, because the low case for free gas will correspond with a high case for solution gas and vice versa. To handle this, a Monte Carlo procedure (using a spreadsheet add-in such as Crystal Ball or @Risk, for example) is required to arrive at the resultant distributions for GIIP and reserves at field level.

6.2.3 Two Levels of Aggregation

As argued earlier, addition of proved reserves in a statistical way will often result in different volumes than the straightforward "bookkeeping" arithmetic addition. Theoretically, this statistical treatment of addition can go up to the highest levels of aggregation. In practice many companies and organisations now appear comfortable with the idea of adding probabilistically up to the field level, provided dependencies are properly handled.

A field containing different reservoir blocks (layers, pools, accumulations) is often fiscally ringfenced and developed as one unit. Fiscal unit-of-production depreciation of the assets is then defined at this level. Above this level of aggregation, statistical addition may lead to fiscal problems. For that reason, there is much less industrywide acceptance for statistical treatment of aggregation above the field level and up to company or regional level. Probabilistic summation at these higher aggregation levels may only be of interest to the small group of professionals involved in portfolio management in the larger companies.

6.3 Adding Proved Reserves

6.3.1 Difference Between Dependent and Independent Addition

If we quote proved reserves, we commonly refer to volumes that are "estimated with reasonable certainty to be commercially recoverable" in the development of the field. In probabilistic reserves estimation methods, SPE interprets reasonable certainty as a 90% probability (P90) of exceeding the quoted value.[2] The proved reserves represent a cautious and relatively conservative estimate of the recoverable resources; for this reason, it is widely used by investors and bankers. In dealing with only a single asset, this makes sense because it allows for the risk that the development will result in much less than the expected hydrocarbon recovery.

Whenever oil companies add proved reserves of several reservoirs in the conventional bookkeeper's way, they routinely underestimate the aggregated value of their assets. The reason for this is that they disregard the fact that the upsides on most reserves estimates will more than compensate for the downsides on the 10% underperforming assets in the portfolio. This is certainly the case if the estimates of the volumes are independent of each other.

In daily life, we are aware of this when we try to spread our risks and avoid putting our eggs in one basket. For instance, a company committing a number of gas fields to a contract seems unnecessarily conservative in assuming that ultimately, each field will only produce its initially estimated proved volume or less. If the reserves estimates are independent, then the upsides in one field may offset a disappointing outcome in others. In other words, the P90 of the total is certainly higher than the (arithmetic) sum of the P90 volumes of the individual fields (see also Schuyler[3]).

If we stick to arithmetic aggregation of proved reserves, we run the risk of systematically underestimating the value of our combined assets. Technically, this can be avoided because tools are readily available to account for the favorable condition of having a mix of assets. In addition, it has been proven possible to convince the investing community (and some governments) to value a combination of assets higher than the sum of the proved volumes of the individual parts.

Organizations that have a portfolio of very diverse resources will naturally be interested in accounting for the uncertainty reduction, which is caused by the diversity of their portfolios. This may be true for larger oil and gas companies as well as for governments.

Governments of some countries around the North Sea, such as Norway and The Netherlands, add the national proved reserves in a probabilistic way to account for the independent nature of these volumes. For instance, the Dutch Ministry of Economic Affairs has applied the method of probabilistic addition for proved reserves since the mid-1980s. In 1996, it stated in its annual report on Dutch exploration and production activities: “The result of applying the method of probabilistic summation is that the total figure obtained for the proved reserves now indeed represents the proved proportion of total Dutch reserves in a statistically more valid manner.”

6.3.2 Arithmetic or Dependent Addition

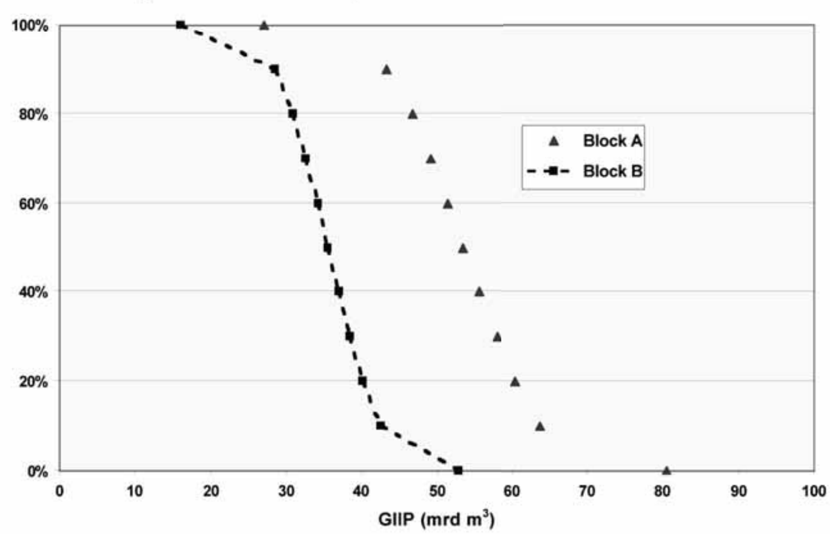
Arithmetic addition is the usual straightforward way of adding volumes and thus of aggregating reserves. Let us look at two gas-bearing reservoir blocks, A and B, with the following dimensions.

TABLE 6.2—EXAMPLE CASE: GAS RESERVOIRS A AND B

		Block A	Block B	Total
Total GRV	10^9 m^3	1.74	1.16	2.9
Porosity		0.22	0.22	0.22
Net-to-gross		0.85	0.85	0.85
Saturation		0.8	0.8	0.8
Gas expansion		205	205	205
Expectation of GIIP	10^9 m^3	53.4	35.6	89.0
Proved GIIP	10^9 m^3	43.3	28.5	71.8

We can construct a probability distribution of the individual blocks as follows, with the cumulative probability of exceeding a given volume on the vertical axis.

Figure 6.4—Probability Distribution Reservoir—Blocks A and B



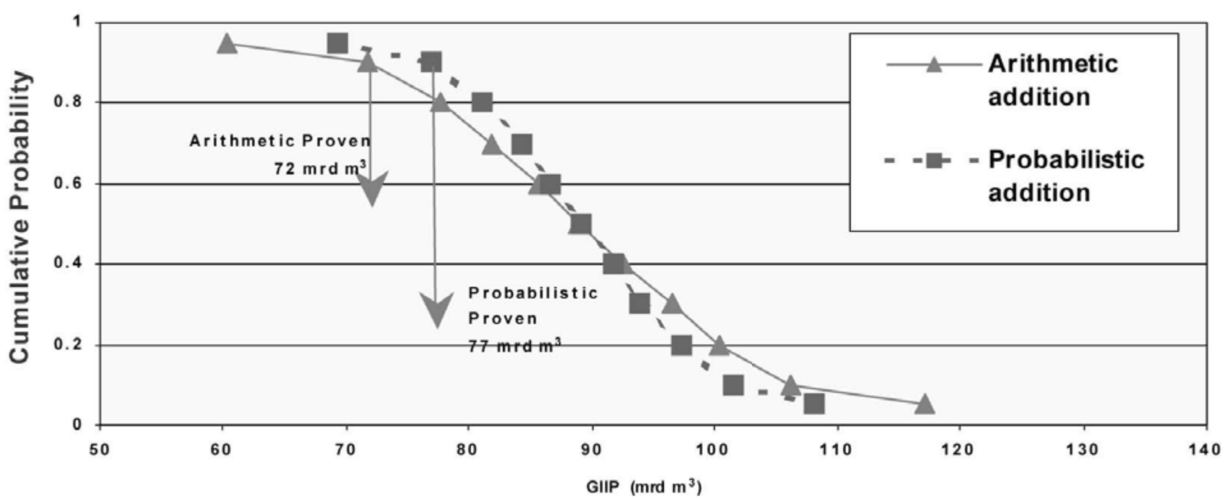
Note that for the sum of the proved reserves in Table 6.2, we have taken the arithmetic sum of two proved numbers, both of which have a 90% probability of being exceeded. In fact, by adding these up we assume complete dependency between the two cases; i.e., we assume that if the low side of one case materializes, the same thing will happen with the other case. In this way, we arrive at a pessimistic number for the proved GIIP, representing the situation that both blocks turn out to be relatively disappointing. This can well be the case if both blocks have a common gas/water contact (GWC), or if their volumes are determined by the same seismic phenomena, as shown in one of the examples in the previous section.

6.3.3 Probabilistic or Independent Addition

If the reservoir volumes of the two blocks are independent of each other, we can still calculate the sum of the expectation values by straightforward addition. However, if we now derive the proved value from the distribution of the sum, we may have situations (e.g., in a Monte Carlo simulation of this case) where a low outcome of Block A will be combined with a high outcome of Block B, or the other way around. What happens in practice is that positive outcomes on one block compensate for the negative outcomes on the other block. This results in a cumulative distribution curve for the combined GIIP, which is steeper (i.e., has a smaller spread) than the curve for the arithmetically added volumes, as shown in Figure 6.5. This tendency of the uncertainty range to narrow is a statistical phenomenon that will always be observed if we add up quantities that have independent statistical distributions.

Applying this approach, we can state with 90% certainty that there is at least 77×10^9 m^3 of gas in both reservoir blocks, as opposed to 72×10^9 m^3 of gas with arithmetic addition. In situations where gas contracts are based on proven reserves, this may have considerable business implications.

Figure 6.5—Arithmetic and Probabilistic Addition, A and B



Methods to aggregate volumes independently (assuming no correlation between possible high and low outcomes) are:

- Scenario trees, representing the possible outcomes as branches of a tree and calculating the overall outcome. This method is treated in Section 6.5.

- Monte Carlo methods, using a spreadsheet add-in (such as @risk or Crystal Ball).
- Treating the volume estimates as a physical measurement with an associated error and then using error propagation methods.

In the last mentioned method, we approach the uncertainty of the estimate for a reservoir volume by $_I$=Expectation Proved.

We can then calculate the uncertainty for the sum of Reservoirs A and B using the relation $^2_{1+2} = {}^2_1 + {}^2_2$.

This method is an approximation that only holds for symmetric distributions, but it has the strong advantage of being easy to calculate. It is very suitable to estimate an upper limit for the effects of probabilistic addition. We have to be aware, however, that volumetric estimates, being the product of a number of parameters, tend to be log-normally distributed (i.e., asymmetrical and with a tail of high values).

6.3.4 The Intermediate Case—Using Correlation Matrices

In the previous section, we discussed fully dependent, or arithmetic, addition and fully independent, or probabilistic, addition of proved reserves. In most practical situations, we will be in between these two extreme cases. The reason for this is that some parameters of our estimates will be correlated, while others will be completely independent of each other. Ignoring correlation in these cases will lead to overestimation of proved reserves. The rigorous solution in this situation is to calculate probability distributions, specify the correlation between them, and generate the resulting probability distribution for the aggregate. Monte Carlo simulation is the obvious method to achieve this. The overriding problem in this approach is the proper specification of the correlation matrix.

An interesting approach to this problem, illustrated with a real-life example, is presented by Carter and Morales.[4] They describe the probabilistic addition of gas reserves for a major gas development project consisting of 25 fields sharing common production facilities.

Each field has a range of gas reserves, expressed at the P90 (proved), P50, P10, and expectation levels. The proved reserves per field are defined as the volume, which has a 90% chance of being exceeded. Adding up these volumes arithmetically results in a volume of proved reserves across the project, which is much lower than the combined P90 owing to the independent nature of many of the risks. Assuming full independence, the authors calculate (by probabilistic addition) a volume for the total project proved reserves that is some 15% higher than the arithmetic sum at the proved level. Because neither full dependence nor full independence can be assumed, the authors then proceed to analyze the areas of potential dependence between the individual estimates.

They apply the following procedure:

1. The areas of dependence are tabulated against individual fields to identify common factors between fields. These areas include technical, methodological, and natural subsurface commonalities between the GIIP estimates of the fields. Commonality is classified as weak, medium, or strong.

2. An estimate of correlation coefficients is made by assigning values of 0.1, 0.3, and 0.5 for a weak, medium, or strong dependence and combining them into an array suitable for use in a Monte Carlo presentation.
3. The reserves distribution (for each field) as defined by the P90, P50, and P10 confidence levels is expressed as a double-triangular probability function.
4. A matrix of correlation coefficients is used to describe the shared risks between fields, with a coefficient for each pair of fields varying from 0 (fully independent) to ± 1 (fully dependent).
5. The reserves distributions for each field are then probabilistically summed up over the project using the previously defined correlation matrices in the @Risk add-in within an Excel spreadsheet.

The result of applying this method for the case described was that the gas reserves at the 90% confidence level are some 9% greater than those resulting from arithmetic addition. Not taking the dependencies between the fields into account, the increase would have been 15% over the straightforward arithmetic addition.

Some common-sense measures are described that make the process more practical. The first of these is that fields with the highest level of dependence were added arithmetically into field groups. This ensures a conservative bias in the approach and reduces the size of the correlation matrices to 15 field groups. High dependence occurs between adjacent gas fields believed to be in pressure communication, or between new gas developments sharing structural risk.

Another important measure is a peer review on the semi-quantitative process of assigning dependencies. The emphasis in this review process is on identifying factors (such as volumetric uncertainty) that cause full or almost full independence, even if other strong links (such as a shared aquifer) can be demonstrated.

A third simplification of the process was that negative correlation coefficients were disregarded in the analysis. It is possible that a correlation coefficient between two fields turns out to be negative. While in principle both positive and negative dependencies can be handled, only positive dependencies were identified for the project fields. It was considered during the peer review process that use of a negative coefficient might unduly narrow the range of uncertainty in the final aggregation.

The linked risks resulting from shared surface facilities and constraints are also excluded from the analysis. They are considered to be common (project) risks and problems with facilities are considered surmountable if they materialize. This type of shared risk can be included in the analysis, if required.

The authors investigated the robustness of their method by changing the dependencies. The result of this sensitivity case supported the general observation that in this type of analysis, the outcome is not very sensitive to changes in individual correlation coefficients.

Use of correlation matrices as described above is similar to other reserve determination methods in two important aspects:

- The figures used are subjective and change when new insights are gained. However, in view of the large number of interrelations (dependencies/ independencies) of the fields, major reversals of opinion must occur to change the overall result by a significant amount.
- As the established risks are addressed in more detail, specific correlation coefficients will be updated with the proper audit trail. For example, a new seismic interpretation by a new team may result in the dependencies in seismic interpretation being removed after the new interpretation has been accepted.

6.4 Aggregating Over Resource Categories

To achieve business growth and reserves replacement objectives, oil companies identify hydrocarbon volumes in their acreage and execute appraisal and development plans to turn these into developed reserves and ultimately into production. To this end, they review UR targets for existing and newly discovered fields as well as for untested resources and identify which activity—appraisal, study, or new technology development—is required to achieve these targets. As explained in Chapter 2, various categories of resource volumes can be defined in this process.

The volumes, which are thus identified, may or may not be ultimately produced, depending on the success of the project. For this reason, it is important not to aggregate reserves, contingent resources, and prospective resources without due consideration of the risk of accumulations not achieving commercial production. We should use here the Mean Success Volumes (MSV) and the Probability of Success (POS), determined by the engineer or geologist.

In adding up such volumes a meaningful total can only be defined by adding up the risked volumes (POS×MSV) resulting in a statistical expectation of the recovery. This will be no problem for a large portfolio of opportunities or for a smaller portfolio where the discounted volumes do not add significantly to the total. Naturally, the range of uncertainty of the aggregate will increase if more speculative categories of resources are included.

Where many risked volumes are being added, the scenario tree may become a required approach to looking at discrete combinations of possible outcomes; scenario trees are discussed in the next section.

6.5 Scenario Methods

6.5.1 Example of Low Dependence Between Reservoir Elements

A powerful method to combine aggregation over reserves categories and reserves levels is the use of scenario methods.

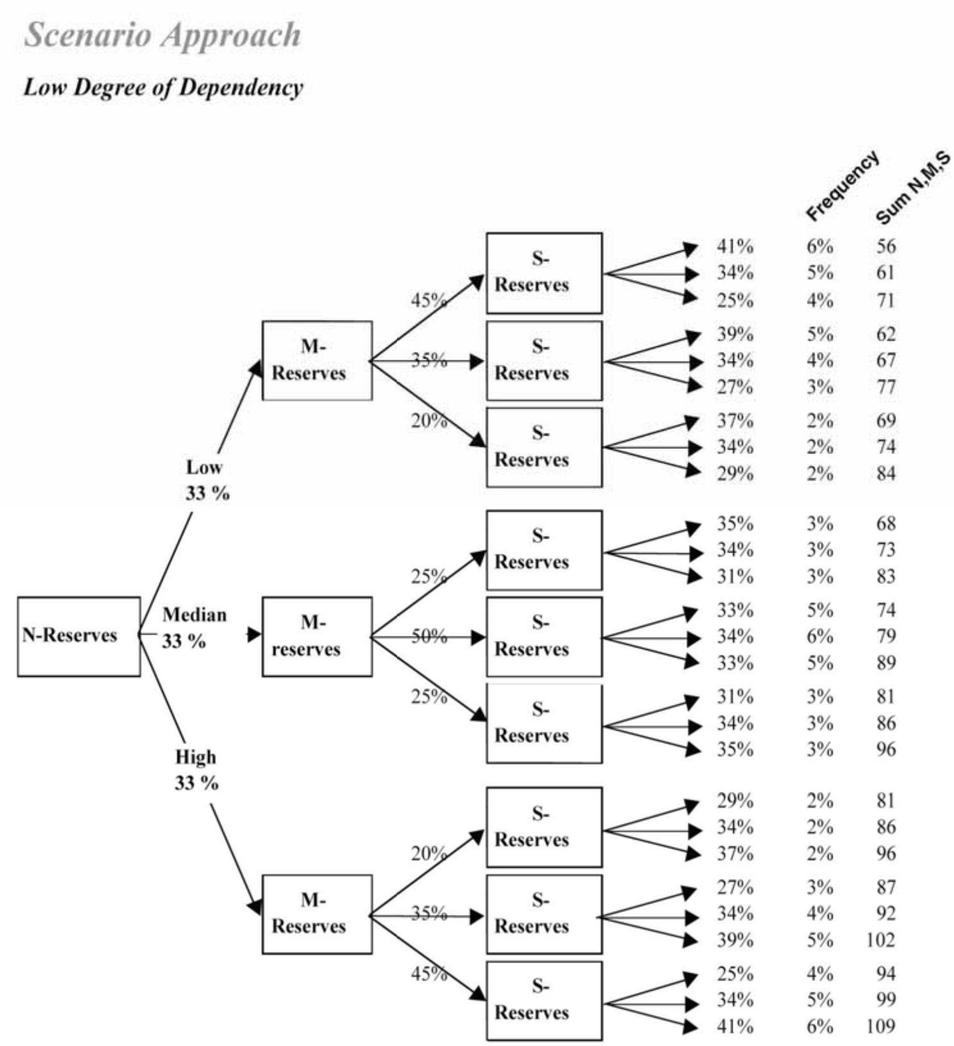
To illustrate this approach we discuss two examples: one where we add volumes with a low degree of dependence, and one where we aggregate highly correlated volumes.

In the first case, we evaluate three sands (M, N, and S) in the same sequence, of which the reservoir parameters and GRVs are relatively independent. The reason for this independence is that the reservoirs occur in different geological formations at very different depths, so there are few factors that cause low and high cases of the sands to coincide. Low, Median, and High STOIIP for the sands is as follows.

TABLE 6.3—STOIIP UNCERTAINTY RANGE OF THREE OIL-BEARING SANDS				
Volumes	Low	Median	High	Mean= Expectation
M-sands	17	23	30	23.3
N-sands	29	41	54	41.3
S-sands	10	15	25	16.7

To construct a scenario tree for this situation, we have taken the equiprobable Low, Median, and High values of STOIIP in the sands with the largest volume, the N-sands. We then combine these first with the M-sands and subsequently with the S-sands. This results in a scenario tree with 27 end branches.

Figure 6.6



As can be seen in this scenario tree, there is not much correlation between the occurrence of Low, High, and Median cases for each of the sands. At the end branches, we can read off the total

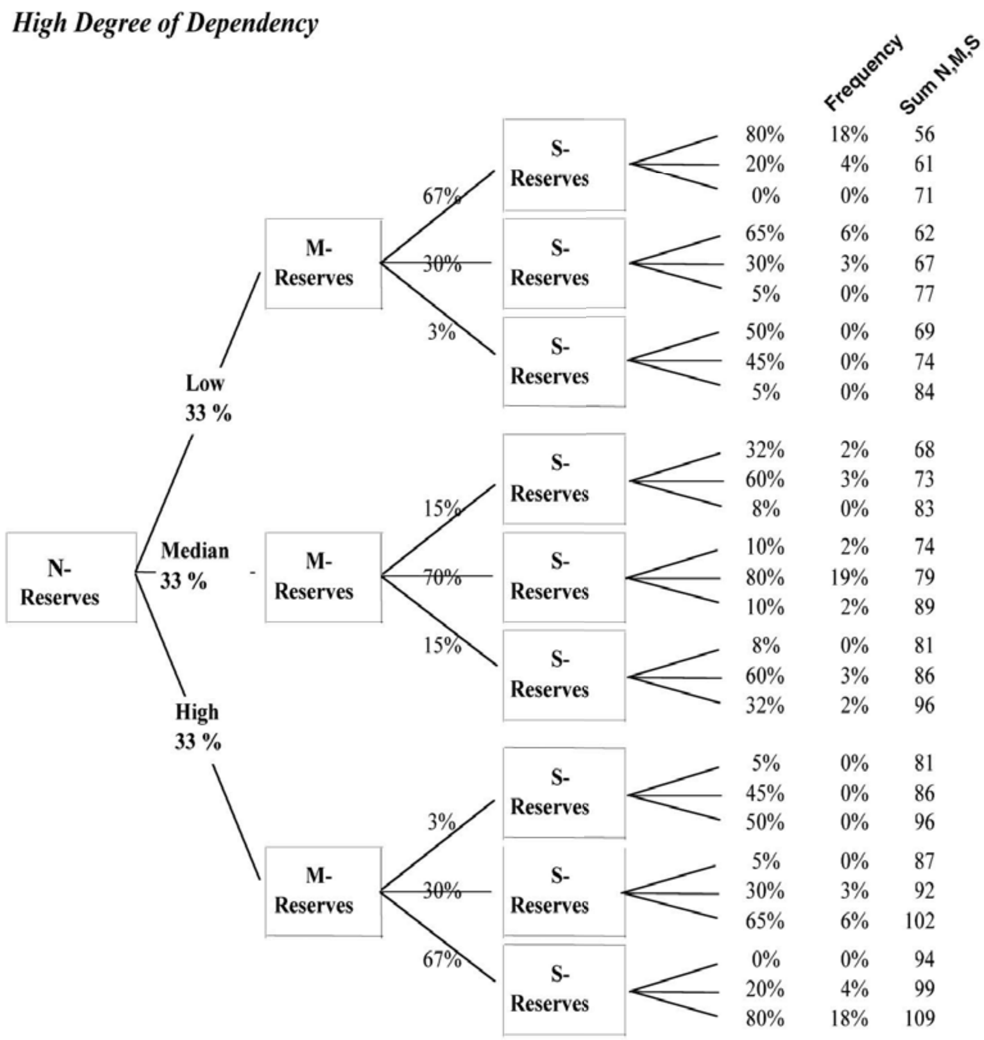
STOIIP in each of the 27 possible combinations of N-, M-, and S-sands, as well as the frequency of occurrence.

It is important to note that the Low value in this example is not the same as the proven value for the particular sand, as it is not the 90% probability point in the cumulative probability curve. In fact, the probability of the branches and the sequence of events represented in the tree should reflect the understanding of the geological processes at work.

6.5.2 Example of Dependent Reservoir Elements

In the second case, the sands are on top of each other in a single geological structure; thus, they are all impacted by the same uncertainty in structural dip and the location of the bounding faults. This is a case with high dependencies between the sand volumes because a high volume of the N-sands will increase the likelihood of a high volume in the other sands. The dependence of the resulting STOIIP is not complete because geological parameters such as porosity or net-to-gross may still be linked. We assume that these parameters play a secondary role and disregard them to keep the number of branches limited. In this case, the scenario tree will look as follows (Figure 6.7).

Figure 6.7

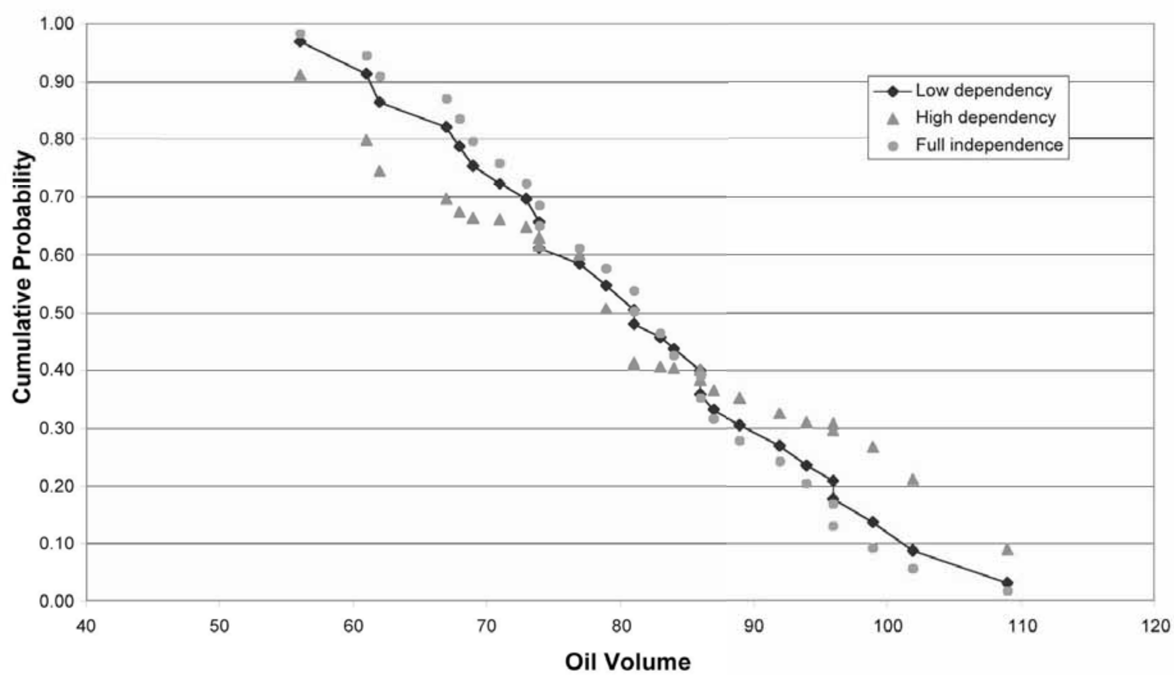


In this scenario tree, the dependence between the three sands shows up as a higher probability that high sand volumes are combined with high volumes. A low case in one sand will tend to go together with a low case in another sand.

6.5.3 Comparing Degrees of Dependence

We can go through the same exercise with a similar scenario tree for full independence. This is a straightforward extension from the previous two examples, with the chance factors on the branches of the tree all taken to be one-third (33%). By using the results of the scenario trees, we can construct the probability curves for each of the three cases by sorting and calculating cumulative probabilities. The result is shown in Figure 6.8.

Figure 6.8—Cumulative Probability Curve



This analysis now results in the following summations of the three sands.

TABLE 6.4—PROBABILISTIC ADDITION WITH VARYING DEGREES OF DEPENDENCY				
STOIIP	P85 = Low	P50 = Median	P15 = High	Expectation = Mean
M-sands	17	23	30	23.3
N-sands	29	41	54	41.3
S-sands	10	15	25	16.7
Independent sum	67	81	96	81.3
Low-dependence sum	64	81	98	81.2
High-dependence sum	59	79	105	81.1
Fully dependent addition (arithmetic)	56	79	109	81.3

As could be expected, the expectation values are hardly affected by the assumptions used in the four aggregation procedures. Because the distributions used are almost symmetric, there is also little variation in the value of the median case. For the low and the high values taken at the 15% and 85% levels, respectively, there are some clear differences. In this example, the low and high values are taken at the 15% and 85% levels for (approximate) consistency with the input of equiprobable Low, Median, and High values of the three sands, which represent a three-point distribution.

The fully independent case and the low-dependency case closely resemble each other in the cumulative probability representation. As expected, the fully independent case results in a narrower range of volumes than the low-dependency case. Apparently, the result is not very sensitive for the chance factors in the scenario tree. This and other experience suggests that we only need to apply a fully independent method if we can identify sizeable correlations.

6.5.4 Comparing Scenario Trees and Correlation Methods

We now have treated two methods for handling dependencies in aggregating volumes: the use of matrices to describe correlation between parameters (in Section 6.3) and the construction of scenario trees in this section. Table 6.5 compares the two methods.

TABLE 6.5—COMPARISON BETWEEN SCENARIO TREE AND CORRELATION MATRIX METHODS

Scenario Trees	Correlation Matrices
Natural link with decision making	Easy link with probabilistic description—allows Monte Carlo approach
Dependencies made visible in the diagram	Dependencies shown in matrices
Conditionality depends on ordering of branches—needs care to construct the tree	Dependencies independent of ordering
Not practical with large number of parameters	Many correlated parameters can be handled
Intuitively clear	Less intuitive/more abstract

The ease of use and the link with decision-making approaches generally will make the scenario tree method the preferred choice.

6.6 Normalization and Standardization of Volumes

Hydrocarbon volumes can only be added up and properly interpreted if there is no doubt as to their meaning. We usually report at surface pressure and temperature, for which convenient values are used. This leads to small differences between reported volumes in different unit systems

The commonly used reporting conditions for oil and natural gas liquid (NGL) field volumes and for fiscalized sales volumes are standard conditions (m^3 or bbl at 15°C, 760 mm Hg; m^3 or bbl at 60°F, 30 in. Hg).

For gas, we can apply two standardization steps:

1. Conversion to standard pressure and temperature conditions. Unfortunately, various combinations of pressure and temperature in field units as well as SI units are in current use. Some useful volume conversion factors are:
   1 m^3 (15°C, 760 mm) = 6.2898 bbl (15°C, 760 mm Hg)
   1 m^3 (15°C, 760 mm) = 35.3147 scf (15°C, 760 mm Hg)

$1\ m^3$ (15°C, 760 mm) = 35.2899 scf (60°F, 30 in. Hg)
$1\ m^3$ (15°C, 760 mm) = 0.9480 Nm^3 (0°C, 760 mm Hg)

The pressure and temperature conversion factors for gas are, to some extent, dependent on gas composition, and slightly different values may be used.

2. Conversion to a volume with an equivalent heating value.
   Heating value conversion factors are:
   9500 kcal/Nm^3 = 39.748 MJ/Nm^3
   1,000 Btu/scf (60°F, 30-in. Hg) = 39.277 MJ/Nm^3

   The volume equivalent in total combustion heat is:
   1 Nm^3 (GHV = 9500 kcal/Nm^3) = 37.674 scf (GHV = 1000 Btu/scf).

Field gas is usually reported *tel quel* (i.e., at the heating value it has at the wellhead), and usually at standard conditions. The conversion to an equivalent heating value is not applied for this category.

Sales gas is usually measured and reported in Nm^3 (e.g., m^3 at 0°C, 760 mm Hg) and sometimes converted to an energy equivalent [e.g., a normalized gross heating volume (GHV) of 9500 kcal/Nm^3].

For additional information on the conversion of gas volumes to oil equivalents, see Chapter 3, Section 3.7.

6.7 Summary—Some Guidelines

1. In aggregating reserves, adding the expectation of volumes can be done arithmetically. In this case, do not confuse the statistical median or P50 (proved + probable) value with the expectation or mean, especially because these may be quite different in asymmetric distributions.
2. In calculating reservoir volumes from well-performance extrapolation or decline-curve analysis, do not rely solely on adding the results of well-performance analysis; this addition may lead to a conservative estimate for the total reservoir. Always check with an overall reservoir performance extrapolation.
3. Arithmetic addition of proved reserves for independent units leads to a conservative estimate for the proved total. Methods and tools for independent addition are available to determine a more realistic value (Monte Carlo, probability trees, and customized tools).
4. Adding proved reserves probabilistically without fully accounting for dependencies will overstate the proved total.
5. An industry view is emerging that probabilistic aggregation is acceptable up to the field level, or the level at which assets are depreciated.
6. For adding volumes with differing ranges of uncertainty and volumes that are correlated, or in situations where discount factors are applied, the scenario method is often the best tool to use.
7. In adding gas volumes, make sure they have a common pressure/temperature reference and, if necessary, a common calorific value.

References

1. “Determination of Oil and Gas Reserves,” Petroleum Society of the Canadian Inst. of Mining, Metallurgy, and Petroleum, Calgary (1994).
2. “Petroleum Reserves Definitions,” Society of Petroleum Engineers and World Petroleum Congresses (March 1997).
3. Schuyler, J.R.: “Probabilistic Reserves Lead to More Accurate Assessments,” paper SPE 49032 prepared for presentation at the 1998 SPE Annual Technical Conference and Exhibition, New Orleans, 27–30 September.
4. Carter, P.J. and Morales, E.: “Probabilistic Addition of Gas Reserves within a Major Gas Project,” paper SPE 50113 presented at the 1998 SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia, 12–14 October.

Chapter 7 Summary

Application of Geostatistics in the Petroleum Industry

Kathryn Gibbons

Resource and reserve estimates are traditionally based on deterministic methods that yield a single static model and a single production profile or, at best, three discrete scenarios (which may be equated to 1P, 2P, and 3P cases). Alternative, equally valid models are not always considered. Business and reservoir-management decisions are dependent on a robust understanding of uncertainties in reserves, and the traditional approach of evaluating these uncertainties does not necessarily lead to optimal decisions. Consequently, over the past decade demands to find, develop, and produce fields at lower costs have led to the birth and ever-increasing application of probabilistic and geostatistical techniques within the petroleum industry.

The sophistication with which the uncertainties for a given reservoir are evaluated and modeled varies along the "Value Chain"—that is, from exploration through to production from mature fields. The geostatistical method applied depends on the amount of data available, the particular application, and the ability to make full use of all available data. Vital to the successful application of probabilistic and geostatistical techniques is the integration of data and knowledge from the various technical disciplines.

Geostatistical methods are grouped here into 1D, 2D, and 3D methods insofar as they represent a progressive sophistication in the manner and approach by which uncertainties are handled. Choice of method often depends on the time and data available. In general, 1D methods are used at the prospect evaluation stage, whereas 2D and 3D methods are used during appraisal through to development and production.

1D Geostatistical Methods

By 1D geostatistical methods we mean a single-point statistic, where that point may represent an area or volume from a specific well or an average value from several wells. The use of 1D geostatistical methods (e.g., Monte Carlo simulation) to quantify and analyze uncertainties for various prospects has a comparatively long tradition within the petroleum industry. In general, the simulations are quick, and there are several user-friendly programs available.

One-dimensional methods provide a convenient tool for evaluation of overall uncertainties in gas or oil reserves. The results can be used to carry out economic analysis upon which various prospects are risked and ranked so that a decision to drill can be made. An assessment for all the key parameters—oil and gas reserves, capital exposure, and economic value (net present value, or NPV)—can be simulated for an entire portfolio.

One-dimensional methods involve the creation of probability distributions for each of the elements in the volumetric equation (area, net pay, porosity, oil saturation, and formation volume factor) and for recovery efficiency, from which values for the different elements are then randomly drawn according to the specified probability distributions. The probability distribution can be portrayed as a histogram or a function that describes the variability of a specific parameter. The distribution may be uniform, triangular, bimodal, or skewed according to the data available or the knowledge about the variability of the specific parameter. Probability distributions for resources and reserves are then calculated on the basis of the realizations from these simulations. Risk factors reflecting the chance of hydrocarbon generation, migration, trapping, and sealing can be used to condition the distributions for chance of geological or technical success.

Common pitfalls when applying 1D methods include:

- ignoring interdependencies among the various input parameters or between different compartments/blocks within a reservoir
- inconsistent evaluation of the probability distributions
- overly pessimistic or optimistic evaluation by the individual or the team carrying out the evaluation

The input of uncertainty ranges for a given parameter, as well as interdependencies between variables, is often subjective, making the comparison of uncertainty estimates for a given set of prospects or fields difficult. Several petroleum companies have established guidelines that can be monitored by advisory teams (Peer Assist) empowered with the task of transferring experience, assuring common practice, and thereby ensuring comparability within the company's portfolio.

2D Geostatistical Methods

By 2D we mean a mapped geostatistical parameter (2D grid). Two-dimensional geostatistical methods differ from 1D methods in that they use the spatial relationship between data points or values rather than simply averaging. Two-dimensional methods can be applied during field appraisal and sanction as more well data become available to condition the uncertainty evaluation and to provide a better understanding of the interdependencies between variables.

It is commonly acknowledged that a single deterministic model of a reservoir does not capture the overall uncertainty of petroleum in place and consequently does not provide a solid basis for a management decision to proceed with development. This is because rock properties and the correlation between rock properties within a reservoir are by nature spatial. The aggregation of rock properties into averages based on data from two or three wells and subsequent calculation of expected hydrocarbon volumes does not take into account either spatial relationships or correlation between properties. This can lead to biased results, as well as the overestimation of P90 and underestimation of P10 values.

Recognition that the definition of gross rock volume (GRV) is an important contributor to overall uncertainties has led to the application of 2D geostatistical modeling of uncertainty on mapped horizons from seismic and uncertainties associated with evaluation of petrophysical parameters. For example, GRV depends on uncertainty in structure as derived from seismic data, and uncertainty in hydrocarbon/water contacts.

Structural uncertainties can be modeled by 2D geostatistical tools that take into account the spatial correlation between data points for a given surface. With these geostatistical tools, stochastic models are created, from which several hundred equally probable realizations of the top structure map can be produced. From these equally probable realizations a range in GRVs can be calculated by combining the uncertainty range for fluid contacts with each of the simulated depth maps. Hydrocarbon-in-place volumes can then be calculated by combining GRV uncertainties with the uncertainty on petrophysical parameters using Monte Carlo simulation.

Once the spread of values for a given parameter has been established, it is possible to model the sensitivity of these parameters on reservoir performance, and ultimately their effect on NPV, for several development scenarios. Although not as quick as 1D methods, 2D geostatistical methods provide for alternative models to be evaluated and offer a better basis for decisions.

3D Geostatistical Methods, Heterogeneity Modeling

The general dilemma facing geoscientists is how to fill a sparsely sampled space so that development strategies and reservoir-performance predictions are based on realistic representations of reservoir heterogeneity. Improvements in the static reservoir model lead to improved understanding of the dynamic behavior of the reservoir. Smooth interpolation of properties (such as linear interpolation) does not account for vertical and horizontal permeability variations and therefore tends to overpredict the recovery efficiency of oil and underpredict channeling and early breakthrough of injected fluids. Stochastic modeling of heterogeneities offers alternative conditional realizations of reservoir property distributions and improves the quantification of the uncertainty in production from a given reservoir.

Three-dimensional geostatistical modeling involves the construction of a geological framework grid using the mapped structural horizons and fault surfaces together with the individual chronostratigraphic reservoir layers or units. This framework is then merged with the sedimentary building blocks, or lithofacies, and their associated petrophysical characteristics. Most importantly, 3D models allow for the population of the sparsely sampled space (between wells) with the individual building blocks of a reservoir (genetic units, facies) and their reservoir properties. From these models, multiple (several hundred or thousand) realizations of a reservoir can be produced from which quantitative models for uncertainty analysis can be derived. The multiple geological realizations can be ranked and integrated with other reservoir technical data [pressure/volume/temperature (PVT), relative permeability endpoint, skin factors], thus yielding a rigorous assessment of the uncertainties in recoverable volumes and the time-dependent production profiles.

Three-dimensional heterogeneity modeling requires a description of the spatial distribution, size, and/or correlation lengths for each of the sedimentary building blocks (such as channel or lithofacies type) and the variability for each specific parameter (e.g., porosity) within the reservoir model. Commonly this is done with (semi)variograms, to represent correlation, and histograms, to represent variability. The procedures and the geostatistical tools used in 3D modeling are dependent on the data, time available, and particular reservoir or problem to be investigated.

Input data to 3D stochastic modeling typically consists of the following:

- correlative, sequence stratigraphic surfaces
- seismic horizons
- facies/sedimentary building blocks within a stratigraphic surface, including trends and stacking patterns available from offset wells or regional interpretation
- widths and thicknesses of channels
- analog data from outcrops, from which size distributions and lateral continuity of the sedimentary building blocks/facies can be derived
- petrophysical parameters: porosity, net-to-gross, and permeability data by zone
- faults and uncertainties associated with the vertical and horizontal position of the faults
- well-test and production data (vertical/horizontal permeability interpretations, interpretations from test data regarding connected volumes, and barriers)
- variability of each input parameter described statistically (variograms, histograms, etc.).

Experience with stochastic modeling over the past 10 years shows that, while the overall preservation of heterogeneities in the geological model leads to an improved description and understanding of constraints on the dynamic model, stochastic models are time-consuming to build. Further, while the models provide for full integration of subsurface data, they also require that geostatistical specialists are included in evaluation teams so that the models can be maintained and updated. Equally important, the effects of critical parameters on reservoir behavior can be lost during the process of upscaling from the fine-scale heterogeneity model to the full-field simulation model. For example, if vertical permeabilities are underestimated owing to the smoothing of heterogeneities, fluid fronts will behave in a piston-like manner. In these cases, the upscaled model is too coarse, and the fine-scale heterogeneities that can control segregation or gravitational effects are underestimated. The resulting simulation will tend to predict unrealistically efficient production performances.

The trend is toward simple, small-element models designed to evaluate the sensitivity of reservoir performance to a particular parameter or set of parameters. In addition to being easier to build and maintain, element models require less computing time, and more iterations or sensitivities can be performed. Consequently, the key factors affecting reservoir performance can be identified and correctly implemented and simulated in the full-field model. Specifically, in connection with the evaluation of a field offshore Norway, a great deal of time and effort was used in detailed description of the heterogeneity within a reservoir consisting of tidal deposits. However, sensitivities performed on the upscaled reservoir-simulation model showed that the sealing capacity and communication along faults was the key factor to predicting the rate at which gas breakthrough would occur. The lesson to be learned from this is that construction of a simple, smaller model built to test key factors can save time and focus teamwork on key issues.

Chapter 7
Application of Geostatistics in the Petroleum Industry

Kathryn Gibbons

7.1 Introduction

Traditionally, reserve estimates are based on deterministic methods that yield a single static model and a single production profile or, at best, three discrete scenarios (which may be equated to 1P, 2P, and 3P cases. Alternative, equally valid models are not always considered. Further, data and knowledge from the various technical disciplines are not necessarily combined in an optimal manner. Business and reservoir-management decisions are dependent on a robust understanding of uncertainties in reserves, and the traditional approach of evaluating these uncertainties does not necessarily lead to optimal decisions. Consequently, over the past decade demands to find, develop, and produce fields at lower costs have led to the birth and ever-increasing application of probabilistic and geostatistical techniques within the petroleum industry.

The sophistication with which the uncertainties for a given reservoir are evaluated and modeled varies along the “Value Chain”—that is, from exploration to production from mature fields (Figure 7.1). This is a reflection of the amount of data available, the particular application and our ability to make full use of available data. One-dimensional methods are widely applied in connection with exploration and field appraisal. By 1D we mean a general statistic based on an single or average value from a well, but one which represents a point in space. For more mature fields geostatistical techniques that enable spatial dependencies and flow characteristics to be modeled (i.e., 2D and 3D modeling) lend themselves to better integration and utilization of available sedimentological, structural, and production data and the creation of geologically realistic numerical models. Data integration is fundamental to geostatistical modeling and, ideally, enables engineers and geologists to work as integrated teams to improve understanding of the uncertainties surrounding both static (petrophysical, geological) and dynamic reservoir (well test, production) parameters. This leads to an understanding of the opportunities associated with development flexibility and the uncertainty in production forecasts and reserves.

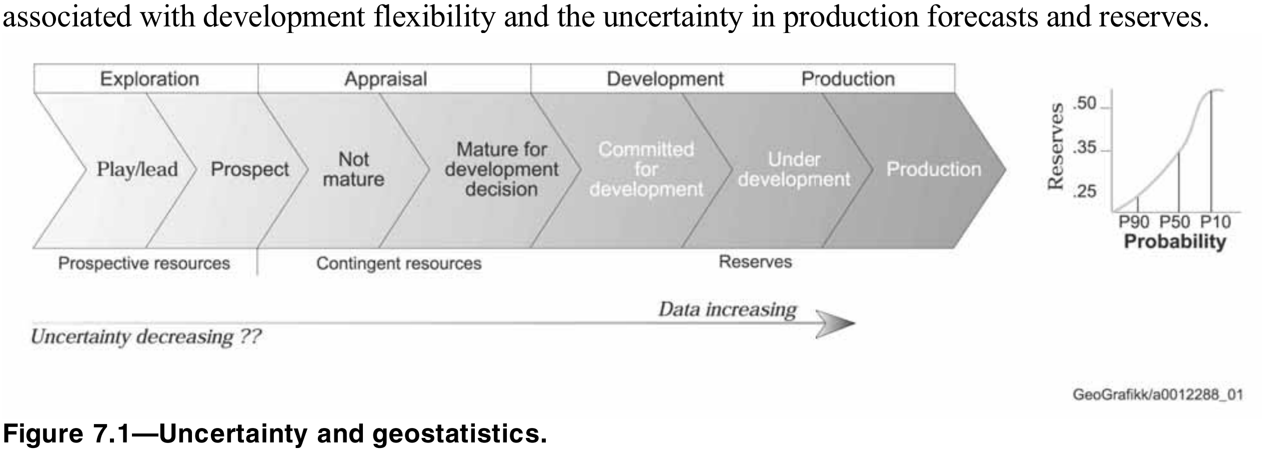


Figure 7.1—Uncertainty and geostatistics.

Geostatistical tools provide a platform for evaluating overall uncertainties and characterization of the risks involved in any given decision. However, it is important to keep in mind that the results of geostatistical modeling (uncertainty ranges, distribution of possible outcomes) are dependent on the amount of data available, the technical evaluation of the input data, and the statistical algorithm used in the modeling. Ultimately, the value of geostatistical evaluation lies in our ability to synthesize all available knowledge and data, thereby enabling systematic evaluation of the risks involved, be it for the purpose of exploration or management of a producing field.

7.1.1 Terminology

Geostatistical modeling involves the application of statistical methods to describe mathematically the variability within any given reservoir unit or pool. As such, many of the terms used in geostatistics originate from statistical or mathematical terms. Some of the most commonly used terms are defined in Appendix 7-A and a more extensive discussion of the basic principles and methods used in geostatistics can be found in Refs. 1 through 3.

7.1.2 Historical Review

One of the founders and leading proponents of geostatistical methods, André Journel, has summarized the past, present, and future of geostatistics in the petroleum industry.[4] Parts of the following are based on Journel's summary.

Until the mid-1970s, geostatistics was used primarily as a tool by the mining and mineral exploration industry to map the spatial distribution of ore bodies. Kriging, a technique for mapping surfaces based on (semi)variograms to model the spatial correlation between points on a surface, was born out of the mining industry. Applications within the petroleum industry were negligible, as witnessed at the 1st International Geostatistical Meeting in 1975, where only one petroleum-related paper was presented. During the early 1980s, kriging was marketed by some research institutions (such as Bluepack) as an alternative gridding algorithm; however, kriging could not compete with commercially available software, and the application was not adopted by the petroleum industry. The breakthrough of geostatistics in the petroleum industry came in the late 1980s with the appearance of stochastic models for petroleum reservoirs. This breakthrough was paralleled by the petroleum industry's recognition that field development and production costs must be lowered in order to compete in an economic climate of low oil prices. Oil prices, portfolio optimization, and cost-effective reservoir management began to have a direct impact on the way engineers in the petroleum sector worked. Improvement in uncertainty characterization reservoir description, and mapping of geological and petrophysical trends became part of the daily vocabulary.

One of the earliest publications[5] dealt with the application of stochastic methods to forecast production from gas fields consisting of isolated sand bodies (fluvial, point-bar deposits). The reservoir model was built with a Statistical Analysis software package (SAS). This paper demonstrated the importance of describing the variations in reserves at the reservoir, well, and platform levels based on several (in this case, 10) geological realizations. After 10 years of production, field behavior has confirmed the modeled results, and the recoverable reserves per well are within 5% of the predicted value. However, the reservoir architecture and connectivity has proved more complex than originally modeled.

By the time that the 4th International Meeting on Geostatistics was held in 1992, geostatistics in the petroleum industry had come of age. Throughout the 1990s, institutions such as Stanford U., the Norwegian Computing Center, and the Inst. Français du Pétrole were actively researching and developing software for the application of geostatistical methods—such as simulated annealing, iterative stochastic simulation algorithms (including Markov Chain), object-based simulation, and multiple point statistics for the training of images—for the petroleum industry. The majority of the major petroleum companies actively apply geostatistics as part of the decision-making process. Although geostatistical software packages are commercially available, geostatistics as a tool remains in the hands of a few experts. Continued demands within the industry for improvement in oil recovery and a focus on optimal field developments will require that more and more engineers are exposed to geostatistics as a tool for evaluating the profitability of well and field development projects. The development of hardware and software enabling faster interpretation and evaluation of data in three dimensions will require that literacy in geostatistical methods becomes part of the engineer's everyday language.

7.2 Application of Geostatistical Methods

Geoscientists and engineers are dependent upon the quality of the basic data and the inherent inadequacies and uncertainties of the data, as a basis for decisions within the petroleum industry. Calculation of hydrocarbon volume for a given area requires the interpretation and input of data from several sources (seismic, well logs, well cores), each of which has an inherent uncertainty and volume of investigation (Figure 7.2). Volumetrically, seismic data represent the most comprehensive data available from the subsurface. Still, reliability of the interpretation of seismic data depends on the quality of seismic response and the pick of a given horizon. Conversion from time to depth depends upon mathematical models that relate velocity and time to depth. These uncertainties are then inherited by top structure maps that, together with hydrocarbon contacts, are used to delineate a pool or field. Petrophysical data—porosity, water saturation, net-to-gross—are all derived from well logs or cores. However, the volumes that petrophysical data represent are on a very different scale (cm^3) compared to the volumes they ultimately represent (m^3, km^3; Figure 7.2).

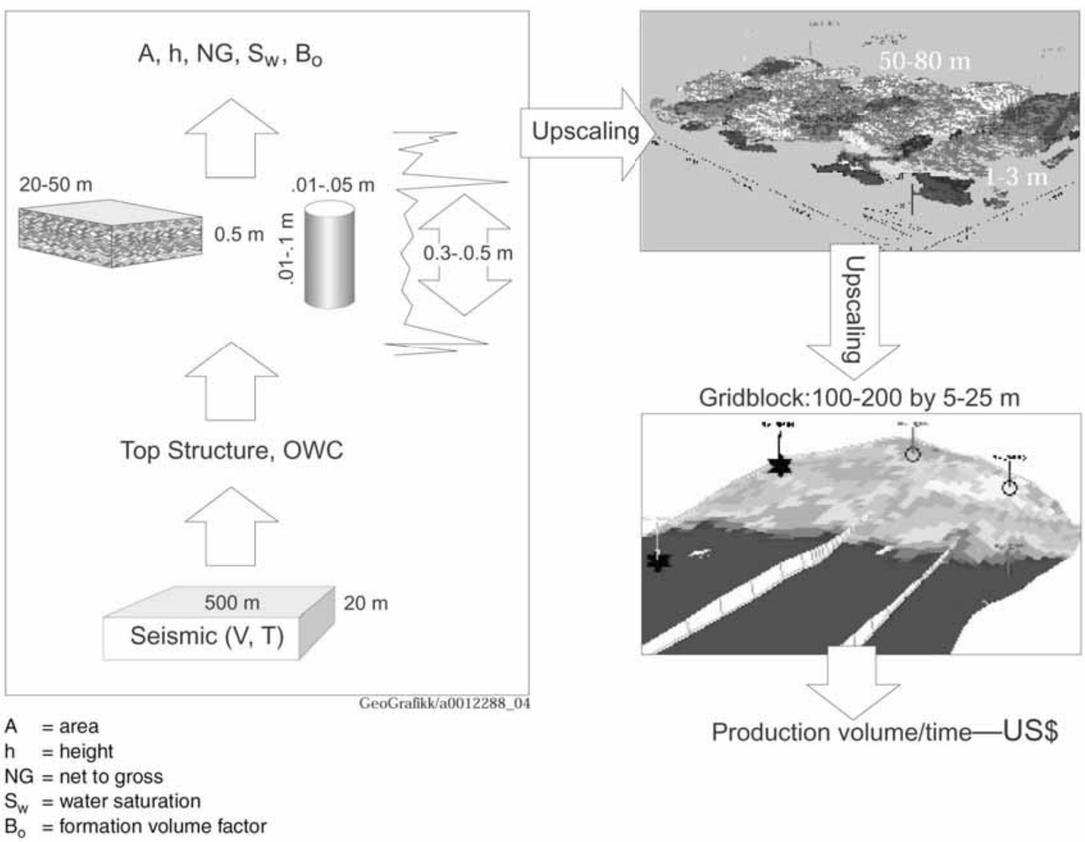


Figure 7.2—Quantification of uncertainty—variables and scales: Each variable or input parameter to the volumetric calculation represents very different scales and volumes. These data are then upscaled to a fine grid representation, and finally a coarse grid representation, for the purposes of reservoir simulation. The

results from these simulations are then ultimately used to calculate production over time and net value in a particular asset.

Geostatistical tools provide a platform for evaluating overall uncertainties and characterization of the risks involved in any given decision. Nevertheless, the results of geostatistical models (uncertainty ranges, distribution of possible outcomes) do not necessarily provide a completely unbiased assessment of uncertainty. This is because of their inherent dependency on the amount of data available, the technical evaluation of the input data, and the statistical algorithm used in the modeling.

The following sections discuss the application of geostatistical methods in order to describe and quantify uncertainties. The methods are grouped into 1D, 2D, and 3D methods insofar as they represent a progressive sophistication in the manner and approach by which uncertainties are handled. The choice of method is often dependent upon the time and data available. In general, 1D methods are used at the prospect evaluation stage, whereas 2D and 3D methods are used during appraisal through to development and production.

7.2.1 1D Geostatistical Methods

By 1D geostatistical methods we mean a single-point statistic, where that point may represent an area or volume from a specific well or an average value from several wells. The use of 1D geostatistical methods (e.g., Monte Carlo simulation) to quantify and analyze uncertainties for various prospects has a comparatively long tradition within the petroleum industry. In general, the simulations are quick, and there are several user-friendly programs available.

1D methods provide a convenient tool for evaluation of overall uncertainties on gas or oil reserves The results can be used to carry out economic analysis upon which various prospects are risked and ranked so that a decision to drill can be made. An assessment for all the key parameters—oil and gas reserves, capital exposure, and economic value (net present value, or NPV)—can be simulated for an entire portfolio.

The most common procedure is to create probability distributions for each of the elements in the volumetric equation (area, net pay, porosity, oil saturation, formation volume factor) and the recovery efficiency, from which values for the different elements are then randomly drawn according to the specified probability distributions. Probability distributions for resources and reserves are then calculated on the basis of the realizations from the simulation. Risk factors reflecting the chance of hydrocarbon generation, migration, trapping, and sealing can be used to condition the distributions for chance of geological or technical success. A comprehensive review of methods and techniques for the evaluation of prospects can be found in Ref. 1.

The input of uncertainty ranges for a given parameter as well as for interdependencies between variables is often subjective, making the comparison of uncertainty estimates for a given set of prospects or fields difficult. Several petroleum companies have established guidelines that can be monitored by advisory teams (Peer Assist) empowered with the task of transferring experience, assuring common practice and thereby ensuring consistency of approach within the company'sportfolio.

Recent work[6] shows that ignoring (systematic) dependencies among the various input parameters or between reservoir compartments can lead to underestimation of the overall uncertainty range for petroleum-in-place. The uncertainty range (P10 to P90) can increase with the introduction of stochastic dependencies between variables such as porosity, permeability, and water saturation, thus providing a better basis for evaluating and risking the upside or downside potential for a given pool or field.[6] Chapter 6 in this volume provides guidelines for handling dependencies.

A comparative study of pre-and post-drill hydrocarbon resource estimates for prospects drilled on the Norwegian Continental Shelf over the past decade[7] shows a strong bias towards overestimation of resources at the prospect evaluation stage (Figure 7.3). Notably, the tendency toward overestimation of resource volumes prior to drilling is not unique within the industry. Overall experience shows that prediction of gross rock volumes (GRVs) is the primary contributing factor leading to this overestimation, while prediction of net-to-gross values is the second most important factor. However, the accuracy with which prospect volumes are estimated can vary considerably and is partly dependent on the length of exploration experience in a particular area and the quality of seismic data.

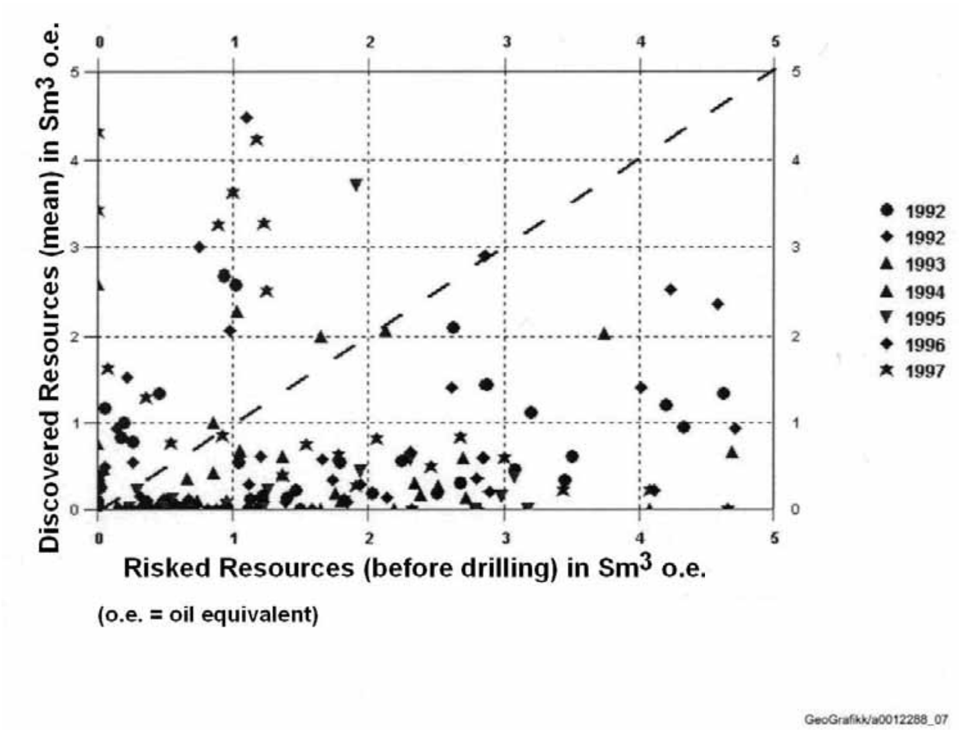


Figure 7.3—Plot of pre- and post-drill resource estimates for prospect drilled in the period 1992–97 offshore Norwegian Continental Shelf. Note a strong bias towards overestimation of resources prior to drilling.

7.2.2 2D Geostatistical Methods

By 2D we mean a mapped (2D grid) geostatistical parameter. The parameter values in the 2D grids can be either depth or some reservoir property. The main difference between 1D and 2D methods is that the spatial variability in structural and petrophysical properties can be modeled. As more well data become available during field appraisal and sanction, more sophisticated geostatistical methods can be applied. This allows the uncertainty evaluation to be more fully described and gives a better understanding of the interdependencies between variables.

Recognition that the definition of GRV is an important contributor to overall uncertainties has led to geostatistical modeling of uncertainty on mapped horizons from seismic and uncertainties associated with evaluation of petrophysical parameters. Structural uncertainties are modeled by geostatistical tools that take into account spatial correlations, while uncertainties in petrophysical parameters are treated, in general, with Monte Carlo simulation programs (i.e., 1D geostatistical methods). For example, water saturation maps can be simulated together with the structural uncertainties in cases where thin oil zones or the thickness of a transition zone plays a significant part in the uncertainty of a particular reservoir. By combining these factors we move from a simple 1D simulation of uncertainties into a 2D simulation of interdependencies and thus a more realistic calculation of the uncertainty range, as discussed in the previous section. However, the successful application of these tools is dependent on the availability of well data for calibration purposes as well as an understanding of variability in seismic response for a given horizon.

Figure 7.4 illustrates the results of the simulations from such a geostatistical evaluation. In this example, uncertainties in GRV are calculated with a geostatistical model that simulates the uncertainty of the velocity model used in depth conversion with the pick or quality of a given seismic horizon and the uncertainty range for the fluid contacts.

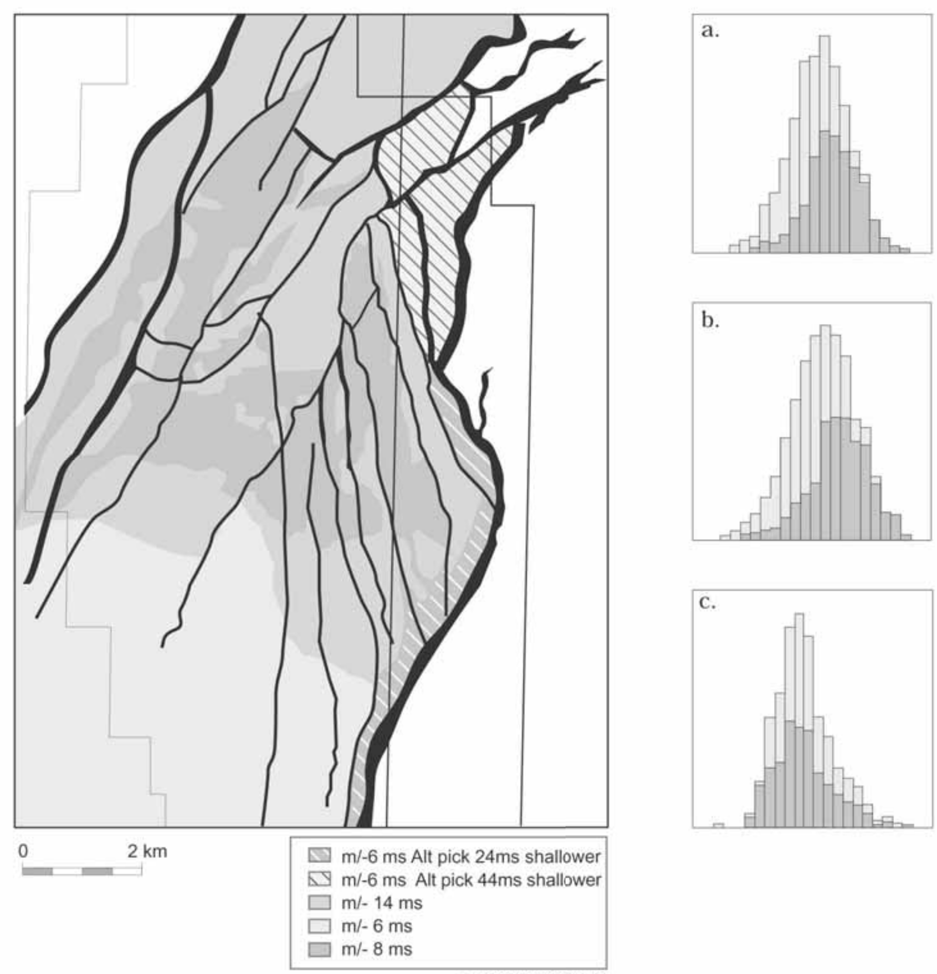


Figure 7.4—2D geostatistical methods: Evaluation of uncertainty in seismic data and GRVs. The seismic map shows the uncertainty in the time pick of top reservoir for a field under evaluation. The hashed lines indicate the parts of the field with two possible picks for top reservoir. Histograms a, b, and c show the

distribution in GRV as calculated from the geostatistical simulation of the two possible seismic picks (shown by the darker and lighter bar color): (a) total for all reservoir units A, B, and C, (b) reservoir units A and B, and (c) reservoir unit C. The pick of top reservoir has a larger impact on reservoir units A and B, which are deeper and therefore more affected by changes in the fluid contacts than reservoir unit C.

The first step is to find an appropriate model for the time-to-depth conversion (i.e., the errors associated with mapping seismic travel times to depth). Often, it is inappropriate to use a uniform velocity grid to calculate the time-to-depth relationship for a given surface (see also Ref. 6). If the velocity map for a given surface contains anomalies caused by lithological variation in the overburden (e.g., overlying channel sands), using a uniform velocity grid in the depth conversion will result in poor time-depth correlations and large discrepancies between the structural grids and well data. Geostatistical methods can be used to model the spatial uncertainty between points on a given surface and thus calibrate a particular depth conversion model and improve the understanding of the model's sensitivities to velocity either as a function of time or for a constant average velocity.

The next step is to evaluate the uncertainty in the pick of a given horizon (i.e., the chosen time/depth point) of a given horizon. In the example shown, the geophysicist recognizes two possible picks for the top structure along the eastern edge of the field, one at 24 ms and another at 44 ms. A number of depth maps (several hundred) can be produced by geostatistical simulation (Bayesian approach, Ref. 8) of the uncertainties on the time interpretation, together with uncertainty in the velocity calibration.

The final step is to calculate variation in GRV. For each of the simulated depth maps, a hydrocarbon contact is drawn from its range of uncertainties and a GRV is calculated. In the example shown (Figure 7.4), the mean value for GRV shifts when uncertainty in the pick of the top reservoir is simulated. A larger impact is seen for reservoir units A and B (Figure 7.4b), which are deeper and therefore more affected by changes in the fluid contacts than reservoir unit C (Figure 7.4c).

As for prospect evaluation, the estimation of uncertainty in reserves during appraisal and sanction is dependent on sound geological and geophysical understanding of the controls on input parameters. A synthetic case study and methodology for uncertainty estimation in volumetrics during appraisal is presented in Ref. 6. The case study presented serves as a good illustration of the importance of calculating the spatial relationships between reservoir parameters, as opposed to scalar, when estimating the uncertainty range for a reservoir or pool.

7.2.3 3D Geostatistical Methods, Heterogeneity Modeling

The general dilemma facing geoscientists is how to fill a sparsely sampled space so that development strategies and reservoir performance predictions are based on realistic representations of reservoir heterogeneity. Improvements in the static reservoir model lead to improved understanding of the dynamic behavior of the reservoir. Smooth interpolation of properties (i.e., linear interpolation) does not account for vertical and horizontal permeability variations and therefore tends to overpredict the recovery efficiency of oil and underpredict channeling and early breakthrough of injected fluids. Stochastic modeling of heterogeneities offers alternative conditional realizations of reservoir property distributions and improves the quantification of the uncertainty in production from a given reservoir. Three-dimensional geostatistical modeling involves the construction of a geological framework grid using the mapped structural horizons and fault surfaces together with the individual chrono-stratigraphic reservoir layers or units. This framework is then merged with the sedimentary building blocks, or lithofacies, and their associated petrophysical characteristics.

A detailed description and illustration of the 3D geostatistical methods used to evaluate the uncertainties in production profiles and development plans for the Åsgard and Veslefrikk Fields on the Norwegian Continental Shelf are given in Refs. 9 and 10. A schematic illustration of the Åsgard evaluation is shown in Figure 7.5.

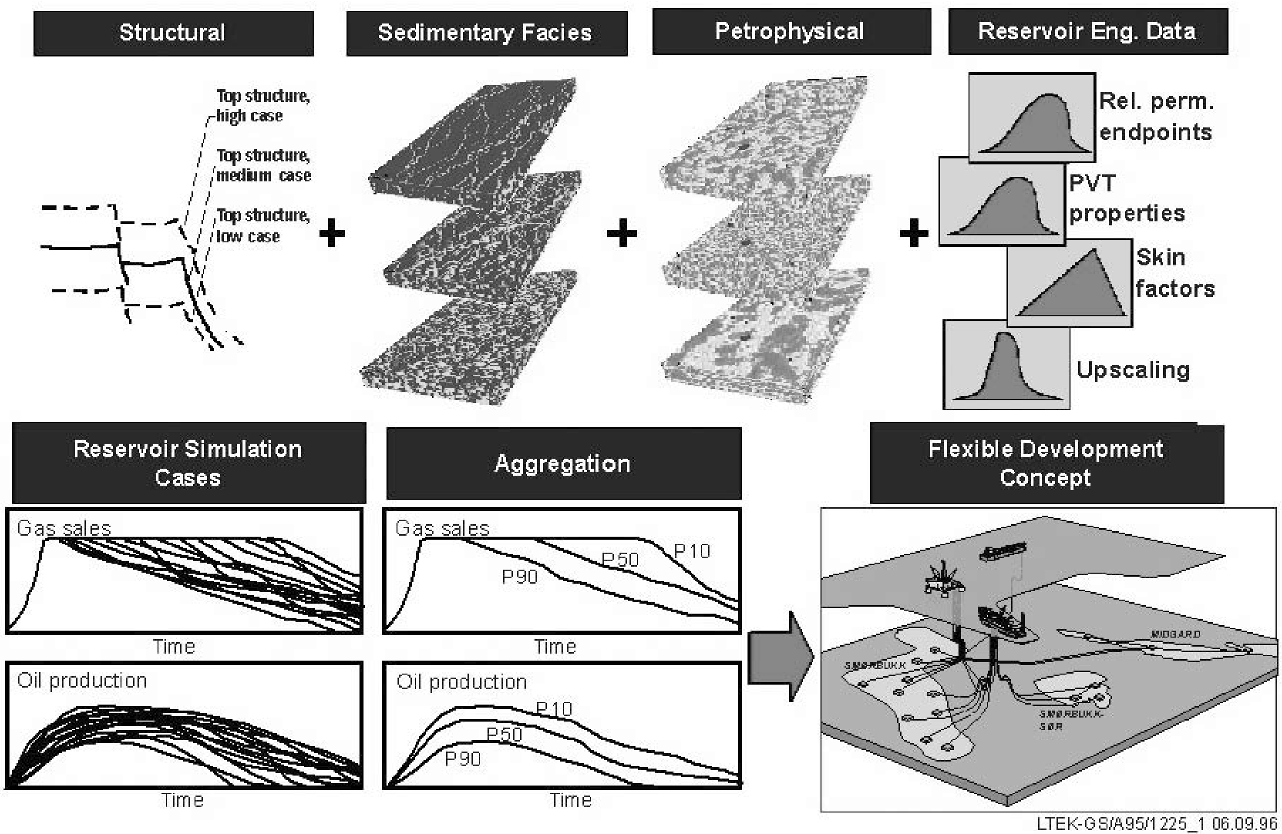


Figure 7.5—3D geostatistical methods: schematic diagram showing the work process and results from an integrated uncertainty analysis of the Åsgard Field, Norway.[8]

Three-dimensional heterogeneity modeling requires a description of the spatial distribution, size, and/or correlation lengths for each of the sedimentary building blocks (i.e., channel or lithofacies type) and the variability for each specific parameter (e.g., porosity) within the reservoir model. Commonly this is done with (semi)variograms to represent correlation, and histograms to represent variability.

The procedures and the geostatistical tools used in 3D modeling are dependent on the data, time available, and particular reservoir or problem to be investigated. Generally, computing capacity and time dictate that the sensitivities and evaluation of the heterogeneities are modeled using a fine-scale model (typical grid size 50 to 80 m 1 to 5 m) before upscaling to a full-field reservoir simulation model (typical grid size 100 to 200 m 5 to 25 m; see Figure 7.2). In the upscaled stochastic model, reservoir heterogeneity should be preserved as much as possible so that the simulation model is conditioned to the variability within a given reservoir.

Three-dimensional stochastic modeling of reservoir heterogeneity involves the following steps:

1. Definition of a conceptual geological model and framework (i.e., what you are trying to model).
2. Classification of well data into appropriate geological classes (e.g., facies).
3. Characterization of inter-well properties defining uncertainty in data (e.g., from seismic data).
4. Generation of realistic 3D heterogeneity models (e.g., distribution of facies or reservoir parameters).
5. Calculation of multiple, equiprobable realizations that can be ranked and thereby integrated with other reservoir technical uncertainties [e.g., relative permeability endpoints, pressure/volume/temperature (PVT) properties, skin factors], thus yielding a rigorous assessment of the uncertainties in recoverable reserves and the time-dependent production profiles.

Input data to 3D stochastic modeling typically consists of:

- correlative, sequence stratigraphic surfaces
- seismic horizons
- facies/sedimentary building blocks within a stratigraphic surface including trends and stacking patterns available from offset wells or regional interpretation, and width and thickness of channels.
- analog data from outcrops from which size distributions and lateral continuity of the sedimentary building blocks/facies can be derived
- petrophysical parameters: porosity, net-to-gross, permeability data by zone
- faults and uncertainties associated with the vertical and horizontal position of the faults
- well-test and production data (vertical/horizontal permeability interpretations, interpretations from test data regarding connected volumes, barriers)
- variability of each input parameter described statistically (variograms, histograms, etc.)

There are two methods for assigning lithofacies codes: object-based and cell-based. The object-based method presents crisp and geologically intuitive simulations. They are constructed by placing sedimentary bodies, such as channels, as objects within a background matrix (shale or other sand bodies). Object-based simulation methods require input of length, width, net-to-gross, and well data for each lithofacies type. An example of a widely used type of cell-based method is the SIS (sequential indicator simulation) algorithm. The SIS algorithm allows the 3D cells or array to be filled with indicator variables honoring well data, global proportions, and variograms defining spatial continuity. Within the geostatistical community there is often a preference for one method or the other. The relative popularity of the cell-based, SIS algorithm is attributed to its simplicity and ability to honor different types of data.[11] However, object-based methods are equally adaptable in terms of honoring data and are visually similar to geological block diagrams.

The advantage of 3D stochastic modeling of heterogeneities is that multiple realizations of rock properties and sand-body distributions/trends can be modeled and still honor well data. Multiple equiprobable realizations provide a tool for evaluating the sensitivity of a given parameter and simulating the effect on flow or production. Multiple simulations provide a range of outcomes that can be ranked and aggregated to give probability densities for in-place volume and production performance (Figure 7.5).[9]

Experience with stochastic modeling over the past 10 years shows that while the overall preservation of heterogeneities in the geological model leads to an improved description and understanding of constraints on the dynamic model, stochastic models are time-consuming to build. Further, while the models provide for full integration of subsurface data, they also require that geostatistical specialists are included in evaluation teams so that the models can be maintained and updated. Equally important, the effects of critical parameters on reservoir behavior can be lost during the process of upscaling from the fine-scale heterogeneity model to the full-field simulation model. For example, if vertical permeabilities are underestimated owing to the smoothing of heterogeneities, fluid fronts will behave in a piston-like manner. In these cases, the upscaled model is too coarse and the fine-scale heterogeneities that can control segregation or gravitational effects are underestimated. The resulting simulation will tend to predict unrealistically efficient production performances.

The trend is toward simple, small-element models designed to evaluate the sensitivity of reservoir performance to a particular parameter or set of parameters. In addition to being easier to build and maintain, element models require less computing time, and more iterations or sensitivities can be performed. Consequently, the key factors affecting reservoir performance can be identified and correctly implemented and simulated in the full-field model. Specifically, in connection with the evaluation of a field offshore Norway, a great deal of time and effort was used in detailed description of the heterogeneity within a reservoir consisting of tidal deposits. However, sensitivities performed on the upscaled reservoir simulation model showed that the sealing capacity and communication along faults was the key factor to predicting the rate at which gas breakthrough would occur. The lesson from this is that construction of a simple, smaller model built to test key factors can save time and focus teamwork on key issues.

Furthermore, a major bottleneck is the maintenance and updating of the stochastic model as new reservoir data becomes available. Once the critical parameters are mapped and understood, full-field models are quicker to update and are actively used in planning and analysis of future locations for infill wells.

7.2.4 New Developments and Areas of Application

Fuzzy Mathematics

Fuzzy mathematics represents a novel, and largely untested, approach to the estimation of resources and reserves.[12] Fuzzy mathematics was originally developed to solve hard-to-formulate problems and is used in areas such as economics, analysis of complex systems, and decision processes. The advantage of fuzzy sets and methods is that they provide a tool for evaluating situations where statistics are not available, making them attractive for use in exploration and field appraisal. Input to the calculations, fuzzy numbers are based on the experience and level of confidence an individual evaluator places on the probable outcome of a specific parameter. The disadvantages of these methods are that the mathematics are not straightforward and the results are dependent on the experience of the user, especially in cases of complex calculus such as numerical simulation. Research into the application of fuzzy mathematics to problems within the petroleum industry is ongoing; as yet, there are very few results that can be compared with the traditional probabilistic approach. However, in the future this method may prove to be an appropriate alternative to probabilistic methods.

Flow Simulation

Fast flow simulation of integrated 3D geostatistical models represents an opportunity for development teams to rapidly assess and integrate their appreciation of uncertainties and risks associated with decision making. Such simulation tools are typically based on a streamline flow approach that permits very quick simulation at the expense, perhaps, of some details in the representation of physical processes.

Well Intervention

The recognition that simple element models provide a good basis for sensitivity evaluation of specific parameters on flow behavior leads nicely to the application of geostatistics for evaluating the timing and consequence of well interventions. Simple models that simulate historical well performance and account for the effect of geological and petrophysical factors (e.g., barriers and local permeability variations) are easy to build. Results of the simulations can be used directly as input to the evaluation of cost or net present value (NPV) for a particular activity.

Figure 7.6 illustrates a simple geostatistical model that was built to evaluate the risks involved in plugging back the water-producing interval in a well that had been producing water (80% water cut) for several years. There was some concern that, after isolation, water could cone up into the oil-producing interval (Figure 7.6a). Consequently, the geostatistical model was designed to analyze the efficiency of shale and calcite layers within the reservoir in preventing water coning. A fine-scale model (1000 1000 40 m) with a resolution of 40 40 120 and a cell size of 25 25 0.3 m was built. More than 30 different realizations were generated by varying the lateral extension and permeability of the shale and calcite layers, but they were still conditioned to data from five neighboring wells. These realizations were then upscaled (40 cells vertically, 5 m horizontally around the well) for fast simulation of the production history (water cut, pressure, and PLT log). In order to match the production history match, the shale and calcite layers needed to be laterally extensive with low vertical permeability (Figure 7.6c), and simulations showed that after zone isolation, the barriers would indeed prevent water coning up into the oil-producing interval (Figure 7.6d).

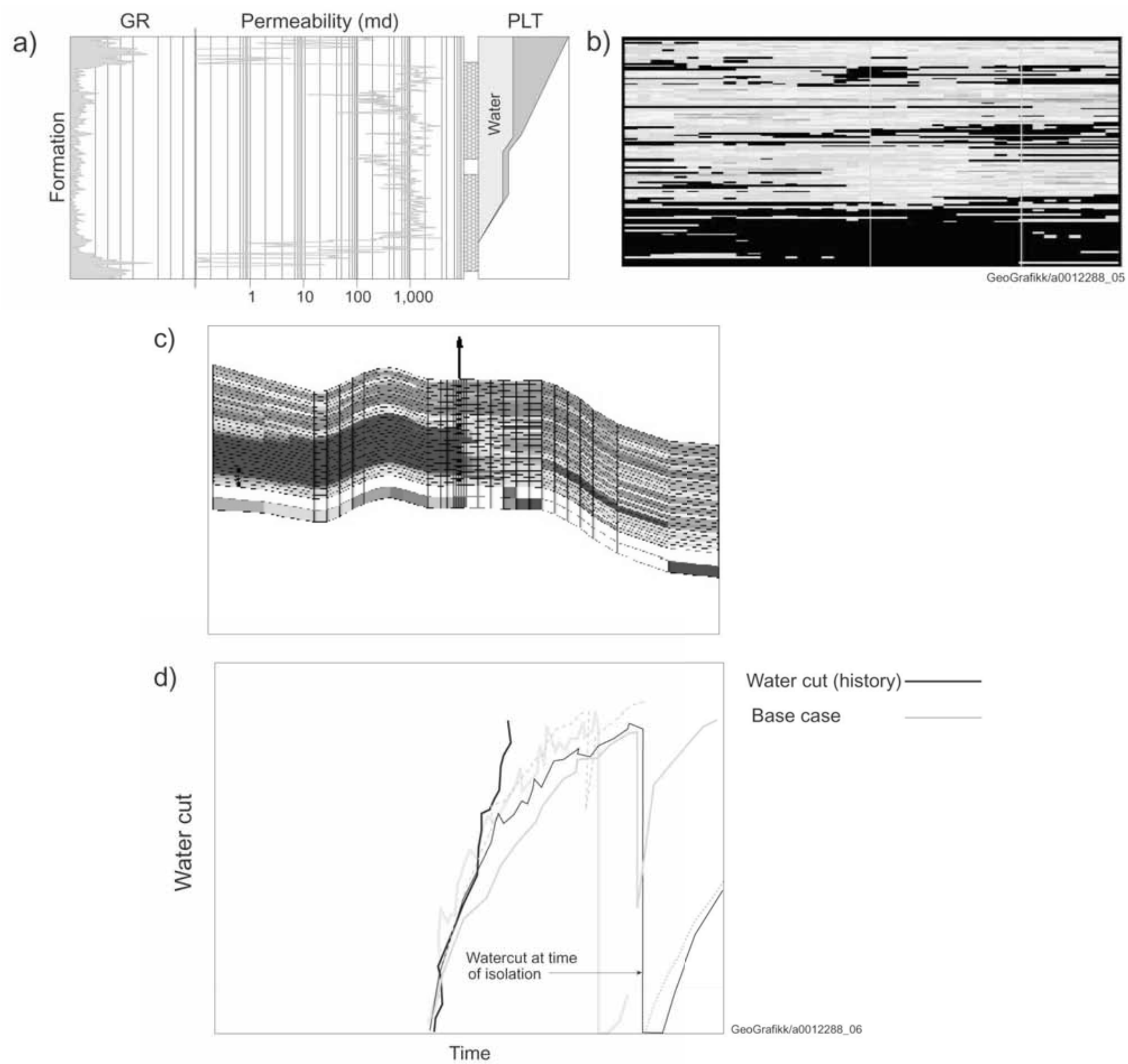


Figure 7.6—Illustration of a simple geostatistical model used to evaluate risk in plugging off a water-producing interval in a well. (a) Well log and production log from well under evaluation. Water production is from the lower part of the formation (PLT). Permeability values less than 10 md are not observed. (b) Vertical slice through the simple geostatistical model built to evaluate the effect of shale and calcite layers and permeability variation on the water cut. Black represents permeabilities less than 20 md. (c) Vertical slice through the upscaled simulation model at the time of the PLT. (d) Results from several simulation runs; simulated history match and prediction of water cut after plugging.

Well Positioning

Uncertainty in a well deviation survey can be 0.1 to 0.2% of the vertical displacement and 0.5% of the horizontal displacement. This uncertainty is not formally incorporated into the procedures for time-to-depth calibration and calculation of reservoir surfaces. Geostatistics can provide tools for incorporation of this uncertainty during the process of constructing reservoir models. This can be important, in particular, for fields that include a number of highly deviated wells.

Geostatistical modeling of uncertainty for a structural horizon or zone, combined with the simulation of uncertainty on the drilling survey, can also aid in the optimization of a well path and well design. The development of software that can be used during planning and drilling of wells will improve cross-disciplinary interaction when updating well design and will contribute to the reduction of well costs. Furthermore, integrating uncertainty in well-path trajectory with seismic and reservoir simulation will enable the planning and optimizing of the well completion and perforation strategy.

Lithology and Fluid Prediction

Research linking seismic attributes with rock properties and prediction of fluid content is a rapidly growing field of investigation. For fields in production, time-lapse or 4D seismic based on correlation of seismic attributes with shale, sand, and/or fluid content is now used in the planning of infill well locations. Results are also used as a quality check for flow simulation models. Similar applications are seen in exploration and evaluation of prospects as direct indicators of the presence of hydrocarbons (DHI = direct hydrocarbon indicators).

The methods are relatively easy to apply, and increasing computing power has led to rapid evaluation of several seismic attributes. Improved understanding of seismic response to lithology and fluid can provide a major breakthrough prediction of geological variations from seismic data. This will mean that in addition to structural surfaces, inter-well facies variations based on seismic data can be included in 3D stochastic models.

7.3 Conclusions

The main driver behind development and application of geostatistical methods is the need to make sound, cost-effective business decisions.

Geostatistics is a powerful tool for combining the full body of knowledge about geologic and recovery processes with data and observations from a reservoir or pool. Geostatistical methods aid in the evaluation of pools and provide a tool by which technical insight into a problem can be gained. As such, geostatistics is not a closed and definitive method, but a decision analysis tool allowing the knowledge of relevant disciplines to be integrated.

The application of geostatistical tools to evaluate overall uncertainty becomes more sophisticated as more data are available. In summary:

- 1D methods are easy and relatively quick to apply, but evaluation of the input data is subjective and requires guidelines to ensure consistent application between teams. The main challenge is to correctly risk and quantify uncertainty at the exploration stage.
- 2D geostatistical methods, which account for spatial variability and interdependencies between variables, provide a better basis for evaluating and risking the upside or downside potential for a given pool or field. Ignoring systematic dependencies among the various input parameters or between reservoir compartments can lead to underestimation of the overall uncertainty range for petroleum-in-place. In most cases, the factors having the strongest impact on the total uncertainty in reserves are seismic interpretation and time-to-depth conversion, together with uncertainty on the position of fluid contacts (i.e., the primary sources for estimation of GRV).

- ➢ The toolbox of 3D geostatistical algorithms and software has increased significantly over the last decade and is still rapidly evolving. The challenge is to balance functionality and easy application with technical sophistication.
- ➢ Small, simple element models that address specific problems are useful for evaluation of well interventions, and well placement and injection strategies.
- ➢ New developments in geostatistical methods and areas of application are continuously arising. A few examples are:
  - ✓ Fuzzy mathematics as an alternative to probabilistic methods.
  - ✓ Fast flow simulation of 3D geostatistical models for rapid uncertainty and risk evaluation.
  - ✓ Lithology and fluid prediction from seismic data.
- Evaluation teams should include, or have direct access to, specialists in geostatistics.

Overall, correct application of geostatistical methods will produce a balanced view of field reserves and their associated uncertainties, which in turn improves the accuracy of the reserve assessments, particularly when reserves of several independent fields are aggregated.

References

1. Harbaugh, J.W., Davis, J.C., and Wendebourg, J.: *Computing Risk for Oil Prospects: Principles and Programs,* Elsevier Science Ltd., Oxford, U.K. (1995).
2. Jensen, J.L. *et al.: Statistics for Petroleum Engineers and Geoscientists,* Prentice-Hall Inc., Englewood Cliffs, New Jersey (1997).
3. Isaaks, E.H. and Srivastava, R.M.: *An Introduction to Applied Geostatistics,* Oxford U. Press, New York City (1989).
4. Journel, A.G.: "Past, Present and Future of Petroleum Geostatistics," keynote address, 1999 EAGE/SPE International Workshop on Geostatistics, Toulouse, France, 20–23 April.
5. Meling L.M., Mørkeseth P.O., and Langeland, T.: "Production Forecasting for Gas Fields With Multiple Reservoirs," *JPT* (December 1990) 1580.
6. Floris, F.J.T. and Peersmann, M.R.H.E.: "Uncertainty estimation in volumetrics for supporting hydrocarbon exploration and production decision-making," *Petroleum Geoscience* (1998) **4,** 33.
7. Ofstad, K., Kullerud, L., and Hilliksen, D.: "Evaluation of Norwegian Wildcat Wells," *Norwegian Petroleum Directorate,* Stavanger (1998).
8. Abrahamsen, P.: "Bayesian kriging for seismic depth conversion of a multi-layer reservoir," *Quantitative Geology and Geostatistics* (1993) **5,** 385.
9. Tyler K. *et al.:* "Integrated Stochastic Modeling in Reservoir Evaluation for Project Evaluation and Risk Assessment," paper SPE 36706 presented at the 1996 SPE Annual Technical Conference and Exhibition, Denver, Colorado, 6–9 October.
10. Lia, O. *et al.:* "Uncertainties in Reservoir Production Forecasts," *AAPG Bulletin,* **81,** No. 5 (1997).
11. Deutsch, C.V. and Meehan, D.N.: "Geostatistical Techniques Improve Reservoir Management," *Petroleum Engineer Intl.* (March 1996) 21.
12. Zolotukhin, A.B.: "A Novel Approach to Resources and Reserves Determination," paper SPE 63199 presented at the 2000 SPE Annual Technical Conference and Exhibition, Dallas, 1–4 October.

Appendix 7-A—Terminology

Equiprobable—A set of events all having equal probability of occurring.

Kriging—Geostatistical contouring algorithm that uses a semivariogram to model the spatial correlation between points on a surface or a 3D grid. This method is named after Danie Krige, the South African mining engineer who introduced statistical methods into mine evaluation.

Monte Carlo Simulation—Statistical method that uses the random sampling of numbers to describe the probability-vs.-value relationship for certain parameters such as oil and gas reserves.

Probability—Relating to the likelihood of something happening, the extent to which an event is likely to occur, often displayed as a histogram or distribution from which the mean (arithmetic average), mode (most likely), P50 (median) P10, and P90 values can be calculated.

Risk—The possibility of loss and the chance or probability of that loss; for example, the evaluation of potential loss or gain of value for a particular asset, or the estimation of geological success for a particular exploration target. Evaluation of risk can be expressed in the form of numerical probability.

Scalar—A measure defined only by magnitude (in contrast to a vector); for example, the description of dependencies between two variables as a linear trend.

Spatial—Accounts for the variability of a particular parameter in space (vector) rather than as a linear trend or average.

Stochastic—A system that has some degree of unpredictability, and generally one that is part deterministic (i.e., based on a conceptual model) and part random, where the random part is described using probabilistic methods. Frequently, one constructs a deterministic framework based on the current geological interpretation and well data (conceptual model) and then distributes facies and petrophysical parameters within the model using probabilistic methods. Based on this input, several stochastic realizations are produced but still conditioned to the deterministic data from wells or seismic. A stochastic process will always give different outcomes even though the conceptual framework is the same. The degree to which the outcomes will differ is controlled by the manner in which the facies and petrophysical parameters are distributed within the framework.

(*Semi*)*variograms*—A measure of spatial correlation calculated as the average squared difference between pairs of points that are separated by a given distance. The statistic is calculated for a range of separations (also known as lags). The resulting statistic is plotted as a function of separation (or lag). This plot is often referred to as the experimental semivariogram and is characterized by a curve that rises to an upper limit called the sill. The distance at which this limit occurs is called the range; beyond the range, points are no longer correlatable. At this point, the statistic is equivalent to the variance of the sample.

Chapter 8 Summary
Seismic Applications

James D. Robertson

A 3D seismic volume is one of the many tools used by the petroleum industry to assess the quantity of oil and gas available for production from a field. The seismic data are integrated with geologic and engineering information from the discovery and appraisal wells to determine if a known accumulation is commercial and to formulate an initial field-development plan. As development wells are drilled and put on production, the interpretation of the seismic data is revised and recalibrated to take advantage of the new borehole information and production histories. The 3D seismic volume evolves into a continually utilized and updated management tool that impacts both estimation of reserves and depletion planning for years after the seismic survey was originally acquired.

The interpretations that a geophysicist derives from 3D seismic data can be grouped conveniently into those that map the geometry of the hydrocarbon trap, those that characterize rock and fluid properties, and those that monitor fluid flow during production.

Trap Geometry
A 3D seismic volume maps the trap as a 3D grid of seismic amplitudes reflected from acoustic impedance boundaries in the rocks in and around the trap. Individual gridblocks typically are 10 to 30 m in lateral dimension and 5 to 15 m in height. A standard 3D seismic volume acquired to image a field contains millions of these gridblocks. Using the variety of interpretive techniques available on a computer workstation, a geophysicist makes numerous cross sections, maps, and 3D visualizations of both the surfaces (bed boundaries, fault planes, and unconformities) and thicknesses of the important stratigraphic units comprising the trap. In particular, the geometric configurations of the reservoirs and their adjacent sealing units are carefully defined. The final work product is an estimation of the reservoir bulk volume of the trap, which can be integrated with reservoir properties like porosity and hydrocarbon saturation to compute original oil and gas in place.

Rock and Fluid Properties
The rock and pore-fluid properties of a reservoir are derived from a 3D seismic volume by comparing reservoir properties measured from boreholes to specific characteristics of the seismic data, such as amplitudes or interval travel times. The geophysicist formulates a seismic model that predicts reservoir properties between boreholes, and subsequent drilling validates and refines the model. Gas saturation in sandstone reservoirs is one property that has been very successfully mapped by 3D seismic surveys. The presence of free gas typically creates a strong acoustic impedance

contrast between a sandstone and surrounding rock, and the contrast produces an anomalously strong seismic amplitude (often called a “bright spot”) that is readily visible on seismic displays. Unfortunately, the seismic tool is not yet capable of distinguishing between a few percent of residual gas saturation and a commercial accumulation. At least one well penetration into a seismic bright spot is needed to prove producibility before the prospective resources in a reservoir defined by an amplitude anomaly can be classified as reserves.

A gas/water contact (GWC) can be mapped by noting where a bright spot terminates downdip across a 3D seismic volume. The terminations should occur at a common structural contour, which is the base of the trapped gas. If several discrete contours are followed by different segments of the downdip edge of the bright spot, this behavior points to the presence of multiple reservoirs with different GWCs. The GWC itself in a sandstone reservoir is generally an interface with a good seismic impedance contrast. Because the contact is horizontal owing to buoyancy, the contact sometimes can be directly detected as a flat, high-amplitude seismic event (flat spot), particularly if the reservoir is thick and gently dipping. The flat spot directly outlines the base of the trapped gas, and the depth of the flat spot is the depth of the GWC.

A flat spot (the seismic expression of the GWC) should terminate at the same structural contour as the downdip edge of the corresponding bright spot (the seismic expression of the reservoir-seal boundary). When both of these seismic hydrocarbon indicators are present and terminate at the same spatial location with the correct seismic polarities, the probability that these seismic effects are caused by free gas is very high, and the exploration drilling risk is substantially reduced. It is often true that a gas reservoir is too thin and/or steeply dipping to exhibit a readily observable flat spot. If no flat spot is obvious, but a bright spot is present and fits structure well, the bright spot by itself significantly lowers drilling risk.

When a known gas accumulation is being appraised, it is reasonable that seismic flat spots and/or bright spots can be used as definitive geological data to classify gas as proved reserves when the following conditions are met:

- The flat spot and/or bright spot is clearly visible in the 3D seismic data.
- The spatial mapping of the flat spot and/or downdip edge of the bright spot fits a structural contour, which usually will be the spill point of the reservoir.
- A well penetrates the GWC in one fault block of the reservoir, so logs, pressure data, and test data provide a direct and unambiguous tie between the GWC in the well and the seismic flat spot and/or downdip edge of the bright spot; i.e., the borehole proves that there is producible gas, not residual gas, down to the seismic indicators of the GWC.
- A well in another fault block penetrates the reservoir updip from the GWC.
- This second well proves gas down to a lowest known depth, and pressure data show that this gas is in communication with the gas in the first fault block.
- The seismic flat spot and/or downdip edge of the bright spot in the second fault block lies below the lowest known gas in the second well and is spatially continuous with and at the same depth as these seismic indicators in the first fault block.

If all these conditions are met, the gas in the second fault block between the lowest known occurrence in the well and the seismic flat spot and/or downdip edge of the bright spot can reasonably be judged to be proved.

It is sometimes possible to directly detect and map oil saturation with 3D seismic data using the same approaches as outlined for gas. Not surprisingly, direct detection of oil saturation works best when the oil has a high API gravity and is gas-saturated; i.e., the oil's stiffness at reservoir conditions is more like free gas than water. If light oil is shown to be directly detectable as a bright spot and/or flat spot on seismic data by comparison with borehole information, then the 3D seismic volume can be used to define proved reserves of oil in the same manner as described for gas.

When rock/pore-fluid conditions are not favorable for producing hydrocarbon-related seismic anomalies, reservoir properties such as porosity or lithologic change can sometimes be directly estimated through comparisons between a 3D seismic volume and borehole information. Quantitative estimation of porosity, for example, is possible if one can track the lateral extent of a reservoir on a seismic horizon and can derive a good seismic model from borehole calibration that predicts porosity from amplitude variations across the horizon.

Flow Surveillance

If two or more 3D seismic volumes spaced months or years apart are acquired over the same field (a procedure called time-lapse, or 4D, seismic), differences between the volumes can highlight how fluids are flowing in the field if a depletion procedure changes a reservoir's properties sufficiently that a robust response occurs in the seismic data. For example, gas injection to pressurize or flood a reservoir produces an expanding seismic amplitude anomaly around the injection well owing to the same rock physics that cause naturally occurring gas zones to appear as bright spots. The expansion of the artificially created bright spot is directly measurable on successive 3D volumes and clearly shows the movement of the front of the injected gas. Observing where the gas does not flow (i.e., where no seismic amplitude develops) highlights areas of the reservoir that are not being swept by the gas injection.

As a second example, bypassed oil reserves can be spotted on time-lapse seismic when a compartment (fault block or other discrete component of the trap) is unaffected by a drop in reservoir pressure below bubblepoint (i.e., there is no indication on the seismic of gas coming out of solution in that particular compartment at the time in the field's production life when overall field pressure is dropping below bubblepoint). When employed in this manner, time-lapse seismic identifies isolated reservoirs that previously were believed to be part of the field's known reservoir or reservoirs. In general, the seismic tool is useful in a time-lapse mode as a check on the validity of the assumptions in a reservoir simulation of reserves. Because the seismic monitoring is more spatially specific than pressure monitoring, estimation and extraction of reserves can be optimized over time by using the seismic to guide detailed simulations of depletion and to resolve contradictions between the seismic and the reservoir model.

Full-Wavefield Seismic Analysis

Over the past 15 years, geophysicists have expanded the seismic information available for reservoir description and estimation of reserves and resources to include not just compressional or P-waves, but also the shear or S-waves that are produced when P-waves are reflected from bed boundaries at non-normal incidence. The splitting of seismic energy into P-waves and S-waves at a boundary is a function of Poisson's ratios of the overlying and underlying layers. Analyzing the S-waves in combination with the P-waves in theory allows a geophysicist to directly compute the elastic moduli of a rock, which ultimately might lead to quantitative determinations of porosity, permeability, and pore-fluid saturation.

Gas or light-oil saturation in particular changes the Poisson's ratio of a reservoir. P-wave 3D seismic data can now be processed to produce one or more volumes that display seismic amplitude as a function of the offset distance between the seismic sources and geophones used in the acquisition of the data. Horizon slices from these amplitude-vs.-offset (AVO) volumes show distinctive amplitude anomalies when gas or light oil is present in a reservoir. AVO analysis applies more broadly than bright-spot analysis, which is generally confined to relatively shallow sandstone reservoirs in Tertiary basins. AVO is often used to detect hydrocarbons in reservoirs too deeply buried to exhibit a conventional bright-spot response.

A recent and promising development in full-wavefield seismic technology is the recognition that seismic receivers placed on the ocean bottom can record with high fidelity the reflected S-waves generated at reservoir boundaries and hydrocarbon contacts by an incident P-wave. The PS waves are sensitive to reservoir lithology, oriented fractures, and hydrocarbon saturation. In particular, initial field experiments are showing that the PS wave has the capability to directly map oil/water contacts (OWCs).

Ocean-bottom recording of the full wavefield is also useful for mapping the geometry of traps overlain by gas chimneys. S-waves are not affected by the type of fluid in pore space, and they propagate through gas chimneys without being attenuated or scattered like P-waves.

As additional research is completed, it is very likely that full-wavefield seismic volumes, perhaps analyzed in a time-lapse mode, will provide reservoir management teams with improved seismic techniques to assess the quantity of oil and gas available for production from a field and to classify a portion of that quantity as proved.

Chapter 8

Seismic Applications

James D. Robertson

8.1 Introduction

A seismic survey is one of the many tools used by the petroleum industry to assess the quantity of oil and gas available for production from a field. The seismic data are integrated with well logs, pressure tests, cores, and other information from the discovery and appraisal wells to determine if a known accumulation is commercial and to formulate an initial field development plan. As development wells are drilled and put on production, the interpretation of the seismic data is revised and recalibrated to take advantage of the new borehole information and production histories. Aspects of the interpretation that were initially ambiguous become more reliable and detailed as uncertainties in the relationships between seismic parameters and field properties are reduced. The seismic data evolve into a continuously utilized and updated management tool that impacts both estimation of reserves and depletion planning for years after the seismic survey was originally acquired.

While 2D seismic lines are useful for mapping structures and estimating reservoir properties, the uncertainty of a seismic prediction decreases dramatically when the seismic data are acquired and processed as a 3D data volume. Not only does 3D acquisition provide full spatial coverage, but the migration procedure in 3D processing also moves reflections to their proper positions in the subsurface and significantly improves the clarity of the seismic image. The following discussion assumes that the seismic data available for interpretation are 3D and not 2D.

8.2. Seismic Estimation of Reserves and Resources

The interpretations that a geophysicist derives from 3D seismic data can be grouped conveniently into those that map the geometry of the hydrocarbon trap, those that characterize rock and fluid properties, and those that monitor fluid flow and pressure depletion during production.

8.2.1 Trap Geometry

Trap geometry is determined by the dips and strikes of reservoirs and seals, the locations of faults that facilitate or block fluid flow, the shapes of the sedimentary bodies that make up a field's stratigraphy, and the orientations of any unconformity surfaces that cut through the reservoir. A 3D seismic volume maps the trap as a 3D grid of seismic amplitudes reflected from acoustic impedance boundaries in the rocks in and around the trap. Individual gridblocks (often called volume elements or voxels) typically are 10 to 30 m in lateral dimension and 5 to 15 m in height (height is frequently measured in seismic travel time rather than meters during much of the seismic processing and interpretation). A standard 3D seismic volume acquired to image a field contains millions of these gridblocks. A geophysicist uses the various interpretive techniques available on a computer workstation to analyze the volume. By mapping travel times or depths to selected acoustic impedance boundaries (geophysicists often call these boundaries seismic horizons), displaying seismic amplitude variations along these horizons, isochroning or isopaching between horizons, noting changes in amplitude and phase continuity through the volume, and displaying slices and volumetric renderings of the seismic data in optimized colors and perspectives, a geophysicist can synthesize a coherent and quite detailed 3D picture of a trap's geometry. The state-of-the-art is that seismic volumes are now interpreted and viewed in computer visualization environments (very large screens or special rooms with 3D projection) as well as on desktop workstations.

To fully analyze a trap, a geophysicist typically makes numerous cross sections, maps, and 3D visualizations of both the surfaces (bed boundaries, fault planes, and unconformities) and thicknesses of the important stratigraphic units comprising the trap. In particular, the geometric configurations of the reservoirs and their adjacent sealing units are carefully defined. The displays ultimately are distilled to geometric renderings of the single or multiple pools that form the field. The final work product of the trap analysis is a mathematical calculation of the reservoir bulk volume of these pools (which will later be integrated with reservoir properties like porosity and hydrocarbon saturation to compute original oil and gas in place).

8.2.2 Rock and Fluid Properties

The second general application of 3D seismic analysis is predicting the rock and pore-fluid properties of the reservoir. Characteristics of the seismic data like amplitude and phase of the seismic reflections, interval travel times between horizons, and frequency variations are compared to porosity, fluid type, lithology, net-pay thickness, and other reservoir properties. The most important seismic characteristic by far for analyzing a reservoir is seismic reflection amplitude. The comparisons require borehole control (well logs, cuttings, cores, etc.), first to suggest an initial hypothesis relating rock/fluid properties to observed seismic characteristics and then to test and refine proposed relationships. A geophysicist develops the initial hypothesis by comparing the 3D seismic volume at the location of a well to the well's information, often through the intermediary of a synthetic seismogram (a modeled seismic trace derived from sonic and density logs) or a vertical seismic profile (a seismic section recorded by placing the seismic source on the earth's surface and one or more receivers down in the well). If synthetic seismograms, vertical seismic profiles, and 3D seismic volume are close matches at the points of well control, rock and fluid properties can then be interpolated among wells by either a deterministic or geostatistical procedure until the interpolations produce an interwell seismic model that matches the actual interwell 3D seismic data. Subsequent drilling validates (or invalidates) the interpolation and provides new borehole data for another iteration of estimating rock and fluid properties between boreholes from the 3D seismic volume.

Gas saturation in sandstone reservoirs is a pore fluid property that has been very successfully mapped by 3D seismic surveys. The presence of free gas typically lowers sharply the seismic velocity of unconsolidated to moderately consolidated sandstones and creates a strong acoustic impedance contrast between the gas-charged sandstone and the surrounding rock. The contrast produces an anomalously strong seismic amplitude that is readily visible on seismic displays. Since the early 1970s, this bright-spot effect has been widely exploited to explore for gas accumulations. When the effect is present in a 3D seismic volume, free gas can be accurately mapped across a field at multiple horizons.

Unfortunately, the seismic tool is not yet capable of quantitatively predicting the percentage of free gas saturation in a reservoir. A saturation of a few percent, which might be the residual left after the seal on an original gas accumulation is broken, produces virtually the same seismic amplitude response as the saturation of a commercial gas reservoir. Hence, at least one well penetration into a seismic bright spot is needed to prove producibility before the prospective resources in a pool defined by an amplitude anomaly can be classified as Reserves.

Gas-induced amplitude anomalies on stacked seismic data typically become less obvious with depth as sandstones become more cemented and less porous. When conventional bright-spot interpretation is no longer applicable, a geophysicist often employs full-wavefield techniques like amplitude-vs.-offset (AVO) analysis to differentiate free gas from water in pore space. This type of seismic analysis is discussed in Section 8.5.

When a seismic amplitude anomaly is the result of gas saturation, the gas/water contact (GWC) itself can be mapped by noting where the bright amplitudes terminate downdip across the 3D seismic volume. The terminations should occur at a common structural contour, which is the base of the trapped gas. Seismic amplitude normally decreases sharply at this contour because the strong acoustic impedance contrast between the reservoir and seal becomes much weaker when the reservoir pore fluid changes from gas to water. If the downdip termination of the bright spot does not follow a structural contour, there is considerable risk that the seismic amplitude anomaly is not caused by the presence of free gas, but instead has a lithologic origin. Of course, if several discrete contours are followed by different segments of the downdip edge of the bright spot, this behavior points to the presence of multiple pools with different GWCs.

Acoustic impedance sometimes changes sufficiently between reservoir and seal at the GWC so that the reservoir-seal reflection actually changes polarity at the contact. This polarity change is highlighted if positive and negative reflections are displayed in two different colors gradationally scaled to the amplitude of the reflections, which is a color convention frequently employed to display 3D seismic data.

The GWC itself in a sandstone reservoir is generally an interface with a good seismic impedance contrast. Because the contact is horizontal owing to buoyancy, the contact sometimes can be directly detected as a flat, high-amplitude seismic event (flat spot), particularly if the reservoir is thick and gently dipping. The flat spot directly outlines the base of the trapped gas, and the depth of the flat spot is the depth of the GWC. (It is important to note that the contact, while flat in depth, sometimes appears to be dipping on seismic time sections owing to lateral seismic velocity variations associated with the gas and to constructive and destructive interference among different reflections in the reservoir interval.)

A flat spot (the seismic expression of the GWC) should terminate at the same structural contour as the downdip edge of the corresponding bright spot (the seismic expression of the reservoir-seal boundary). When both of these seismic hydrocarbon indicators are present and terminate at the same spatial location with the correct seismic polarities, the probability that these seismic effects are caused by free gas is very high, and drilling risk is substantially reduced. It is often true that a gas reservoir is too thin and/or steeply dipping to exhibit a readily observable flat spot. If no flat spot is obvious, but a bright spot is present and fits the structure well, the bright spot by itself significantly lowers drilling risk.

When a known gas accumulation is being appraised, it is reasonable that seismic flat spots and/or bright spots can be used as definitive geological data to classify gas as proved reserves when the following conditions are met.

- The flat spot and/or bright spot are clearly visible in the 3D seismic data.
- The spatial mapping of the flat spot and/or downdip edge of the bright spot fits a structural contour, which usually will be the spill point of the reservoir.
- A well penetrates the GWC in one fault block of the reservoir, so logs, pressure data, and test data provide a direct and unambiguous tie between the GWC in the well and the seismic flat spot and/or downdip edge of the bright spot (i.e., the borehole proves that there is producible gas, not residual gas, down to the seismic indicators of the GWC).
- A well in another fault block penetrates the reservoir updip from the GWC.
- This second well proves gas down to a lowest known depth, and pressure data show that this gas is in communication with the gas in the first fault block.
- The seismic flat spot and/or downdip edge of the bright spot in the second fault block lie below the lowest known gas in the second well and are spatially continuous with and at the same depth as these seismic indicators in the first fault block.

If all these conditions are met, the gas in the second fault block between the lowest known occurrence in the well and the seismic flat spot and/or downdip edge of the bright spot can reasonably be judged to be Proved.

While the discussion above has focused on free gas, it is sometimes possible to directly detect and map oil saturation with 3D seismic data using the same approaches as outlined for gas. Not surprisingly, direct detection of oil saturation works best when the oil has a high API gravity and is gas-saturated (i.e., the oil's stiffness at reservoir conditions is more like free gas than water). If light oil is shown to be directly detectable as a bright spot and/or flat spot on seismic data by comparison with borehole information, the 3D seismic volume can be used to define proved reserves of oil in the same manner as described earlier for gas.

When rock/pore-fluid conditions are not favorable for producing hydrocarbon-related seismic anomalies, reservoir properties like porosity or lithologic change can sometimes be directly estimated through comparisons between a 3D seismic volume and borehole information. Quantitative estimation of porosity, for example, is possible if one can track the lateral extent of a reservoir on a seismic horizon and can derive a good seismic model from borehole calibration that predicts porosity from amplitude variations across the horizon. Such quantitative predictions typically are more feasible and reliable when porosity is relatively high and the bulk and shear moduli of the rock matrix are relatively low.

8.2.3 Flow Surveillance

The third general application of 3D seismic analysis is monitoring changes in pore-fluid composition, pressure, and temperature as fluids flow in a reservoir. This application is often called time-lapse seismic or 4D seismic (the two terms mean the same thing and are used interchangeably by geophysicists). Flow surveillance is possible if one (a) acquires a baseline 3D seismic volume at a point in calendar time, (b) allows fluid flow to occur through production and/or injection with attendant pressure/temperature changes, (c) acquires a second 3D seismic volume sometime after the baseline, (d) observes differences between the seismic character of the two volumes in the reservoir interval, and (e) demonstrates through seismic modeling that the differences are the result of physical changes related to the hydrocarbon recovery process. One must be careful not to vary seismic acquisition and processing parameters drastically between surveys and thereby introduce differences between the seismic data sets that can be mistaken for reservoir effects. One expects that the seismic character of horizons laterally away from and above the reservoir would be virtually identical between the seismic volumes because background geology would be much less affected by production/injection than the reservoir interval. Hence, observing the difference between the volumes highlights reservoir changes caused by depletion. Obviously one can acquire a third or fourth 3D seismic survey and continue the surveillance by comparing successive 3D volumes to one another.

Time-lapse seismology impacts estimation of reserves when an extraction procedure changes a reservoir's properties sufficiently so that a robust response occurs in the seismic data. For example, gas injection to pressurize or flood a reservoir produces an expanding seismic amplitude anomaly around the injection well owing to the same rock physics that causes naturally occurring gas zones to appear as bright seismic amplitudes. In this case, the expansion of the seismic bright spot is directly measurable on successive 3D volumes and clearly shows the movement of the front of the injected gas. Observing where the gas does not flow (i.e., where no seismic amplitude develops) highlights areas of the reservoir that are not being swept by the gas injection.

As a second example, bypassed oil reserves can be spotted on time-lapse seismic when a compartment (fault block or other discrete component of the trap) is unaffected by a drop in reservoir pressure below bubblepoint (i.e., there is no indication on the seismic of gas coming out of solution in that particular compartment at the time in the field's production life when overall field pressure is dropping below bubblepoint). When employed in this manner, time-lapse seismic identifies isolated pools that previously were believed to be part of the field's connected pool or pools.

As a third example, direct detection of the original vs. current depth of the oil/water contact (OWC) in a producing field is easier on time-lapse seismic volumes than on a single 3D volume because injection of cold water at the base of a pool creates a temperature change that can noticeably alter the acoustic impedance of the part of the reservoir swept by the water. This impedance change can be detected by time-lapse seismic comparisons.

In general, the seismic tool is useful in a time-lapse mode as a check on the validity of the assumptions in a reservoir simulation of reserves. Because seismic monitoring is more spatially specific than pressure monitoring, estimation and extraction of reserves can be optimized over time by using the seismic to guide detailed simulations of depletion and to resolve contradictions between the seismic and the reservoir model.

8.3 Uncertainty in Seismic Predictions

Like most predictions in the physical sciences, predictions from 3D seismic data—whether about trap geometry, rock/fluid properties or fluid flow—have an inherent uncertainty. The accuracy of a given seismic prediction is fundamentally dependent on the quality of the seismic data (bandwidth, frequency, signal-to-noise ratio, and optimal processing) and the quality of the seismic model used to tie subsurface control to the 3D volume. A seismic model that is accurately predicting a subsurface parameter or process as judged by drilling results from new wells has demonstrated an ability to reduce uncertainty that can be quantified after several successful predictions. Such a seismic model is far more valuable than an untested seismic model or method, even though the latter may be more sophisticated. Until the new approach demonstrates its worth, it is merely an unproven hypothesis. A non-geophysicist should freely ask a geophysical interpreter about the track record of a given 3D seismic volume in predicting subsurface parameters at new well locations before drilling. The predictive record is the best indicator of the degree of confidence with which one can employ the seismic to estimate reserves and resources as exploration and development proceeds in an area.

The following is a general quantification of the uncertainty in using 3D seismic to estimate reserves and resources. Specific cases should be analyzed individually with the geophysical team member to determine if a project's seismic accuracy is better or worse than these generalities.

8.3.1 GRV of a Trap

Seismic events generally can be picked to an accuracy of 1 millisecond, which can be considered the irreducible uncertainty in defining the vertical closure of a trap when the top seal boundary is pinned at one point by a well and the seismic velocity field is accurately known. At depths shallower than 1500 m, this uncertainty translates to about 2 m of vertical closure; below 3000 m, the uncertainty is about 5 m. Seismic generally cannot reduce uncertainty below these numbers, so a minimum uncertainty in the GRV calculation can be estimated by subtracting these numbers from one's best estimate of closure and then recomputing GRV. Normal 3D seismic data contain some noise and lateral velocity uncertainty, so doubling these numbers (i.e., a 10-m uncertainty at depths greater than 3000 m) is probably appropriate for a general estimate of error. The conversion of this uncertainty in vertical closure into a percentage of GRV obviously is a function of trap geometry. The uncertainty will be a large percentage if vertical closure is small and the trap is laterally extensive. A trap with substantial vertical closure is relatively less impacted by the same absolute error in estimating closure. The uncertainties outlined earlier assume that seismic events are properly correlated across faults offsetting the reservoir. If a geophysicist incorrectly correlates across a fault (skips a cycle), that mistake typically produces an error of the order of 50 to 100 m in vertical closure.

There is also uncertainty in locating the lateral position of the lowest closing contour or bounding fault of a trap. Accurately migrated 3D seismic data generally have a lateral uncertainty of 10 m at depths above 1500 m and 30 m at depths below 3000 m simply owing to picking and spatial sampling. These numbers can be used to perturb the lowest closing contour for a recalculation of GRV and estimation of error if the dip on the seal is less than 30°. If bedding dip is greater or there are significant shallow complications like biogenic gas, then there are likely to be lateral seismic velocity gradients and structural complexities that make seismic migration more difficult. In these cases, doubling the above numbers for lateral uncertainty before recomputing GRV is probably appropriate.

It is important to appreciate that this discussion in Section 8.3.1 addresses estimates of the expected error in predicting depth to a trapping surface at a second location once the trap depth is precisely known at an initial well location. This relative uncertainty is much less than the error in predicting trap depth in an exploration setting prior to the drilling of the first well. That uncertainty generally is tens to hundreds of meters because there is no borehole control on the vertical velocity from the earth's surface down to the trap.

8.3.2 Reservoir Bulk Volume

If the trap volume under the seal is completely filled with reservoir rock, then the GRV of the trap of course is identical to reservoir bulk volume. Generally, this is not the case, and the thickness and geometry of the one or more reservoir units within the trap have to be estimated to derive reservoir bulk volume. The accuracy of the estimate of the thickness of each reservoir is a critical element in assessment of reserves.

Estimation of reservoir thickness is dependent on the bandwidth and frequency content of the seismic data and on the seismic velocity of the reservoir. A broadband, high-frequency wavelet in a shallow clastic section where velocity is relatively slow can resolve a much thinner bed than a ringing, low-frequency wavelet deep in the earth in a fast, carbonate section. Fortunately, geophysicists can analyze seismic and sonic log data to estimate what thicknesses can reasonably be measured for particular reservoirs under investigation. The following are some general guidelines for the minimum reservoir thickness needed in a particular depth interval for the seismic to contain a measurable event at both the top and bottom of the reservoir. Given that the top and bottom of the reservoir are both imaged (i.e., reservoir thickness is greater than the following numbers), the thickness of the reservoir can be directly measured on high-quality 3D seismic data to an accuracy of +/- 20%.

TABLE 8.1	
Depth Below Surface (m)	Minimum Resolvable Reservoir Thickness (m)
0 to 1500	10
1500 to 3000	20
>3000	30

If a reservoir is thinner than these guidelines, the seismic reflections from the top and bottom of the reservoir overlap and interfere with each other to such an extent that the two interfaces have no individual expression. However, because the interference is destructive, there is a continuous decrease in the amplitude of the composite reflection as the reservoir thins, and sometimes the magnitude of the decrease can be directly scaled to thinness. The scaling works best when one has a very accurate synthetic seismogram from a borehole through the reservoir that can be used to calibrate and model the amplitude decrease. Even if no quantitative estimate of thickness is possible, a 3D seismic volume generally contains at least an observable reflection indicating that the reservoir is present until the reservoir gets thinner than 10 to 20% of the numbers in Table 8.1.

Stacked reservoirs in a trap can be individually resolved and separate reservoir bulk volumes can be computed if the reservoirs and their intervening seals individually meet the minimum thickness criteria listed previously. Under these conditions, a deterministic estimate of reserves in each reservoir is possible. When the individual reservoirs and seals are too thin to satisfy these conditions, seismic modeling can be used to get a general idea of how much net pay might be present in a gross trapped volume. These calculations generally are highly uncertain given the many parameters (bed thickness, spacing among beds, porosity, etc.) that can be varied. In this circumstance, a geostatistical estimate of net pay from well data is usually more reliable than a direct estimate of net pay from the seismic data.

8.3.3 Reservoir Properties

The two reservoir properties that 3D seismic can reasonably predict (i.e., the seismic data can be used to assign a probability) under good data conditions are porosity and presence of gas/light-oil saturation.

Porosity can be loosely estimated from the stratigraphic model of the reservoir derived from well data, 3D seismic analysis, and field analogs. By knowing whether the depositional system is fluvial, deltaic, deepwater, or another system, a geoscience team can apply general geologic understanding and predict reservoir porosity to within approximately 5 porosity units. If the team can assemble a good seismic model that predicts porosity directly from some seismic attribute like amplitude variation across the seismic horizon at the top of the reservoir, the uncertainty often can be reduced to the order of 2 porosity units.

As outlined in Section 8.2.2, seismic predictions of gas/light-oil saturation are limited to the presence or absence of hydrocarbons over the areal extent of an amplitude anomaly (i.e., to estimating the risk that the seismic anomaly is a direct hydrocarbon indicator). The technology does not yet exist to convert seismic traces deterministically into quantitative estimates of hydrocarbon saturation with an attendant uncertainty that is small enough to be useful in exploration or field management.

8.4 Seismic Inversion

Standard 3D seismic volumes display seismic amplitude in either travel time or depth. Some geophysicists prefer to convert the standard volumes from seismic amplitude to acoustic impedance (the product of velocity and density) through a process termed inversion. Inversion removes the seismic wavelet from the volume and changes the reflectivity information into an impedance display through either a direct integration or an iterative model-based procedure. It is important to recognize that an inverted 3D volume contains the same basic information as a conventional volume, but the data are displayed in a format that looks like well logs and hence is more familiar to geologists and engineers than seismic traces. Some features in the data may be more obvious or easier to interpret in the inverted format than the conventional format, so there can be value to analyzing the basic seismic information in both formats. The discussions in Sections 8.1 through 8.3 apply to both forms of display. It is very important to appreciate that the computational process of inversion is not robust and can easily produce false and misleading results if the phase and polarity of the original seismic data are not properly understood and handled. The practical result of this sensitivity is that most 3D seismic interpretations are done on standard volumes and not inverted volumes.

8.5 Full-Wavefield Seismic Analysis

Over the past 15 years, geophysicists have expanded the seismic information available for reservoir description and estimation of reserves and resources to include not just standard compressional or P-waves, but also the shear or S-waves that are produced when P-waves are reflected from bed boundaries at non-normal incidence. Using both P-waves and S-waves in an interpretation is generally referred to as full-wavefield or elastic-wave analysis. The splitting of the seismic energy into P-waves and S-waves at a boundary is governed by the angle of incidence of the incoming wave and the Poisson's ratios of the overlying and underlying layers, as well as the acoustic impedances of the layers. Recording and analyzing the S-waves in combination with the P-waves in theory allows a geophysicist to directly compute the elastic moduli of a rock, which ultimately might lead to quantitative determinations of porosity, permeability, and pore-fluid saturation.

Gas or light-oil saturation in particular changes the Poisson's ratio of a reservoir. P-wave 3D seismic data can now be processed to produce one or more volumes that display seismic amplitude as a function of the offset distance between the seismic sources and geophones used in the acquisition of the data. These AVO volumes highlight changes in Poisson's ratio and show distinctive amplitude anomalies when gas or light oil is present in a reservoir. Like bright spots on stacked 3D volumes, AVO anomalies are useful for detecting and mapping the lateral extent and vertical thickness of gas pools. AVO analysis applies more broadly than bright-spot analysis, which is generally confined to relatively shallow sandstone reservoirs in Tertiary basins. AVO is often used to detect hydrocarbons in reservoirs too deeply buried to exhibit a conventional bright-spot response. AVO variations can be modeled if one has both P-wave and S-wave information from a full-waveform sonic log in analogous fashion to computing synthetic seismograms from a conventional P-wave sonic log. A geophysicist can vary reservoir properties in a deterministic fashion to create modeled AVO responses, then compare the models to actual AVO responses in an iterative fashion to obtain a reasonable match. While currently directed at detecting and mapping gas/light-oil saturation, AVO has the potential, with additional research, to substantially improve the ability of the seismic tool to make quantitative estimates of reservoir thickness, lithology, porosity, and hydrocarbon saturation.

A recent and promising development in seismic technology is the recognition that seismic receivers placed on the ocean bottom can record with high fidelity the reflected S-waves generated at reservoir boundaries and hydrocarbon contacts by an incident P-wave. This type of seismic acquisition is called 4-component or 4C because the ocean-bottom receiver contains three orthogonal geophones and one hydrophone. One particular wave that is recorded on this type of seismic system is the seismic arrival that propagates as a P-wave from the ocean bottom to the target horizon and then is converted upon reflection to an S-wave for the return trip from the horizon to the ocean bottom. This PS wave appears to be sensitive to reservoir lithology, oriented fractures and hydrocarbon saturation because the conversion depends on the Poisson's ratio of the reservoir rock/pore-fluid system. In particular, initial field experiments are showing that the PS wave has the capability to directly map OWCs.

Ocean-bottom recording of the full wavefield is also useful for mapping the geometry of traps overlain by gas chimneys. S-waves are not affected by the type of fluid in pore space and propagate through gas chimneys without being attenuated or scattered like P-waves.

As additional research is completed, it is very likely that full-wavefield seismic volumes, perhaps analyzed in a time-lapse mode, will provide reservoir management teams with improved seismic techniques to assess the quantity of oil and gas available for production from a field and to classify a portion of that quantity as Proved.

Additional Reading

Brown, A.R.: *Interpretation of Three-Dimensional Seismic Data*, fifth edition, Memoir 42, AAPG (1999), and *Investigations in Geophysics* 9, SEG (Joint Publication of AAPG and SEG).

Caldwell, J.G.: "Marine Multicomponent Seismic-Acquisition Technologies," paper 10981 presented at the 1999 Offshore Technology Conference, Houston, 3–6 May.

Jack, I.: "Time-Lapse Seismic in Reservoir Management," Distinguished Instructor Series No. 1, SEG (1998).

Morton-Thompson, D., and Woods, A.M.: *Development Geology Reference Manual,* Methods in Exploration Series No. 10, AAPG (1992).

"Reservoir Geophysics," *Investigations in Geophysics* 7, R.E. Sheriff (ed.), SEG (1992).

Chapter 9 Summary

Reserve Recognition Under Production-Sharing and Other Nontraditional Agreements

Claude L. McMichael and E.D. Young

Oil and gas reserves are the fundamental assets of producing companies and host countries alike. Numerous international regulatory bodies have developed standards for reporting reserves within their respective countries.

U.S. Securities and Exchange Commission (SEC)

Historically, the agency that has had the most influence in setting standards for external reserves reporting has been the U.S. Securities and Exchange Commission (SEC). With the agency's wide-spread influence, the SEC definition of proved reserves has become the standard used by most publicly held companies for external reporting purposes. The SEC definition for proved reserves is as follows:

> *"Proved Oil and Gas Reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made."*

While this definition provides technical guidelines for what a company can define as proved reserves, it provides little guidance for when or if a company is entitled to book those reserves. This is particularly confusing with agreements in which reserve ownership and control resides, by law, with the host country rather than with the contractor. To determine when and what can be booked, many companies refer to the SEC Section S-X, Rule 4-10b, "Successful Efforts Method." This definition provides criteria for establishing when an interest in a property exists and, consequently, when reserves can be reported.

> ***SEC Section S-X, Rule 4-10b: Successful Efforts Method***
> *"Mineral Interests in Properties Including:*
> *(i) a fee ownership or lease, concession or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;*
> *(ii) royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others; and*
> *(iii) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the*

underlying reserves (as opposed to being an independent purchaser, broker, dealer or importer). Properties do not include other supply agreements or contracts that represent the right to purchase, rather than extract, oil and gas."

This regulation can be summarized into elements that must be present in an international agreement or contract to allow the recognition and reporting of proved reserves. Those elements that support proved reserves recognition and reporting include the right to extract oil or gas, the right to take volumes in kind, exposure to economic and technical risk, and the opportunity for reward through participation in producing activities.

In addition, the regulations establish specific elements that do not support the recognition and reporting of proved reserves. These include participation that is limited only to the right to purchase volumes, supply or brokerage arrangements, and agreements for services or funding that do not contain aspects of risk and reward or convey a clear mineral interest.

Financial Accounting Standards Board (FASB)

In an effort to promote greater consistency in the interpretation of the SEC regulations and reporting of reserves and financial information, the FASB has prepared numerous standards that amplify and provide useful examples for the interpretation of SEC regulations. The standards relating to reserves reporting and accounting for oil and gas properties include FASB 19, 69, and 121.

U.K. Oil Industry Accounting Committee—Statement of Recommended Practice

For purposes of reserves reporting, the Oil Industry Accounting Committee uses the concept of an "interest". The term is used broadly so as to encompass any rights or obligations associated with licenses or oil and gas reserves. An interest may range from a license to a contractual arrangement related to reserves or future production.

Interpretive Differences

Without the benefit of clear guidelines and definitions, there are many areas of interpretive differences that can result in significant variations in the reserves reported for a given project and contract type.

Production-Sharing Contracts

Production-sharing agreements and contracts cover a wide spectrum of fiscal and contractual terms established by host countries to best meet their sovereign needs. Currently, there is no consistent industry approach or established practice under SEC regulations for recognizing reserves under the wide variety of these types of contracts. In a production-sharing agreement between a contractor and a host government, the contractor typically bears all risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the investment from production (cost hydrocarbons), subject to specific limits and terms. The contractor also receives a stipulated share of the production remaining after cost recovery, referred to as profit hydrocarbons. Ownership is retained by the host government; however, the contractor normally receives title to the prescribed share of the volumes as they are produced. Reserves consistent with the cost recovery plus profit hydrocarbons that are recoverable under the terms of the contract ("entitlement") are typically reported by the upstream contractor.

Risked-Service Contracts

These agreements are very similar to the production-sharing agreements described previously, with the exception of contractor payment. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production. As in the production-sharing contract, the contractor provides the capital and technical expertise required for exploration and development. If exploration efforts are successful, the contractor can recover those costs from the sale revenues and receive a share of profits through a contract-defined mechanism. Under existing SEC regulations, it may be more difficult for the contractor to justify reserves recognition, and special care must be taken in drafting the agreement. Provided that the requirements for reserves recognition are satisfied, reported reserves are typically based on the economic interest held or the financial benefit received.

Under pure service agreements, where the contractor does not bear any market risk, no reserves would generally be attributable to the contractor.

Risk and Reward, Level of Rights

Risk and reward associated with oil and gas production activities stems primarily from the variation in revenues from technical and economic risks. Many companies use exposure to risk in conjunction with the rights that they are assigned to operate and to take volumes in kind to support reserves reporting. Technical risk affects a company's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on the ability to economically recover the in-place hydrocarbons.

Taxes and Reserves

An economic interest typically exists where a taxpayer has a working interest, royalty interest, overriding royalty interest, or other interest that is materially similar. In general, reserves are reported for volumes in which there is a mineral or economic interest, on a pre-tax basis, and after deduction for any royalty owed. Production-sharing or other types of operating agreements normally lay out the conditions and formulas for calculating the share of produced volumes to which a contracting company will be entitled. These volumes are normally divided into cost recovery and profit volumes. The summation of the cost and profit volumes that the contractor will receive through the term of the contract represents the reserves that are normally booked.

In many instances, these agreements may also contain clauses that state that host-country income taxes will be paid by the government or the national oil company on behalf of the contractor. While there is a financial benefit to the contractor for the taxes paid, the hydrocarbons produced to fund the payments are not usually specified and are inferred to come from the government's share of production. The contractor may, therefore, be unable to book reserves for these volumes. However, if the contract recognizes a link between the volumes and the tax payments and satisfies the requirements for a mineral interest, the contractor could potentially book these volumes as reserves, depending on the financial treatment used for revenues and taxes.

Royalty and Reserves

Royalty volumes are normally excluded from reported reserves. Please refer to Chapter 3 in this document for more information on interpretive issues.

Net Working Interest Share
Normally, the reserves reported by a company under a production-sharing contract are the entitlement volumes on a pre-tax basis, or those volumes equivalent to the economic interest in a risked-service contract. In the past, some companies have reported the volumes that correspond to their participation in the agreement without consideration of the specific terms. For example, if the company was the sole participant, 100% of the produced volumes would have been reported. This can dramatically overstate the reserves entitlement, production, and related investment community metrics compared to the information that normally would be reported based on actual fiscal terms and entitlements.

Term Used for Reserves
Normally, reported proved reserves correspond to the volumes that are expected to be produced through the actual term length of the contract. However, if the contract contains an extension clause (at the company's option) or there is reasonable certainty that the contract will be extended (supported by historical precedent), many companies will report volumes related to a longer period. However, assuming that fiscal terms in a negotiated extension will be similar to the initial terms could lead to an overstatement of reserves.

Volumes Reported
Reserves reported under production-sharing contracts (PSCs) are typically the contractor's entitlement, expected to be recovered from the reservoir through the term of the contract. Reserves reported under risked-service agreements are typically those equivalent to the economic benefit derived. They would exclude royalty (except as noted in Chapter 3), flare, and other losses. Injected gas volumes relating to improved recovery processes or gas conservation schemes may also be included in reported reserves, provided that the volumes satisfy all the criteria for gas reserves. However, production, reserves, and related financials must be reported in a consistent and appropriate manner.

Conclusions
Production-sharing and risked-service agreements offer the host country and the contractor alike considerable flexibility in tailoring agreement terms to best meet sovereign and corporate requirements. Under current reporting regulations, it is possible for a company to report reserves without loss of host-country sovereign ownership.

The SEC Section S-X, Rule 4-10b, "Successful Efforts Method," provides criteria required to establish a mineral interest in hydrocarbon reserves. These criteria are widely used throughout the industry to determine when reserves can be reported. However, the distinction between when reserves can and cannot be reported under many service-type contracts may not be clear and may be highly dependent on subtle aspects of contract structure and wording.

Unlike traditional agreements, the cost-recovery terms typically reduce the production (and hence reserves) obtained by a contractor in periods of high price and increase the volumes in periods of low price. While this assures cost recovery, the effect on reserves and investment metrics may be counterintuitive. Consequently, if a few large projects using production-sharing or risked-service agreements form a significant portion of the asset inventory of a company, a significant impact on the company performance indicators may occur if contract terms or product prices change.

Chapter 9
Reserve Recognition Under Production-Sharing and Other Nontraditional Agreements

Claude L. McMichael and E.D. Young

9.1 Summary
Hydrocarbon reserves, and the ability to produce them profitably, are the lifeblood of the upstream petroleum industry. Aggressive competition, ever-sharpening scrutiny by the investment community, and volatile product prices drive companies to search for attractive new exploration and producing venture opportunities that will add the greatest value for a given investment. Production-sharing and other nontraditional agreements have become popular given the flexibility they provide host countries in tailoring fiscal terms to fit their sovereign needs. However, actual agreement terms, including those that relate to royalty payments, cost recovery, profit sharing, and taxes, can have a significant impact on the ability to recognize and report hydrocarbon reserves. This chapter focuses on reserves recognition and reporting under the more common fiscal systems being used throughout the industry. The various types of production sharing, service, and other contracts are reviewed to illustrate their impact on recognition and reporting of oil and gas reserves.

9.2 Introduction
Oil and gas reserves are the fundamental assets of producing companies and host countries alike. They are literally the fuel that drives economic growth and prosperity. When produced and sold, they provide the crucial funding for future exploration and development projects. With the sharpening focus of the investment community on reserves inventories and the value of new reserves that are added each year, many companies are reluctant to undertake a project that does not provide the opportunity to report reserves.

9.3 Regulations, Standards, and Definitions
In defining reserves, it is important to distinguish between the specific regulations that govern the reporting of reserves externally and the internal reporting requirements for technical and business-planning purposes. But what is meant by reserves? The term is used throughout the industry but has many different and often conflicting meanings. The explorationist refers to the reserves of an undrilled prospect, the engineer refers to the reserves of a producing property, the financial analyst refers to the reserves of a company, and governments refer to the reserves of the country. Rarely do all these groups mean the same thing, even though they use the same terms. Before the impact of agreement terms on reserves reporting can be addressed, the term *reserves,* and the various purposes for which reserves are reported, must be defined. A summary of the key regulations, standards, and definitions are given in Figures 9.1 and 9.2. [1–3]

Figure 9.1—Reserves Classification Categories

SEC Regulations and SPE Definitions

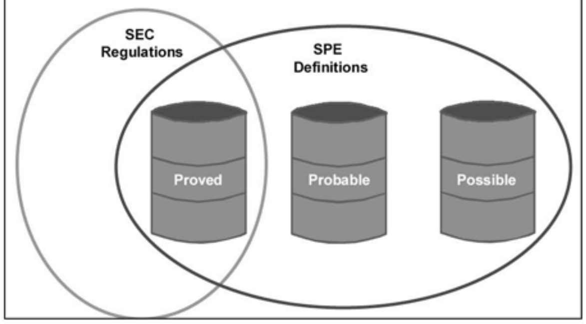


Figure 9.2—Regulations, Standards, and Definitions

- Financial
  - Securities and Exchange Commission (SEC)
    - Section S-X Rule 4-10b
  - Financial Accounting Standards Board
    - Standards 19, 69, 121
  - U.S. Treasury Department
    - Tax Code
  - Host Country Statutes
- Technical
  - Society of Petroleum Engineers
  - World Petroleum Congresses
  - Host Country Technical Definitions

9.3.1 Regulations—U.S. Securities and Exchange Commission

Numerous international regulatory bodies have developed standards for reporting reserves within their respective countries.[4–6] Historically, however, the agency that has had the most influence in setting standards for external reserves reporting has been the U.S. Securities and Exchange Commission (SEC).[4] The SEC regulates all publicly held companies, including those foreign companies whose stock is sold through one of the U.S. stock exchanges. With the exception of government-owned companies, this includes most major oil and gas companies and many of the smaller producing companies. While the SEC acknowledges the existence of unproved properties, hydrocarbon reserves published in the supplementary disclosures in a company's annual report are restricted to only proven volumes. With the agency's widespread influence, the SEC definition of proved reserves has become the standard used by most publicly held companies for external reporting purposes. For that reason, this section considers only the SEC requirements. The SEC definition for proved reserves is as follows:

> *"Proved Oil and Gas Reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made."*

There are difficulties in applying this regulation to many of the agreements evolving today. While it provides technical guidelines for what a company can define as Proved Reserves, it provides little guidance for when or if a company is entitled to book those reserves. This is particularly confusing with agreements in which reserve ownership and control resides, by law, with the host country rather than with the landowner. To determine what can be booked and when, many companies refer to the SEC Section S-X, Rule 4-10b, "Successful Efforts Method."[4] While this section of the regulations primarily addresses the treatment of costs incurred during exploration and producing activities, it does contain a key definition for a mineral interest. This definition provides criteria for establishing when an interest in a property exists and, consequently, when reserves can be reported.

> *SEC Section S-X, Rule 4-10b Successful Efforts Method: "Mineral Interests in Properties. Including:*
> *(i)a fee ownership or lease, concession or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;*

(ii)royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others; and
(iii) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer or importer). Properties do not include other supply agreements or contracts that represent the right to purchase, rather than extract, oil and gas.

9.4 Regulation Summary—Elements Supporting Reserves Reporting

This regulation can be summarized into elements that support proved reserves recognition and reporting. These include:

- The right to extract oil or gas
- The right to take volumes in kind
- Exposure to market and technical risk
- The opportunity for reward through participation in producing activities

In addition, the regulations establish specific elements that do not support the recognition and reporting of proved reserves. These include:

- Participation that is limited only to the right to purchase volumes
- Supply or brokerage arrangements
- Agreements for services or funding that do not contain aspects of risk and reward or convey a clear mineral interest

In many contracts and agreements, there is a wide range of arrangements that have features of property trades, loans, and production purchase contracts. The SEC refers to these as conveyances in Regulation S-X and provides examples for situations where assets are transferred between participants, assets are pooled, or loans are provided in return for the right to purchase volumes. Even though the right to purchase volumes is not sufficient in itself to recognize reserves, examples of purchase arrangements where reserves may be booked are described in SEC S-X 4-10 (h)(5)(i). An example of an asset pooling arrangement is given in clause (h)(5)(ii). These have been excerpted as follows:

> *(h)(1) Certain transactions, sometimes referred to as conveyances, are In substance borrowings repayable in cash or Its equivalent and shall be accounted for as borrowings.*
>
> *5(1) through (4) .Examples of borrowings that are not specifically noted to allow reserve bookings.*
>
> *(5)(i) Some production payments differ In that the seller's obligation is not expressed In monetary terms but as an obligation to deliver, free and clear of all expenses associated with operation of the property, a specified quantify of oil or gas to the purchase out of a specified share of future production. Such a transaction Is a sale of a mineral interest.*

The purchaser of such a production payment has acquired an interest in a mineral property... The estimated oil or gas reserves and production data shall be reported, ...as those of the purchaser of the production payment and not of the seller.

(5)(ii) An assignment of the operating interest in an unproved property with retention of a nonoperating interest in return for drilling, development and operation by the assignee Is a pooling of assets in a joint undertaking... The assignor's cost of the original interest shall become the cost of the interest retained. .... if oil or gas Is discovered, each party shall report Its share of oil and gas reserves.

A key aspect in all these regulations is the element of risk and reward. Many companies use this aspect to differentiate between agreements that would allow reserves to be recognized and those purely for services that would not allow reserves recognition. Risk and reward associated with oil and gas production activities stems primarily from the variation in revenues from technical and economic risks. Technical risk affects a company's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on the ability to economically recover the in-place hydrocarbons. It is highly dependent on the economic environment over the life of the project and fluctuates with the prevailing price and cost structures. It should be noted that risk associated with variations in operating cost alone is not sufficient to fulfill the requirements of risk and reward and allow reserves recognition and reporting.

9.4.1 U.S. Treasury Department

In addition to the concept of a mineral interest in a property that is outlined in the SEC regulations, the U.S. Treasury tax regulations—Sec. 1.611–1(6)(1)—provide a definition for an economic interest. The concept of an economic interest is important for tax purposes and can be used to build logic to support additional reserve recognition under production sharing and other operating agreements. This is covered in more detail next.

U.S. Treasury Regulation Sec. 1.611–1(6)(1): An economic Interest is possessed in every case in which the taxpayer has acquired by investment any Interest in mineral in place... and secures, by any form of legal relationship, income derived from the extraction of the mineral.... to which he must look for a return of his capital.

9.4.2 Taxes and Reserves

An economic interest typically exists where a taxpayer has a working interest, royalty interest, overriding royalty interest, or other interest that is materially similar. In general, reserves are reported for volumes in which there is a mineral/economic interest, on a pre-tax basis, after deduction for any royalty owed. Production sharing or other types of operating agreements lay out the conditions and formulas for calculating the share of produced volumes to which a contracting company will be entitled. These volumes are normally divided into cost recovery and profit volumes. The summation of the cost and profit volumes that the contractor will receive through the term of the contract represents the reserves that are normally booked.

In many instances, these agreements may also contain clauses that state that host-country income taxes will be paid by the government or the national oil company on behalf of the contractor. While there is a financial benefit to the contractor for the taxes paid, the hydrocarbons produced to fund the payments are not usually specified and are inferred to come from the government's share of production. The contractor may, therefore, be unable to book reserves for these volumes. However, if the contract recognizes a link between the volumes and the tax payments and satisfies the requirements for a mineral interest, the contractor could potentially book these volumes as reserves depending on the financial treatment used for revenues and taxes.

9.4.3 Royalty and Reserves

Royalty volumes are normally excluded from reported reserves. Please refer to Chapter 3 in this volume for more information on interpretive issues.

9.4.4 Accounting Standards

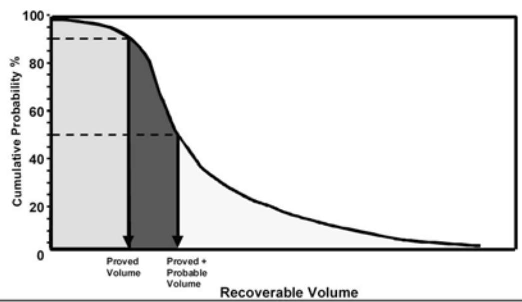
Financial Accounting Standards Board (FASB). FASB has used the concept of a mineral interest in properties to develop an additional class of fiscal arrangements known as Mineral Property Conveyances and Related Transactions. A mineral interest in a property is frequently conveyed to others for a variety of reasons, including the desire to spread risks, to obtain financing, to improve operating efficiency, and to achieve tax benefits. Conveyances of those interests may involve the transfer of all or a part of the rights and responsibilities of operating a property or an operating interest. The transferor may or may not retain an interest in the oil and gas produced that is free of the responsibilities and costs of operating the property (a nonoperating interest). A transaction may, on the other hand, involve the transfer of a nonoperating interest to another party and retention of the operating interest.

> *Certain transactions, sometimes referred to as conveyances, are in substance borrowings repayable in cash or its equivalent and shall be accounted for as borrowings and do not qualify for the recognition and reporting of oil and gas reserves. These include:*
>
> > *1) a) Cash advances to operators to finance exploration in return for the right to purchase oil or gas discovered. b) Funds advanced for exploration that are repayable by offset against purchases of oil or gas discovered, or in cash if insufficient oil or gas is produced by a specified date.*
> >
> > *2) Funds advanced to an operator that are repayable in cash out of the proceeds from a specified share of future production of a producing property, until the amount advanced plus interest at a specified or determinable rate is paid in full, shall be accounted for as a borrowing and do not qualify for the recognition of reserves. The advance is a payable for the recipient of the cash and receivable for the party making the advance. Such transactions fall into a category commonly referred to as production payments.*

Other transactions convey a mineral interest and may be used for the recognition and reporting of oil and gas reserves. These types of conveyances differ from those described above in that the seller's obligation is not expressed in monetary terms but as an obligation to deliver, free and clear of all expenses associated with operation of the property, a specified quantity of oil or gas to the purchaser out of a specified share of future production. Such a transaction is a sale of a mineral interest for which the seller has a substantial obligation for future performance. The purchaser of such a production payment has acquired an interest in a mineral property that shall be recorded at cost and amortized by the unit-of-production method as delivery takes place. The related reserve estimates and production shall be reported as those of the purchaser of the production payment and not of the seller.

U.K. Oil Industry Accounting Committee—Statement of Recommended Practice. For purposes of recognition and reporting of reserves, the Oil Industry Accounting Committee uses the concept of commercial reserves.[7]

Figure 9.3—U.K. Proven and Probable Reserves



Commercial reserves may, at a company's option, be taken as either (a) proved and probable oil and gas reserves (see Figure 9.3) or (b) proved developed and undeveloped oil and gas reserves, as defined in this section. These alternative definitions are mutually exclusive, and the option chosen must be applied consistently with respect to all exploration and development activities.

> *Proven and probable oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty (see below) to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 per cent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50 per cent statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proven and probable reserves are 90 per cent and 10 per cent respectively.*
>
> *Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon reasonable assessment of the future economics of such production, a reasonable expectation that there is a market for all or substantially all the expected hydrocarbon production, and evidence that the necessary production, transmission and transportation facilities are available or can be made available.*
>
> > *(I) Reserves may only be considered proven and probable if producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proven includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically*

productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(II) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proven and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

Proved developed and undeveloped oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as at the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not of escalations based upon future conditions.

(I) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information of fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

For purposes of reporting oil and gas reserves, the U.K. Oil Industry Accounting Committee uses the concept of an “Interest”. The term is used broadly so as to encompass any rights or obligations associated with licenses or oil and gas reserves. An interest may range from those held as licenses to those constituted by contractual arrangements related to reserves or future production. Of those included in the list of transactions, the following are of particular interest within the context of this chapter. They are carried interest, production-sharing agreements and net profit interests, forward sales, production loans, and project finance.

9.5 Interpretive Differences

Without the benefit of clear guidelines and definitions, there are many areas of interpretive differences that can result in significant variations in the reserves reported for a given project and contract type.

9.6 Agreements and Contracts

Agreements and contracts cover a wide spectrum of fiscal and contractual terms established by host countries to best meet their sovereign needs. Currently, there is no consistent industry approach or established practice under SEC regulations for recognizing reserves under the wide variety of these contracts.

Figure 9.4—Classification of Petroleum Fiscal System

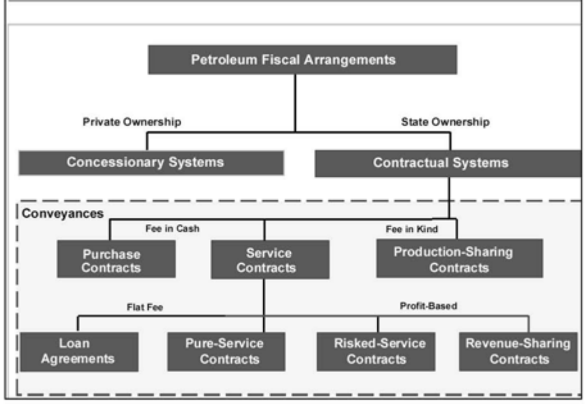
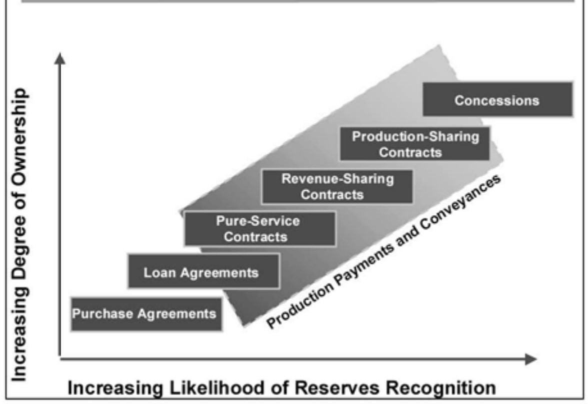


Figure 9.5—Spectrum of Petroleum Fiscal Systems



The purpose of this section is to promote consistency in the approaches and to foster the development of generally accepted practices for recognition and reporting of reserves under the wide range of contract types encountered. This chapter follows the classification system template proposed by Johnston (see Figure 9.4).[8,9] This template has also been expanded to include three additional types of agreements; purchase agreements, loan agreements, and production payments and conveyances. The expanded template of agreement types along with their ranking in terms of the ability to recognize and report reserves is shown in Figure 9.5. Key aspects of each type of agreement are summarized in Table 9.1.

Table 9.1—Contract Summary

Contract Type	Ownership	Payment	Reserves
Concession	Contractor	In-Kind	Yes
Production Share	Contractor (When Produced)	In-Kind	Yes
Revenue Share	Government	Share of Revenue	Yes
Risked Service	Government	Fee-Based	Likely
Pure Service	Government	Fee-Based	No
Purchase	Government	Product Cost	No
Loan	Government	Interest	No
Conveyance	Government	Production Pmnt	Likely

9.6.1 Concessions, Mineral Leases, and Permits

Historically, leases and concessions have been the most commonly used agreements between oil companies and governments or mineral owners. In such agreements, the host government or mineral owner grants the producing company the right to explore for, develop, produce, transport, and market hydrocarbons or minerals within a fixed area for a specific amount of time. The concession and production and sale of hydrocarbons from the concession is then subject to rentals, royalties, bonuses, and taxes. Under these types of agreements, the company typically bears all risks and costs for exploration, development, and production and generally would hold title to all resources that will be produced while the agreement is in effect. Reserves consistent with the net working interest (after deduction of any royalties owned by others) that can be recovered during the term of the agreement are typically reported by the upstream contractor. Ownership of the reserves producible over the term of the agreement is normally taken by the company; however, if the contract is voided for any reason, ownership reverts back to the mineral owner or government.

9.6.2 Production-Sharing Contracts

In a production-sharing agreement between a contractor and a host government, the contractor typically bears all risks and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the investment from production (cost hydrocarbons), subject to specific limits and terms. The contractor also receives a stipulated share of the production remaining after cost recovery (profit hydrocarbons). Ownership is retained by the host government; however, the contractor normally receives title to the prescribed share of the volumes as they are produced. Reserves consistent with the cost recovery plus profit hydrocarbons that are recoverable under the terms of the contract are typically reported by the upstream contractor. A simplified schematic indicating the distribution of yearly project production between contractor and government is shown in Figure 9.6.

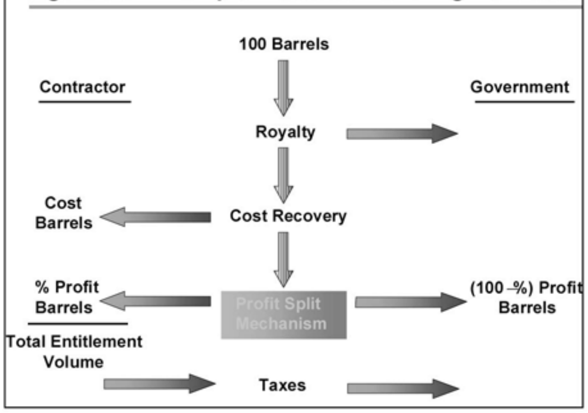


Figure 9.6—Example Production-Sharing Contract

9.6.3 Revenue-Sharing/Risked-Service Contracts

Revenue-sharing contracts are very similar to the production-sharing contracts described earlier, with the exception of contractor payment. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production. As in the production-sharing contract, the contractor provides the capital and technical expertise required for exploration and development. If exploration efforts are successful, the contractor can recover those costs from the sale revenues. A simplified schematic showing the distribution of yearly project revenue between contractor and government is shown in Figure 9.7. A very similar type of agreement is commonly known as a risked-service contract. This type of agreement is also often used where the contracting party provides expertise and capital to rehabilitate or institute improved recovery operations in an existing field. Provided that the requirements for reserves recognition are satisfied, reported reserves are typically based on the economic interest held or the financial benefit received, as shown in Figure 9.8.

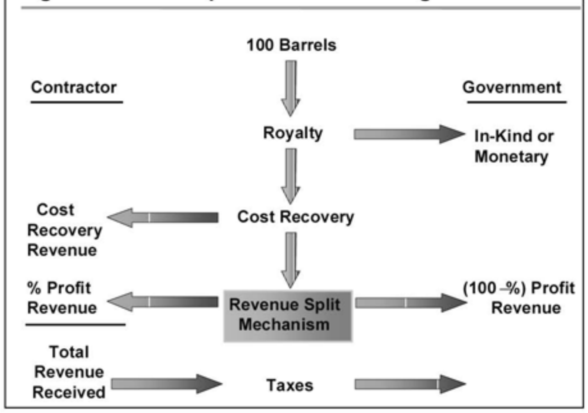


Figure 9.7—Example Revenue-Sharing Contract

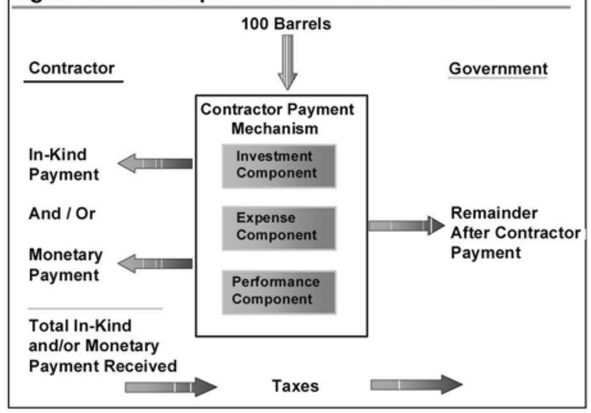


Figure 9.8—Example Risked-Service Contract

Under the existing regulations, it may be more difficult for the contractor to justify reserves recognition, and special care must be taken in drafting the agreement. If regulations are satisfied, reserves equivalent to the value of the cost-recovery-plus-revenue-profit split are normally reported by the contractor.

9.6.4 Pure-Service Contracts

A pure-service contract is an agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific period of time. The service company investment is typically limited to the value of equipment, tools, and personnel used to perform the service. In most cases, the service contractor's reimbursement is fixed by the terms of the contract with little exposure to either project performance or market factors. Payment for services is normally based on daily or hourly rates, a fixed turnkey rate, or some other specified amount. Payments may be made at specified intervals or at the completion of the service. Payments, in some cases, may be tied to the field performance, operating cost reductions, or other important metric.

Risks of the service company under this type of contract are usually limited to nonrecoverable cost overruns, losses owing to client breach of contract, default, or contract dispute. These agreements generally do not have exposure to production volume or market price; consequently, reserves are not usually recognized under this type of agreement. A simplified schematic showing the distribution of yearly project revenue between contractor and government is shown in Figure 9.9.

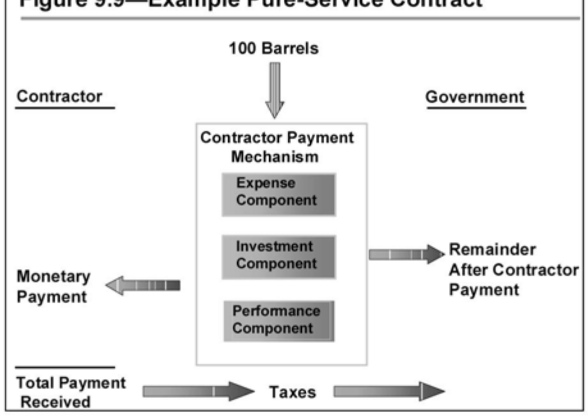


Figure 9.9—Example Pure-Service Contract

9.6.5 Loan Agreements

A loan agreement is typically used by a bank, other financial investor, or partner to finance all or part of an oil and gas project. Compensation for funds advanced is limited to a specified interest rate. The lender does not participate in profits earned by the project above this interest rate. There is normally a fixed repayment schedule for the amount advanced, and repayment of the obligation is usually made before any return to equity investors. Risk is limited to default of the borrower or failure of the project. Variations in production, market prices, and sales do not normally affect compensation. Reserves are not recognized under this type of agreement.

9.6.6 Production Loans, Forward Sales, and Similar Arrangements

There are a variety of forms of transactions that involve the advance of funds to the owner of an interest in an oil and gas property in exchange for the right to receive the cash proceeds of production, or the production itself, arising from the future operation of the property. In such transactions, the owner almost invariably has a future performance obligation, the outcome of which is uncertain to some degree. Determination as to whether the transaction represents a sale or financing rests on the particular circumstances of each case.

If the risks associated with future production, particularly those related to ultimate recovery and price, remain primarily with the owner, the transaction should be accounted for as financing or contingent financing. In such circumstances the repayment obligation will normally be defined in terms of cash or cash equivalent. If the risks associated with future production, particularly those related to ultimate recovery and price, rest primarily with the purchaser, the transaction should be accounted for either as a contingent sale or as a disposal of fixed assets. Oil and gas reserves recognition and reporting should follow the relevant accounting treatment.

9.6.7 Carried Interest

A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the pre-production costs of another party (the carried party) on a license in which both own a portion of the working interest. This arises when the carried party is either unwilling to bear the risk of exploration or is unable to fund the cost of exploration or development directly. Owners may enter into carried interest arrangements with existing or incoming joint venture partners at the exploration stage, the development stage, or both.

If the exploitation of the property is successful, then the carrying party will be reimbursed either (a) in cash out of the proceeds of the share of production attributable to the carried party, or (b) by receiving a disproportionately high share of the production until the carried costs have been recovered. If the project is unsuccessful, the carrying party may not be reimbursed for all or part of the costs that it has incurred on behalf of the owner. Such arrangements represent, in the case of a cash reimbursement, contingent repayable financing and, in the case of reimbursement, by an increased share of production and the acquisition of additional reserves.

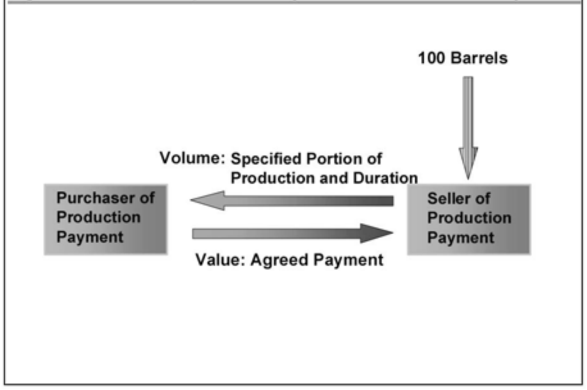
9.6.8 Purchase Contracts

A contract to purchase oil and gas provides the right to purchase a specified volume at an agreed price for a defined term. Under purchase contracts, exposure to technical and market risks are borne by the seller. While a purchase or supply contract can provide long-term access to reserves through production, it does not convey the right to extract, nor does it convey a financial interest in the reserves. Consequently, reserves would not be recognized under this type of agreement.

9.6.9 Production Payments and Conveyances

In addition to the contracts and agreements noted previously, there are a wide range of arrangements that have features of property trades, loans, and production purchase contracts. The SEC refers to these as production payments and conveyances in the Successful Efforts Method of accounting. The SEC highlights where assets are transferred between participants, assets are pooled, or loans are provided in return for the right to purchase volumes. In certain cases, reserves may be recognized by purchaser. An example of a typical conveyance is given in Figure 9.10.

Figure 9.10—Example Conveyance—Production Payment



9.7 Example Cases

9.7.1 Base Case Example

For purposes of explanation, the base case is a 500 million-bbl oil field, of which 400 million bbl are considered Proved. The contract provides for an initial exploration period and extends 20 years from the start of production. The general field data is summarized in Table 9.2. The production forecast is based on the proved reserves with the remaining 100 million bbl of unproved reserves in enhanced recovery projects and contract extensions. The total project production forecast and full-life cost summary are shown in Table 9.3.

Table 9.2—Example Field

Field Information Summary

Field Size	500 million bbl
Production During PSC	400 million bbl
Exploration Cost	$150 million
Drilling Cost	$200 million
Development Cost	$250 million
Fixed Operating Cost	$600 million
Variable Operating Cost	$0.55 / bbl

Table 9.3—Project Production and Cost Schedule

Year	Annual Oil Production (million bbl)	Expiration Costs ($ MM)	Capital ($ MM)	Drilling ($ MM)	Op. Cost ($ MM) Fixed	Op. Cost ($ MM) Variable	Total
1	0.0	100	0	0	0	0	100.0
2	2.7	50	35	40	30	1.5	156.5
3	11.5	0	123	60	30	6.3	219.3
4	19.9	0	92	100	30	10.9	232.9
5	30.4	0	0	0	30	16.7	46.7
6	33.3	0	0	0	30	18.3	48.3
7	34.5	0	0	0	30	19.0	49.0
8	34.7	0	0	0	30	19.1	49.1
9	31.3	0	0	0	30	17.2	47.2
10	28.1	0	0	0	30	15.5	45.5
11	25.3	0	0	0	30	13.9	43.9
12	22.8	0	0	0	30	12.5	42.5
13	20.5	0	0	0	30	11.3	41.3
14	18.5	0	0	0	30	10.2	40.2
15	16.6	0	0	0	30	9.1	39.1
16	14.9	0	0	0	30	8.2	38.2
17	13.5	0	0	0	30	7.4	37.4
18	12.1	0	0	0	30	6.7	36.7
19	10.9	0	0	0	30	6.0	36.0
20	9.8	0	0	0	30	5.4	35.4
21	8.8	0	0	0	30	4.9	34.9
Total	400.0	150	250	200	600	220.0	1420.0

Production startup is midyear in the second year of the project and builds to a peak rate of 95.0 TBOPD (34.7 million bbl annualized) in the eighth year. Project exploration costs are U.S. $150 million for exploratory drilling. No bonus payment is required in this case. The total development costs are U.S. $450 million for both project development and drilling. Operating costs are comprised of a fixed cost of U.S. $30 million per year and a variable cost of U.S. $0.55/bbl during the peak period.

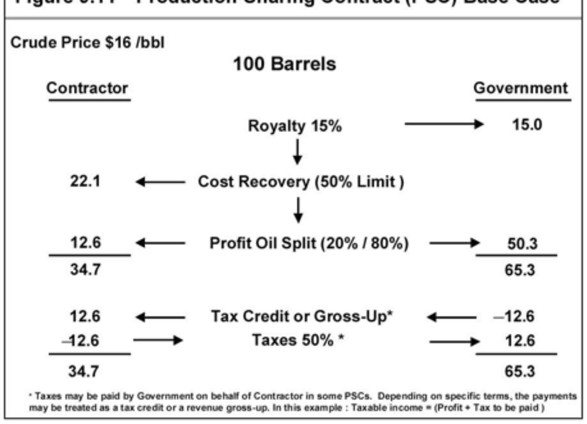
The impact on contractor reserves will be evaluated in the following paragraphs assuming that the project is undertaken as a production-sharing contract, risked-service contract, and a conveyance. In each case, the impact of the various contract terms, crude prices, and tax treatments will be evaluated.

9.7.2 Production-Sharing Contract Terms—Normal Tax Treatment

The example contract was derived from several existing production-sharing agreements, which contain the most common contractual terms affecting the industry today. These include bonus payments, royalty payments, limitations on the revenue available for cost sharing, a fixed profit-share split, and income taxes. The example case is a typical production-sharing agreement in which the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers investments and operating expenses out of the gross production stream and is entitled to a share of the remaining profit oil. The contractor receives payment in oil production and is exposed to both technical and market risks.

The general terms of the contract are shown in Figure 9.11. The contract is for a 20-year production term with the possibility of an extension until project termination. The terms include a royalty payment on gross production of 15%. Yearly cost recovery is limited to a maximum of 50% of the annual gross revenue, with the remaining cost carried forward to be recovered in future years. The contractor's profit share is a based on a simple split: 20% to the contractor and 80% to the host government after applying a production sliding scale that is limited to 80% of net recovery.

Figure 9.11—Production-Sharing Contract (PSC) Base Case



Contractor Yearly Entitlement Calculation. The terms of a production-sharing contract determine the contractor's yearly entitlement or share of the project production based on the yearly cost recovery and profit split. The anticipated production, investment, and cost profile for the project is shown in Table 9.3. The calculation of the contractor's revenue entitlement for the peak year with 34.72 million bbl of production is shown in Table 9.4. At U.S. $16/bbl, the gross revenue from 34.72 million bbl in Year 8 is U.S. $556 million. At a royalty rate of 15%, the government would receive as royalty U.S. $83 million before cost recovery or profit split. The remaining U.S. $472 million would remain for cost recovery and profit split according to the terms of the contract. In the base case, revenue available for cost recovery is limited to 50% after royalty, or U.S. $236.57 million.

Costs and expenses for the peak year total U.S. $67.50 million, including costs carried forward from previous years. The yearly costs are fully recoverable. In case of unrecovered costs, they would be carried forward by the contractor for recovery in future years. The remaining revenue after royalty and cost recovery is shared by the contractor and government according to the contract profit split. In this case, the contractor's profit share is U.S. $80.95 million, or 20% of the available revenue. The contractor's revenue entitlement is the sum of the contractor's cost recovery and profit.

Table 9.4—Project Cost and Profit-Share Schedule

Year	Total Recoverable Current Year Costs ($MM)	Costs Carried Forward ($MM)	Total Contractor Costs Recovered ($MM)	Revenue Available For Profit Sharing ($MM)	Excess Cost Revenue Available For Sharing ($MM)	Total For Sharing ($MM)	Contractor Profit Share ($MM)	Total Contractor Cost +Profit ($MM)	Contractor Share %	Contractor Reserves (MMBO)
1	20.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.0
2	108.48	110.19	18.28	18.28	0.00	18.28	3.66	21.94	51.0	1.4
3	157.90	190.19	77.91	77.91	0.00	77.91	15.58	93.49	51.0	5.8
4	220.93	275.97	135.15	135.15	0.00	135.15	27.03	162.18	51.0	10.1
5	126.72	195.99	206.70	206.70	0.00	206.70	41.34	248.04	51.0	15.5
6	108.33	77.75	226.57	226.57	0.00	226.57	45.31	271.89	51.0	17.0
7	91.97	0.00	169.71	234.52	64.81	299.33	59.87	229.58	41.6	14.3
8	67.50	0.00	67.50	236.11	168.61	404.73	80.95	148.44	26.7	9.3
9	47.19	0.00	47.19	212.50	165.31	377.81	75.56	122.75	24.5	7.7
10	45.47	0.00	45.47	191.25	145.78	337.03	67.41	112.88	25.1	7.1
11	43.92	0.00	43.92	172.13	128.20	300.33	60.07	103.99	25.7	6.5
12	42.53	0.00	42.53	154.91	112.38	267.30	53.46	95.99	26.3	6.0
13	41.28	0.00	41.28	139.42	98.14	237.57	47.51	88.79	27.1	5.5
14	40.15	0.00	40.15	125.48	85.33	210.81	42.16	82.31	27.9	5.1
15	39.13	0.00	39.13	112.93	73.80	186.73	37.35	76.48	28.8	4.8
16	38.22	0.00	38.22	101.64	63.42	165.06	33.01	71.23	29.8	4.5
17	37.40	0.00	37.40	91.47	54.08	145.55	29.11	66.51	30.9	4.2
18	36.66	0.00	36.66	82.33	45.67	128.00	25.60	62.26	32.1	3.9
19	35.99	0.00	35.99	74.09	38.10	112.20	22.44	58.43	33.5	3.7
20	35.39	0.00	35.39	66.68	31.29	97.98	19.60	54.99	35.0	3.4
21	34.85	0.00	34.85	60.02	25.16	85.18	17.04	51.89	36.7	3.2
Total	1420.00		1420.00	2720.10	1300.10	4020.20	804.04	2224.05	34.8	139.0

In the base case, the calculated average contractor share in Year 8 is U.S. $148.44 million, or about 27% of the project gross revenue. Because the cost and revenue vary yearly, the calculated entitlement applies only to the year in question. In addition, in the base case, the contractor is obligated to pay income tax out of his share of the profit, which totals U.S. $40.48 million at the tax rate of 50%.

Contractor Reserves Calculations. The above calculation represents the contractor's share of the yearly project revenue. In production-sharing contracts, however, the contractor usually takes payment in kind, and the cost and profit share must be converted to an equivalent volume of the production. While the crude price may vary over the year, for purposes of this calculation, the year-end crude price will be used to maintain consistency with the SEC regulations. The contractor's crude entitlement is equal to the profit share before tax plus cost recovery oil divided by the year-end crude price. For the example, in the case where the year-end crude price is U.S. $16/bbl, the contractor's yearly entitlement is 6.3 million bbl.

This calculation provides only the contractor's share of the yearly production for the year in question. Because reserves represent ultimate future recovery from the project, forecasts of future production, investments, and operating expenses are required and forecasted future yearly entitlements are calculated. The contractor's reserves are obtained by the summation of the estimated yearly volume entitlements over the remaining life of the project. Table 9.4 shows the forecasted entitlements from project initiation to project termination. They were calculated with the forecasted production schedule, exploration bonus and drilling costs, the anticipated project investment schedule, and the forecasted operating expense through the life of the project. For this case, the revenue calculation assumes a constant year-end crude price of U.S. $16/bbl. The contractor's proved reserves are estimated at 139 million bbl, or 34.8% of the total project proved of 400 million bbl.

Crude-Price Sensitivity. Clearly, contractor reserves are highly sensitive to the assumed production schedule, crude-price projections, and cost forecasts. The most volatile of these factors is the crude price. Table 9.5 demonstrates the volatile relationship between crude price and contractor reserves. For a U.S. $2/bbl decrease in crude price, the contractor's reserves increase from 139 million bbl to 149 million bbl. Such swings in reserves can be expected when using volatile year-end crude prices. The contractor's actual ultimate recovery will, however, be determined by the weighted average crude price over the project life, and the use of year-end pricing for future periods introduces an unavoidable error in the reserves forecasts.

Table 9.5—Base Case, Oil Price, and Tax Sensitivity

	Low Case $14 Oil Price			Base Case $16 Oil Price			High Case $18 Oil Price		
Parameter Measured	Normal Tax	Carried Tax	Carried Tax With Gross Up or Credit	Normal Tax	Carried Tax	Carried Tax With Gross-Up or Credit	Normal Tax	Carried Tax	Carried Tax With Gross-Up or Credit
Reserves (million bbl)	149	149	197	139	139	189	131	131	183
Cost of Finding & Dev. ($/bbl)	$4.02	$4.02	$3.05	$4.32	$4.32	$3.17	$4.58	$4.58	$3.27
Profit/bbl ($/bbl)	$4.48	$4.48	$6.79	$5.78	$5.78	$8.50	$7.17	$7.17	$10.25
Production Costs ($/bbl)	$5.50	$5.50	$4.17	$5.90	$5.90	$4.33	$6.25	$6.25	$4.47
Net Production Income ($/bbl)	$2.24	$4.48	$3.39	$2.89	$5.78	$4.25	$3.58	$7.17	$5.13
NPV@10%(FASB) ($MM)	$7.34	$123.78	$123.78	$42.72	$183.30	$183.30	$76.07	$241.02	$241.02
SMOG/BBL ($/bbl)	$0.05	$0.83	$0.63	$0.31	$1.32	$0.97	$0.58	$1.84	$1.31
Contractor IRR	10.5%	16.7%	16.7%	12.8%	20.1%	20.1%	15.1%	23.3%	23.3%

Alternative Reserves Calculation. The above reserves calculation is general and can be used for production-sharing contracts at all levels of project maturity. It accounts for varying yearly investment levels and the relative relationship between project costs and project revenue. In a mature project, where the relationship between project costs and project revenue is relatively constant, some companies simplify the process by assuming that the reserves share is equal to an average entitlement percentage. In general, this approach is believed to be sufficiently accurate, and any error made by the assumption is more than offset by the error in production, cost, and crude-price forecasts (where defined by sales contract).

9.7.3 Production-Sharing Contract—Carried Tax Treatment

In the normal case, the contractor is obligated to pay income tax out of his share of the project profit. In such cases, the contractor's tax obligation impacts the project's economic performance but has no impact on the reserve calculations because reserves are calculated on a before-tax basis. In some production-sharing agreements, however, the government or state-owned oil company agrees to pay tax on behalf of the contractor. Depending on the terms and wording of the agreements, these taxes may or may not be recognized for purposes of the contractor's U.S. tax obligation. If a mineral interest cannot be demonstrated, they cannot be considered part of the contractor's reserves, and the carried tax reserves will equal those obtained in the normal tax case as shown in Table 9.5.

If, under the terms of the contract the contractor derives a benefit from and an economic/mineral interest in the hydrocarbon volumes used to fund the tax payments, those payments may be considered as the contractor's reserves. The impact on both the project financial indicators and reserves is shown in Table 9.5. The contractor's cost recovery and profit share are computed in the standard fashion, but instead of the being the contractor's entitlement before tax, they may now be viewed as the net entitlement after tax. The revenue entitlement before tax must be grossed up by an amount equal to the tax paid on the contractor's behalf. The implied contractor entitlement then becomes the summation of the cost recovery, contractor profit share, and the tax paid on behalf of the contractor. If these payments are recognized for U.S. tax purposes, the implied volumes associated with the payments may then be acceptable for inclusion in the contractor's reserves reporting to U.S. authorities. With carried tax, the contractor's base-case reserves increase by 50 million bbl to 189 million bbl.

9.7.4 Risked-Service Contract

Service contracts are based on the principle that the contractor is hired or contracted to perform exploration and/or production operations on behalf of the government or state oil company. With the risked-service contract used in this example, the contractor makes the necessary exploration and development investments, performs as operator of the field, and is responsible for expenses related to operating the field. In return, the contractor is entitled to cost recovery as specified by the terms of the contract and is paid a fee for service in accordance with a formula specified in the contract. Whether such an agreement entitles the contractor to book reserves from the project remains in question. This answer depends on the degree to which the contractor acts as producer of the hydrocarbons, has access to those hydrocarbons, is exposed to both technical and market risk, and has the opportunity for reward through participation in the producing activities; the answer also depends on whether a clear mineral interest has been established. For purposes of this study, a variation of the base case will be used in which revenue profit sharing is replaced by a service fee (see Figure 9.12). The contractor will act as the producer, but ownership of the produced crude will be retained by the host government or state-owned company.

Numerous service-fee arrangements exist across the industry. The nature of these arrangements is critical in determining the contractor's ability to recognize reserves from the project. Service fees range from fixed fees for service that are independent of the project's production and financial performance to those that are directly tied to the contractor's ability to enhance production and financial performance. In this example, the service fee is based on a sliding scale that is based on project production. The contractor acts as producer and delivers the crude to the government at a designated transfer point.

Figure 9.12—Risked-Service Contract

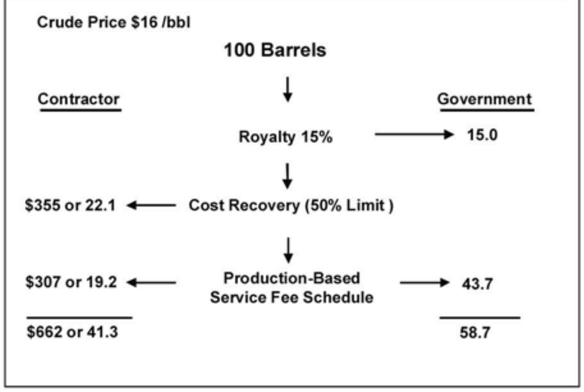


Table 9.6—Fixed and Production-Dependent Terms

Production Level	Tranch: #1	#2	#3	#4	#5
Production Level (TBD)	15.0	30.0	45.0	60.0	60+
Royalty	15.0%	15.0%	15.0%	15.0%	15.0%
Profit Split	20.0%	17.5%	15.0%	12.5%	10.0%
Tax Rate	50.0%	50.0%	50.0%	50.0%	50.0%
Service Fee	30.0%	25.0%	23.0%	20.0%	18.0%
Variable Operating Cost ($/bbl)	$0.55	$0.55	$0.55	$0.55	$0.55

Contractor Yearly Revenue. Contractor cost recovery is calculated as in the production-sharing example. Reimbursement for costs is in the currency stipulated in the contract and may be taken in kind. The contractor service fee represents a share of the project profit. The service-fee calculation is shown in Table 9.6. The contractor percentage is based on a sliding scale and ranges from a high of 30% on the first 15,000 BOPD of production to a minimum of 18% on all production over 60,000 BOPD. The average fee over the life of the project is 22%. Annual contractor service-fee revenue over the life of the project is shown in Table 9.7.

Table 9.7—Service-Fee Calculation

Year	Annual Production (MM bbl)	Daily Oil Production (M bbl)	Production Costs ($/bbl)	Development and Production Costs ($MM)	Prod.-Based "R" Factor	Service Fee ($MM)
0	0.00	0.00	0.00	0.00	0.30	$0.00
1	0.00	0.00	0.00	100.00	0.30	$10.00
2	2.69	7.37	11.71	156.48	0.30	$19.11
3	11.46	31.39	3.17	219.30	0.23	$55.74
4	19.87	54.45	2.06	232.93	0.20	$78.71
5	30.40	83.28	1.54	46.72	0.18	$83.80
6	33.32	91.29	1.45	48.33	0.18	$92.09
7	34.49	94.49	1.42	48.97	0.18	$95.41
8	34.72	95.13	1.41	49.10	0.18	$96.07
9	31.25	85.62	1.51	47.19	0.18	$86.23
10	28.13	77.05	1.62	45.47	0.18	$77.36
11	25.31	69.35	1.74	43.92	0.18	$69.39
12	22.78	62.41	1.87	42.53	0.18	$62.21
13	20.50	56.17	2.01	41.28	0.20	$61.48
14	18.45	50.56	2.18	40.15	0.20	$55.03
15	16.61	45.50	2.36	39.13	0.20	$49.23
16	14.95	40.95	2.56	38.22	0.23	$50.04
17	13.45	36.86	2.78	37.40	0.23	$44.64
18	12.11	33.17	3.03	36.66	0.23	$39.79
19	10.90	29.85	3.30	35.99	0.25	$38.19
20	9.81	26.87	3.61	35.39	0.25	$33.92
21	8.83	24.18	3.95	34.85	0.25	$30.08
Total	400.00			1420.00		1228.50

Reserves Entitlements. The key question remaining is whether the contractor is entitled to book and report a portion of the project reserves. The question centers around the extent to which the contractor is exposed to financial risk, acts as the producer of the hydrocarbons, and is exposed to market risk and rewards. In the previous case, the contractor is responsible for exploration and field development, acts as the producer, and has a service fee that is dependent on project profit and production. The contractor does control the crude before the transfer point and satisfies several of the requirements for establishing a mineral interest as defined by the FASB and SEC. In general, most companies would conclude that proved reserves could be reported in this case for the combined cost recovery and fee amounts, which equate to 165 million bbl, as shown in Table 9.8. Other fee arrangements also tend to support the booking of reserves. One in particular would be a fee based on a per-barrel nominal payment with full cost recovery. In both cases, the financial risks and rewards of the contractor are strongly tied to market factors.

Table 9.8—Contractor Reserves Calculation

Year	Contractor Cost Recovery ($MM)	Service Fee ($MM)	Contractor Profit Share ($MM)	Crude Price ($/bbl)	Contractor Reserves (MMbbl)
0	0.00	0.00	0.00	16.00	0.00
1	0.00	10.00	0.00	16.00	0.63
2	18.28	19.11	0.00	16.00	2.34
3	77.91	55.74	0.00	16.00	8.35
4	135.15	78.71	0.00	16.00	13.37
5	206.70	83.80	0.00	16.00	18.16
6	226.57	92.09	0.00	16.00	19.92
7	188.11	95.41	0.00	16.00	17.72
8	49.10	96.07	0.00	16.00	9.07
9	47.19	86.23	0.00	16.00	8.34
10	45.47	77.36	0.00	16.00	7.68
11	43.92	69.39	0.00	16.00	7.08
12	42.53	62.21	0.00	16.00	6.55
13	41.28	61.48	0.00	16.00	6.42
14	40.15	55.03	0.00	16.00	5.95
15	39.13	49.23	0.00	16.00	5.52
16	38.22	50.04	0.00	16.00	5.52
17	37.40	44.64	0.00	16.00	5.13
18	36.66	39.79	0.00	16.00	4.78
19	35.99	38.19	0.00	16.00	4.64
20	35.39	33.92	0.00	16.00	4.33
21	34.85	30.08	0.00	16.00	4.06
Total	1420.00	1228.51	0.00	16.00	165.53

9.7.5 Pure-Service Contract

Pure-service contracts differ from risked-service contracts in several different ways. In some cases, the contractor makes the necessary exploration and development investments, but the return on the investment is fixed. Reimbursement for costs is on a fixed schedule and does not depend on either project production performance or market factors. It is unlikely that the contractor could establish either an economic or mineral interest in the project and normally would not be able to book or report reserves from the project. Service contracts vary across the industry, and the question of reserves booking must be handled on an individual contract basis. The wording of the contract is critical in this determination.

9.7.6 Conveyances—Production Payments

As previously noted, production payments are one form of a conveyance and can be structured to be paid in kind with production or defined in monetary terms. The production payment may be retained by the party having the mineral interest in the hydrocarbons or may be assigned by the mineral interest holder to another party in exchange for an agreed monetary sum. For the purpose of this example, the production payment will be assigned by the mineral-interest owner and will be paid in kind. This could occur when a company provides capital, technology, and operating expertise for the construction of a downstream enterprise, such as an independent power plant, and seeks to help fund the development of a nearby gas field to provide fuel needed for power generation. In this example, the power company agrees to pay U.S. $50 million to help develop a gas field containing an estimated 500 Bcf of gas in exchange for half the production from the field over a 25-year period. There is full expectation of producing the 500 BCF of gas during the term of the production payment. Based on the development planned, the production is anticipated to be uniform throughout the life of the agreement. Production not dedicated to the production payment with be sold locally to other consumers by the field owner.

Reserves Allocation. In this example, the power company has acquired a volume-denominated production payment in exchange for a monetary payment that will be used to develop the gas field to provide the fuel needed for power generation. If obligated by SEC regulations to report reserves, the power company would recognize half, or 250 Bcf of the field reserves. The field owner would recognize the remaining 250 Bcf, of reserves, less any royalties owned by others. The proved and proved developed reserves reported by each party would be dependent on the extent of development of the field in any given reporting interval less cumulative volumes produced.

9.8 Conclusions

Production-sharing, risked-service, and other related contracts offer the host country and the contractor alike considerable flexibility in tailoring agreement terms to best meet sovereign and corporate requirements.

When considering projects, each fiscal system must be reviewed on a case-by-case basis to determine if there is an opportunity to report proved reserves for public-disclosure purposes. Particular care should be taken at the time of the negotiations to ensure that the contractual terms satisfy the company's business objectives and that the impact of alternative agreement structures is understood and considered.

The SEC Section S-X, Rule 4-10b, "Successful Efforts Method" provides criteria required to establish a mineral interest in hydrocarbon reserves. These criteria are widely used throughout the industry to determine when reserves can be reported. However, the distinction between when reserves can and cannot be reported under many service-type contracts may not be clear and may be highly dependent on subtle aspects of contract structure and wording.

Unlike traditional agreements, the cost-recovery terms in production-sharing, risked-service, and other related contracts typically reduce the production (and hence reserves) obtained by a contractor in periods of high price and increase the volumes in periods of low price. While this ensures cost recovery, the effect on investment metrics may be counterintuitive. Consequently, if a few large projects using these types of contracts form a significant portion of the asset inventory of a company, a significant impact on the company performance indicators may potentially occur if contract terms or product prices change.

The treatment of taxes and the accounting procedures used can also have a very significant impact on the reserves recognized and production reported from these contracts.

References

1. "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information," SPE, Richardson, Texas (December 1979).
2. Martinez, A.R. *et al.:* "Classification and Nomenclature Systems for Petroleum and Petroleum Reserves," Study Group Report, 1987 World Petroleum Congress, Houston.

3. “Guidelines for Application of Petroleum Reserves Definitions,” Soc. of Petroleum Evaluation Engineers, Houston (1998).
4. *SEC Guidelines, Rules, and Regulations,* Warren Groom Lamont, Research Inst. of America Inc. (1993).
5. “Mineral Companies,” Chapter 19, London Stock Exchange.
6. “Australian Petroleum Production and Exploration Association,” Guidelines for Reporting Oil and Gas Reserves,” Canberra, Australia (May 1995).
7. “Statement of Recommended Practices—Fourth in a Series of SORP’s,” U.K. Oil Industry Accounting Committee (January 1991).
8. Johnston, D.: *Petroleum Fiscal Systems and Production Sharing Contracts,* PennWell Publishing Co., Tulsa, Oklahoma (1994).
9. Johnston, D. “Different Fiscal Systems Complicate Reserves Values,” *Oil and Gas J.* (29 May 1995) 39.

Appendix A
Petroleum Reserves Definitions

Preamble

Petroleum[1] is the world's major source of energy and is a key factor in the continued development of world economies. It is essential for future planning that governments and industry have a clear assessment of the quantities of petroleum available for production and quantities which are anticipated to become available within a practical time frame through additional field development, technological advances, or exploration. To achieve such an assessment, it is imperative that the industry adopt a consistent nomenclature for assessing the current and future quantities of petroleum expected to be recovered from naturally occurring underground accumulations. Such quantities are defined as reserves, and their assessment is of considerable importance to governments, international agencies, economists, bankers, and the international energy industry.

The terminology used in classifying petroleum substances and the various categories of reserves have been the subject of much study and discussion for many years. Attempts to standardize reserves terminology began in the mid 1930's when the American Petroleum Institute considered classification for petroleum and definitions of various reserves categories. Since then, the evolution of technology has yielded more precise engineering methods to determine reserves and has intensified the need for an improved nomenclature to achieve consistency among professionals working with reserves terminology. Working entirely separately, the Society of Petroleum Engineers (SPE) and the World Petroleum congresses (WPC) produced strikingly similar sets of petroleum reserve definitions for known accumulations which were introduced in early 1987. These have become the preferred standards for reserves classification across the industry. Soon after, it became apparent to both organizations that these could be combined into a single set of definitions which could be used by the industry worldwide. Contacts between presentatives of the two organizations started in 1987, shortly after the publication of the initial sets of definitions. During the World Petroleum Congress in June 1994, it was recognized that while any revisions to the current definitions would require the approval of the respective Boards of Directors, the effort to establish a worldwide nomenclature should be increased. A common nomenclature would present an enhanced opportunity for acceptance and would signify a common and unique stance on an essential technical and professional issue facing the international petroleum industry.

As a first step in the process, the organizations issued a joint statement which presented a broad set of principles on which reserves estimations and definitions should be based. A task force was

[1] **PETROLEUM:** For the purpose of these definitions, the term petroleum refers to naturally occurring liquids and gases which are predominately comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulfur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide, and hydrogen sulfide.

established by the Boards of SPE and WPC to develop a common set of definitions based on this statement of principles. The following joint statement of principles was published in the January 1996 issue of the SPE *Journal of Petroleum Technology* and in the June 1996 issue of the *WPC Newsletter:*

> *There is a growing awareness worldwide of the need for a consistent set of reserves definitions for use by governments and industry in the classification of petroleum reserves. Since their introduction in 1987, the Society of Petroleum Engineers and the World Petroleum Congresses reserves definitions have been standards for reserves classification and evaluation worldwide.*
>
> *SPE and WPC have begun efforts toward achieving consistency in the classification of reserves. As a first step in this process, SPE and WPC issue the following joint statement of principles.*
>
>> *The SPE and the WPC recognize that both organizations have developed a widely accepted and simple nomenclature of petroleum reserves.*
>>
>> *The SPE and the WPC emphasize that the definitions are intended as standard, general guidelines for petroleum reserves classification which should allow for the proper comparison of quantities on a worldwide basis.*
>>
>> *The SPE and the WPC emphasize that, although the definition of petroleum reserves should not in any manner be construed to be compulsory or obligatory, countries and organizations should be encouraged to use the core definitions as defined in these principles and also to expand on these definitions according to special local conditions and circumstances.*
>>
>> *The SPE and the WPC recognize that suitable mathematical techniques can be used as required and that it is left to the country to fix the exact criteria for reasonable certainty of existence of petroleum reserves. No methods of calculation are excluded, however, if probabilistic methods are used, the chosen percentages should be unequivocally stated.*
>>
>> *The SPE and the WPC agree that the petroleum nomenclature as proposed applies only to known discovered hydrocarbon accumulations and their associated potential deposits.*
>>
>> *The SPE and the WPC stress that petroleum proved reserves should be based on current economic conditions, including all factors affecting the viability of the projects. The SPE and the WPC recognize that the term is general and not restricted to costs and price only. Probable and possible reserves could be based on anticipated developments and/or the extrapolation of current economic conditions.*
>>
>> *The SPE and the WPC accept that petroleum reserves definitions are not static and will evolve.*

A conscious effort was made to keep the recommended terminology as close to current common usage as possible in order to minimize the impact of previously reported quantities and changes required to bring about wide acceptance. The proposed terminology is not intended as a precise system of definitions and evaluation procedures to satisfy all situations. Due to the many forms of occurrence of petroleum, the wide range of characteristics, the uncertainty associated with the geological environment, and the constant evolution of evaluation technologies, a precise classification system is not practical. Furthermore, the complexity required for a precise system would detract from its understanding by those involved in petroleum matters. As a result, the recommended definitions do not represent a major change from the current SPE and WPC definitions which have become the standards across the industry. It is hoped that the recommended terminology will integrate the two sets of definitions and achieve better consistency in reserves data across the international industry.

Reserves derived under these definitions rely on the integrity, skill, and judgment of the evaluator and are affected by the geological complexity, stage of development, degree of depletion of the reservoirs, and amount of available data. Use of these definitions should sharepn the distinction between the various classifications and provide more consistent reserves reporting.

Definitions

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further subclassified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Proved Reserves

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as development or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that hve yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

Unproved Reserves

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

Probable Reserves

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, trreatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

Possible Reserves

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

Reserve Status Categories

Reserve status categories define the development and producing status of wells and reservoirs.

Developed: Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

Producing: Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-producing: Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves: Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Appendix B

Petroleum Resources Definitions

In March 1997, the Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC) approved a set of petroleum[1] reserves definitions which represented a major step forward in their mutual desire to improve the level of consistency in reserves estimation and reporting on a worldwide basis. As a further development, the SPE and WPC recognized the potential benefits to be obtained by supplementing those definitions to cover the entire resource base, including those quantities of petroleum contained in accumulations that are currently sub-commercial or that have yet to be discovered. These other resources represent potential future additions to reserves and are therefore important to both countries and companies for planning and portfolio management purposes. In addition, the American Association of Petroleum Geologists (AAPG) participated in the development of these definitions and joined SPE and WPC as a sponsoring organization.

In 1987, the WPC published its report “Classification and Nomenclature Systems for Petroleum and Petroleum Reserves,” which included definitions for all categories of resources. The WPC report, together with definitions by other industry organizations and recognition of current industry practice, provided the basis for the system outlined here.

Nothing in the following resource definitions should be construed as modifying the existing definitions for petroleum reserves as approved by the SPE/WPC in March 1997.

As with unproved (i.e., probable and possible) reserves, the intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of quantities classified as resources. Such disclosure is left to the discretion of the countries or companies involved.

Estimates derived under these definitions rely on the integrity, skill, and judgment of the evaluator and are affected by the geological complexity, stage of exploration or development, degree of depletion of the reservoirs, and amount of available data. Use of the definitions should sharpen the distinction between various classifications and provide more consistent resources reporting.

[1]For the purpose of these definitions, the term “petroleum” refers to naturally occurring liquids and gases that are predominantly comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulfur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide, and hydrogen sulfide.

Definitions

The resource classification system is summarized in Figure 1 and the relevant definitions are given below. Elsewhere, resources have been defined as including all quantities of petroleum which are estimated to be initially-in-place; however, some users consider only the estimated recoverable portion to constitute a resource. In these definitions, the quantities estimated to be initially-in-place are defined as Total Petroleum-initially-in-place, Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, and the recoverable portions are defined separately as Reserves, Contingent Resources, and Prospective Resources. In any event, it should be understood that reserves constitute a subset of resources, being those quantities that are discovered (i.e,. in known accumulations), recoverable, commercial and remaining.

Total Petroleum-Initially-in-Place

Total Petroleum-initially-in-place is that quantity of petroleum which is estimated to exist originally in naturally occurring accumulations. Total Petroleum-initially-in-place is, therefore, that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced therefrom, plus those estimated quantities in accumulations yet to be discovered. Total Petroleum-initially-in-place may be subdivided into Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, with Discovered Petroleum-initially-in-place being limited to known accumulations.

It is recognized that all Petroleum-initially-in-place quantities may constitute potentially recoverable resources since the estimation of the proportion which may be recoverable can be subject to significant uncertainty and will change with variations in commercial circumstances, technological developments, and data availability. A portion of those quantities classified as Unrecoverable may become recoverable resources in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

Discovered Petroleum-Initially-in-Place

Discovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced therefrom. Discovered Petroleum-initially-in-place may be subdivided into Commercial and Sub-commercial categories, with the estimated potentially recoverable portion being classified as Reserves and Contingent Resources respectively, as defined below.

Reserves: Reserves are defined as those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. Reference should be made to the full SPE/WPC Petroleum Reserves Definitions for the complete definitions and guidelines.

Estimated recoverable quantities from known accumulations which do not fulfill the requirement of commerciality should be classified as Contingent Resources, as defined below. The definition of commerciality for an accumulation will vary according to local conditions and circumstances and is left to the discretion of the country or company concerned. However, reserves must still be categorized according to the specific criteria of the SPE/WPC definitions and therefore proved reserves will be limited to those quantities that are commercial under current economic conditions, while probable and possible reserves may be based on future economic conditions. In general, quantities should not be classified as reserves unless there is an expectation that the accumulation will be developed and placed on production within a reasonable timeframe.

In certain circumstances, reserves may be assigned even though development may not occur for some time. An example of this would be where fields are dedicated to a long-term supply contract and will only be developed as and when they are required to satisfy that contract.

Contingent Resources: Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

It is recognized that some ambiguity may exist between the definitions of contingent resources and unproved reserves. This is a reflection of variations in current industry practice. It is recommended that if the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable timeframe, the estimated recoverable volumes for the accumulation be classified as contingent resources.

Contingent Resources may include, for example, accumulations for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is still at an early stage.

Undiscovered Petroleum-Initially-in-Place

Undiscovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in accumulations yet to be discovered. The estimated potentially recoverable portion of Undiscovered Petroleum-initially-in-place is classified as Prospective Resources, as defined below.

Prospective Resources: Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

Estimated Ultimate Recovery

Estimated Ultimate Recovery (EUR) is not a resource category as such, but a term which may be applied to an individual accumulation of any status/maturity (discovered or undiscovered). Estimated Ultimate Recovery is defined as those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

Aggregation

Petroleum quantities classified as Reserves, Contingent Resources or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources or Prospective Resources will not achieve commercial production.

Range of Uncertainty

The Range of Uncertainty, as shown in Figure 1, reflects a reasonable range of estimated potentially recoverable volumes for an individual accumulation. Any estimation of resource quantities for an accumulation is subject to both technical and commercial uncertainties, and should, in general, be quoted as a range. In the case of reserves, and where appropriate, this range of uncertainty can be reflected in estimates for Proved Reserves (1P), Proved plus Probable Reserves (2P) and Proved plus Probable plus Possible Reserves (3P) scenarios. For other resource categories, the terms Low Estimate, Best Estimate and High Estimate are recommended.

The term “Best Estimate” is used here as a generic expression for the estimate considered to be the closest to the quantity that will actually be recovered from the accumulation between the date of the estimate and the time of abandonment. If probabilistic methods are used, this term would generally be a measure of central tendency of the uncertainty distribution (most likely/mode, median/P50 or mean). The terms "Low Estimate" and “High Estimate” should provide a reasonable assessment of the range of uncertainty in the Best Estimate.

For undiscovered accumulations (Prospective Resources) the range will, in general, be substantially greater than the ranges for discovered accumulations. In all cases, however, the actual range will be dependent on the amount and quality of data (both technical and commercial) which is available for that accumulation. As more data become available for a specific accumulation (e.g. additional wells, reservoir performance data) the range of uncertainty in EUR for that accumulation should be reduced.

Resources Classification System

Graphical Representation

Figure 1 is a graphical representation of the definitions. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas 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 an accumulation towards production.

As indicated in Figure 1, the Low, Best and High Estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved, Proved plus Probable, and Proved plus Probable plus Possible, respectively. While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.

If probabilistic methods are used, these estimated quantities should be based on methodologies analogous to those applicable to the definitions of reserves; therefore, in general, there should be at least a 90% probability that, assuming the accumulation is developed, the quantities actually recovered will equal or exceed the Low Estimate. In addition, an equivalent probability value of 10% should, in general, be used for the High Estimate. Where deterministic methods are used, a similar analogy to the reserves definitions should be followed.

As one possible example, consider an accumulation that is currently not commercial due solely to the lack of a market. The estimated recoverable volumes are classified as Contingent Resources, with Low, Best and High estimates. Where a market is subsequently developed, and in the absence of any new technical data, the accumulation moves up into the Reserves category and the Proved Reserves estimate would be expected to approximate the previous Low Estimate.

FIGURE 1—RESOURCES CLASSIFICATION SYSTEM