World Petroleum Council

Guidelines for Application of the Petroleum Resources Management System

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Society of Petroleum Engineers (SPE)
American Association of Petroleum Geologists (AAPG)
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Introduction

Satinder Purewal

1.1 Rationale for New Applications Guidelines

SPE has been at the forefront of leadership in developing common standards for petroleum resource definitions. There has been recognition in the oil and gas and mineral extractive industries for some time that a set of unified common standard definitions is required that can be applied consistently by international financial, regulatory, and reporting entities. An agreed set of definitions would benefit all stakeholders and provide increased

- Consistency
- Transparency
- Reliability

A milestone in standardization was achieved in 1997 when SPE and the World Petroleum Council (WPC) jointly approved the "Petroleum Reserves Definitions." Since then, SPE has been continuously engaged in keeping the definitions updated. The definitions were updated in 2000 and approved by SPE, WPC, and the American Association of Petroleum Geologists (AAPG) as the "Petroleum Resources Classification System and Definitions." These were updated further in 2007 and approved by SPE, WPC, AAPG, and the Society of Petroleum Evaluation Engineers (SPEE). This culminated in the publication of the current "Petroleum Resources Management System," globally known as PRMS. PRMS has been acknowledged as the oil and gas industry standard for reference and has been used by the US Securities and Exchange Commission (SEC) as a guide for their updated rules, "Modernization of Oil and Gas Reporting," published 31 December 2008.

SPE recognized that new applications guidelines were required for the PRMS that would supersede the 2001 *Guidelines for the Evaluation of Petroleum Reserves and Resources*. The original guidelines document was the starting point for this work, and has been updated significantly with addition of the following new chapters:

- Estimation of Petroleum Resources Using Deterministic Procedures (Chap. 4)
- Unconventional Resources (Chap. 8)

In addition, other chapters have been updated to reflect current technology and enhanced with examples. The document has been considerably expanded to provide a useful handbook for many reserves applications. The intent of these guidelines is not to provide a comprehensive document that covers all aspects of reserves calculations because that would not be possible in a short, precise update of the 2001 document. However, these expanded new guidelines serve as a very useful reference for petroleum professionals.

Chap. 2 provides specific details of PRMS, focusing on the updated information. SEG Oil and Gas Reserves Committee has taken an active role in the preparation of Chap. 3, which addresses geoscience issues during evaluation of resource volumes. The chapter has been

specifically updated with recent technological advances. Chap. 4 covers deterministic estimation methodologies in considerable detail and can be considered as a stand-alone document for deterministic reserves calculations. Chap. 5 covers approaches used in probabilistic estimation procedures and has been completely revised. Aggregation of petroleum resources within an individual project and across several projects is covered in Chap. 6, which has also been updated. Chap. 7 covers commercial evaluations.

Chap. 8 addresses some special problems associated with unconventional reservoirs, which have become an industry focus in recent years. The topics covered in this chapter are a work in progress, and only a high-level overview could be given. However, detailed sections on coalbed methane and shale gas are included. The intent is to expand this chapter and add details on heavy oil, bitumen, tight gas, gas hydrates as well as coalbed methane and shale as the best practices evolve.

Production measurement and operations issues are covered in Chapter 9 while Chapter 10 contains details of resources entitlement and ownership considerations. The intent here is not to provide a comprehensive list of all scenarios but furnish sufficient details to provide guidance on how to apply the PRMS.

A list of Reference Terms used in resources evaluations is included at the end of the guidelines. The list does not replace the PRMS Glossary, but is intended to indicate the chapters and sections where the terms are used in these Guidelines.

1.2 History of Petroleum Reserves and Resources Definitions

Ron Harrell

The March 2007 adoption of PRMS by SPE and its three cosponsors, WPC, AAPG, and SPEE, followed almost 3 years and hundreds of hours of volunteer efforts of individuals representing virtually every segment of the upstream industry and based in at least 10 countries. Other organizations were represented through their observers to the SPE Oil and Gas Reserves Committee (OGRC), including the US Energy Information Agency (EIA), the International Accounting Standards Board (IASB), and the Society of Exploration Geophysicists (SEG). SEG later endorsed PRMS. The approval followed a 100-day period during which comments were solicited from the sponsoring organizations, oil companies (IOCs and NOCs), regulators, accounting firms, law firms, the greater financial community, and other interested parties.

AAPG was founded in 1917; SPE began as part of AIME in 1922, and became an autonomous society in 1957; WPC began in 1933; and SPEE was created in 1962. Active cooperation between these organizations, particularly involving individuals holding joint membership in two or more of these organizations, has been ongoing for years but was not formally recognized until now.

The initial efforts at establishing oil reserves definitions in the US was led by the American Petroleum Institute (API). At the beginning of World War I (WWI), the US government formed the National Petroleum War Service Committee (NPWSC) to ensure adequate oil supplies for the war effort. At the close of WWI, the NPWSC was reborn as the API. In 1937, API created definitions for Proved oil reserves that they followed in their annual estimates of US oil reserves. Little attention was paid to natural gas reserves until after 1946 when the American Gas Association (AGA) created similar definitions for Proved gas reserves.

SPE's initial involvement in establishing petroleum reserves definitions began in 1962 following a plea from US banks and other investors for a consistent set of reserves definitions

that could be both understood and relied upon by the industry in financial transactions where petroleum reserves served as collateral. Individual lenders and oil producers had their own “in-house” definitions, but these varied widely in content and purpose. In 1962, the SPE Board of Directors appointed a 12-man committee of well-recognized and respected individuals. They were known as a “Special Committee on Definitions of Proved Reserves for Property Evaluation.” The group was composed of two oil producers, one pipeline company, one university professor, two banks, two insurance companies (lenders), and four petroleum consultants.

These learned men collaborated over a period of 3 years, debating the exact wording and terms of their assignment before submitting their single-page work product to the SPE Board in 1965. The SPE Board adopted the committee’s recommendation by a vote of seven in favor, three dissenting, and two abstaining. The API observer was supportive; the AGA observer opposed the result.

In 1981, SPE released updated Proved oil and gas definitions that contained only minor revisions of the initial 1965 version.

The 1987 SPE petroleum reserves definitions were the result of an effort initiated by SPEE, but ultimately were developed and sponsored by SPE. These definitions, issued for the first time by a large professional organization, included recognition of the unproved categories of Probable and Possible Reserves. Much discussion centered around the use of probabilistic assessment techniques as a supplement or alternative to more-traditional deterministic methods. Following the receipt of comments from members worldwide, and in particular from North America, the SPE Board rejected the inclusion of any discussion about probabilistic methods of reserves evaluation in the 1987 definitions. As a consequence, these definitions failed to garner widespread international acceptance and adoption.

The 1997 SPE/WPC reserves definitions grew out of a cooperative agreement between WPC and SPE and appropriately embraced the recognition of probabilistic assessment methods. AAPG became a sponsor of and an integral contributor to the 2000 SPE/WPC/AAPG reserves and resources definitions. The loop of cooperation was completed in 2007 with recognition of SPEE as a fourth sponsoring society.

This recitation is not intended to omit or minimize the creative influence of numerous other individuals, organizations, or countries who have made valuable contributions over time to the derivation of petroleum resources definitions out of an initial mining perspective. Further, the PRMS sponsors recognize the “evergreen” nature of reserves and resources definitions and will remain diligent in working toward periodic updates and improvements.

Future Updates. Next time PRMS is reviewed and updated, it may be worth considering inclusion and recognition of 1U, 2U, and 3U as alternative acronyms for Prospective Resources estimates for low, best, and high in a similar fashion to 1P, 2P, and 3P, and 1C, 2C, and 3C. All stakeholder societies should encourage the use of the project maturity subclasses to link reservoir recognition to investment decisions, investment approvals, and field development plans, as discussed in Chapter 2.

Chapter 2

Petroleum Resources Definitions, Classification, and Categorization Guidelines

James G. Ross

2.1 Introduction

PRMS is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources. Although the system encompasses the entire resource base, it is focused primarily on estimated recoverable sales quantities. Because no petroleum quantities can be recovered and sold without the installation of (or access to) the appropriate production, processing, and transportation facilities, PRMS is based on an explicit distinction between (1) the development project that has been (or will be) implemented to recover petroleum from one or more accumulations and, in particular, the chance of commerciality of that project; and (2) the range of uncertainty in the petroleum quantities that are forecast to be produced and sold in the future from that development project.

This two-axis PRMS system is illustrated in **Fig. 2.1.**

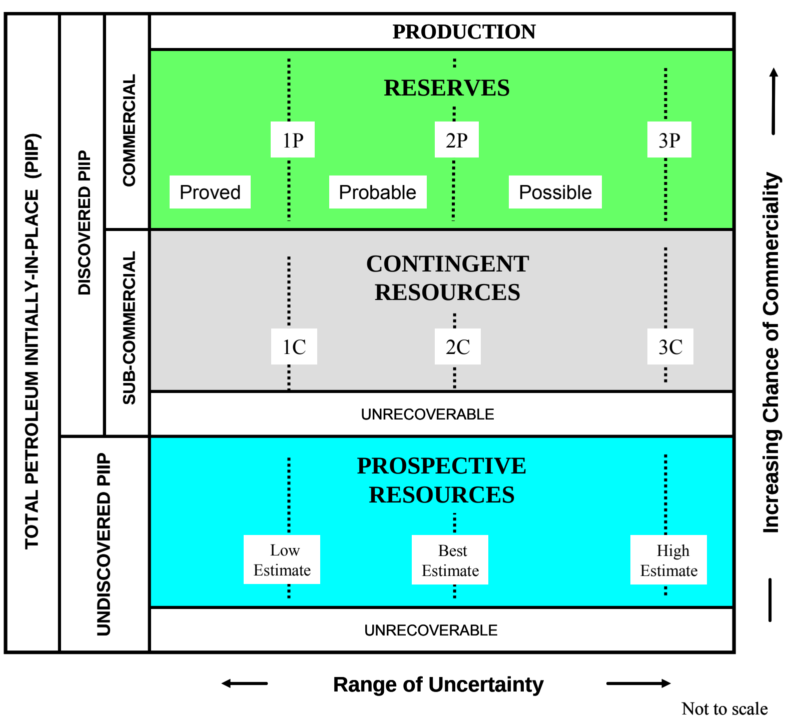

Fig. 2.1—Resources classification framework.

Each project is classified according to its maturity or status (broadly corresponding to its chance of commerciality) using three main classes, with the option to subdivide further using subclasses. The three classes are Reserves, Contingent Resources, and Prospective Resources. Separately, the range of uncertainty in the estimated recoverable sales quantities from that specific project is categorized based on the principle of capturing at least three estimates of the potential outcome: low, best, and high estimates.

For projects that satisfy the requirements for commerciality (as set out in Sec. 2.1.2 of PRMS), Reserves may be assigned to the project, and the three estimates of the recoverable sales quantities are designated as 1P (Proved), 2P (Proved plus Probable), and 3P (Proved plus Probable plus Possible) Reserves. The equivalent categories for projects with Contingent Resources are 1C, 2C, and 3C, while the terms low estimate, best estimate, and high estimate are used for Prospective Resources. The system also accommodates the ability to categorize and report Reserve quantities incrementally as Proved, Probable, and Possible, rather than using the physically realizable scenarios of 1P, 2P, and 3P.

Historically, as discussed in Chap. 1, there was some overlap (and hence ambiguity) between the two distinct characteristics of project maturity and uncertainty in recovery, whereby Possible Reserves, for example, could be classified as such due to either the possible future implementation of a development project (reflecting a project maturity consideration) or as a reflection of some possible upside in potential recovery from a project that had been committed or even implemented (reflecting uncertainty in recovery). This ambiguity has been removed in PRMS and hence it is very important to understand clearly the basis for the fundamental distinction that is made between project classification and reserve/resource categorization.

2.2 Defining a Project

PRMS is a project-based system, where a project: "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 in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity 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 resources for that project."

A project may be considered as an investment opportunity. Management decisions reflect the selection or rejection of investment opportunities from a portfolio based on consideration of the total funds available, the cost of the specific investment, and the expected outcome (in terms of value) of that investment. The project is characterized by the investment costs (i.e., on what the money will actually be spent) and provides the fundamental basis for portfolio management and decision making. In some cases, projects are implemented strictly on the basis of strategic drivers but are nonetheless defined by these financial metrics. The critical point is the linkage between the decision to proceed with a project and the estimated future recoverable quantities associated with that project.

Defining the term "project" unambiguously can be difficult because its nature will vary with its level of maturity. For example, a mature project may be defined in great detail by a comprehensive development plan document that must be prepared and submitted to the host government or relevant regulatory authority for approval to proceed with development. This document may include full details of all the planned development wells and their locations, specifications for the surface processing and export facilities, discussion of environmental

considerations, staffing requirements, market assessment, estimated capital, operating and site rehabilitation costs, etc. In contrast, the drilling of an exploration prospect represents a project that could become a commercial development if the well is successful. The assessment of the economic viability of the exploration project will still require a view of the likely development scheme, but the development plan will probably be specified only in very broad conceptual terms based on analogues.

In all cases, the decision to proceed with a project requires an assessment of future costs, based on an evaluation of the necessary development facilities, to determine the expected financial return from that investment. In this context, the development facilities include all the necessary production, processing, and transportation facilities to enable delivery of petroleum from the accumulation(s) to a product sales point (or to an internal transfer point between upstream operations and midstream/downstream operations). It is these development facilities that define the project because it is the planned investment of the capital costs that is the basis for the financial evaluation of the investment and hence the decision to proceed (or not) with the project. Evaluation of the estimated recoverable sales quantities, and the range of uncertainty in that estimate, will also be key inputs to the financial evaluation, and these can only be based on a defined development project.

A project may involve the development of a single petroleum accumulation, or a group of accumulations, or there may be more than one project implemented on a single accumulation. The following are some examples of projects:

a. Where a detailed development plan is prepared for partner and/or government approval, the plan itself defines the project. If the plan includes some optional wells that are not subject to a further capital commitment decision and/or government approval, these would not constitute a separate project, but would form part of the assessment of the range of uncertainty in potentially recoverable quantities from the project.
b. Where a development project is defined to produce oil from an accumulation that also contains a significant gas cap and the gas cap development is not an integral part of the oil development, a separate gas development project should also be defined, even if there is currently no gas market.
c. Where a development plan is based on primary recovery only, and a secondary recovery process is envisaged but will be subject to a separate capital commitment decision and/or approval process at the appropriate time, it should be considered as two separate projects.
d. Where decision making is entirely on a well-by-well basis, as may be the case in mature onshore environments, and there is no overall defined development plan or any capital commitment beyond the current well, each well constitutes a separate project.
e. Where late-life installation of gas-compression facilities is included in the original approved development plan, it is part of a single gas development project. Where compression was not part of the approved plan and is technically feasible, but will require economic justification and a capital commitment decision and/or approval before installation, the installation of gas-compression facilities represents a separate project.
f. In the assessment of an undrilled prospect, a risked economic evaluation will be made to underpin the decision whether to drill. This evaluation must include consideration of a conceptual development plan in order to derive cost estimates and theoretically recoverable quantities (Prospective Resources) on the basis of an assumed successful outcome from the exploration well (see also discussion of commercial risk in Sec. 2.5). The project is defined by the exploration well and the conceptual development plan.

g. In some cases, an investment decision may be requested of management that involves a combination of exploration, appraisal, and/or development activities. Because PRMS subdivides resource quantities on the basis of three main classes that reflect the distinction between these activities (i.e., Reserves, Contingent Resources, and Prospective Resources), it is appropriate in such cases to consider that the investment decision is based on implementing a group of projects, whereby each project can fit uniquely into one of the three classes.

Projects may change in character over time and can aggregate or subdivide. For example, an exploration project may initially be defined on the basis that, if a discovery is made, the accumulation will be developed as a standalone project. However, if the discovery is smaller than expected and perhaps is unable to support an export pipeline on its own, the project might be placed in "inventory" and delayed until another discovery is made nearby, and the two discoveries could be developed as a single project that is able to justify the cost of the pipeline. The subsequent investment decision is then based on proceeding with the development of the two accumulations simultaneously using shared facilities (the pipeline), and the combined development plan then constitutes the project. Again, the key is that the project is defined by the basis on which the investment decision is made.

Similarly, a discovered accumulation may initially be considered as a single development opportunity and then subsequently be subdivided into two or more distinct projects. For example, the level of uncertainty (e.g., in reservoir performance) may be such that it is considered more prudent to implement a pilot project first. The initial concept of a single field development project then becomes two separate projects: the pilot project and the subsequent development of the remainder of the field, with the latter project contingent on the successful outcome of the first.

A key strength of using a project-based system like PRMS is that it encourages the consideration of all possible technically feasible opportunities to maximize recovery, even though some projects may not be economically viable when initially evaluated. These projects are still part of the portfolio, and identifying and classifying them ensures that they remain visible as potential investment opportunities for the future. The quantities that are estimated to be Unrecoverable should be limited to those that are currently not technically recoverable. A proportion of these Unrecoverable quantities may of course become recoverable in the future as a consequence of new technology being developed.

Technology refers to the applied technique by which petroleum is recovered to the surface and, where necessary, processed into a form in which it can be sold. Some guidelines are provided in Sec. 2.3 on the relationship between the status of technology under development and the distinction between Contingent Resources and those quantities that are currently considered as Unrecoverable.

Finally, it is very important to understand clearly the distinction between the definition of a project and the assignment of Reserves based on Reserves Status (see Sec. 2.8). Reserves Status is a subdivision of recoverable quantities within a project and does not reflect a project-based classification directly unless each well is validly defined as a separate project, as discussed above in Example d.

2.3 Project Classification

Under PRMS, each project must be classified individually so that the estimated recoverable sales quantities associated with that project can be correctly assigned to one of the three main classes:

Reserves, Contingent Resources, or Prospective Resources (see Fig. 2.1). The distinction between the three classes is based on the definitions of (a) discovery and (b) commerciality, as documented in Secs. 2.1.1 and 2.1.2 of PRMS, respectively. The evaluation of the existence of a discovery is always at the level of the accumulation, but the assessment of potentially recoverable quantities from that discovery must be based on a defined (at least conceptually) project. The assessment of commerciality, on the other hand, can only be performed at a project level.

Although the definition of "discovery" has been revised to some extent from that contained in the SPE/WPC/AAPG Guidelines (SPE 2001) for a "known accumulation," it remains completely independent from any considerations of commerciality. The requirement is for actual evidence (testing, sampling, and/or logging) from at least one well penetration in the accumulation (or group of accumulations) to have demonstrated a "significant quantity of potentially moveable hydrocarbons." In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery.

The use of the phrase "potentially moveable" in the definition of "discovery" is in recognition of unconventional accumulations, such as those containing natural bitumen, that may be rendered "moveable" through the implementation of improved recovery methods or by mining.

Estimated recoverable quantities from a discovery are classified as Contingent Resources until such time that a defined project can be shown to have satisfied all the criteria necessary to reclassify some or all of the quantities as Reserves. In cases where the discovery is, for example, adjacent to existing infrastructure with sufficient excess capacity, and a commercially viable development project is immediately evident (i.e., by tying the discovery well into the available infrastructure), the estimated recoverable quantities may be classified as Reserves immediately. More commonly, the estimated recoverable quantities for a new discovery will be classified as Contingent Resources while further appraisal and/or evaluation is carried out. In-place quantities in a discovered accumulation that are not currently technically recoverable may be classified as Discovered Unrecoverable.

The criteria for commerciality (and hence assigning Reserves to a project) are set out in Sec. 2.1.2 of PRMS and should be considered with care and circumspection. While estimates of Reserve quantities will frequently change with time, including during the period before production startup, it should be a rare event for a project that had been assigned to the Reserves class to subsequently be reclassified as having Contingent Resources. Such a reclassification should occur only as the consequence of an unforeseeable event that is beyond the control of the company, such as an unexpected political or legal change that causes development activities to be delayed beyond a reasonable time frame (as defined in PRMS). Even so, if there are any identifiable areas of concern regarding receipt of all the necessary approvals/contracts for a new development, it is recommended that the project remains in the Contingent Resources class until such time that the specific concern has been addressed.

Contingent Resources may be assigned for projects that are dependent on "technology under development." It is recommended that the following guidelines are considered to distinguish these from quantities that should be classified as Unrecoverable:

1. The technology has been demonstrated to be commercially viable in analogous reservoirs. Discovered recoverable quantities may be classified as Contingent Resources.

2. The technology has been demonstrated to be commercially viable in other reservoirs that are not analogous, and a pilot project will be necessary to demonstrate commerciality for this reservoir. If a pilot project is planned and budgeted, discovered recoverable quantities from the full project may be classified as Contingent Resources. If no pilot project is currently planned, all quantities should be classified as Unrecoverable.
3. The technology has not been demonstrated to be commercially viable but is currently under active development, and there is sufficient direct evidence (e.g., from a test project) to indicate that it may reasonably be expected to be available for commercial application within 5 years. Discovered Recoverable quantities from the full project may be classified as Contingent Resources.
4. The technology has not been demonstrated to be commercially viable and is not currently under active development, and/or there is not yet any direct evidence to indicate that it may reasonably be expected to be available for commercial application within 5 years. All quantities should be classified as Unrecoverable.

2.4 Range of Uncertainty Categorization

The "range of uncertainty" (see Fig. 2.1) reflects a range of estimated quantities potentially recoverable from an accumulation (or group of accumulations) by a specific, defined, project. Because all potentially recoverable quantities are estimates that are based on assumptions regarding future reservoir performance (among other things), there will *always* be some uncertainty in the estimate of the recoverable quantity resulting from the implementation of a specific project. In almost all cases, there will be significant uncertainty in both the estimated in-place quantities and in the recovery efficiency, and there may also be project-specific commercial uncertainties. Where performance-based estimates are used (e.g., based on decline curve analysis), there must still be some uncertainty; however, for very mature projects, the level of technical uncertainty *may* be relatively minor in absolute terms.

In PRMS, the range of uncertainty is characterized by three specific scenarios reflecting low, best, and high case outcomes from the project. The terminology is different depending on which class is appropriate for the project, but the underlying principle is the same regardless of the level of maturity. In summary, if the project satisfies all the criteria for Reserves, the low, best, and high estimates are designated as Proved (1P), Proved plus Probable (2P), and Proved plus Probable plus Possible (3P), respectively. The equivalent terms for Contingent Resources are 1C, 2C, and 3C, while the terms "low estimate," "best estimate," and "high estimate" are used for Prospective Resources.

The three estimates may be based on deterministic methods or on probabilistic methods, as discussed in Chap. 4 and Chap. 5. The relationship between the two approaches is highlighted in PRMS with the statement that:

> "A deterministic estimate is a single discrete scenario within a range of outcomes that could be derived by probabilistic analysis."

Further:

> "Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It

is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods."

The critical point in understanding the application of PRMS is that the designation of estimated recoverable quantities as Reserves (of any category), or as Contingent Resources or Prospective Resources, is based solely on an assessment of the maturity/status of an identified project, as discussed in Sec. 2.3. In contrast, the subdivision of Reserves into 1P, 2P, and 3P (or the equivalent incremental quantities) is based solely on considerations of uncertainty in the recovery from that specific project (and similarly for Contingent/Prospective Resources). Under PRMS, therefore, provided that the project satisfies the requirements to have Reserves, there should always be a low (1P) estimate, a best (2P) estimate, and a high (3P) estimate, unless some very specific circumstances pertain where, for example, the 1P (Proved) estimate may be recorded as zero.

While estimates may be made using deterministic or probabilistic methods (or, for that matter, using multiscenario methods), the underlying principles must be the same if comparable results are to be achieved. It is useful, therefore, to keep in mind certain characteristics of the probabilistic method when applying a deterministic approach:

1. The range of uncertainty relates to the uncertainty in the estimate of Reserves (or Resources) for a specific project. The full range of uncertainty extends from a minimum estimated Reserve value for the project through all potential outcomes up to a maximum Reserve value. Because the absolute minimum and absolute maximum outcomes are the extreme cases, it is considered more practical to use low and high estimates as a reasonable representation of the range of uncertainty in the estimate of Reserves. Where probabilistic methods are used, the P_{90} and P_{10} outcomes are typically selected for the low and high estimates.[1]
2. In the probabilistic method, probabilities actually correspond to ranges of outcomes, rather than to a specific scenario. The P_{90} estimate, for example, corresponds to the situation whereby there is an estimated 90% probability that the correct answer (i.e., the actual Reserves) will lie somewhere between the P_{90} and the P_0 (maximum) outcomes. Obviously, there is a corresponding 10% probability that the correct answer lies between the P_{90} and the P_{100} (minimum) outcome, assuming of course that the evaluation of the full range of uncertainty is valid. In a deterministic context, "a high degree of confidence that the quantities will be recovered" does not mean that there is a high probability that the exact quantity designated as Proved will be the actual Reserves; it means that there is a high degree of confidence that the actual Reserves will be at least this amount.
3. In this uncertainty-based approach, a deterministic estimate is, as stated in PRMS, a single discrete scenario that should lie within the range that would be generated by a probabilistic analysis. The range of uncertainty reflects our inability to estimate the actual recoverable quantities for a project exactly, and the 1P, 2P, and 3P Reserves estimates are simply single discrete scenarios that are representative of the extent of the range of uncertainty. In PRMS there is no attempt to consider a range of uncertainty separately for each of the 1P, 2P, or 3P scenarios, or for the incremental Proved, Probable, and Possible Reserves, because the objective is to estimate the range of uncertainty in the actual recovery from the project as a whole.

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[1] Under PRMS, the requirement is for the selected cases to be "at least" 90% and 10% probability levels, respectively.

4. Because the distribution of uncertainty in an estimate of reserves will generally be similar to a lognormal shape, the correct answer (the actual recoverable quantities) will be *more likely* to be close to the best estimate (or 2P scenario) than to the low (1P) or high (3P) estimates. This point should not be confused with the fact that there is a higher probability that the correct answer will exceed the 1P estimate (at least 90%) than the probability that it will exceed the 2P estimate (at least 50%).

For very mature producing projects, it *may* be considered that there is such a small range of uncertainty in estimated remaining recoverable quantities that 1P, 2P, and 3P reserves can be assumed to be equal. Typically, this approach is used where a producing well has sufficient long-term production history that a forecast based on decline curve analysis is considered to be subject to relatively little uncertainty. In reality, of course, the range of uncertainty is never zero (especially when considered in the context of remaining quantities), and any assumption that the uncertainty is not material to the estimate should be carefully considered, and the basis for the assumption should be fully documented. Note that this is the *only* circumstance where a project can have Proved Reserves, but zero Probable and Possible Reserves.

Typically, there will be a significant range of uncertainty and hence there will be low, best, and high estimates (or a full probabilistic distribution) that characterize the range, whether for Reserves, Contingent Resources, or Prospective Resources. However, there are specific circumstances that can lead to having 2P and 3P Reserves, but zero Proved Reserves. These are described in Sec. 3.1.2 of PRMS.

Conceptually, the framework of PRMS was originally designed on the basis of the "uncertainty-based philosophy" of reserve estimation [as discussed in Sec. 2.5 of *Guidelines for Evaluation of Reserves and Resources* (SPE 2001)], as is clearly demonstrated by its separation of project maturity from the range of uncertainty and by the simple fact that uncertainty in any estimate (e.g., reserves attributable to a project) can only be communicated by either a complete distribution of outcomes derived from probabilistic methodologies or by reporting selected outcomes (e.g., low, best, and high scenarios) from that distribution, as may be estimated using deterministic scenario methods. However, as PRMS indicates that the "deterministic incremental (risk-based) approach" remains a valid methodology in this context, further explanation is necessary to ensure that this reference is not confused with the "risk-based philosophy" described in the guidelines (SPE 2001).

As highlighted in the guidelines (SPE 2001), a major limitation of the risk-based philosophy was that it failed to distinguish between uncertainty in the recoverable quantities for a project and the risk that the project may not eventually achieve commercial development. Because this distinction is at the very heart of PRMS, it is clear that such an approach could not be consistent with the system. In particular, no reserves (of any category) can be assigned unless the project satisfies all the commerciality criteria for reserves. Thus, for reserves at least, the project should be subject to very little, if any, commercial risk. The reserve categories are then used to characterize the range of uncertainty in recoverable quantities from that project.

Provided that the definitions and guidelines specified within PRMS are respected, the incremental approach (or any other methodology) can be used to estimate reserves or resources. Estimating discrete quantities associated with each of the three reserves categories (Proved, Probable, and Possible) remains valid, though it is noted that some of the definitions and guidelines may still require explicit consideration of deterministic scenarios. For example, Probable Reserves should be such that: *"It is equally likely that actual remaining quantities*

recovered will be greater than or less than the sum of the estimated ***Proved plus Probable Reserves (2P)****"* (PRMS Sec. 2.2.2 and Table 3, emphasis added).

2.5 Methods for Estimating the Range of Uncertainty in Recoverable Quantities

There are several different approaches to estimating the range of uncertainty in recoverable quantities for a project and the terminology is often used in confusing ways. These mathematical approaches, such as Monte Carlo analysis, largely relate to volumetric methods but are also relevant to other methodologies. In this context "deterministic" is taken to mean combining a single set of discrete parameter estimates (gross rock volume, average porosity, etc.) that represent a physically realizable and realistic combination in order to derive a single, specific estimate of recoverable quantities. Such a combination of parameters represents a specific scenario. On this basis, even the probabilistic method is scenario-based. Irrespective of the approach utilized, the uncertainty in recoverable quantities is associated with the applied (or planned) project, while the risk (chance of commerciality) of the project is defined by its assignment to a resource class or subclass.

Keeping in mind that the object of the exercise is to estimate at least three outcomes (estimated recoverable quantities) that reflect the range of uncertainty for the project, broadly defined as low, best, and high estimates, it is important to recognize that the underlying philosophy must be the same, regardless of the approach used. The methods are discussed in more detail in Chap. 4 and Chap 5.

Evaluators may choose to apply more than one method to a specific project, especially for more complex developments. For example, three deterministic scenarios may be selected after reviewing a Monte Carlo analysis of the same project. The following terminology is recommended for the primary methods in current use:

Deterministic (scenario) method. In this method, three discrete scenarios are developed that reflect a low, best and high estimate of recoverable quantities. These scenarios must reflect realistic combinations of parameters and particular care is required to ensure that a reasonable range is used for the uncertainty in reservoir property averages (e.g., average porosity) and that interdependencies are accounted for (e.g., a high gross rock volume estimate may have a low average porosity associated with it). It is generally not appropriate to combine the low estimate for each input parameter to determine a low case outcome, as this would not represent a realistic low case scenario (it would be closer to the absolute minimum possible outcome).

Deterministic (incremental) method. The deterministic (incremental) method is widely used in mature onshore environments, especially where well-spacing regulations apply. Typically, Proved Developed Reserves are assigned within the drilled spacing-unit and Proved Undeveloped Reserves are assigned to adjacent spacing-units where there is high confidence in continuity of productive reservoir. Probable and Possible Reserves are assigned in more remote areas indicating progressively less confidence. These additional quantities (e.g., Probable Reserves) are estimated discretely as opposed to defining a Proved plus Probable Reserves scenario. In such cases, particular care is required to define the project correctly (e.g., distinguishing between which wells are planned and which are contingent) and to ensure that all uncertainties, including recovery efficiency, are appropriately addressed.

Probabilistic method. Commonly, the probabilistic method is implemented using Monte Carlo analysis. In this case, the user defines the uncertainty distributions of the input parameters and the relationship (correlations) between them, and the technique derives an output distribution

based on combining those input assumptions. As mentioned above, each iteration of the model is a single, discrete deterministic scenario. In this case, however, the software determines the combination of parameters for each iteration, rather than the user, and runs many different possible combinations (usually several thousand) in order to develop a full probability distribution of the range of possible outcomes from which three representative outcomes are selected (e.g., P_{90}, P_{50} and P_{10}). Stochastic reservoir modeling methods may also be used to generate multiple realizations.

Multiscenario method. The multiscenario method is a combination of the deterministic (scenario) method and the probabilistic method. In this case, a significant number of discrete deterministic scenarios are developed by the user (perhaps 100 or more) and probabilities are assigned to each possible discrete input assumption. For example, three depth conversion models may be considered possible, and each one is assigned a probability based on the user's assessment of the relative likelihood of each of the models. Each scenario leads to a single deterministic outcome, and the probabilities for each of the input parameters are combined to give a probability for that scenario/outcome. Given sufficient scenarios (which may be supplemented through the use of experimental design techniques), it is possible to develop a full probability distribution from which the three specific deterministic scenarios that lie closest to P_{90}, P_{50} and P_{10} (for example) may be selected.

2.6 Commercial Risk and Reported Quantities

In PRMS, commercial risk can be expressed quantitatively as the chance of commerciality, which is defined as the product of two risk components:

1. The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."
2. Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."

Because Reserves and Contingent Resources are only attributable to discovered accumulations, and hence the chance of discovery is 100%, the chance of commerciality becomes equivalent to the chance of development. Further, and as mentioned previously, for a project to be assigned Reserves, there should be a very high probability that it will proceed to commercial development (i.e., very little, if any, commercial risk). Consequently, commercial risk is generally ignored in the estimation and reporting of Reserves.

However, for projects with Contingent or Prospective Resources, the commercial risk is likely to be quite significant and should always be carefully considered and documented. Industry practice in the case of Prospective Resources is fairly well established, but there does not appear to be any consistency yet for Contingent Resources.

Consider, first, industry practice for Prospective Resources. The chance of discovery is assessed based on the probability that all the necessary components for an accumulation to form (hydrocarbon source, trap, migration, etc.) are present. Separately, an evaluation of the potential size of the discovery is undertaken. Typically, this is performed probabilistically and leads to a full distribution of the range of uncertainty in potentially recoverable quantities, given that a discovery is made. Because this range may include some outcomes that are below the economic threshold for a commercially viable project, the probability of being above that threshold is used to define the chance of development, and hence a chance of commerciality is obtained by multiplying this by the chance of discovery. The distribution of potential outcomes is then

recomputed for the “success case;” i.e., for a discovery that is larger than the economic threshold.

Because Prospective Resources are generally not reported externally, companies have established their own internal systems for documenting the relationship between risk and expected outcomes. Usually, if a single number is captured, it would be the “risked mean” or “risked mean success volume,” where the risk is the chance of commerciality and the mean is taken from the distribution of recoverable quantities for the “success case.” Note that it is mathematically invalid to determine a P_{90} of the risked success-case distribution (or any other probability level other than the mean itself) by multiplying an unrisked success-case P_{90} by the chance of commerciality.

It would be easy to assume that a similar process could be applied for Contingent Resources to determine a “success case” outcome, based on the probability that the estimated recoverable quantities are above a minimum economic threshold, but this would not be correct.

Once a discovery has been made, and a range of technically recoverable quantities has been assessed, these will be assigned as Contingent Resources if there are any contingencies that currently preclude the project from being classified as commercial. If the contingency is purely nontechnical (such as a problem getting an environmental approval, for example), the uncertainty in the estimated recoverable quantities generally will not be impacted by the removal of the contingency. The Contingent Resource quantities (1C, 2C, and 3C) should theoretically move directly to 1P, 2P, and 3P Reserves once the contingency is removed, provided of course that all other criteria for assigning Reserves have been satisfied and the planned recovery project has not changed in any way. In this example, the chance of commerciality is the probability that the necessary environmental permit will be obtained.

However, another possible contingency precluding a development decision could be that the estimated 1C quantities are considered to be too small to commit to the project, even though the 2C level is commercially viable. It is not uncommon, for example, for a company to first test that the 2C estimate satisfies all their corporate hurdles and then, as a project robustness test, to require that the low (1C) outcome is at least break-even. If the project fails this latter test and development remains contingent on satisfying this break-even test, further data acquisition (probably appraisal drilling) would be required to reduce the range of uncertainty first. In such a case, the chance of commerciality is the probability that the appraisal efforts will increase the low (1C) estimate above the break-even level, which is not the same as the probability (assessed before the additional appraisal) that the actual recovery will exceed the break-even level. In this situation, because the project will not go ahead unless the 1C estimate is increased, the “success case” range of uncertainty is different from the pre-appraisal range.

As mentioned above, there is no industry standard for the reporting of Contingent Resource estimates. However, the commercial risk associated with such projects can vary widely, with some being "almost there" with, say, an 80% chance of proceeding to development, while others might have a less than, say, 30% chance. If Contingent Resources are reported externally, the commercial risk can be communicated to users (e.g., investors) by various means, including: (1) describing the specific contingencies associated with individual projects; (2) reporting a quantitative chance of commerciality for each project; and/or (3) assigning each project to one of the Project Maturity subclasses (see Sec. 2.7).

Aggregation of quantities that are subject to commercial risk raises further complications, which are discussed in Chap. 6.

2.7 Project Maturity Subclasses

Under PRMS, identified projects must always be assigned to one of the three classes: Reserves, Contingent Resources, or Prospective Resources. Further subdivision is optional, and three subclassification systems are provided in PRMS that can be used together or separately to identify particular characteristics of the project and its associated recoverable quantities. The subclassification options are project maturity subclasses, reserves status, and economic status.

As illustrated in **Fig. 2.2,** development projects (and their associated recoverable quantities) may be subclassified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production. This approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality, as discussed in Sec. 2.6. The boundaries between different levels of project maturity may align with internal (corporate) project "decision gates," thus providing a direct link between the decision-making process within a company and characterization of its portfolio through resource classification. This link can also act to facilitate the consistent assignment of appropriate quantified risk factors for the chance of commerciality.

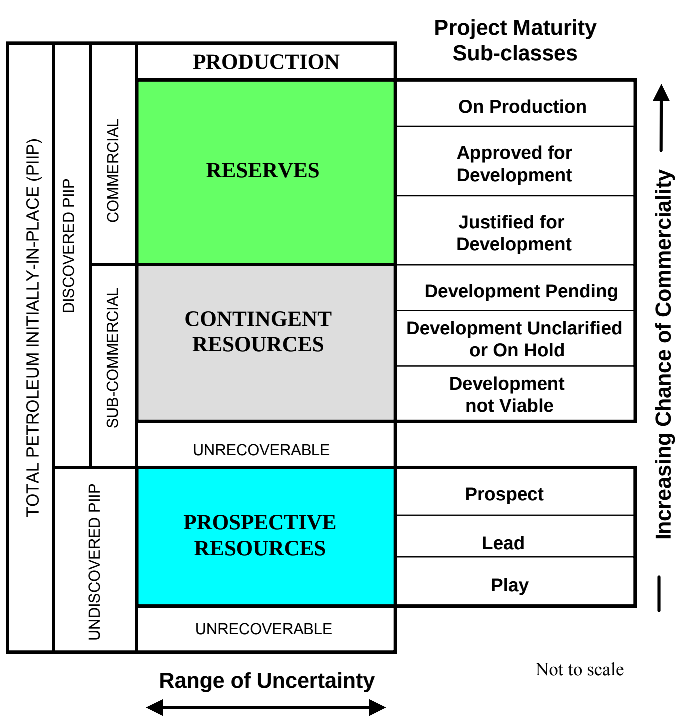

Fig. 2.2—Subclasses based on project maturity.

Evaluators may adopt alternative subclasses and project maturity modifiers to align with their own decision-making process, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management. Note that, in quantitative terms, the "chance of commerciality" axis shown in Figs. 2.1 and 2.2 is not intended to represent a linear scale, nor is it necessarily wholly sequential in the sense that a Contingent Resource project that is classified as "Development not Viable" could have a lower

chance of commerciality than a low-risk prospect, for example. In general, however, quantitative estimates of the chance of commerciality will increase as a project moves “up the ladder” from an exploration concept to a field that is producing.

If the subclasses in Fig. 2.2 are adopted, the following general guidelines should be considered in addition to those documented in Table 1 of PRMS:

1. **On Production** is self-evident in that the project must be producing and selling petroleum to market as at the effective date of the evaluation. Although implementation of the project may not be 100% complete at that date, and hence some of the reserves may still be Undeveloped (see Sec. 2.8), the full project must have all necessary approvals and contracts in place, and capital funds committed. If a part of the development plan is still subject to approval and/or commitment of funds, this part should be classified as a separate project in the appropriate subclass.
2. **Approved for Development** requires that all approvals/contracts are in place, and capital funds have been committed. Construction and installation of project facilities should be underway or due to start imminently. Only a completely unforeseeable change in circumstances that is beyond the control of the developers would be an acceptable reason for failure of the project to be developed within a reasonable time frame.
3. Projects normally would not be expected to be classified as **Justified for Development** for very long. Essentially, it covers the period between (a) the operator and its partners agreeing that the project is commercially viable and deciding to proceed with development on the basis of an agreed development plan (i.e., there is a “firm intent”), and (b) the point at which all approvals and contracts are in place (particularly regulatory approval of the development plan, where relevant) and a “final investment decision” has been made by the developers to commit the necessary capital funds. In PRMS, the recommended benchmark is that development would be expected to be initiated within 5 years of assignment to this subclass (refer to Sec. 2.1.2 of PRMS for discussion of possible exceptions to this benchmark).
4. **Development Pending** is limited to those projects that are actively subject to project-specific technical activities, such as appraisal drilling or detailed evaluation that is designed to confirm commerciality and/or to determine the optimum development scenario. In addition, it may include projects that have nontechnical contingencies, provided these contingencies are currently being actively pursued by the developers and are expected to be resolved positively within a reasonable time frame. Such projects would be expected to have a high probability of becoming a commercial development (i.e., a high chance of commerciality).
5. **Development Unclarified** or **On Hold** comprises two situations. Projects that are classified as On Hold would generally be where a project is considered to have at least a reasonable chance of commerciality, but where there are major nontechnical contingencies (e.g., environmental issues) that need to be resolved before the project can move toward development. The primary difference between Development Pending and On Hold is that in the former case, the only significant contingencies are ones that can be, and are being, directly influenced by the developers (e.g., through negotiations), whereas in the latter case, the primary contingencies are subject to the decisions of others over which the developers have little or no direct influence and both the outcome and the timing of those decisions is subject to significant uncertainty.
6. Projects are considered to be **Unclarified** if they are still under evaluation (e.g., a recent discovery) or require significant further appraisal to clarify the potential for development,

and where the contingencies have yet to be fully defined. In such cases, the chance of commerciality may be difficult to assess with any confidence.

7. Where a technically viable project has been assessed as being of insufficient potential to warrant any further appraisal activities or any direct efforts to remove commercial contingencies, it should be classified as **Development not Viable.** Projects in this subclass would be expected to have a low chance of commerciality.

It is important to note that while the aim is always to move projects "up the ladder" toward higher levels of maturity, and eventually to production, a change in circumstances (disappointing well results, change in fiscal regime, etc.) can lead to projects being "downgraded" to a lower subclass.

One area of possible confusion is the distinction between Development not Viable and Unrecoverable. A key goal of portfolio management should be to identify all possible incremental development options for a reservoir; it is strongly recommended that all technically feasible projects that could be applied to a reservoir are identified, even though some may not be economically viable at the time. Such an approach highlights the extent to which identified incremental development projects would achieve a level of recovery efficiency that is at least comparable to analogous reservoirs. Or, looking at it from the other direction, if analogous reservoirs are achieving levels of recovery efficiency significantly better than the reservoir under consideration, it is possible that there are development options that have been overlooked.

A project would be classified as Development not Viable if it is not seen as having sufficient potential for eventual commercial development, at the time of reporting, to warrant further appraisal. However, the theoretically recoverable quantities are recorded so that the potential development opportunity will be recognized in the event of a major change in technology and/or commercial conditions.

Quantities should only be classified as Unrecoverable if no technically feasible projects have been identified that could lead to the recovery of any of these quantities. A portion of Unrecoverable quantities may become recoverable in the future due to the development of new technology, for example; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks. See also the discussion regarding technology under development in Sec. 2.3.

2.8 Reserves Status

Estimated recoverable quantities associated with projects that fully satisfy the requirements for Reserves may be subdivided according to their operational and funding status. Under PRMS, subdivision by reserves status is optional and includes the following status levels: Developed Producing, Developed Nonproducing, and Undeveloped. In addition, although the prior (1997) definitions of these subdivisions were associated only with Proved Reserves, PRMS now explicitly allows the subdivision to be applied to all categories of Reserves (i.e., Proved, Probable, and Possible).

Reserve status has long been used as a subdivision of Reserves in certain environments, and it is obligatory under some reporting regulations to subdivide Proved Reserves to Proved Developed and Proved Undeveloped. In many other areas, subdivision by Reserves status is not required by relevant reporting regulations and is not widely used by evaluators. Unless mandated by regulation, it is up to the evaluator to determining the usefulness of these, or any of the other, subdivisions in any particular situations.

Subdivision by reserves status or by project maturity subclasses is optional and, because they are to some degree independent of each other, both can be applied together. Such an approach requires some care, as it is possible to confuse the fact that project maturity subclasses are linked to the status of the project as a whole, whereas reserves status considers the level of implementation of the project, essentially on a well-by-well basis. Unless each well constitutes a separate project, reserves status is a subdivision of Reserves within a project. Reserves status is not project-based, and hence there is no direct relationship between reserves status and chance of commerciality, which is a reflection of the level of project maturity.

The relationship between the two optional classification approaches may be best understood by considering all the possible combinations, as illustrated below. The table shows that a project that is On Production could have Reserves in all three reserves status subdivisions, whereas all project Reserves must be Undeveloped if the project is classified as Justified for Development.

Project Maturity Subclass	Reserves Status		
	Developed Producing Reserves	Developed Non-Producing Reserves	Undeveloped Reserves
On Production	☑	☑	☑
Approved for Development	☒	☑	☑
Justified for Development	☒	☒	☑

Applying reserves status in the absence of project maturity subclasses can lead to the mixing of two different types of Undeveloped Reserves and will hide the fact that they may be subject to different levels of project maturity:

1. Those Reserves that are Undeveloped simply because implementation of the approved, committed and budgeted development project is ongoing and drilling of the production wells, for example, is still in progress at the date of the evaluation; and,
2. Those Reserves that are Undeveloped because the final investment decision for the project has yet to be made and/or other approvals or contracts that are expected to be confirmed have not yet been finalized.

For portfolio analysis and decision-making purposes, it is clearly important to be able to distinguish between these two types of Undeveloped Reserves. By using project maturity subclasses, a clear distinction can be made between a project that has been Approved for Development and one that is Justified for Development, but not yet approved.

2.9 Economic Status

A third option for classification purposes is to subdivide Contingent Resource projects on the basis of economic status, into Marginal or Submarginal Contingent Resources. In addition, PRMS indicates that, where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is

"undetermined." As with the classification options for Reserves that are based on reserves status, this is an optional subdivision that may be used alone or in combination with project maturity subclasses.

Broadly speaking, one might expect the following approximate relationships between the two optional approaches:

<table>
<tr><th>Project Maturity Subclass</th><th>Additional Sub-Classification</th><th>Economic Status</th></tr>
<tr><td>Development Pending</td><td>Pending</td><td rowspan="2">Marginal Contingent Resources</td></tr>
<tr><td rowspan="2">Development Unclarified or On Hold</td><td>On Hold</td></tr>
<tr><td>Unclarified</td><td>Undetermined</td></tr>
<tr><td>Development Not Viable</td><td>Not Viable</td><td>Sub-marginal Contingent Resources</td></tr>
</table>

2.10 References

Petroleum Resources Management System, SPE, Richardson, Texas, USA (March 2007).

Guidelines for the Evaluation of Reserves and Resources, SPE, Richardson, Texas, USA (2001).

Chapter 3

Seismic Applications

Jean-Marc Rodriguez*

3.1 Introduction

Geophysical methods, principally seismic surveys, are 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 interpretations and conclusions from seismic data are integrated with the analysis of well logs, pressure tests, cores, geologic depositional knowledge and other information from exploration 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 seismic interpretation that initially were considered ambiguous become more reliable and detailed as uncertainties in the relationships between seismic attributes and field properties are reduced. The seismic data evolve into a continuously utilized and updated subsurface tool that impacts both estimation of reserves and depletion planning.

While 2D seismic lines are useful for mapping structures, the uncertainties associated with all aspects of a seismic interpretation decreases considerably when the seismic data are acquired and processed as a 3D data volume. Not only does 3D acquisition provide full spatial coverage, but the 3D processing procedures (seismic migration in particular) are better able to move reflections to their proper positions in the subsurface, significantly improving the clarity of the seismic image. In addition, 3D seismic data can provide greater confidence in the prediction of reservoir continuity away from well control. 3D seismic offers the geoscientist the option to extract a suite of more complex seismic attributes to further improve the characterization of the subsurface. 3D data acquisition and processing improve continuously; a recent example is the development of Wide Azimuth (WAZ) seismic acquisition and processing that provides improvements in structural definition and signal to noise ratio in complex geologies.

The following discussion focuses on the application of 3D seismic data in the estimation of Reserve and Resource volumes as classified and categorized by PRMS. However, in some areas, 2D data may still play a crucial role when Prospective Resources are being estimated. Once a discovery is made, and as an individual asset or project matures, it has become the norm to acquire 3D seismic data, which provide critical additional information in support of the estimation of Contingent Resources and/or Reserves. Finally, once a field has been on production for some time, repeat seismic surveys may be acquired if conditions are suitable. The

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*With key contributions from the following SEG Oil and Gas Reserves Committee members: Patrick Connolly, Henk Jaap Kloosterman, James Robertson, Bruce Shang, Raphic van der Weiden and Robert Withers.

information from these time-lapse seismic surveys, also known as 4D seismic, are integrated with performance data and feed into the Reserves and Resource volumes estimates and updates to the field development plan.

3.2. Seismic Estimation of Reserves and Resources

The interpretations that a geoscientist derives from 3D seismic data can be grouped conveniently into those that map the structure and geometry of the hydrocarbon trap (including fault related aspects), those that characterize rock and fluid properties, and those that are directed at highlighting changes in the distribution of fluids and/or pressure variations, resulting from production.

3.2.1 Trap Geometry. Trap geometry is determined by the dips and strikes of reservoirs and seals, the locations of faults and barriers that facilitate or block fluid flow, the shapes and distribution 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 allows an interpreter to map the trap as a 3D grid of seismic amplitudes reflected from acoustic/elastic impedance[3] boundaries associated with the rocks and fluids in and around the trap. The resolution of 3D seismic typically ranges from 12.5 to 50 m laterally and 8 to 40 m vertically, depending on the depth and properties of the objective reservoir as well as the nature of the seismic survey acquisition parameters and the details of the subsequent processing. A geoscientist uses various interpretive techniques available on a computer workstation to analyze the seismic volume(s). A geoscientist can synthesize a coherent and quite detailed 3D picture of a trap's geometry depending on the seismic quality and resolution. Mapping travel times to selected acoustic/elastic impedance boundaries (geoscientists often call these boundaries seismic horizons), displaying seismic amplitude variations along these horizons, isochroning between horizons, noting changes in amplitude and phase continuity through the volume, and displaying time and/or horizon slices and volumetric renderings of the seismic data in optimized colors and perspectives all contribute to the detailed picture of the trap's geometry. Velocity data from wells, optionally supplemented with seismic velocity data, is used to convert the horizons picked in time into depth and thickness.

To fully analyze a trap, a geoscientist 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 product of the trap analysis is a calculation of the reservoir bulk volume of these pools (which will later be integrated with reservoir properties such as porosity, net-to-gross, and hydrocarbon saturation to compute an estimate of the original oil and gas in place).

For fields interpreted to be faulted, it may be necessary to classify resource estimates differently for individual fault blocks. It is important to make a distinction whether the fault that separates the undrilled fault block from a drilled fault block can be considered a major, potentially sealing fault or not. This will depend on the analysis of the extent of the fault, the fault throw as well as

[3] Acoustic impedance is the product of density and velocity. Since seismic reflection coefficients/strengths change with angle elastic impedance is sometimes used for oblique incidence.

an assessment of fault transmissibility. Seismic amplitudes and flat-spots (see 3.2.2) may be included in this assessment.

3.2.2 Rock and Fluid Properties. The second general application of 3D seismic analysis is predicting the rock and pore-fluid properties of the reservoir and sometimes its pressure regime. The reservoir properties that 3D seismic can potentially predict under suitable conditions are porosity, lithology, presence of gas/oil saturation as well as pressure. Predictions must be supported by well control and a representative depositional model. Depending on conditions predictions may be either qualitative or quantitative. Lithology, including net-to-gross, and porosity can be loosely estimated from a depositional model of the reservoir based on well data, 3D seismic facies 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 appropriate ranges from reservoir analogues.

In some situations more accurate and higher resolution predictions can be made based on seismic attributes such as amplitude. The use of such seismic attributes requires that

- A relationship exists at log scale between these attributes and specific reservoir characteristics
- This relationship still exists at seismic scale (which exhibits lower vertical resolution)
- The seismic quality is satisfactory
- A reliable seismic to well tie exists

The geoscientist should work through each of these: first, by demonstrating a relationship between a log-scale seismic attribute, such as p-wave or s-wave impedance or elastic impedance and a reservoir property; second, by demonstrating that a useful relationship still exists at seismic resolution and for the anticipated geometries of the reservoir; third, the geoscientist should demonstrate that the data quality of the seismic at the reservoir level is good and that, for example, overburden effects do not obscure or distort the imaging of the reservoir; and finally, it should be demonstrated that well synthetics (modeled seismic derived from density and sonic logs) adequately tie the seismic data.

Qualitative predictions such as the stratigraphic extent of a reservoir may be based on relatively simple attribute extractions supported by well data and analogues. Quantitative predictions for example of porosity or net-to-gross will need more sophisticated approaches that compensate for the tuning[4] effects caused by the band-limited nature of the seismic data. These could be either 2D map based approaches or 3D seismic inversion based. They may involve either a direct calibration of the seismic attribute to a reservoir property or a two-stage approach by first estimating the impedance values. The risks and uncertainties of seismic inversion are discussed in 3.4.

Attributes may be extracted from conventional stacked volumes or, increasingly, from AVO attribute volumes such as intercept or gradient or linear combinations of the two. This can improve correlations between the seismic attribute and the reservoir property. Inversion algorithms make use either AVO volumes or prestack data. In all cases the quality of the track

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[4] For thin reservoirs, the seismic reflections from the top and the base of the reservoir overlap and interfere constructively and destructively with each other to such an extent that the two interfaces have no individual expression; geophysicists call this effect "tuning." The tuning thickness is the bed thickness at which the two seismic reflections become indistinguishable in time. It is important to know this thickness before one starts interpreting seismic data. To this end, geophysicists produce tuning models for the relevant seismic data that can act as a guide for determining the tuning thickness.

record and confidence ranges, either locally within the 3D volume or regionally, will need to be considered when determining the reliability of seismic based estimates.

The presence of hydrocarbons typically lowers the seismic velocity and density of unconsolidated to moderately consolidated sandstones and hence modifies the impedance contrast with surrounding shales relative to the contrast of water bearing sands with the same shales. Typically this will increase reflectivity but if brine sands are harder than shales, the reflectivity can be reduced or change polarity. The down-dip limit of this changed reflectivity will show up as a change of amplitude that conforms with a structural contour.

If the reservoir thickness is above seismic resolution, a reflection from the hydrocarbon/water contact may be visible as a reflection event known as a ”flat-spot.” Flat-spots are normally attributed to a depth (unless there is a lateral pressure gradient in the aquifer) but may not be flat in time.

The field in the example below shows a seismic expression of an apparent oil-water contract in a high quality oil sand. The normalized seismic amplitude map in Figure 3.1 shows a good fit-to-structure of the amplitude change at the apparent oil-water contact. However, some amplitude variations are present as well at shallower levels, suggesting variability in the lithology. Key results are shown in the plot on the right in Figure 3.1. The impact of both reservoir thickness as well as pore-fill on the seismic response can be observed. The outcome to this analysis underpins the low, best, and high estimates that feed into the resource classification.

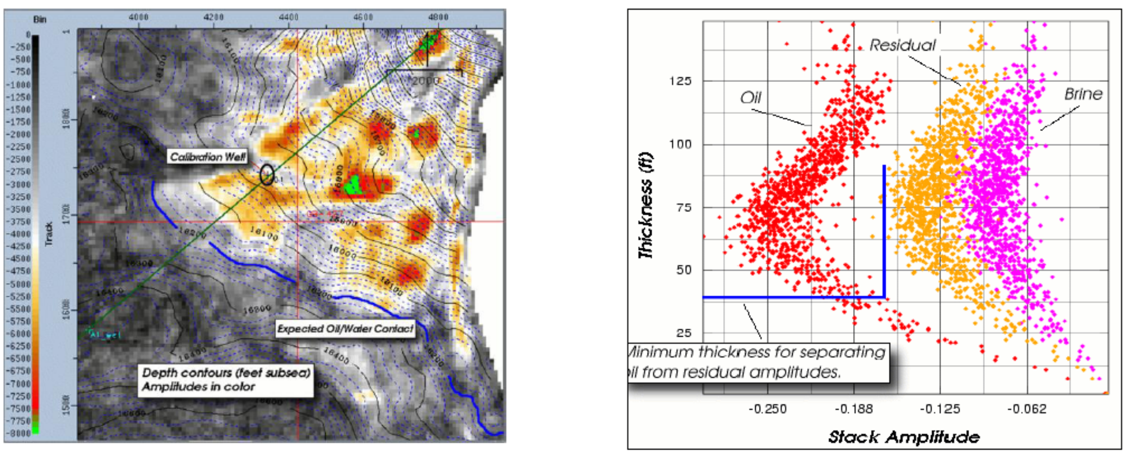


Fig. 3.1—Example of using Seismic Technology to assess fluid contacts. The plot on the right shows the results of a Monte Carlo seismic modeling exercise in which the full range of key uncertainties (reservoir thickness, porosity, net-to-gross, rock and fluid properties, etc.) were evaluated.

The visibility of hydrocarbon-related amplitude conformance and flat-spots (Direct Hydrocarbon Indicators or DHIs) may be enhanced through the use of appropriate AVO volumes. In all cases, seismic rock property analysis should be provided to support the identification of an event as a DHI to ensure that the strength and polarity of reflections is consistent with expectations. DHIs must also be shown to be consistent with the trapping geometry.

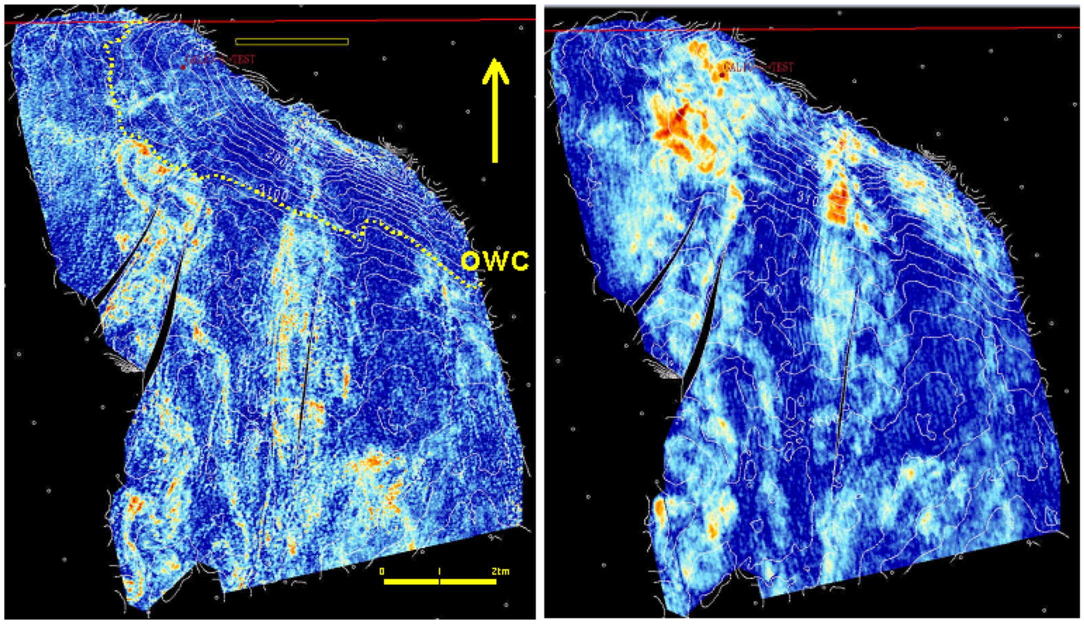


Figure 3.2—Amplitude maps from a deepwater oil field (hot colors are high negative amplitudes). The oil accumulation is trapped against a fault to the northeast dipping to an oil-water contact (owc) to the southwest. The maps are from a near offset (left) and far offset (right) volume. The oil-water contact appears as an amplitude increase on the near offsets and an amplitude decrease on the far offsets. Both run along a structural contour. The response is consistent with the trap geometry, the depositional model and the seismic rock properties from the well data.

It is usually not possible to distinguish a fully saturated gas accumulation from a partially saturated column (residual gas) using full stack or conventional (two-term) AVO analysis, so this may remain as an unresolved risk. Direct estimation of density contrast using higher order AVO analysis can in principle distinguish between the two, but this is an emerging technology and would need to be supported by a historical track record.

It is noted that in many other examples, in which the seismic evidence itself is not as convincing, other data sources (e.g., pressure data, performance data, geologic deposition model) will also contribute as part of an integrated analysis to achieve comparable confidence of the recoverable volumes below the Lowest Known Hydrocarbons (LKH), as observed in the wells.

When a known hydrocarbon accumulation is being appraised, seismic flat-spots and/or seismic amplitude anomalies can be used to increase confidence in fluid contacts when the following conditions are met:

- The flat-spot and/or seismic amplitude anomaly is clearly visible in the 3D seismic, and not related to imaging issues.
- Within a single fault block, well logs, pressure, and well test and/or performance data demonstrate a strong tie between the calculated hydrocarbon/water contact (not necessarily drilled) and the seismic flat-spot and/or down-dip edge of the seismic anomaly.
- The spatial mapping of the flat-spot and/or down-dip edge of the amplitude anomaly within the reservoir fairway fits a structural contour, which usually will be the down-dip limit of the accumulation.

Seismic amplitude anomalies may also be used to support reservoir and fluid continuity across a faulted reservoir provided that the following conditions are met:

- Within the drilled fault block, well logs, pressure, fluid data, and test data demonstrate a strong tie between the hydrocarbon-bearing reservoir and the seismic anomaly.
- Fault throw is less than reservoir thickness over (part of) the hydrocarbon bearing section across the fault and the fault is not considered to be a major, potentially sealing, fault.
- The seismic flat-spot or the seismic anomaly is spatially continuous and at the same depth across the fault.

If these conditions are met, the presence of hydrocarbon in the adjacent fault block above the seismic flat-spot or seismic amplitude anomaly may be judged sufficiently robust to qualify the hydrocarbon volumes as within the same known accumulation and thus qualify as reserves. If these conditions are only partially met, the interpreter must consider the increased level of uncertainty inherent in the data and appropriately classify the volumes based on the uncertainty components. Caution should be exercised in assigning reserves and resource classification categories. The levels of risk and uncertainty should be commensurate the quality of the data, velocity uncertainty, repeatability, and quality of supporting data.

3.2.3 Surveillance. The third general application of 3D seismic analysis is monitoring changes in pore-space composition, pressure, and temperature with fluid movement in the reservoir. This application is often called time-lapse seismic or more commonly as 4D seismic. Surveillance is possible if one

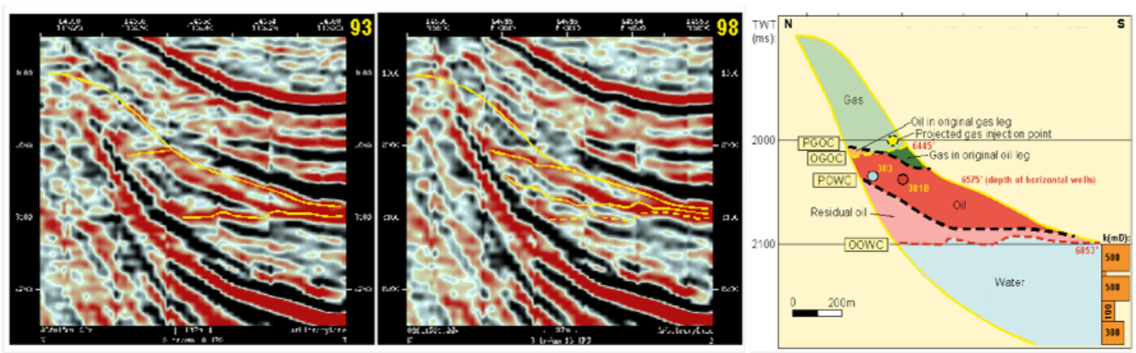
- Acquires a baseline seismic data-set
- Allows fluid flow to occur through production and/or injection with associated pressure/temperature changes
- Acquires additional 3D seismic data-sets sometime after the baseline
- Observes differences between the seismic character of the two data-sets in the reservoir interval
- Demonstrates through seismic modeling and/or rock and fluid physics based on a relevant set of well log data 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 distant would be virtually identical between the seismic data-sets because background geology would be much less affected by production/injection than the hydrocarbon interval. Hence, observing the difference between the data-sets highlights changes caused by depletion/injection in the reservoir interval (and possibly in the overburden if compaction occurs). Obviously one can acquire a third or fourth seismic survey and continue the surveillance by comparing successive data-sets 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 amplitude anomalies. 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 changes) 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 bubble point (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 bubble point). 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 versus current depth of the oil/water contact (OWC) in a producing field is easier on time-lapse seismic data-set than on a single data-set because changes of saturation in the interval swept by the water can noticeably alter the acoustic/elastic impedance of this part of the reservoir. This impedance change can be detected by time-lapse seismic comparisons. An example of this is given in Figure 3.3 below:



Baseline Survey **Repeat Survey** **Interpretation**

Fig. 3.3—Example of using time-lapse seismic to assess OWC movement.

These OWC changes as derived from the time-lapse seismic results can then subsequently be mapped out laterally and be used to update the static and dynamic reservoir models that underpin the Resources and Reserves volumes estimate.

In general, the seismic tool is useful in time-lapse mode as a check on the validity of the assumptions in the geologic model that is used in a reservoir simulation of fluid flow. 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. In general, the incorporation of time-lapse seismic results prompt geologic model updates that usually improve production history matches.

An example to illustrate this is presented below. In this case, time-lapse seismic results revealed an area in the west of the F block without 4D sweep (Figure 3.4, left panel), different from what was expected. New spectrally boosted 3D seismic (Figure 3.4, center panel) shows evidence for a normal fault cutting the F block into two separate blocks. The 3D horizon (Figure 3.4, right panel) shows that the downthrown block corresponds to the same area seen to be unswept on the time-lapse seismic (left panel).

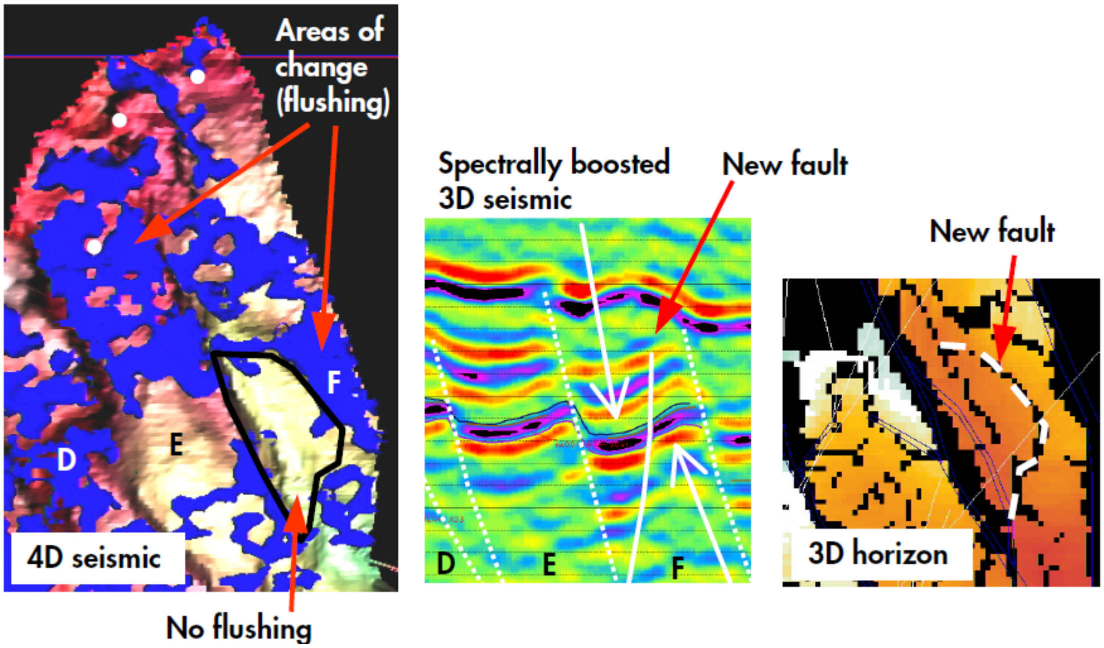


Fig. 3.4—Time-lapse seismic results indicate the presence of a sealing fault.

The new fault was incorporated in the model update, allowing for an improved history match by adjusting the fault seal properties. Simulated production data from the northern EF blocks prior to the time-lapse seismic results (Figure 3.5.lower left panel—solid lines) show a much later water breakthrough, as compared to actual production data (Figure 3.5 lower left panel—diamonds). Incorporating the new fault into the model, resulted in the bypassing the block (Figure 3.5 right panel) and greatly improved the timing of water breakthrough (Figure 3.5 lower left panel—dotted lines). As a result from incorporating the time-lapse seismic results, the bypassed volumes in the SW part of block F will have to be reclassified from Developed Reserves into Contingent Resources until further development activities are in place.

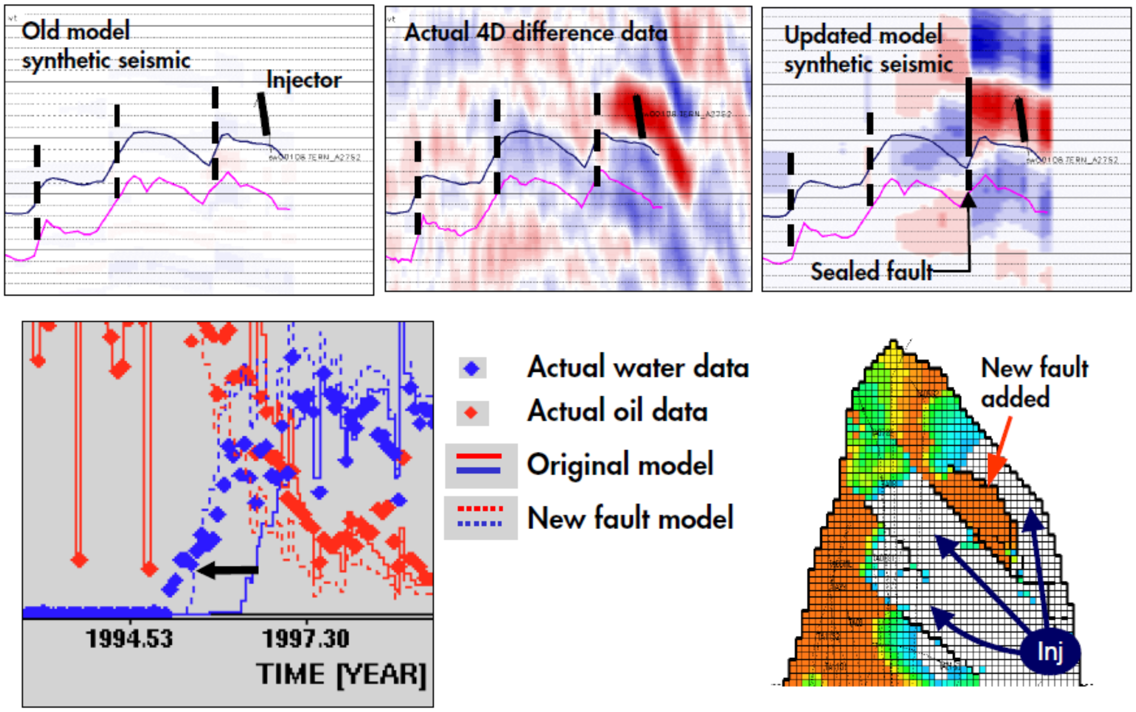


Fig. 3.5—Integration of time-lapse seismic results into Reservoir Simulation..

3.3 Uncertainty in Seismic Predictions

Predictions from 3D seismic data aimed at defining trap geometry, rock/fluid properties or fluid flow have an inherent uncertainty. The accuracy of a given seismic-based prediction is fundamentally dependent on the resulting interplay between

- The quality of the seismic data (bandwidth, frequency content, signal-to-noise ratio, acquisition and processing parameters, overburden effects, etc.)
- The uncertainty in the rock and fluid properties and the quality of the reservoir model used to tie subsurface control to the 3D seismic volume

A derived reservoir model that is accurately predicting a subsurface parameter or process as proven by drilling results from new wells has demonstrated a reduction in uncertainty and the current level of uncertainty can be revised accordingly after several successful predictions. Such a reservoir model is far more valuable than an untested reservoir model, even though the latter may be more sophisticated. Care should be taken extrapolating the results from new wells, if such programs targeted high amplitude or "sweet spot" and remaining targets are not in a similar setting. Appropriate consideration should be made regarding predictability.

It is useful to assess the track record of a given 3D seismic volume or of regional analogues 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 and

geology team members to determine if a project's seismic accuracy is better or worse than this general quantification.

3.3.1 Gross Rock Volume (GRV) of a Trap. The gross rock volume of a field is defined by structural elements, such as depth maps and fault planes resulting from an interpretation based on seismic and well data. Uncertainties in the GRV, and hence in the in-place volumes, reserves and production profiles, can arise from

- The incorrect positioning of structural elements during the processing of the seismic
- Incorrect interpretation
- Errors in the time to depth conversion

An assessment of these uncertainties is an essential step in a field study for evaluation, development, or optimization purposes.

It is important to appreciate that the relative uncertainty in predicting depth to a trapping surface at a new location, once the trap depth is precisely known at initial well locations, is much less than the errors 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. In addition to the uncertainties in the velocities, alternative interpretations of the seismic data are the major source of uncertainties in (green-field) exploration settings, affecting the evaluation of Prospective Resources.

3.3.2 Reservoir Bulk Volume. If the trap volume under the seal is completely filled with reservoir rock, the GRV of the trap is of course 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. Broadband, high-frequency seismic data in a shallow clastic section where velocity is relatively slow can resolve a much thinner bed than, for example, narrow- band, low-frequency seismic data deep in the earth in a fast, carbonate section. Fortunately, geoscientists can analyze seismic and sonic log data to estimate what thicknesses can reasonably be measured for particular reservoirs under investigation.

Stacked reservoirs in a trap can be individually resolved and separate reservoir bulk volumes can be computed if the reservoirs and their intervening seals can be interpreted separately and individually meet the minimum thickness derived from the relevant tuning model. 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 hydrocarbons might be present in a gross trapped volume. In some circumstances it may be possible to detune the seismic response of thin reservoirs to estimate the total net or gross reservoir. The reliability of these calculations will depend on a number of factors; bed thicknesses, spacing among beds, porosity variation, etc.

3.4 Seismic Inversion

Standard 3D seismic volumes display seismic amplitude in either travel time or depth. Conversion of seismic amplitude data to acoustic impedance (product of P-velocity and density) and shear impedance (product of S-velocity and density) volumes or related elastic parameters is still a growing field. The conversion process is called seismic inversion. There will typically be

a relationship between acoustic and shear impedance and lithology, porosity, pore fill and other factors and hence estimates of these parameters may be derived from an analysis of these relationships (a rock property model) combined with inverted seismic.

Inverted seismic data focuses on layers rather than interfaces, and 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.

Inversion requires the seismic to be combined with additional data and hence good-quality impedance inverted volumes will contain more information than a conventional seismic volume. Specifically additional data is required to compensate for the lack of low frequencies in the seismic. However, there will rarely be enough data to fully constrain the low-frequency component so inversion results will be nonunique. Because of this uncertainty, a probabilistic approach can be followed to try to capture the full range of possible outcomes. The uncertainty analysis should cover the nonuniqueness of the inversion process and the uncertainties arising from the rock property model. The probabilities of the various outcomes can then subsequently be used as input to Reserves and Resource volume assessments. However, estimating all the uncertainties in the process is difficult. Use of this technology would need to be supported by a strong track record. Additionally, a relationship between acoustic impedance or elastic impedance and petrophysical properties must be established at log scale resolution. The type of inversion method should also be considered as well as the confidence in the well-based background model used for generating the low frequency component.

An example of probabilistic seismic inversion is given below. In this example, the key uncertainty for estimation of in-place volumes is the net sand thickness distribution. Porosity variation within a reservoir unit is small, although there is a general trend where deeper reservoir levels have slightly lower porosity. Likewise, variation in oil saturation is small. However, variation in reservoir thickness and sand percentage is large. Probabilistic inversion was used to provide a better estimate of net sand distribution, and also to quantify the range of uncertainty. The inversion works on a layer-based model, where all input data are represented as grids. The inversion combines in a consistent manner the petrophysical and geologic information with the seismic data. Probability density functions for reservoir parameters such as layer thickness, net-to-gross, porosity and fluid saturations are obtained from well and geologic data with soft constraints obtained from seismic amplitudes. Using this prior information, the program then generates numerous subsurface models that match the actual seismic data within the limits set by the noise that is derived from the seismic data. The net sand maps in Figure 3.6 illustrate the probabilistic output from the inversion for low, mid, and high cases. Each map fits the well data used to constrain the model. The three net sand maps reflect the uncertainty in the net sand distribution and can be used to constrain three different “oil-in-place” scenarios in low-, mid- and high-case static models that can be carried through to reservoir simulation and are thus key input to the resource volume assessment and classification.

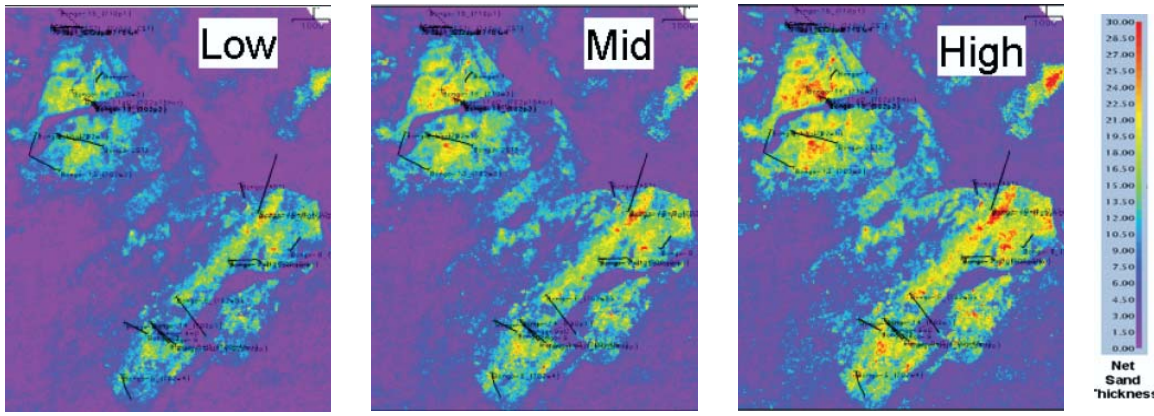


Fig. 3.6—Model-based, probabilistic seismic inversion provides low, mid, and high scenarios for net sand distribution, which is the main driver for variation in oil in place estimates.

Additional Reading

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Chapter 4

Assessment of Petroleum Resources Using Deterministic Procedures

Yasin Senturk

4.1 Introduction

This chapter provides additional guidance to the Petroleum Resources Management System (PRMS) Sec. 4.1 (SPE 2007) regarding the application of three broad categories of deterministic analytical procedures for estimating the range of recoverable quantities of oil and gas using (a) analogous methods, (b) volumetric methods, and (c) production performance analysis methods. During exploration, appraisal, and initial development periods, resource estimates can be "indirectly" derived only by estimating original in-place volumes using static-data-based volumetric methods and the associated recovery efficiency based on analog development projects, or using analytical methods. In the later stages of production, recoverable volumes can also be estimated "directly" using dynamic-data-based production performance analysis.

It must be recognized that PRMS embraces two equally-valid deterministic approaches to reserves estimation: the "incremental" approach and the "scenario" approach. Both approaches are reliable and arrive at comparable results, especially when aggregated at the field level; they are simply different ways of thinking about the same problem.

In the incremental approach, experience and professional judgment are used to estimate reserve quantities for each reserves category (Proved, Probable, and Possible) as discrete volumes. When performing volumetric analyses using the incremental approach, a single value is adopted for each parameter based on a well-defined description of the reservoir to determine the in-place, resources, or reserves volumes.

In the scenario approach, three separate analyses are prepared to bracket the uncertainty through sensitivity analysis (i.e., estimated values by three plausible sets of key input parameters of geoscience and engineering data). These scenarios are designed to represent the low, the best (qualitatively considered the most likely) and the high realizations of original in-place and associated recoverable petroleum quantities. Depending on the stage of maturity, these scenarios underpin the PRMS categorization of Reserves (1P, 2P, and 3P) and Contingent Resources (1C, 2C, and 3C) of the projects applied to discovered petroleum accumulations, or Prospective Resources (low, best, and high) of the undiscovered accumulations with petroleum potential.

The advantages of a deterministic approach are (a) it describes a specific case where physically inconsistent combinations of parameter values can be spotted and removed, (b) it is direct, easy to explain, and manpower efficient, and (c) there is a long history of use with estimates that are reliable and reproducible. Because of the last two advantages, investors and shareholders like the deterministic approach and it is widely used to report Proved Reserves for regulatory purposes. The major disadvantage of the deterministic approach is that it does not quantify the likelihood of the low, best and high estimates. Sensitivity analysis is required to assess both the upside (the high) and the downside (the low) estimates by respectively using

different values of key input reservoir parameters (geoscience and engineering data) to plausibly reflect that particular realization or scenario.

The guidance in this chapter is focused only on the deterministic methods where the range of uncertainty is captured primarily using a scenario approach. Chapter 5 provides guidance on applying probabilistic methods. The goal of this chapter is to promote consistency in reserves and resources estimates and their classification and categorization using PRMS guidelines.

Fig. 4.1 shows how changes in technical uncertainty impact the selection of applicable resources assessment method(s) for any petroleum recovery project over its economic life cycle.

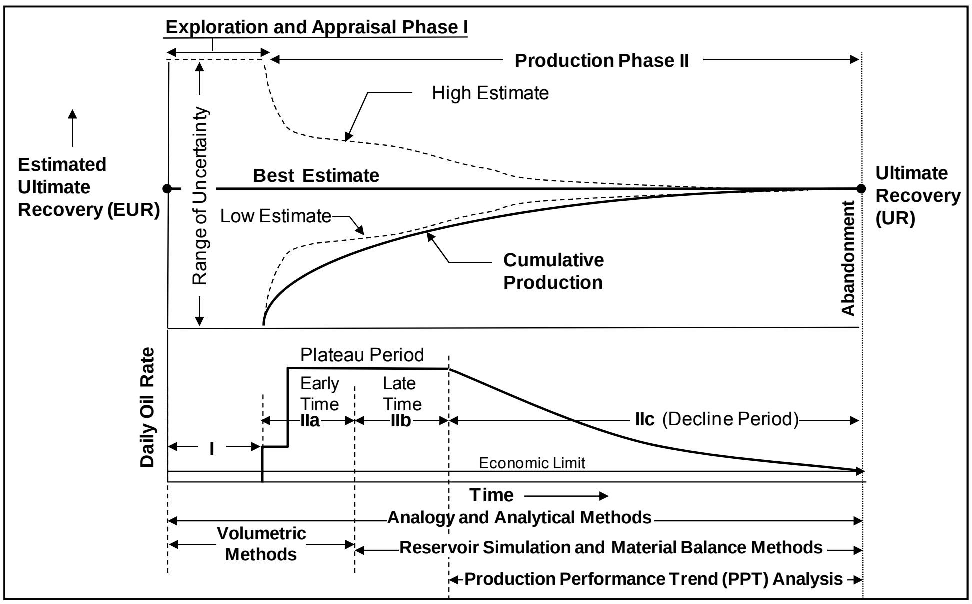


Fig. 4.1—Change in uncertainty and assessment methods over the project's E&P life cycle.

Fig 4.1 illustrates that the range of estimated ultimate recovery (EUR) of any petroleum project decreases over time as the accumulation is discovered, appraised (or delineated), developed, and produced, with the degree of uncertainty decreasing at each stage. Once discovered, the duration of each period depends both on the size of accumulation (e.g., appraisal period) and the development design capacity in terms of annual reservoir depletion rate (e.g., as % of reserves produced per year). For example, projects with lower depletion rates will support a relatively longer plateau period followed by a longer decline period, and vice versa. While the "best estimate" is conceptually illustrated as remaining constant, in actual projects there may be significant volatility in this estimate over the field appraisal and development life cycle.

Assessment of petroleum recoverable quantities (reserves and resources) can be performed deterministically by using both indirect and direct analytical procedures**,** involving the use of *the volumetric-data-based "static"* and the *performance-data-based "dynamic"* methods, respectively.

The selection of the appropriate method to estimate reserves and resources, and the accuracy of estimates, depend largely on the following factors:

- The type, quantity, and quality of geoscience, engineering, and economics data available and required for both technical and commercial analyses.
- Reservoir-specific geologic complexity, the recovery mechanism, stage of development, and the maturity or degree of depletion.

More importantly, reserves and resources assessment relies on the integrity, skill and judgment of the experienced professional evaluators.

4.2 Technical Assessment Principles and Applications

This section provides a technical summary description of the appropriate deterministic resource assessment methods applied to an example oil project in various stages of its maturity, retraced over its full E&P life cycle as depicted by phases and stages identified in Fig. 4.1. In addition, an example of reserves assessment of a nonassociated mature gas reservoir is included to demonstrate the use of the widely practiced production performance-based material balance method of (p/z) vs. cumulative gas production relationship. The focus is on assessment of risk and uncertainty and how these are represented by PRMS classes and categories of petroleum reserves and resources.

4.2.1 Definition of the Example Oil Project—Setting the Stage. Since it is used to demonstrate the applications of each major assessment method using deterministic procedures, it is important to set the stage and describe the example oil reservoir and point out its distinguishing characteristics.

Fig. 4.1a shows the time line and the assessment methods used to estimate the example project's in-place and recoverable oil and gas volumes at different stages of project maturity.

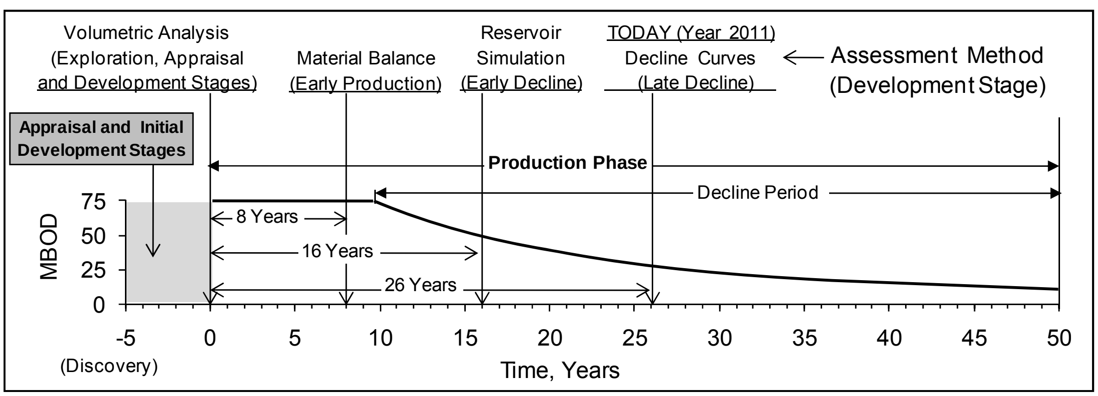


Fig. 4.1a—Timeline for example oil project maturity stages and assessment methods used.

The example oil reservoir represents a typical accumulation in a mature petroleum basin containing extremely large structures with well-established regional reservoir continuity and numerous adjacent analog development projects. Therefore, the project scale and internal confidence in reservoir limits may not be typical for assessments carried out in other petroleum basins. It is a very prolific carbonate reservoir located onshore. Analog projects with varying sizes have already produced over 60% of their respective EURs from the same geological formations in the same petroleum basin, all depleted under well-established and effective peripheral water injection schemes implemented initially at project start-ups.

In general, because of the leverage of having high-quality large oil reservoirs with excess development potential relative to market needs prevalent in the Middle East, the ways these reservoirs are developed and produced may be significantly different than those commonly practiced elsewhere. These reservoirs were developed at relatively low depletion rates, ranging from 2 to 4% of EUR per year, which means

- Low development size (e.g., level of daily plateau oil production rate) naturally necessitated reservoir development in stages. For example, instead of drilling most of the well-spacing units (WSU's) initially at once to achieve higher daily production rates, it was common to drill only a fraction (20 to 30%) of them to achieve the target rate. The number of producers depends on their established Productivity Indices (PIs). As a result, annual drilling continues over extended periods (sometimes exceeding 50 years) to sustain the target plateau production rate as long as possible to better manage decline and improve overall reservoir volumetric sweep efficiency.
- Longer plateau periods are followed by relatively low annual decline rates and longer decline periods and project economic lives, sometimes exceeding 100 years. In reality, the project lives will eventually be shortened to 50–70 years as the approaching planned artificial lift and EOR projects are implemented to both accelerate production (e.g., higher depletion rates) and increase ultimate recovery. Moreover, longer project lives are very beneficial because:
    - It allows the operator to take advantage of new technological applications that may not be available in other reservoirs with shorter lives and thus potentially benefiting from lower capital and operating costs. It also defers capital costs for delayed EOR projects.
    - Growth in water production (or water-cut) is relatively low because of peripheral water injection and low depletion rates. Lower and slow growth in water-cuts help delay the need for installation of artificial lift facilities and again defers costs.

Note that for purposes of this oil example project, all associated raw gas volumes are deemed to be transferred to the host government at the wellhead before shrinkage for condensate recovery and/or subsequent processing to remove nonhydrocarbons and natural gas liquids (NGLs) to yield marketable natural gas. Thus, gas volumes are excluded from entitlement to the license holder. For more details, readers should refer to Chapters 9 and 10 on production measurements, reporting, and entitlement.

Many other important and more complex project-specific issues that may require different interpretations, judgments, and resolutions by the analysts are not addressed. The main objective of this chapter is to illustrate the applications of the major petroleum resources assessment procedures for estimating plausible ranges of project in-place and recoverable quantities that are deemed to be "reasonable," "technically valid," and are "compliant" with PRMS guidance.

4.2.2 Volumetric and Analogous Methods. Static data-based volumetric methods to estimate petroleum initially in-place (PIIP) and analogous methods to estimate recovery efficiencies are the indirect estimating procedures used during exploration, discovery, post-discovery, appraisal, and initial development (or exploitation) stages of the E&P life cycle of any recovery project.

a.) Technical Principles. These procedures may be called "indirect" because the EUR cannot be derived directly, but requires independent estimates of reservoir-specific PIIP volume and appropriate recovery efficiency (RE). It is generally expressed in terms of a simple classical volumetric relationship defined by

$$\text{EUR (STB or scf)} = \text{PIIP (STB or scf)} \times \text{RE (fraction of PIIP)} \tag{4.1a}$$

In terms of average variables of area (A), net pay (h), porosity (ϕ), initial water saturation (S_{wi}) and hydrocarbon formation volume factor (FVF) (B_{hi}) for oil (RB/STB) or gas (Rcf/scf), the generalized classic volumetric equation for the PIIP [oil initially in place (OIIP) or gas initially in place (GIIP)] is given by

$$\text{PIIP (STB or scf)} = A\ h\ \phi\ (1 - S_{wi})\ /\ B_{hi}, \tag{4.1b}$$

where oil or gas volumes are in barrels or cubic feet, abbreviated as STB and RB or scf and Rcf, representing the measurements at standard surface (s) and reservoir (R) conditions, respectively, based on respective pressures and temperatures.

For each petroleum resource category, the estimates of PIIP are determined volumetrically using Eq. 4.1b. However, an independently estimated RE is necessary to calculate project EUR. Recovery efficiency may be assigned from appropriate analogs, using analytical methods or, as a last resort, using published empirical correlations.

PRMS encourages the use of available analogs to assign RE. The rationale for the selection of analogous reservoirs are well provided for in Cronquist (2001) and Harrell et al. (2004) and in the PS-CIM publications (2004, 2005, and 2007). Technical principles of natural and supplementary oil recovery mechanisms and analytical procedures to estimate recovery efficiency may be found in many references, including Cronquist (2001), Walsh and Lake (2003), and Dake (1978 and 2001) (for natural reservoir drives); Craig (1971), Smith (1966), and Sandrea and Nielson (1974) (immiscible water and gas injection schemes for pressure maintenance); Taber and Martin (1983) [enhanced oil recovery (EOR) screening]; Prats (1982) and Boberg (1988) (thermal processes); Lake (1989) and Latil (1980) (polymer flooding); and Dake (1978), Stalkup (1983), Klins (1984), Lake (1989), Green and Willhite (1998), and Donaldson *et al.* (1985) (miscible processes and chemical methods of micellar-polymer and alkaline-polymer flooding). For a quick review, PS-CIM (2004) and Carcoana (1992) are recommended. Finally, the published empirical correlations to estimate RE can be found in many references, including Cronquist (2001), Walsh and Lake (2003), and Craig (1971). However, it should be emphasized that even a rough estimate of recovery efficiency from a near-analog or determined by using a physically based analytical method is preferable to using empirical correlations.

With the availability of computational power and integrated work-processes, these analytical procedures may be supplemented by recovery process-specific reservoir simulation model studies. Rigorous models may effectively predict not only any reservoir-specific recovery performance including EOR, but also incorporate the ever-changing recovery enhancing practices resulting from the successful application of field-tested drilling and completion (e.g., multilateral, extended-reach and smart wells with inflow-control devices, etc.), reservoir development and production engineering technologies that optimize the overall flow system starting from reservoir through well completions, wellbore and the surface facilities and pipelines.

b.) Applications to Example Oil Project During Its Exploration and Appraisal Phase and Initial Development Stage. Geological maps for an example petroleum project during these phases and different stages within each phase (see **Figs. 4.2** through **4.5**) were re-created through a look-back process. These maps were developed and associated net reservoir rock volumes

were estimated by Wang (2010). However, the appraisal and development plans described estimates of PIIPs and recoverable volumes including the assignment of different categories of reserves and resources were made by the author.

Excellent guidance on how to construct better maps and minimize mapping errors is provided by Tearpock and Bischke (1991). Moreover, Harrell et al. (2004) provides an excellent review on the complex nature of the reserves assessment process, the use of analogs, and recurring mistakes and errors, including subsurface mapping.

Based on the PRMS definitions and guidelines, assessment and assignment of different categories of resources and reserves for the example oil project during its E&P life cycle stages are presented below.

*Prediscovery Stage***.** In the prediscovery stage, the range of Prospective Resources is estimated based on a combination of volumetric analyses and use of appropriate analogs. The geological realization of this "exploratory prospect" shown in Fig. 4.2a was developed based on a combination of seismic and geological studies that define the shape and closure for potentialpetroleum accumulation. The 2D seismic defined a structural spill point, but provided no indication of fluid contacts. Based on the analog carbonate reservoirs, it was assumed that this exploratory petroleum prospect would most likely contain light crude with gravity 30 to 33^{o} API.

The volumetric assessment process starts with the estimate of gross reservoir rock volume depicted by the cross section presented as Fig. 4.2a. Based on regional analogs, the high estimate assumed the structure to be fully charged to its spill point at 6,410 ft subsea. The volume above 6,120 ft subsea was assigned conservatively to represent the low estimate and the vertical limit for the best estimate was set at an intermediate depth of 6,265 ft subsea. Typically, information on regional and local geology are used to construct net-to-gross (NTG) maps (obtained from the nearby analog reservoirs after applying parameter cutoffs to exclude portions of the reservoir that do not meet the minimum criteria to support production), and integrated with gross reservoir volume to yield net pay maps. In this case, analysts applied a constant average NTG ratio of 0.70. The net pay isochore maps depicted as Figs. 4.2b, 4.2c, and 4.2d were developed, representing the reservoir pay volumes for low, best, and high estimate scenarios, respectively. The vertical and areal extent associated with each scenario is illustrated in these maps.

Furthermore, the chance of discovery was estimated at 40% based on independent assessments of source rock, trap integrity, reservoir adequacy, and regional migration paths. The chance of such a technical success being commercially developed, or the chance of development, is estimated at 60% based on analysis of economic scenarios and assessment of other commercial contingencies. Hence, the overall chance of commerciality of this exploratory prospect, defined as the product of these two risk components is estimated to be 24%.

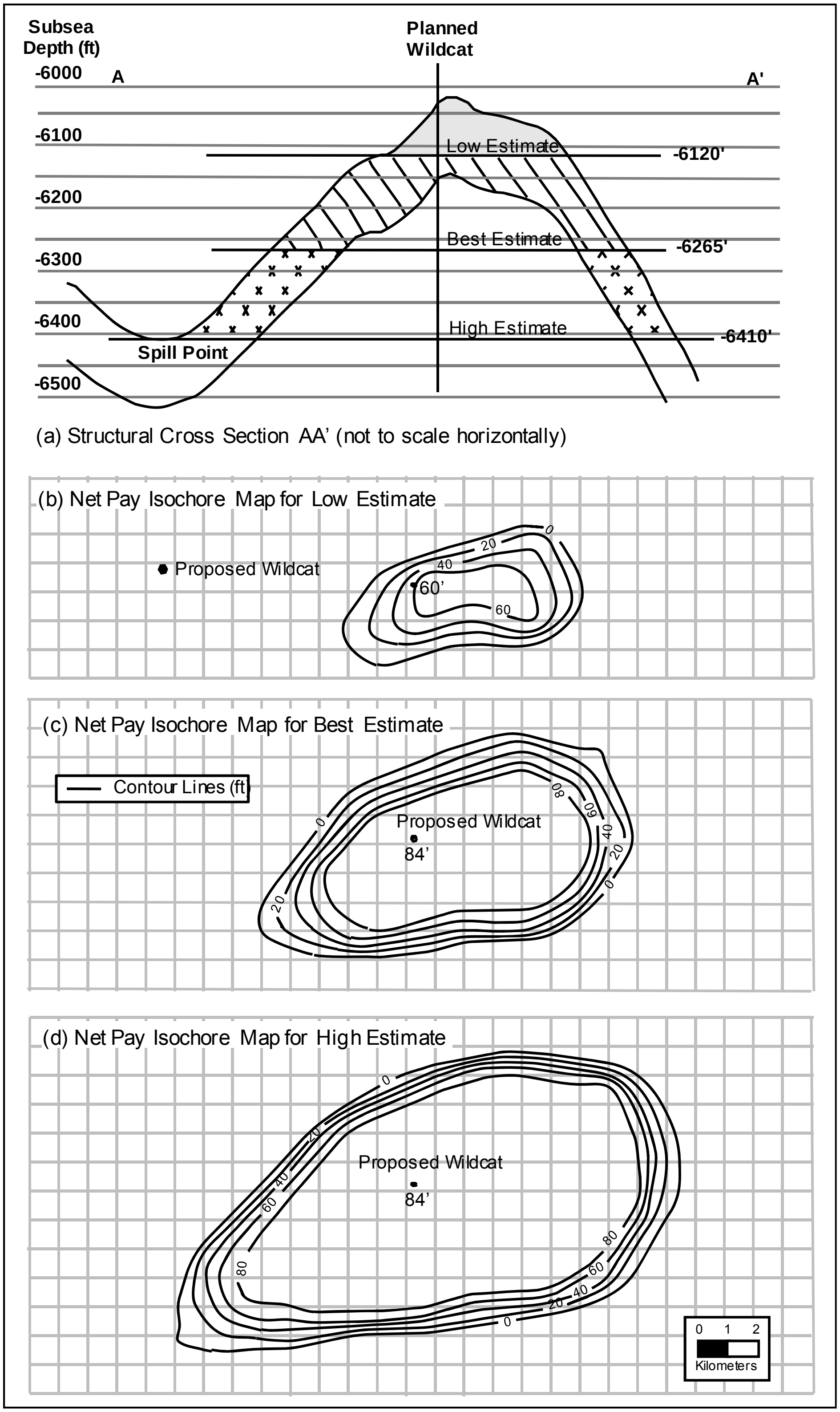


Fig. 4.2—Volumetric assessment of Prospective Resources: *prediscovery stage* [Wang (2010)].

Assuming a discovery, **Table 4.1** documents the estimates of average reservoir parameters (i.e., rock and fluid properties, and a range of recovery efficiencies expected from peripheral water injection projects already implemented and well-established in several similar nearby reservoirs), and the resulting estimates of oil and gas volumes of these yet undiscovered Prospective Resources**.** As poorer reservoir quality in peripheral areas was included in the volumes of each successive resource category, the expected average value of porosity (or initial water saturation) was decreased (or increased).

Table 4.1—Volumetric Assessment of Prospective Resources (Prediscovery Stage): Estimates of Project PIIPs and EURs

		Bases and Categories of **Prospective Resources**		
Estimated Parameters	Units	Low Estimate	Best Estimate	High Estimate
Bulk Reservoir Pay Volume	M ac-ft	241.4	1,055.6	2,134.7
Average Porosity	%	17%	16%	15%
Pore Volume (PV)	M ac-ft	**41.0**	**168.9**	**320.2**
Average Initial Water Saturation	%	18%	19%	20%
Hydrocarbon Pore Volume (HCPV)	M ac-ft	**33.7**	**136.8**	**256.2**
Average FVF (B_{oi})	RB/STB	1.4	1.4	1.4
Oil Initially In-Place (OIIP)	MMSTB[1]	**186.5**	**758.1**	**1,419.5**
Recovery Factor[2]	% OIIP	35%	40%	45%
Recoverable Oil(EUR)*	MMSTB	**65.3**	**303.2**	**638.8**
Initial Solution Gas-Oil Ratio (R_{si})	scf/STB	500	500	500
Gross-Heating Value of Raw Solution Gas	Btu/scf	1,200	1,200	1,200
Gas Initially In-Place (OGIP)	Bscf	**93.2**	**379.0**	**709.8**
Recoverable Raw Gas (EUR)*	Bscf	**32.6**	**151.6**	**319.4**
	MMBOE[3]	6.8	31.4	66.1

[1] Calculated by using the conversion factor of 7,758 bbl/acre-ft.
[2] Under Peripheral Water Injection, already well-established in several nearby analog reservoirs and projects.
[3] Calculated using an average conversion factor of 5.8 MMBtu per BOE.
* Estimated Oil and Gas Prospective Resources categories of **Low, Best** and **High**, respectively.

Post-Discovery Stage. The wildcat well was drilled and encountered a significant oil column sufficient to declare a "discovery." The geologic model was updated as Fig. 4.3 for the discovered structure and well-based reservoir data with an estimated average NTG ratio of 0.75, translating into a net pay of 89 ft.

The discovery Well 1 flowed oil, but insufficient pressure data were retrieved and gradient analysis could not be performed, thus the low estimate of technically recoverable volume could not be allocated below the lowest known hydrocarbon (LKH) at 6,155 ft subsea.

Although preliminary economics of a proposed development plan were encouraging, there was still significant uncertainty, and the chance of its commercial development was estimated to be only 60%. Therefore, estimates of technically recoverable volumes of this discovered accumulation could only be reclassified as Contingent Resources. Even though the chance of an updip gas cap above the highest known hydrocarbon (HKH) could not be ruled out, the majority of analog reservoirs are undersaturated and hence, for simplicity, it was neglected while developing these maps and until the detailed pressure/volume/temperature (PVT) analysis and pressure-gradient data became available for confirmation.

High estimate (3C) assumed that the structure is full with oil to its spill point, and alternative geologic maps indicated a larger closure and higher recovery efficiency. Lacking any further control than the LKH, which defined the 1C limit, regional analogs supported the forecast that

the vertical limit for the best estimate (2C) could be set at an intermediate depth of 6,283 ft subsea and that the recovery efficiency is slightly above that assumed for the 1C scenario. Based on the discovery well structure and log data, and an average oil gravity of 32^o API measured from the oil samples collected, the volumetric weighted average reservoir parameters were revised accordingly, but recovery factors were kept the same at this stage.

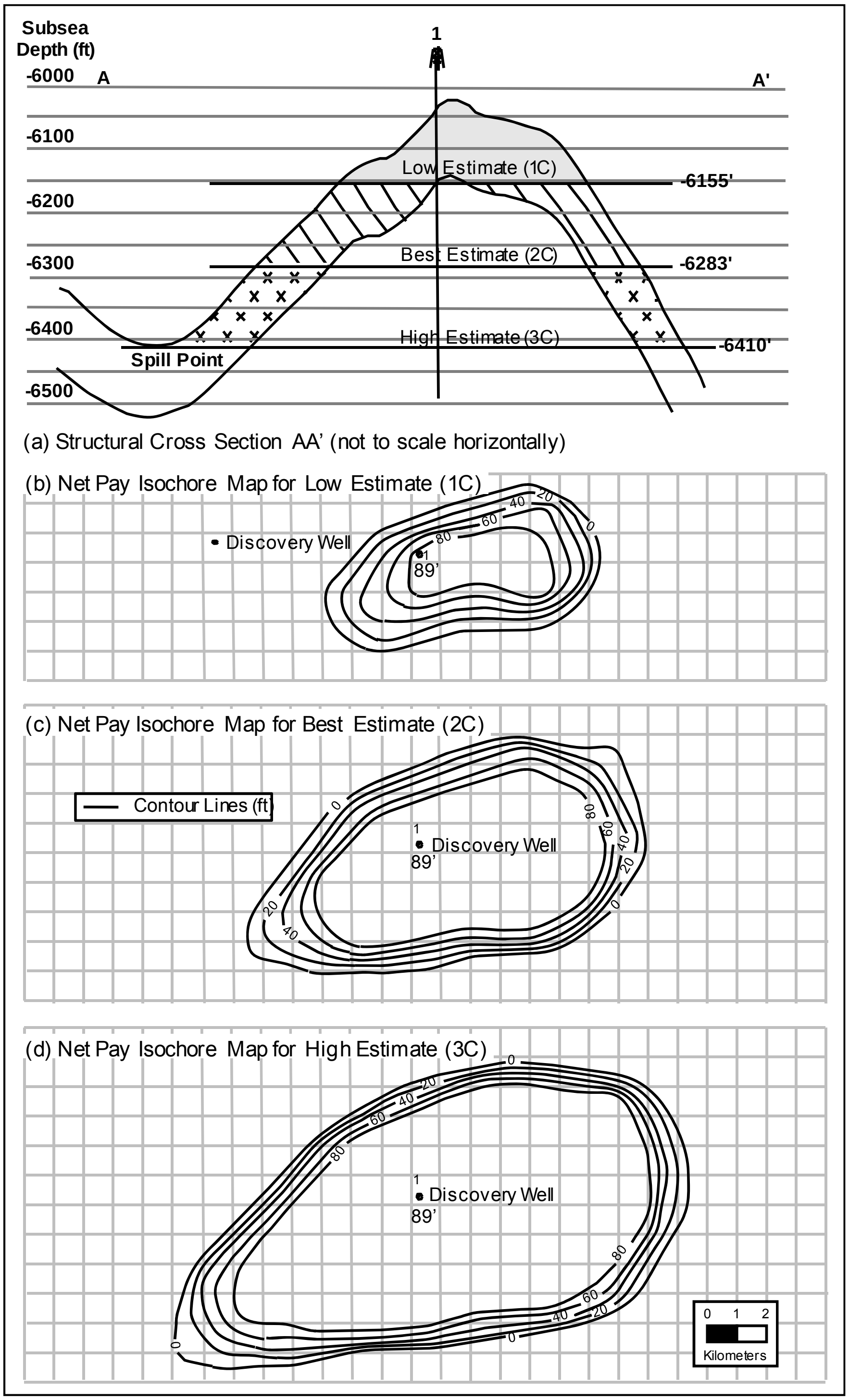


Fig. 4.3—Volumetric assessment of Contingent Resources: post-discovery stage [Wang (2010)]

Table 4.2 documents average reservoir rock and fluid properties, and resulting estimates of relevant volumes of oil and gas for Contingent Resources. Note again that the "average" porosity is lower in the 2C and 3C scenarios, reflecting decreasing porosity (and increasing water saturation) in the peripheral areas included in the higher estimates of bulk reservoir pay volume.

Table 4.2—Volumetric Assessment of Contingent Resources (Post-Discovery Stage): Estimates of Project PIIPs and EURs

		Bases and Categories of **Contingent Resources**		
Estimated Parameters	Units	Low Estimate	Best Estimate	High Estimate
Bulk Reservoir Pay Volume	M ac-ft	448.4	1,258.7	2,287.1
Average Porosity	%	19.1%	18.9%	18.7%
Pore Volume (PV)	M ac-ft	**85.6**	**237.9**	**427.7**
Average Initial Water Saturation	%	14.5%	14.8%	15.2%
Hydrocarbon Pore Volume (HCPV)	M ac-ft	**73.2**	**202.7**	**362.7**
Average FVF (B_{oi})	RB/STB	1.4	1.4	1.4
Oil Initially In-Place (OIIP)	MMSTB[1]	**405.8**	**1,123.2**	**2,009.8**
Recovery Factor[2]	% OIIP	35%	40%	45%
Recoverable Oil(EUR)*	MMSTB	**142.0**	**449.3**	**904.4**
Initial Solution Gas-Oil Ratio (R_{si})	scf/STB	500	500	500
Gross-Heating Value of Raw Solution Gas	Btu/scf	1,200	1,200	1,200
Gas Initially In-Place (OGIP)	Bscf	**202.9**	**561.6**	**1,004.9**
Recoverable Raw Gas (EUR)*	Bscf	**71.0**	**224.6**	**452.2**
	MMBOE[3]	14.7	46.5	93.6

[1] Calculated by using the conversion factor of 7,758 bbl/acre-ft.
[2] Under Peripheral Water Injection, already well-established in several nearby analog reservoirs and projects.
[3] Calculated using an average conversion factor of 5.8 MMBtu per BOE.
* Estimated Oil and Gas Contingent Resources categories of **1C, 2C** and **3C**, respectively.

At this stage, remaining uncertainty in the project's commercial development was still considered significant, and without the benefit of additional data (e.g., from further delineation, bottomhole PVT samples, pressure-gradient and definitive production tests and associated analysis), the owners were not willing to commit funds to a development project. To better ascertain its commercial potential, an appraisal program designed to further evaluate the discovery was deemed necessary.

Appraisal (or Delineation) Stage. An appraisal program was designed and implemented, including (1) drilling of two additional wells with well testing and PVT analysis, and (2) acquisition and interpretation of 3D seismic data. It took two years to execute the Appraisal Program and complete the necessary analyses and interpretations.

Both Wells 2 and 3 penetrated and established new LKH depths, thereby extending the base for the low estimate to 6,240 ft subsea. PVT analysis of bottomhole fluid samples showed that oil was undersaturated. Undersaturated oil, supported also by pressure-gradient measurements, eliminated the potential for a gas cap. It was further determined that

- The carbonate reservoir had an initial pressure (p_i) of 3,230 psia, temperature of 200°F, estimated average porosity of 18.7%, 15% initial water saturation, and 400 md permeability.
- The wells tested at rates (rounded to the lower 100) ranging from 2,500 to 5,000 BOPD, with an average stabilized oil rate of 3,500 BOPD, oil gravity of 33°API, and viscosity of 0.7 cp.
- The reservoir had a bubblepoint pressure (p_b) of 1,930 psia, initial solution gas/oil ratio (GOR), or R_{si}, of 550 scf/STB, and initial (B_{oi}) and bubblepoint (B_{ob}) FVFs of 1.33 RB/STB and 1.35 RB/STB, respectively.

Fig. 4.4 illustrates the revision made for additional data obtained from this appraisal program. Based on the net reservoir distribution (via NTG ratios) in Well 1 (0.75), Well 2 (0.70), and Well 3 (0.55), a NTG surface was generated and used to develop the map views (Figs 4.4b to 4.4d), illustrating the interpreted areal extent and net reservoir volume for each reserves category.

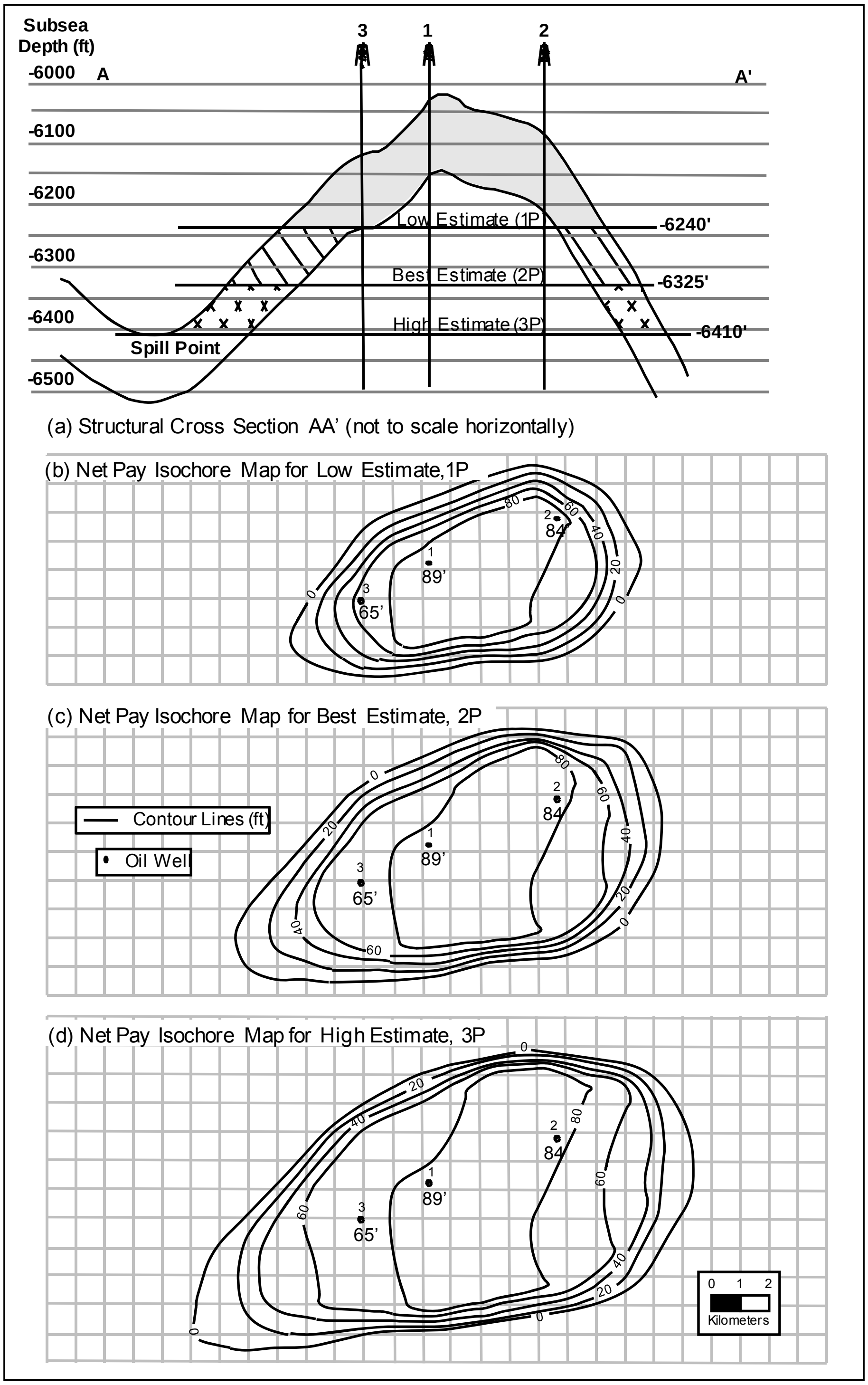


Fig. 4.4—Volumetric assessment of Reserves: appraisal stage [Wang (2010)]

An initial development program including pressure maintenance by means of peripheral water injection was applied. This recovery method is a well-established and common depletion method in several analog reservoirs and projects. With favorable project economics, the owners committed investment funds to the project and gave approval to proceed with the next development stage. No market, legal, or environmental contingencies were foreseen. Therefore, consistent with PRMS, the new estimates of recoverable quantities from the applied project are now reclassified as Reserves.

1P Reserves were assigned to the PIIP volume above the LKH established at 6,240 ft subsea. Although seismic amplitude analysis indicated potential extending below the LKH, it was insufficient to support extending Proved Reserves below this LKH depth. 2P Reserves were allocated to the total PIIP volume above 6,325 ft subsea. In the absence of original oil/water contact (OWC), 3P Reserves were assigned to the total PIIP volume above 6,410 ft subsea (or spill point). Three wells and 3D seismic data provided increased structural control. Based on similar regional analogs, there was reasonable potential that the structure was filled with oil to the spill point.

It may be important to note that in deterministic analysis, both scenario and incremental approaches (allowed by PRMS) generate the materially equivalent estimates. Based on the bulk reservoir pay volume associated with each incremental category obtained from the difference between the relevant maps, the incremental approach can also be used to directly calculate the Proved, Probable and Possible Reserves. Estimates should be very consistent with those obtained from the cumulative (scenario) approach provided that care is taken in estimating reasonable average values of porosity and initial water saturation for each incremental volume to yield correct the PIIPs. For simplicity in presentation, incremental analyses are not included here.

Table 4.3 documents the revised average reservoir rock and fluid properties, and resulting estimates of relevant oil and gas volumes for each reserves category. The project is located close to existing infrastructure; therefore, an overall development plan was prepared for immediate implementation.

Table 4.3 — Volumetric Assessment of Reserves (Appraisal Stage): Estimates of Project PIIPs and EURs

		Bases and Reserves Categories		
Estimated Parameters	Units	**Low Estimate**	**Best Estimate**	**High Estimate**
Bulk Reservoir Pay Volume	M ac-ft	821.0	1,370.8	1,917.9
Average Porosity	%	18.9%	18.7%	18.5%
Pore Volume (PV)	M ac-ft	**155.2**	**256.3**	**354.8**
Average Initial Water Saturation	%	14.8%	15.0%	15.3%
Hydrocarbon Pore Volume (HCPV)	M ac-ft	**132.2**	**217.9**	**300.5**
Average FVF (B_{oi})	RB/STB	1.330	1.330	1.330
Oil Initially In-Place (OIIP)	MMSTB[1]	**771.2**	**1,271.0**	**1,753.0**
Recovery Factor[2]	% OIIP	35%	40%	45%
Recoverable Oil(EUR)*	MMSTB	**269.9**	**508.4**	**788.8**
Initial Solution Gas-Oil Ratio (R_{si})	scf/STB	550	550	550
Gross-Heating Value of Raw Solution Gas	Btu/scf	1,200	1,200	1,200
Original Gas In-Place (GIIP)	Bscf	**424.1**	**699.0**	**964.1**
Recoverable Raw Gas (EUR)*	Bscf	**148.4**	**279.6**	**433.9**
	MMBOE[3]	30.7	57.9	89.8

Calculated by using the conversion factor of 7,758 bbl/acre-ft.

Under Peripheral Water Injection, already well-established in several nearby analog reservoirs and projects.

Calculated using an average conversion factor of 5.8 MMBtu per BOE.

Estimated Oil and Gas Reserves categories of **1P, 2P** and **3P,** respectively.

The total area, about 60 1-km WSUs, defined as Proved by three wells in this example reflects an extremely high confidence in the lateral continuity of the productive reservoir. Such continuity of a high-quality reservoir with average permeability of 400 md was also supported by numerous surrounding analogs. Thus, it meets PRMS criteria for reasonable certainty**.** 1P reserves are considered Proved Undeveloped (PUD) status for now. However, based on a well drainage area of 1 km^2 (or about 250 acres) derived from single-well simulation studies, at least three 1-km WSUs (out of a total Proved of about 60) penetrated by these three productive wells represent a portion of approximately 5% of the total Proved volume (or about 38.5 MMSTB of the OIIP), which can be carried under Proved Developed (PD) status immediately after the installation of necessary equipment.

Initial Development (or Exploitation) Stage. Similar to well-established development and production practices in several nearby analogs producing from the same reservoir, a single recovery project integrating the primary and secondary waterflood development programs was recommended and approved for immediate implementation. The project was designed with an initial plateau production rate of 75,000 BOPD targeting an annual depletion of 5.4% of 2P reserves of 508.4 MMSTB (from Table 4.3) and supported by peripheral water injection with an injection rate of 100,000 BWPD. Pressure maintenance by peripheral water injection had been established to be a very effective depletion method in several nearby analog projects where the water injected into a partially active edgewater aquifer displaces the oil column updip thereby achieving oil recoveries, in some cases, exceeding 60% OIIP.

Based on an assumed conservative average well production rate that may vary between 2,500 and 3,000 BOPD, the initial development project required a total of 34 producers (including the three existing productive wells) to establish a balanced withdrawal fieldwide. The time line accounted for an operating factor in production rate considering annual downtime for preventive maintenance of surface facilities, including inspection, repairs, and testing. The project also required eight water supply wells from a local shallow aquifer and 19 peripheral water injectors (to inject produced plus externally supplied water) to maintain reservoir pressure and to provide balanced updip displacement. The project included pertinent surface production and injection facilities and associated pipelines. Based on this well-defined development plan, the production profile and required initial capital investment (for drilling and well completions, well flowlines, surface production and injection facilities and pipelines), and future capital (for future wells and flowlines) and operating expenditures required during the project's economic life, the recovery project's economic viability was reconfirmed. The approval was given to include the project in the company's capital budget.

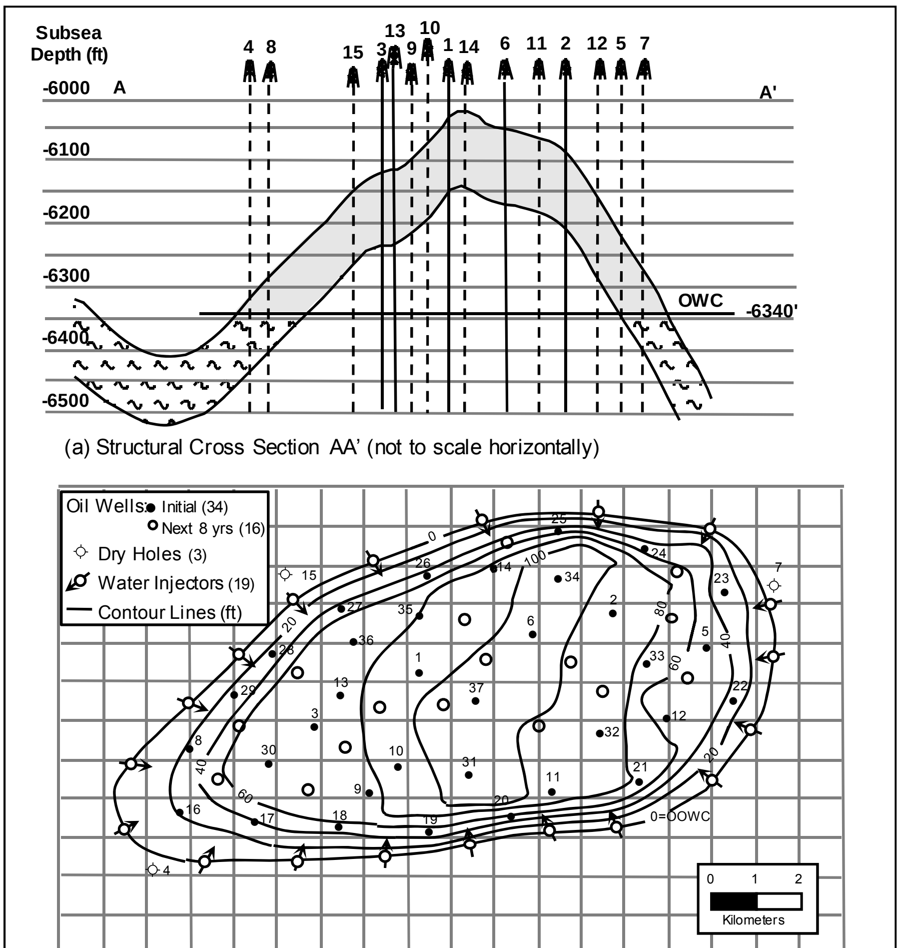
The project development took 3 years to complete and bring on stream in the fourth year (or just 3 years after appraisal and 5 years after the initial discovery). First, a total of 8 water supply wells (from a shallow and large regional aquifer already proven to be productive and supporting water injection in several other fields) and 34 additional oil wells in this example oil reservoir were drilled that included three dry holes (Wells 4, 7, and 15). It was followed by drilling the 19 water injectors at the periphery. The example oil reservoir was significantly delineated by these 56 wells. The original OWC was established at 6,340 ft subsea by well logs and supported by analysis of pressure-gradient data.

Fig. 4.5a represents the cross section based on the revised interpretation. Wells illustrated by dashed lines on this cross section are projected. The net pay isochore map (Fig. 4.5b) was developed with NTG ratios ranging from 0.3 to 0.9 (with majority greater than 0.7) obtained

from the well logs and available cores, and supported further by full production tests conducted in six more strategically placed wells. Measured stabilized well rates and estimated reservoir permeability from buildup tests had ranged from 1,500 to 5,000 BOPD, and 150 to 500 md, respectively, with overall reservoir averages estimated to be about 2,500 BOPD and 350 md.

The reservoir parameters entered for each polygon are the volume-weighted averages. Because several wells penetrated the original OWC at 6,340 ft subsea, the entire enclosure was judged to represent a single most likely OIIP estimate of about 1,430 MMSTB. Based on similar nearby analog reservoirs with minor changes in reservoir structure and average reservoir parameters (and their distributions), developing separate OIIP for each reserves category was considered unwarranted by analysts at the time. It is recognized that this may not be typical of other developments where significant uncertainty associated with in-place volumes persists into late stages of development. In all cases, uncertainty should decrease over time as the amount and quality of data improves, including periodic updates of PIIPs using performance-based methods.

It may be important to note that Fig. 4.5b depicts the well requirements (in black dots) for *initial development* only, representing just over one-third of the total WSUs available. Additional drilling of oil producers (and a few water injectors) was carried out during the later stages of the



(a) Structural Cross Section AA' (not to scale horizontally)

(b) Net pay isochore map and depiction of wells for initial development plan and beyond

Fig. 4.5—Volumetric assessment of Reserves (initial development stage).

production phase (e.g., 16 producers, not numbered but shown in hollow circles were actually drilled during the first 8 years of production) to extend the plateau production rate, to help improve volumetric sweep, and to better manage the production decline. More wells were drilled during the later stages to fully develop the reservoir.

As compared with its appraisal stage, the reservoir was significantly delineated, and analyses of an additional 31 productive oil well logs and tests indicated a better average reservoir quality than that seen in analogs. Thus, the recovery efficiencies for all reserves categories were increased modestly by 5% OIIP from their respective levels in the appraisal phase, bringing the high estimate to 50% OIIP. However, these estimates would be revised in future re-assessment studies as additional production data was obtained and new wells were drilled.

Reservoir average rock and PVT data were revised and documented in **Table 4.4.** With the revised OIIP (1,429.6 MMSTB) and increased reserves, the initial plateau production rate of 75,000 BOPD represented an annual depletion rate of only 4.3% of 2P reserves.
Analysis of six additional well tests and several single-well simulation studies have further supported the validity of 1 km^2 (or about 250 acres) average well spacing. There were approximately 98 1-sq-mile WSUs in the area described by the original OWC. Although wells were not necessarily drilled in the center of each WSU (Fig. 4.5b), about 35 WSUs (or about 36% of total) may be allocated to the Proved Developed (PD) reserves status. Therefore, under PRMS guidelines and as described in the Appraisal Stage earlier, based on the developed OIIP portion of 514.5 MMSTB (refer to Table 4.4), 25.7 MMSTB (= 514.7 x 0.05) oil and 14.7 Bscf raw gas from the recoverable volumes assigned to both 2P and 3P can be allocated to Developed status in Table 4.4, but were not shown separately here to keep the table as simple as possible.

Table 4.4—Volumetric Assessment of Reserves (Initial Development Stage): Estimates of Project PIIPs and EURs

		Bases and Reserves by Category and Status				
		Proved	Proved Status*			
Estimated Parameters	Units	Low Estimate	Proved Developed (PD)	Proved Undeveloped (PUD)	Best Estimate	High Estimate
Bulk Reservoir Pay Volume	M ac-ft	**1,523.3**	**548.4**	**974.9**		
Average Porosity	%	19%	19.0%	19.0%		
Pore Volume (PV)	M ac-ft	**289.4**	**104.2**	**185.2**		
Average Initial Water Saturation	%	15%	15.0%	15.0%		
Hydrocarbon Pore Volume (HCPV)	M ac-ft	**246.0**	**88.6**	**157.4**		
Average FVF (B_{oi})	RB/STB	1.335	1.335	1.335		
Original Oil In-Place (OIIP)	MMSTB[1]	**1,429.6**	**514.7**	**915.0**	**1,429.6**	**1,429.6**
Recovery Factor[2]	% OIIP	40%	40%	40%	45%	50%
Recoverable Oil(EUR)*	MMSTB	**571.9**	**205.9**	**366.0**	**643.3**	**714.8**
Initial Solution Gas-Oil Ratio (R_{si})	scf/STB	570	570	570	570	570
Gross-Heating Value of Raw Solution Gas	Btu/scf	1,350	1,350	1,350	1,350	1,350
Original Gas In-Place (GIIP)	Bscf	**814.9**	**293.4**	**521.5**	**814.9**	**814.9**
Recoverable Raw Gas (EUR)*	Bscf	**326.0**	**117.3**	**208.6**	**366.7**	**407.4**
	MMBOE[3]	75.9	27.3	48.6	85.4	94.8

[1] Calculated by using the conversion factor of 7,758 bbl/acre-ft.
[2] Under Peripheral Water Injection, already well-established in several nearby analog reservoirs and projects.
[3] Calculated using an average conversion factor of 5.8 MMBtu per BOE.
* Estimated Oil and Gas Reserves categories of **1P, 2P** and **3P,** respectively.

Finally, the example oil project's EOR potential is supported by the results of a miscible CO_2 pilot project from an analog reservoir with incremental recovery of 20% OIIP. Based on the same single project OIIP estimate, three categories of Contingent Resources were assigned for this potential project using conservative incremental recovery efficiencies of 5%, 10%, and 15% OIIP and summarized in Table **4.5**.

Table 4.5—Volumetric Assessment of Contingent Resources (Initial Development Stage): Estimates of Project EURs

		Bases and Categories of **Contingent Resources**		
Estimated Parameters	Units	Low Estimate	Best Estimate	High Estimate
Original Oil In-Place (OIIP)	MMSTB	**1,429.6**	**1,429.6**	**1,429.6**
Recovery Factor[1]	% OIIP	5%	10%	15%
Recoverable Oil*	MMSTB	**71.5**	**143.0**	**214.4**
Initial Solution Gas-Oil Ratio (R_{si})	scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas	Btu/scf	1,350	1,350	1,350
Original Gas In-Place (GIIP)	Bscf	**814.9**	**814.9**	**814.9**
Recoverable Raw Gas*	Bscf	**40.7**	**81.5**	**122.2**
	MMBOE[2]	9.5	19.0	28.5

[1] Under a CO_2 Miscible Flood based on the results of an already implemented nearby anolog CO_2 Pilot Project.
[2] Calculated using an average conversion factor of 5.8 MMBtu per BOE.
* Estimated Oil and Gas Contingent Resources categories of **1C, 2C** and **3C**, respectively.

c.) Use of Geocellular Models in Estimating Petroleum In-Place Volumes. While not illustrated in this particular example oil recovery project, given the 3D seismic and early well control, conventional geologic mapping is often supplemented by 3D geologic modeling. Advances in computer technology have facilitated the widespread applications in building multimillion-cell digital geocellular models populated cell by cell with the static geological, geophysical, petrophysical, and engineering data characterizing the subsurface reservoir structure in 3D, similar to the depiction in **Fig. 4.6**.

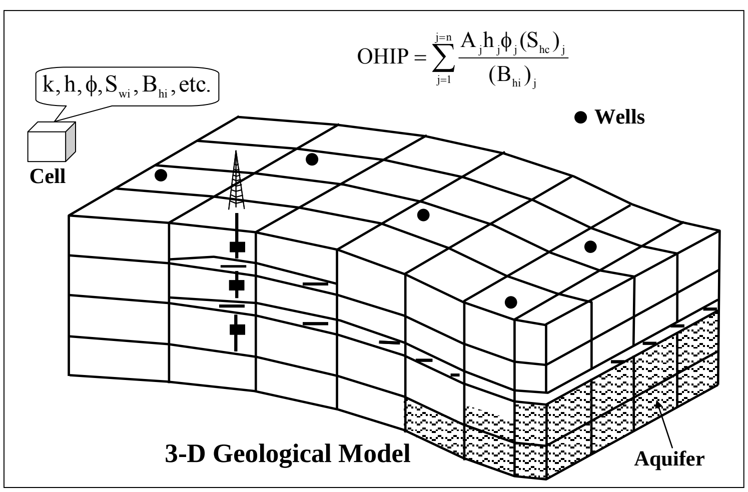


Fig. 4.6—3D multicell geological model [adapted from PS-CIM (2004)]

In a gridded mapping process, the parameters in the original hydrocarbon in-place (OHIP) equation change from cell to cell, and the total OHIP is obtained by the sum of the individual values assigned to, calculated for, and/or matched for each cell. Based on early well performance, modifications to the development program including supplemental secondary and enhanced recovery projects can be designed using streamline and/or finite-difference simulation models with such multimillion-cell reservoir characterization models, including several cases of "what-if" scenarios represented by different plausible realizations. However, refinement and verification of these large geocellular models with actual analogs and thus the degree of certainty in the resulting estimates to a large extent is dependent on both the quantity and quality of geoscience, engineering, and, more importantly, the performance data.

4.2.3 Performance-Based Methods. As illustrated in Fig. 4.1, the Production Phase can be divided into three producing stages (or periods) of Early Time (IIa), Late Time (IIb), and Decline (IIc), which show the increasing project maturity and changing of applicable resources assessment methods over time. Depending on the amount and quality of historical pressure, production and other reservoir performance data available, a combination of reservoir simulation, material balance, and production performance trend (PPT) analysis (or decline curve analysis) can be used not only to directly estimate the recoverable petroleum, but also the petroleum in-place quantities (by the first two methods only), and thereby provide a useful second check and validation of estimates obtained earlier by volumetric methods.

Material Balance Methods. Material balance methods are part of performance-based dynamic analyses. The performance data include production and injection profiles, volume-weighted average reservoir pressures, and reservoir-specific relevant fluid and rock properties (c_o, c_g and c_w; B_o, B_g, R_s, R_v, and B_w) all as a function of reservoir pressure and temperature. Independent of the volumetric methods, the material balance methods can be used to directly and simultaneously estimate PIIP, the size of its gas-cap (m), or its in-place volume [gas cap initially in place (GCIIP)], and/or the water influx (W_e). The results of material balance analysis are considered more reliable with longer performance histories and high-quality production data, both measured and interpreted. A well-established and reasonable assumption is that use of the material balance analysis to estimate PIIP is often considered valid if the cumulative production exceeds 10% PIIP providing the development of the accumulation is such that the pressures used in the analysis represent an average over the entire reservoir. Uncertainty in the estimate is expected to decrease over time as historical production performance data cover at least the early production period (IIa) and beyond.

Application to Example Oil Project in Its Early-Production Stage. *a.)Technical Principles.* Technical principles and definition of terms involved in developing the conventional material balance equation (MBE) applicable to any oil and gas reservoir (i.e., black or volatile oil and retrograde or nonretrograde gas) and applications may be found in Walsh and Lake (2003), and Towler (2002). Modern flowing and dynamic material balance analyses developed by Mattar and McNeil (1998) and Mattar and Anderson (2005) may also be used.

The example oil project represents a black-oil reservoir, initially undersaturated (i.e., no gas cap) with partially active water influx, which was developed by peripheral down-dip water injection to supplement reservoir energy and to help maintain a constant reservoir pressure 100 to 200 psia above the bubblepoint pressure. Furthermore, above the bubblepoint ($R_s = R_{si} = R_p$),

all gas produced at the surface would be dissolved in the oil. The straight line Havlena-Odeh-type (Havlena and Odeh 1963 and 1964) MBE for this particular case can be written as

$$F_p = N\,[(B_o - B_{oi}) + (c_w S_{wi} + c_f)/S_{oi})\,\Delta P\ B_{oi}] + (W_e + W_{inj} B_w) \tag{4.2}$$

It can be further simplified and re-written in terms of effective reservoir compressibility (c_e) as follows:

$$F_p = N\,(B_{oi}\ c_e\ \Delta P) + (W_e + W_{inj} B_w) \tag{4.3}$$

where the variables and terms given are defined by the following relationships:

1) Left side of Eq. 4.3 represents cumulative net reservoir withdrawal (F_p) defined by

$$F_p = N_p\ B_{oi} + W_p B_w \tag{4.3a}$$

2) Right side of Eq. 4.3 represents cumulative net reservoir expansion terms (E_p) and the water influx (W_e), which is given in terms of the van Everdingen and Hurst (1949) unsteady solution by

$$W_e = U \sum_{j=0}^{k\_1} \Delta P_{j+1} W_D(r_D, \Delta t_{Dj}) \tag{4.3b}$$

where j = 0 indicates initial reservoir conditions when $P_i = P_o$ and k = 1, 2,…., n and n is the number of time intervals for which the historical pressure, production, and injection data are available.

The effective, saturation-weighted compressibility of the reservoir system (oil, water, and the formation or reservoir rock pore volume) in Eq. 4.3 is defined by

$$c_e = (c_o S_{oi} + c_w S_{wi} + c_f)/S_{oi} \tag{4.3c}$$

Eq. 4.3 can also be re-arranged as

$$F_p/(B_{oi}\ c_e\ \Delta P) = N + [W_e + W_{inj}\ B_w]/(B_{oi}\ c_e\ \Delta P) \tag{4.4}$$

This MBE represents reservoir depletion under a combined waterdrive (i.e., water influx and/or down-dip water injection into the aquifer) that is effective and strong enough to maintain average reservoir pressure above the bubblepoint pressure. Because water is injected into the aquifer at the periphery, it is treated as part of the water aquifer irrespective of how much of the water actually enters the oil zone and helps displace oil or how much of it enters the aquifer.

Eq. 4.4 suggests that a plot of the left-hand side vs. the second term of the right-hand side should yield a straight line of unit slope intercepting the ordinate at N (or OIIP). Data necessary for this plot can be generated at each timestep as follows: At any time period with an appropriate ΔP, (1) the F_p, c_e data can be calculated using the relevant relationships and measured production and injection data, (2) the unsteady-state water influx theory of van Everdingen and Hurst (1949) may be used to estimate dimensionless influx rates (W_D), and (3) Eq. 4.3b can be used to calculate water influx (W_e).

b.) Application. The oil reservoir evaluated in this application example is a prolific carbonate reservoir with undersaturated oil, developed and producing with very effective down-dip water injection that has maintained the reservoir pressure over the bubblepoint. An additional 16 new oil producers and one water injector were also drilled during this 8-year production period (bringing the total to 50 and 20 wells, respectively) to maintain plateau rate and help improve overall recovery efficiency. The project produced 220.8 MMSTB of oil (15.4% OIIP of 1,429.6 MMSTB estimated and reported earlier in Table 4.4), 126 Bscf of solution gas and 80 MMSTB of water and injected 385 MMSTB of produced and supply water into the aquifer below the original OWC.

Based on the average reservoir pressure observed, production and injection performance data recorded over an 8-year period (the first-year data were erroneous, out of scale, and excluded), the terms in Eq. 4.4 were calculated and plotted in **Fig. 4.7**.

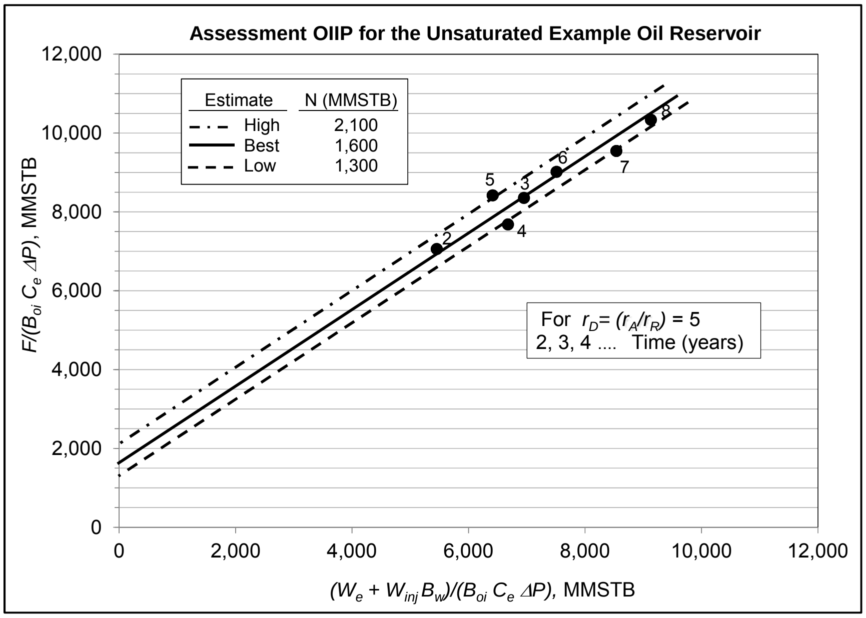


Fig. 4.7—Assessment of OIIP by material balance methods (early-production stage).

With the variations shown in the plotted data, it was possible to draw three parallel straight lines with a unit slope confirming the correct value of the dimensionless radius, r_D= 5 (defined as a ratio of the aquifer radius and reservoir radius) and bracketing the degree of uncertainty in the measured and interpreted data and thus the resulting estimates of in-place volumes. These minimum, most likely, and maximum interpretations of OIIP (or *N*) values of 1,300, 1,600, and 2,000 MMSTB were assumed to represent the low, best, and high estimates, respectively. These OIIP estimates were judged to be a valid basis for assigning 1P, 2P, and 3P Reserves categories because (1) the project produced more than 10% OIIP (or about 17% of low and 14% of best OIIP), (2) a reasonably good match was obtained in Fig. 4.7 and deviations are accounted for, and (3) it was supported by a new volumetric in-place estimate of 1,567 MMSTB reported by analysts updating the old estimate (versus 1,430 MMSTB after completion of initial development) by incorporating additional data from 16 new producers drilled over this 8 years of production.

Over the past 8 years, the ongoing peripheral waterflood project confirmed similar performance to the analogs nearby and a second CO_2 pilot was also implemented showing similar initial performance to the first one already completed. However, to further ensure

reasonable confidence in the estimates, the recovery efficiencies were not changed at the time and kept the same as the initial development stage 8 years earlier. Based on these low, best, and high estimates OIIPs, the respective EURs and Reserves (under the ongoing Peripheral Waterflood Project) and the Contingent Resources (under a proposed CO_2 Miscible Project) were calculated and summarized in **Table 4.6**.

Table 4.6 —Assessment using Material Balance Methods (Early-Production Stage): Estimates of Project PIIPs, EURs, Reserves and Contingent Resources

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves and Resources Category: Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Oil	MMSTB	**220.8**	**220.8**	**220.8**
		% OIIP	17.0%	13.8%	11.0%
	- Raw Gas	Bscf	**125.9**	**125.9**	**125.9**
Original Oil In-Place (OIIP)		MMSTB	**1,300**	**1,600**	**2,000**
Recovery Factor[1]		% OIIP	40%	45%	50%
Recoverable Oil (EUR)*	- Original	MMSTB	**520.0**	**720.0**	**1,000.0**
	- Remaining*	MMSTB	**299.2**	**499.2**	**779.2**
Initial Solution Gas-Oil Ratio (R_{si})		scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas		Btu/scf	1,350	1,350	1,350
Original Gas In-Place (GIIP)		Bscf	**741.0**	**912.0**	**1,140.0**
Recoverable Raw Gas (EUR)	- Original	Bscf	**296.4**	**410.4**	**570.0**
		MMBOE[2]	69.0	95.5	132.7
	- Remaining*	Bscf	**170.5**	**284.5**	**444.1**
		MMBOE[2]	39.7	66.2	103.4
		Units	Basis and Categories of Contingent Resources: Low Estimate	Best Estimate	High Estimate
Recovery Factor[3]		% OIIP	5%	10%	15%
Recoverable Oil*		MMSTB	**65.0**	**160.0**	**300.0**
Recoverable Raw Gas*		Bscf	**37.1**	**91.2**	**171.0**
		MMBOE[2]	8.6	21.2	39.8

[1] Under Peripheral Water Injection Scheme that maintains reservoir pressure above the bubblepoint.
[2] Calculated using an average conversion factor of 5.8 MMBtu per BOE.
[3] Under a CO_2 Miscible Flood based on the results of one CO_2 Pilot already implemented and a positive response from a second pilot being applied in another nearby analog reservoir.
* Estimated categories of Oil and Gas Reserves of **1P, 2P** and **3P** and Contingent Resources of **1C**, **2C** and **3C**.

Moreover, it was recommended that these estimates be updated in the future based on the results of new re-assessment studies expected to incorporate data from additional wells drilled and production performance data observed and recorded. It is recognized that this type of traditional material balance analysis using analytical procedures has routinely been performed by reservoir simulation studies, which are discussed next under Reservoir Simulation Methods.

Application to a Volumetric Gas Reservoir in Its Late Production and Early Decline. *a) Technical Principles.* In volumetric gas reservoirs there is no (or insignificant) aquifer water influx, and the volume of initial HCPV will not significantly decrease and remain constant during reservoir pressure depletion. Therefore, with no adjoining aquifer or water influx (W_e = 0), no water production (W_p = 0), and injection of gas (G_{inj} = 0), the generalized conventional MBE for a volumetric gas reservoir reduces to (Lee and Wattenbarger 1996):

$$G_p B_g = G\,(E_g + B_{gi}\,E_w + B_{gi}\,E_f) \tag{4.5}$$

Except for the special case of abnormally pressured gas reservoirs, relative to significantly high gas compressibility (or c_g approximately equal to the inverse of reservoir pressure), the formation water (E_w) and formation or pore-volume compression (E_f) terms can be neglected because E_g >>> ($B_{gi} E_w + B_{gi} E_f$), and the Eq. 4.5 will further reduce to:

$$G_p B_g = G E_g = G (B_g - B_{gi}) \tag{4.6}$$

and the gas formation factor (B_g) can be calculated using

$$B_g \text{ (RB/scf)} = 5.0435(10^{-3})\, zT/p \text{ [or } 2.8269\,(10^{-2})\, zT/p \text{ in Rcf/scf]} \tag{4.6a}$$

where standard surface pressure (p_{sc}) and temperature (T_{sc}) conditions are 14.7 psia and 60 ^{o}F.

It is common practice to express this relationship in terms of average reservoir pressure by combining Eqs. 4.6 and 4.6a and rearranging to yield this well-known material balance equation applicable only to volumetric gas reservoirs:

$$(p/z) = (p_i/z_i) - [(p_i/z_i)/G]\, G_p, \tag{4.7}$$

where
p_i, p = average reservoir pressure (psia) at reservoir datum and "*i*" stands for initial,
T = average reservoir temperature at reservoir datum (^{o}R),
z_i and z = gas compressibility factors evaluated at p_i and T and any p and T, respectively,
G = GIIP (scf), and
G_p = cumulative gas production (scf) at any reservoir pressure (p).

Eq. 4.7 simply asserts that in volumetric gas reservoirs, the gas production, and therefore the ultimate recovery under natural pressure depletion is a direct function of the expansion of the free gas initially in-place. The lower the economic limit (or abandonment pressure), the higher the EUR. Furthermore, Eq. 4.7 suggests that a plot of (p/z) vs. G_p should yield a straight line with an intercept (p_i/z_i) and a slope of [-(p_i/z_i)/G] from which the GIIP = G and EUR at the economic limit (p/z) can be estimated.

b.) Application to Example Gas Project. A deep carbonate, normally-pressured and volumetric reservoir with wet gas has been on production for the past 22 years and produced about 316 Bscf of raw natural gas and 9 MMSTB of condensate. Based on several analog onshore projects producing from the same formation in different nearby gas fields, it has been determined that the gas exhibits borderline retrograde behavior. However, several laboratory tests and compositional model study results verified that condensate dropout in the reservoir during depletion drive below dewpoint pressure is not significant enough to justify gas cycling. This minor loss has been reflected by the use of lower condensate recovery confirmed by the analogs. The measured initial condensate gas ratio (CGR_i) of 30 STB/MMscf was confirmed during production above its reservoir dewpoint pressure, declining only to 27 STB/MMscf at a reservoir pressure of about 5,500 psia (compared to 7,000 psia initial). The small loss was taken into account by the use of a lower condensate recovery efficiency confirmed by the analogs.

Fig. 4.8 depicts the p/z vs. G_p performance plots for this example wet-gas reservoir. Because of variations in the observed data under pressure depletion, it was possible to draw three different straight lines bracketing the potential degree of uncertainty in the measurement and interpretation of the historical data. These minimum, most likely, and maximum interpretations of GIIP estimates from Fig. 4.8 were judged to represent the valid basis for assigning different reserves categories of 1P, 2P, and 3P, respectively, based on an estimated (p/z) economic limit of 1,500

psia. The resulting implied volumetric recovery efficiency is calculated to be about 75 to 76% of GIIP. Estimates are further supported by and considered reasonable because (1) the reservoir has been established to be volumetric with nonretrograde gas, (2) it is fully delineated and developed with a best estimate GIIP of 1,800 Bscf using volumetric methods, (3) it has already produced 316.2 Bscf, which is more than 17.6% of this volumetric GIIP or 21.1% of the low GIIP estimate from Fig. 4.8, and (4) the project economics based on these three different scenarios are all determined to be viable with discounted cash flow rates of return (DCF-RORs) exceeding 20%. The reserves status is considered Developed.

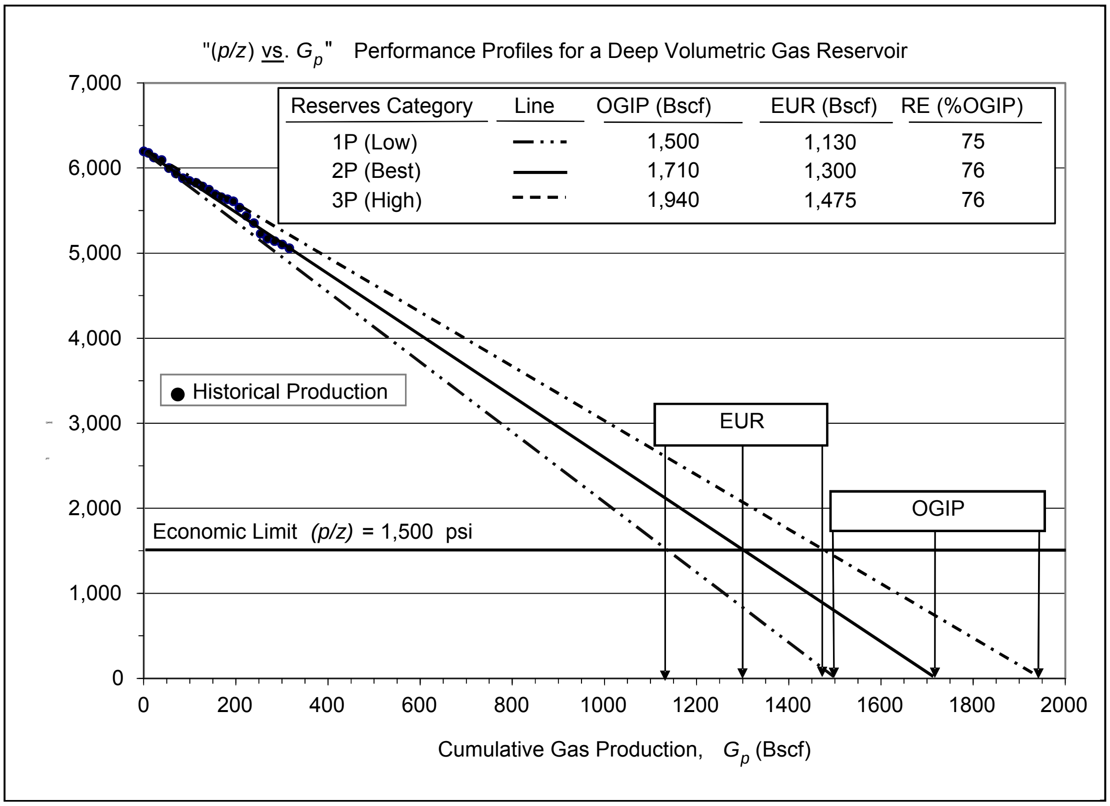


Fig. 4.8—Gas reserves assessment by material balance methods (Late-Production Stage).

Based on the initial condensate gas ratio (CGR_i) of 30 STB/MMscf raw gas (with a gross heating value of 1,100 Btu/scf) and a recovery factor of 60% original condensate in-place (OCIP) from the nearby analog reservoirs, the in-place and reserves estimates for this gas reservoir are summarized in **Table 4.7.** Note that the recoverable raw gas volumes (in terms of both scf and therefore the barrels-oil-equivalent, BOE) summarized in Table 4.7 must be reduced by approximately 20% for the surface loss to yield their residue sale gas equivalents or reserves (EUR), consisting of 3.2% for the shrinkage of condensate reserves and 16.8% for the subsequent processing to remove nonhydrocarbons (8.1%) and recovery of C_2 plus NGLs (8.7%). For more detail, readers should refer to Chapters 9 and 10 on production measurements, reporting, and entitlement issues.

Table 4-7—Gas Reserves Assessment by Material Balance Methods (Late-Production Stage): Estimates of Project GIIPs, CIIPs, EURs and Reserves

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves Category		
			Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Raw Gas	Bscf	**316.2**	**316.2**	**316.2**
		% GIIP	21.1%	18.5%	16.3%
	- Condensate	MMSTB	**9.4**	**9.4**	**9.4**
Gas Initially In-Place (GIIP)[1]		Bscf	**1,500**	**1,710**	**1,940**
Gross-Heating Value of Raw Gas		Btu/scf	1,100	1,100	1,100
Recoverable Raw Gas (EUR)[1]	- Original	Bscf	**1,130**	**1,300**	**1,475**
		MMBOE[2]	214.3	246.6	279.7
	- Remaining*	Bscf	**813.8**	**983.8**	**1,158.8**
		MMBOE[2]	154.3	186.6	219.8
Implied Recovery Factor		% GIIP	75%	76%	76%
Initial Condensate-Gas Ratio (CGR_i)		STB/MMscf	30	30	30
Condensate Initially In-Place (CIIP)		MMSTB	**45.0**	**51.3**	**58.2**
Condensate Recovery Factor[3]		% CIIP	60%	60%	60%
Recoverable Condensate (EUR)	- Original	MMSTB	**27.0**	**30.8**	**34.9**
	- Remaining*	MMSTB	**17.6**	**21.4**	**25.5**

[1] Estimated directly from Figure 4-8 based on (P/Z) values of 0 and 1,500 psia (economic limit), respectively.
[2] Calculated using an average conversion factor of 5.8 MMBtu per BOE
[3] Based on several nearby analog reservoirs and accounts for condensate dropout in the reservoir, if any.
* Estimated Gas and Condensate Reserves categories of **1P, 2P** and **3P**, respectively.

It is a common practice to determine whether "gas compression" is economically viable and can be used to lower wellbore backpressure to help gas wells produce at lower average reservoir abandonment pressures (or associated p/z economic limits) and thus provide additional reserves. The wellbore backpressure is the sum of the backpressure imposed by the sales gas pipeline and the pressure drops in the gas gathering system at the surface and the tubing string in the wellbore. A gas well will stop flowing when the average reservoir pressure drops to and equals this wellbore backpressure. This "no flow" average reservoir pressure and therefore its (p/z) value does not necessarily represent the economic limit because the wellbore imposed backpressure can be reduced by designing and installing an optimal gas compression facility (with an optimum compression ratio) at the point of sales (or plant feed) to significantly reduce the sales gas pipeline imposed backpressure.

The economic limit (p/z) of 1,500 psia for this example deep gas reservoir represents a point where the value of production is just equal to the operating cost of producing the project under pressure depletion without compression. It is a deep gas reservoir and although gas compression is expected to reduce the economic (p/z) limit to as low as 1,000 psia, it is uneconomic because the value of incremental gas reserves realizable is determined to be less than the capital and operating costs of installing and running the compression facility. Thus the incremental volumes associated with compression are considered as Contingent Resources (but not reported here) pending future updates for cost reduction and/or higher gas prices

Reservoir Simulation Methods (RSM). *a) Technical Principles.* The body of scientific knowledge on the development and use of integrated reservoir simulation models is extensive and may be reviewed in many books, including Aziz and Settari (1979), Mattax and Dalton (1990), Ertekin et al. (2001), Fanchi (2006), and many others. PS-CIM (2004) provides a brief and concise review of the subject, including the different phases of a typical reservoir simulation study.

A reservoir simulation model characterizes the reservoir by integrating the static geological model (similar to that in Fig. 4.6) and the dynamic flow model populated with actual reservoir performance data (pressures, tests, production rates, inter fluid-rock characteristic curves characterized by the capillary and relative permeability curves, PVT data, etc). Moreover, the results of integrated reservoir simulation models can be used with increased confidence as the amount and quality of static geoscientific and dynamic reservoir performance data increase. Reservoir simulation can be used during any production stage (or period) to directly estimate both the original in-place and the recoverable quantities of petroleum or the EUR for any oil and gas recovery project. Estimates may be derived for any petroleum recovery project under any recovery method, including primary drive mechanisms, secondary pressure maintenance and displacement schemes (crestal immiscible gas injection, and down-dip peripheral and pattern waterfloods), and various potentially applicable EOR processes.

Developing a meaningful reservoir model capable of generating reliable results with reasonable certainty requires a multidisciplinary team with appropriate technical skills and broad experience. Once a reasonably good history match is obtained, the model can be used to predict production and injection profiles, infill wells, well workovers, stimulation, and other requirements according to specified prediction guidelines (related to drilling, well completions, production engineering and reservoir management, including vertical flow and surface flow systems) under various “what-if” conditions for reservoir development, production and management strategies. Based on a comparative economic analysis, the optimum development and producing strategy can be selected for implementation. Depending on the amount and quality of performance data available, the projected cumulative production to the economic limit with this optimum strategy should establish the most likely EUR.

Determination and assignment of different reserves categories, however, must be consistent with PRMS definitions and therefore would depend on the degree of uncertainty the evaluator determined to exist in these estimates. Irrespective of the assessment method, it is good practice to consider the following two key points:

1. The degree of uncertainty in the estimates (or the range of outcomes) is expected to decrease as the amount and quality of geoscience, engineering and production performance data increase.
2. Compare the estimates obtained using several different methods (e.g., volumetric, material balance, reservoir simulation and/or production performance trend analyses) and the analog projects, if available, before booking reserves.

There are no published generally accepted rules, but several key observations can be made regarding best practices employed in the assessment of petroleum in-place and recoverable volumes using reservoir simulation studies. With *limited data* (geoscience and engineering), the model is best suited to make sensitivity scenario projections to bracket what is possible around the best estimate defined as the base case. The uncertainty in the range of estimates is expected to be larger than those estimated using more data. As specified in the PRMS, based on the

respective project economics and whether or not all project contingencies are met, resulting estimates may be assigned to different categories of Reserves and/or Contingent Resources. As *the amount and quality of data increases,* the range of estimates of in-place and recoverable volumes obtained using these integrated reservoir simulation models (matched using long observed production performance data) will decrease. In actual practice, one may have the following two extreme cases in which to assess and categorize the estimates using simulation models:

- **Case 1**. One may have three different geological realizations (representing the low, best, and high scenarios) and associated reservoir simulation models that can be used to directly estimate the respective in-place volumes, EURs, Reserves **(**e.g., the EURs reduced for cumulative production realized, if any), and/or Contingent Resources categories. This is definitely preferred, but not a common practice given the time and expense to develop several rigorous models.
- **Case 2.** One may only have a single integrated reservoir simulation model, which can be used to directly estimate a single most likely (or best) value of project PIIP, EUR, Reserves, and/or Contingent Resources. In deterministic analysis, it is common practice to run sensitivity predictions to understand the range of uncertainty and assign the 1P and 3P categories accordingly.

Irrespective of the assessment method used and amount and quality of necessary data available, the estimates must fulfill the premise stated in Point 2 above before booking.

Expertise gained over many years of working with the reservoir simulation models and the ability to select the model most appropriate for the oil and gas reservoir (or recovery project) under evaluation are critically necessary skills required to complement a thorough understanding and application of PRMS guidelines for the classification and categorization of petroleum resources. However, it is absolutely critical to be realistic and pay attention to the following wise and cautionary statement by Thiele (2010) that applies to all analyses, but specifically the reservoir simulation: "The industry has long recognized the importance of quantifying uncertainty. As a result, computational resources are being directed more toward simulating large ensembles of models rather than adding ever increasing levels of detail and physics to a single representation of the subsurface. For multimillion-dollar capital investments, it is far more important to acknowledge the possibility of catastrophic outliers and invest in reducing uncertainty by guided data acquisition than to tweak a single reality to excess."

b.) Application to Example Oil Project. This application represents an oil recovery project at its mature late-production and early-decline stages. The example oil reservoir was developed and produced under a very effective down-dip water injection scheme over the past 16 years. During that time, 36 new oil producers and 3 water injectors were also drilled (bringing the total to 70 and 22 wells, respectively) to better manage production decline and to help further improve overall recovery efficiency.

Based on the extensive log, core, and testing data obtained over the past 19 years (discovery year, 2-year appraisal period followed by a 3-year initial development and a 16-year of production periods depicted by Fig.4.1a), a 0.5 million-cell geocellular model (similar to that depicted in Fig. 4.6) was built and used to estimate an OIIP of about 1,525 MMSTB with a reported single statement that "the results of sensitivity runs, using this geological model, showed about a 6% downside (meaning 1,434 MMSTB) and a 14% upside (meaning 1,739 MMSTB) in the OIIP estimate." It is important to note that since the Material Balance Analysis

of this example oil project was conducted 8 years ago, the range in the OIIP estimates were reduced to a ratio of 1.21 (=1,739/1,434) from 1.54 (=2,000/1,300), a 21% reduction in the range of both the OIIPs and the EURs (because of using the same recovery factors). Hence, the relative degree of uncertainty in these estimates should also have been reduced.

Based on this most likely or best 3D geological realization (with an OIIP estimate of 1,525 MMSTB), a related integrated 3D and three-phase reservoir simulation model was developed by a multidisciplinary team and used to match this extensive reservoir performance history covering a period of 16 years with 399 MMSTB (26.2% OIIP) produced.

This history-matched black-oil model was used to predict future reservoir performance under the ongoing base-case operations using peripheral waterflood, including economically justified well workovers, infill drilling, and well completions to better manage the decline. The historical and predicted profile for the Best Scenario (Base Waterflood) is presented in **Fig. 4.9**. As shown in Fig. 4.9, an EUR of 686.3 MMSTB (45% OIIP) at an economic limit of about 2,700 BOPD was predicted. It represented the most likely or the “best” scenario for the ongoing waterflood performance already confirmed by the excellent performance observed over the past 16 years. It confirmed the 45% OIIP recovery factor assigned 8 years earlier in Material Balance Analysis.

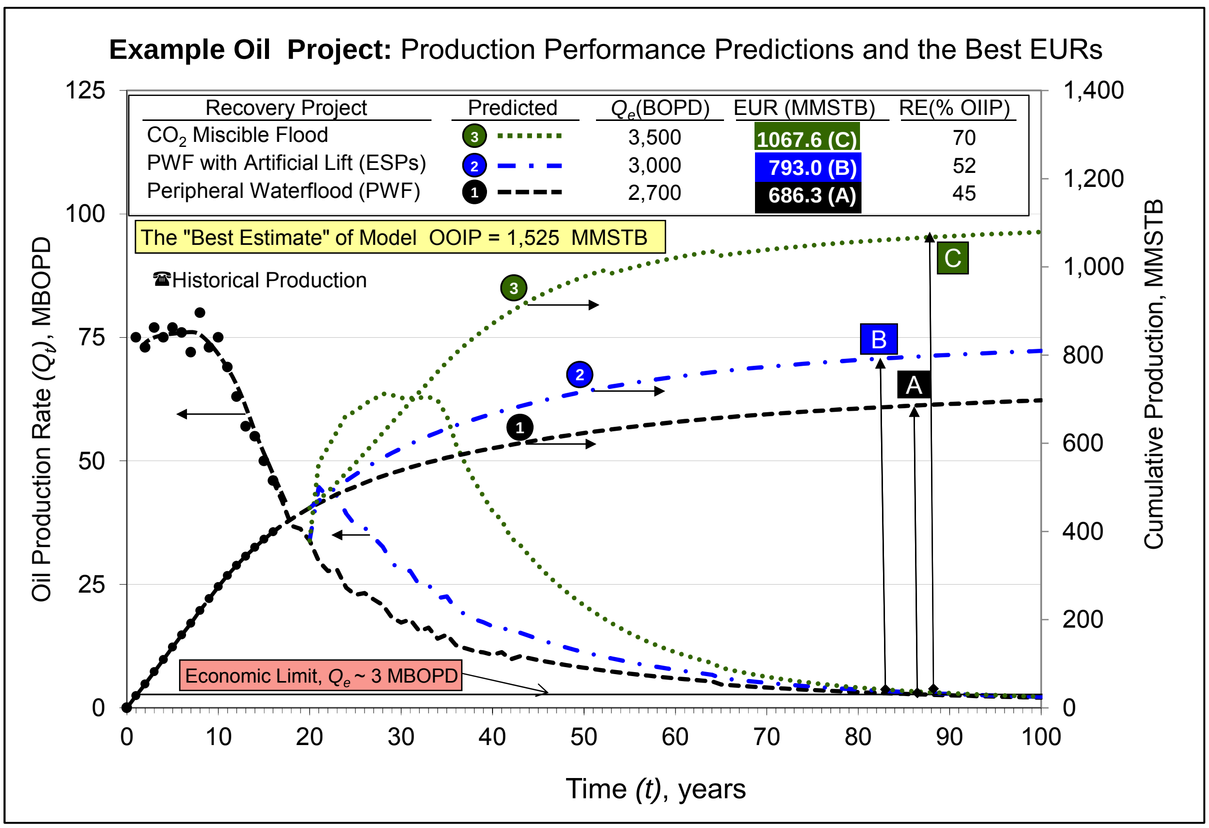


Fig. 4.9—Dynamic and direct assessment of reserves using reservoir simulation.

Based on the reported low and high estimates of OIIP from the sensitivity analysis and using the respective same REs, the project EURs and Reserves were calculated. The results are summarized in **Table 4.8**.

Table 4.8—Assessment using Reservoir Simulation Studies (Early-Decline Stage): Estimates of Project PIIPs, EURs and Reserves Under Peripheral Waterflood Only

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves Category		
			Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Oil	MMSTB	**399**	**399**	**399**
		% OIIP	27.8%	26.2%	23.0%
	- Raw Gas	Bscf	**227.4**	**227.4**	**227.4**
Original Oil In-Place (OIIP)		MMSTB	**1,434**	**1,525**	**1,739**
Recovery Factor[1]		% OIIP	40%	45%	50%
Recoverable Oil (EUR)[2]	- Original	MMSTB	**573.4**	**686.3**	**869.3**
	- Remaining*	MMSTB	**174.4**	**287.3**	**470.3**
Economic Oil Rate Limit		STB/D	2,700	3,000	3,500
Initial Solution Gas-Oil Ratio (R_{si})		scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas		Btu/scf	1,350	1,350	1,350
Original Gas In-Place (GIIP)		Bscf	**817.1**	**869.3**	**990.9**
Recoverable Raw Gas (EUR)[1]	- Original	Bscf	**326.8**	**391.2**	**495.5**
		MMBOE[3]	76.1	91.1	115.3
	- Remaining*	Bscf	**99.4**	**163.8**	**268.0**
		MMBOE[3]	23.1	38.1	62.4

[1] Waterflood RFs, calculated or implied for the Best Estimate and assigned for the Low and High Estmates.
[2] The Best Estimate is obtained from the projected production profile of a project-specific Reservoir Simulation Study.
[3] Calculated using an average conversion factor of 5.8 MMBtu per BOE
* Estimated Oil and Raw Gas Reserves categories of **1P, 2P** and **3P**, respectively.

The same black oil model was used to study a “what-if” reservoir performance scenario of installing a fieldwide artificial lift facility using electrical submersible pumps (ESPs) in all oil producers by the Year 21. Based on a conservative economic limit of about 3,000 BOPD, an EUR of 793 MMSTB (or about 52% OIIP) was predicted for the combined project of peripheral waterflood with artificial lift using ESPs. The project’s production profile and resulting estimates are also presented in Fig. 4.9 to illustrate its performance relative to the ongoing peripheral waterflood project without the ESPs. This 7% OIIP incremental “what-if” predicted performance had confirmed the results of an earlier study and was supported by several nearby analog artificial lift projects showing incremental economic recoveries as high as 9% OIIP.

The company committed to the ESP implementation. The additional recovery was judged to have reasonable certainty and placed in the Proved category with Undeveloped status at the time, expecting it to be transferred to Proved Developed in 4 years time (or in Year 21), when the project was expected to be completed and put on-stream.

Although some may consider the artificial lift as a separate project, it was in fact a combined project that just enhances the ongoing waterflood by only installing ESPs in some producers. In actual practice, artificial lift is generally implemented in stages (especially with ESPs) to minimize operating expenses because oil producers reach their critical water-cut levels at different times making a fieldwide simultaneous installation as a separate project not as attractive.

Irrespective of how one treats the artificial lift projects, their impact was incorporated with the ongoing peripheral waterflood project by adding this constant 7% OOIP increase in recovery efficiency to the recovery efficiency of each low, best, and high scenario estimated and/or assigned in Table 4.8. The project increased the respective recovery efficiencies to 47%, 52%, and 57% of the OIIPs. As a result, the respective EURs and reserves categories for the "combined project" were recalculated and the results are now summarized in **Table 4.8a**.

Table 4.8a—Assessment using Reservoir Simulation Studies (Early-Decline Stage): Estimates of Project PIIPs, EURs and Reserves under Peripheral Waterflood with ESPs

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves Category		
			Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Oil	MMSTB	**399**	**399**	**399**
		% OIIP	27.8%	26.2%	23.0%
	- Raw Gas	Bscf	**227.4**	**227.4**	**227.4**
Original Oil In-Place (OIIP)		MMSTB	**1,434**	**1,525**	**1,739**
Recovery Factor[1]		% OIIP	47%	52%	57%
Recoverable Oil (EUR)[2]	- Original	MMSTB	**673.7**	**793.1**	**990.9**
	- Remaining*	MMSTB	**274.7**	**394.1**	**591.9**
Economic Oil Rate Limit		STB/D	2,700	3,000	3,500
Initial Solution Gas-Oil Ratio (R_{si})		scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas		Btu/scf	1,350	1,350	1,350
Original Gas In-Place (GIIP)		Bscf	**817.1**	**869.3**	**990.9**
Recoverable Raw Gas (EUR)[1]	- Original	Bscf	**384.0**	**452.0**	**564.8**
		MMBOE[3]	89.4	105.2	131.5
	- Remaining*	Bscf	**156.6**	**224.6**	**337.4**
		MMBOE[3]	36.5	52.3	78.5

[1] Waterflood RFs, calculated or implied for the Best Estimate and assigned for the Low and High Estmates.
[2] The Best Estimate is obtained from the projected production profile of a project-specific Reservoir Simulation Study.
[3] Calculated using an average conversion factor of 5.8 MMBtu per BOE
* Estimated Oil and Raw Gas Reserves categories of **1P, 2P** and **3P**, respectively.

Furthermore, based on the same geological model representing the best case scenario, and relevant CO_2 and hydrocarbon compositional data (including miscibility test results), an integrated compositional model was developed to study the performance of CO_2 miscible displacement process and several alternatives using different water-alternating-gas (WAG) scenarios. Assumed to be on stream by Year 21 (similar to the "what-if" artificial lift study), several production performance predictions were carried out to a 3,500 BOPD economic limit, yielding a cumulative oil recovery of about 1,068 MMSTB (or 70% OIIP) for the case with an optimum CO_2 injection at the crest. The results for this best-case scenario are also presented in Fig. 4.9 to illustrate its performance relative to the ongoing base peripheral waterflood and the second peripheral waterflood with artificial lift projects. This predicted incremental recovery of 18% OIIP for a CO_2 EOR project was supported by two CO_2 pilots already implemented in analog oil projects nearby and yielding a reported maximum recovery efficiencies of 22% OIIP, which established the upper limit.

Although the project economics were positive, it was not reasonably certain that the project would be implemented in Year 21 as initially assumed. The infrastructure for sequestration and delivery of CO_2 to the project site were assessed to take longer and delayed because of the expected budgetary constraints at the time. Consequently, the estimated recoverable quantities of

oil and raw natural gas were classified as Contingent Resources. Therefore, incremental recoverable quantities attributable to CO_2 miscible project had to be separated from the second project and reported incrementally (using a low and a high recovery efficiency of 15% and 22% OIIP, respectively, to bracket uncertainty) as shown in **Table 4.8b**. There was a note stating that "these estimates should be reviewed periodically to confirm whether these unfulfilled contingencies still exist and if fulfilled, they can be classified as Reserves."

Table 4.8b—Assessment of Contingent Resources using Reservoir Simulation Studies (Early Decline Stage): EURs Under a Planned CO_2 Miscible Flood Project

Measured and Estimated Parameters	Units	Bases and Estimates by Resource Category: Low Estimate	Best Estimate	High Estimate
Original Oil In-Place (OIIP)	MMSTB	**1,434**	**1,525**	**1,739**
Initial Solution Gas-Oil Ratio (R_{si})	scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas	Btu/scf	1,350	1,350	1,350
Recovery Factor[1]	% OIIP	15%	18%	22%
Recoverable Oil*	MMSTB	**215.0**	**274.5**	**382.5**
Recoverable Raw Gas*	Bscf	**122.6**	**156.5**	**218.0**
	MMBOE[3]	28.5	36.4	50.7

[2] Under a CO_2 Miscible Flood based on the results of two implemented anolog CO_2 Pilot Projects.
[3] Calculated using an average conversion factor of 5.8 MMBtu per STB of crude oil.
* Estimated Oil and Gas Contingent Resources categories of **1C, 2C** and **3C**, respectively.

Production Performance Trend (PPT) Analyses. PPT analyses have proved to be very useful and commonly used methods to directly estimate the EURs for oil and gas wells, reservoirs and specific development (or recovery) projects. Although PPT analyses are traditionally known as decline curve analyses (DCAs), other forms of PPTs exist and can also be used to estimate petroleum (oil and gas) reserves. Historical production performance trends observed in mature wells, reservoirs, or projects may generally be extrapolated to the cumulative production at the economic limit, and provide a reasonable assessment of the EUR. Moreover, the predicted production rate profiles obtained using analytical or reservoir simulation studies could establish performance trends that are <u>not long enough</u> to include the project's economic life. In these cases, the DCA can also be used to best-fit these trends and extrapolate them all the way to project economic limit and determine the EURs.

To better comprehend the limitations of PPT analysis, Harrell et al. (2004) pointed out the following conditions under which production decline trends would provide acceptable projections of production profiles and the resulting reserves estimates for the asset under study:

- Production conditions, methods, and the overall production strategy are not changed significantly over the projected remaining producing life.
- The reservoir has been fully developed, and therefore, the well count is relatively stable.
- Wellbore interventions and other remedial work can be classified solely as maintenance.

Production performance trends are not only reservoir specific but also depend on the specific reservoir management and production practices used. Any significant change in these practices could easily lead to erroneous results. Therefore, the reliability of production profiles projected using DCA depends not only on the quality and quantity of the past production data, but also on the evaluator's professional experience gained through working on many hands-on assessments and reconfirmations of results over time with actual performance, including the use of appropriate analog reservoirs.

a) Technical Principles. Decline analysis is based on the solution of the following differential generalized hyperbolic equation defining the nominal decline rate (D) as the fraction of "change in production rate with time (t)" (also known as *loss ratio*) as

$$D_t = -(dQ/dt)Q_t = KQ^b, \quad (4.8)$$

where

D_t = nominal (or continuous) decline rate (slope of the line) at any time (t) and is a fraction of production rate (Q_t) with a unit of reciprocal time ($1/t$) in per month, per year, etc, which must be consistent with the units of production rate,

Q_t= production rate (STB/D, STB/month or STB/yr),

b = decline exponent, and

K= integration constant

Decline trends analysis of production rate vs. time advanced by Arps (1945) is a hyperbolic equation similar to Eq. 4.8, and therefore, it has a semitheoretical basis. The PPTs and their extrapolations to the economic limit are governed by the mathematical equations (as solutions to hyperbolic differential Eq. 4.8) summarized in **Table 4.9** below.

Table 4.9—Traditional Decline Analysis: Governing Equations and Characteristic Linear Plots

Generalized governing hyperbolic decline equation: $D = -\dfrac{dQ/dt}{Q} = KQ^b$

	Hyperbolic Model	Exponential Model	Harmonic Model
Nominal Decline Rate (D)	$(D_t/D_i) = (Q_t/Q_i)^b$	$D_t = D_i = D_t$=constant	$(D_t/D_i) = (Q_t/Q_i)$
Decline Exponent (b)	"b" varies except for 0 & 1	$b = 0$	$b = 1$
Rate -Time Relationships	$Q_t = Q_i\,[1+nD_i t]^{(-1/b)}$ $\log Q_t = \log Q_i - (1/b)\log(1+bD_i t)$	$Q_t = Q_i\,e^{-Dt}$ $\log Q_t = \log Q_i - (D/2.3)\,t$	$Q_t = .Q_i\,(1+D_i t)^{-1}$ $\log Q_t = \log Q_i - \log(1+D_i t)$
Type of Linear Plots:	$\log Q_t$ vs. $\log(1+Ct)$ *where* $C=bD_i$	$\log Q_t$ vs. t	$1/Q_t$ vs. t or $\log Q_t$ vs. $\log(1+D_i t)$
Rate-Cumulative Relationships	$N_{pt} = \dfrac{Q_i^b}{(1-b)\,D_i}\left[Q_i^{(1-b)} - Q_t^{(1-b)}\right]$	$N_{pt} = (Q_i - Q_t)/D$ $Q_t = Q_i - D\,N_{pt}$	$N_{pt} = \dfrac{Q_i}{D_i} ln(Q_i/Q)$ $\log Q_t = \log Q_i - D_i/(2.3\,Q_i)\,N_{pt}$
Type of Linear Plots	*Not available*	Q_t vs. N_{pt}	$\log Q_t$ vs. N_{pt}

i = stands for initial time or point at which the decline trend has onset or started.
D_t = nominal decline rate (as fraction of Q_t) with a unit of inverse time ($1/t$), equals to D_i when $Q_t = Q_i$.
Q_t = oil or gas production rate at any time *"t"* in STB/D or MMscf/D, etc*.
t = time and the subscript for oil rate & cumulative production variables*.
N_{pt} = cumulative oil or gas production or oil recovery at any time *"t"* in consistent units*.
* Rate *(Q)* & time *(t)* must be in consistent units in above formulae (i.e., if *"Q"* is in STB/D, *"t"* is in days, etc.).

Well-known and widely used DCAs provide a visual illustration of historical production performance of a well, a group of wells, or a reservoir and of whether the established trend can be extrapolated to the economic limit to estimate petroleum reserves. Review, derivation, and understanding of these governing equations and the characteristic linear plots (summarized in Table 4.9) representing each decline model are very important for correct use and application of the traditional DCA. Note that the exponential and harmonic models are just specific cases of the hyperbolic model with constant decline exponent (b) of 0 and 1, respectively.

The *hyperbolic decline model* is not only the most common decline trend observed in the actual performance of oil and gas wells and reservoirs, but also represents the most general and challenging decline trend with two unknown parameters of initial nominal annual decline rate (D_i) and decline exponent (b). Moreover, the hyperbolic decline exponent (b) is not fixed but varies, and may have any value except b = 0 and b = 1, which represent the special cases defined by exponential and harmonic models, respectively, among wells and reservoirs producing under different reservoir depletion methods. It has been widely reported that the value of (b) varies with reservoir drive mechanism. Although the development of unconventional reservoirs in North America has resulted in observed "b" values significantly exceeding one, the following values generally applicable to conventional reservoirs reported by Fekete Associates (2008) may be used:

Value of Decline Exponent (*b*)	**Governing Reservoir Drive Mechanism**
0	Single-phase liquid (oil above bubblepoint)
0	Single-phase gas at high pressure
0.1-0.4	Solution gas drive
0.4-0.5	Single-phase gas
0.5	Effective edgewater drive
0.5-1.0	Comingled layered reservoirs

Initial nominal decline rate (D_i) is the nominal (or continuous) decline rate corresponding to initial production rate at which decline begins. The ratio of nominal decline rate at any time (t) (or D_t) to initial decline rate (D_i) when production decline first begins is proportional to a power (b) (except 0 and 1) of the respective production rates and defined by

$$D_t / D_i = (Q_t / Q_i)^b \tag{4.9}$$

Rate of decline depends on several factors, such as the reservoir depletion rate, maturity, the average reservoir pressure, the reservoir rock and fluid properties (magnitude and distribution), and the reservoir management and production practices. The D_i is further related to the initial effective (or stepwise) decline rate (d_i), which is a step function rather than a continuous function between two consecutive rates, by the following relationship:

$$d_i = 1 - [1 + b\, D_i]^{-(1/b)} \quad . \tag{4.10}$$

For example, if D_i =0.25/yr and b =0.5, then d_i = 1-[1- 0.5 x 0.25]$^{-(1/0.5)}$ = 0.21/yr.

The governing rate-time relationship of a general hyperbolic decline model (see Table 4.9) is given by

$$Q_t = Q_i\,(1 + b\, D_i\, t)^{-1/b} \quad . \tag{4.11a}$$

Eq. 4.11a may also be re-written as:

$$\log Q_t = \log Q_i - (1/b) \log (1 + b\, D_i\, t) = \log Q_i - (1/b) \log (1 + C\, t), \tag{4.11b}$$

where $C = b\, D_i$, which is an arbitrarily defined unknown constant (refer also to Table 4.9).

For a correct value of C, Eq. 4.11b suggests that a log-log plot of Q_t vs. (1+ $C\,t$) should yield a straight line with a slope, m (= -1/b) and intercept of Q_i at time zero or when initial decline starts.

Given the initial production rate at the onset of decline (Q_i) and other oil production data observed over the decline period, the traditional and modern DCAs have been largely an exercise in curve fitting to establish characteristic straight lines and/or type curves and conducting nonlinear regression analysis to simultaneously estimate the correct values of these two unknown

parameters D_i and b. Hyperbolic decline is known to occur as gravity drainage becomes the dominating reservoir drive mechanism during later stages of a well life. However, it is possible for this trend to become exponential again at a later stage when the solution GOR is very low and stabilized. With estimated correct values of these two unknowns, the EUR defined by the cumulative production at economic limit, N_{pe}, of the petroleum asset under evaluation can now be directly calculated using the following relationship:

$$\text{EUR} = N_{pe} = N_{pi} + N_{pde} = N_{pi} + \frac{Q_i^{\,b}}{(1-b)\,D_i}\left[Q_i^{\,(1-b)} - Q_e^{\,(1-b)}\right] \tag{4.12}$$

where Q_i and Q_e represent the production rate at initial time (i) or time zero (t=0) or at the onset of decline and at economic limit (e), respectively; and N_{pi}, N_{pde} and N_{pe} represent the cumulative production all the way to the initial (i) production rate **(**Q_i) or to time zero (t=0) before decline begins, during the entire decline period (de) analyzed all the way to economic limit, and overall project to economic limit (e) or the EUR, respectively.

b.) Types of PPT Analysis. Various well-established methods using PPT analyses may be classified and described under three broad categories: traditional DCAs (TDA), modern DCAs (MDA), and other PPT analyses.

Traditional Decline Analysis (TDA). A trial-and-error procedure is used to calculate sets of values for (1+ $C\,t$) for several assumed values of C and generating the resulting "log Q_t vs. log (1+ $C\,t$)" plots until a straight line is obtained. As shown in Eq. 4.11b, for a correct value of C (an arbitrary constant defined by the multiplication of these two unknown decline parameters n and D_i), the slope (m = -1/b) of such a log-log plot should yield the value of decline exponent (b = -1/m) and the initial decline rate is estimated using $D_i = C/b$. However, the practical use of this method is limited. It is extremely difficult to quantitatively evaluate the correct value of the decline exponent (b) because it is very insensitive to this type of analysis attempting to estimate two unknowns (C and b) simultaneously and usually yielding erroneous results. It is quite possible to have the same "b" but different D_i's matching the same decline trend that extrapolates to different estimates of reserves. Hence, this procedure is not recommended.

It would be highly desirable to estimate the nominal decline (D_i) first and then perform a simple trial-and-error procedure iterating on this single insensitive decline exponent (b) to evaluate and establish the best-matched decline trend that corresponds to the best value of (b). In this regard, a method similar to that recommended by Exxon Production Research Company (EPRCO 1982) proved to be very useful in actual practice. It uses the following a 7-step procedure described and applied to the analyses of this example oil project below.

Application of TDA to Example Oil Project. The project produced under peripheral water injection over the past 26 years with a cumulative production of 518.9 MMSTB. Production decline started at the beginning of Year 11. During the latest 10-year period (Years 17 through 26), an additional production of 120 MMSTB was realized by drilling an additional 12 new oil producers and 3 water injectors, bringing the total to 82 oil producers and 25 water injectors. Note that caution is warranted anytime DCA is used at a level of aggregation beyond the well or completion. Changing well count with time and operational adjustments can alter the shape of the aggregated curve in an unpredictable manner. Please refer to section 6.2.1 for further discussion.

Historical decline observed over the past 16 years, with quarterly average production rates reported during the last 5 years to better illustrate possible variations, were used to draw and establish three slightly different plausible decline trends and to estimate the associated annual nominal decline rates (D_i's) that reflect the uncertainty in the observed production data and

interpolations. With a total of 82 wells already producing (and only 10 infill wells remaining), the well count is judged to be reasonably stable enough not to significantly impact these decline rates. The resulting D_i's and the observed decline data were used to estimate the related hyperbolic decline exponents (b's) from the respective best-fit trends obtained. These three plausible decline trends or interpretations are judged to quantify the degree of uncertainty in the estimates of respective decline parameters and the extrapolations of these established trends to estimate the reserves (or cumulative production) for low, best, and high scenarios at their respective project economic limits.

The following EPRCO procedure is used to establish the plausible annual decline rates (D_i's) and associated decline exponents (b's) that yield the best fit for three possible hyperbolic decline trends established for the example oil project:

Step 1. Prepare a "Q_t vs. time (t)" (instead of "log Q_t vs. t") plot and draw the best smooth curve through data (quarterly average production rate data are used for the last 5 years to help better show the variations), but giving the greatest weight to and matching the latest data as closely as possible as illustrated in **Fig. 4.10a**. Note that the EPRCO recommended semi-log plot of "log Q_t vs. time (t)" almost eliminates the variations in the observed production data and hence does not allow for more than one interpretation and thus it was not used.

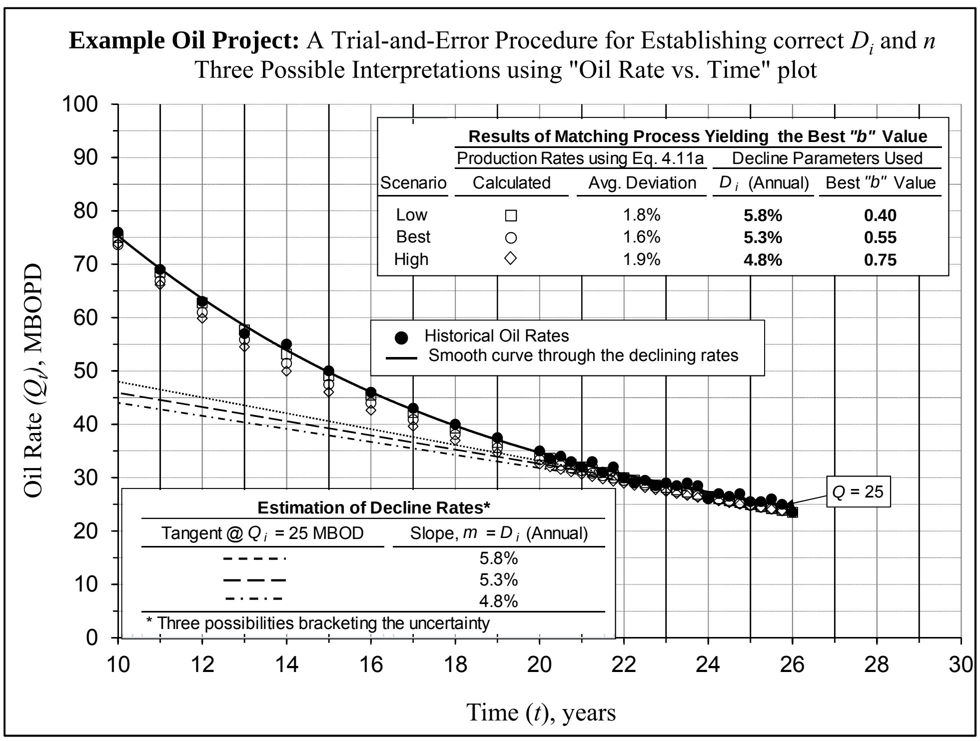


Fig. 4.10a—Estimation of hyperbolic decline parameters using rate vs. time plots.

Step 2. Draw a series of three plausible straight lines as tangents to the curve at a point near the latest values of production rate at a time (t = 26 years) and production rate (Q_t = 25 MBOPD) to estimate the respective slopes (m) and hence the nominal decline rates (D_t). Fig. 4.10a illustrates how this process works and summarizes the resulting hyperbolic decline parameters.

Step 3. Assume several plausible values of (b) and use any value of D_i (5.3% per year for the best scenario for instance) and Eq. 4.11a to calculate the production rates for various negative values of time (t). Time is negative because decline rate is determined at the most recent time (t =

25.75 years) when Q = 25 MBOPD and times between this rate and earlier Q's all the way to Q_i of 75 MBOPD (initial rate at which production decline began) must have negative values to satisfy Eq. 4.11a.

Step 4. Plot both the calculated values of Q's for various plausible values of b obtained in Step 3 and the actual production rate data to establish the best b value for the best-fit curve that has the least average deviation. Calculated data with an b value of 0.55 (shown with hollow circles in Fig. 4.10a) yielded the best-fit to actual data (shown in black dots) with a minimum average deviation of about 1.6%.

Step 5. Repeat Steps 3 and 4 with the remaining annual decline rates of 5.8% and 4.8%, to determine the best "b" values of 0.40 and 0.75 for the low and high scenarios, yielding best-fits with minimum average deviations of about 1.8% and 1.9%, respectively**.** Fig. 4.10a presents the results obtained using the above five-step process.

Step 6. Use the correct decline exponent (b) of 0.55 and the nominal annual decline rate 5.3% at 25 MBOPD and Eq. 4.9 to calculate the initial nominal annual decline rate (D_i) of 9.7% at Q_i of 75 MBOPD (initial rate at which production decline began) for the best-case scenario. Similarly, values of D_i of 9.0% and 11.1% are calculated for the low and high case scenarios, respectively.

Step 7. Finally, for the best scenario for example project operating under peripheral down-dip water injection scheme, use D_i = 9.7% and b = 0.55 and Eq. 4.11a to calculate the oil production rate profile and the cumulative production from Q_i of 75 MBOPD (end of Year 10 when decline first begins) to economic limit determined to be about 3.2 MBOPD and determine the portion of cumulative production over the whole decline period (N_{pde}). Then use Eq. 4.12 to calculate the total EUR (or N_{pe}) of 747.3 MMSTB and the 2P Reserves of 228.4 MMSTB (the EUR adjusted for the cumulative production of 518.9 MMSTB), which illustrated and reported in **Fig. 4.10b**. Note that for the best-case scenario, the same results can be obtained by using D_i of 5.3% and b of 0.55 to forecast oil rates and cumulative production from Q_i of 25 MBOPD (end of Year 26) to the same economic limit and adding to it the cumulative production realized during the first 26 years, etc.

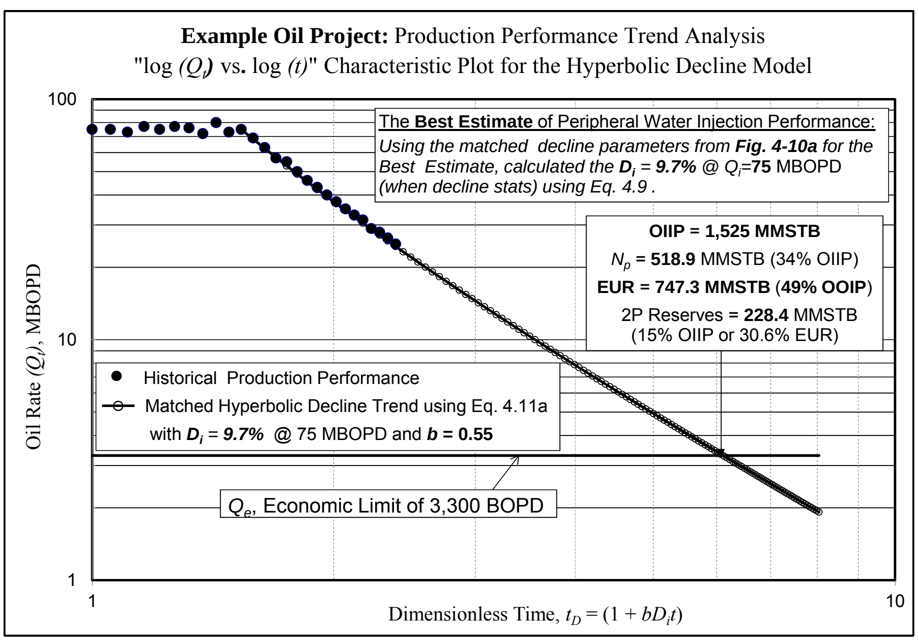


Fig. 4.10b—Dynamic and direct assessment of reserves by TDA.

Fig. 4.10b is a resulting *characteristic linear plot* of "log Q_t vs. log (1+ b D_i t)" for the best-estimate scenario only. High-quality matches obtained from using the EPRCO procedure is clearly demonstrated by the actual data (represented by black dots) relative to the calculated data (represented by hollow diamonds, circles, and squares) in Fig. 4.10a and the resulting similar high-quality decline trend match obtained in the characteristic linear plot of Fig. 4.10b for the best scenario only (for simplicity in the presentation). It confirms a higher-quality match obtained using a more reliable and repeatable EPRCO procedure of estimating these unknown decline parameters sequentially. The traditional trial-and-error method attempts to estimate the complex arbitrary constant C (= b x D_i) and b simultaneously, usually yielding erroneous results because the evaluation of "b" is known to be very insensitive to this procedure [Fekete Associates (2008)].

Table 4.10 documents the resulting reserves categories of 1P, 2P, and 3P estimated based on the plausible scenarios of low, best, and high production performance analyzed and exhibited above, which was supported by the example project under an effective peripheral water injection operation (without artificial lift using ESPs) observed over the past 26 years.

Based on the similar reasons and rationale developed and discussed earlier under Reservoir Simulation Methods, the second combined peripheral waterflood with artificial lift project was expected to have additional oil recovery of 5% OOIP over peripheral waterflood, bringing the project recovery to 54% OOIP for the best scenario. Similarly, these additional reserves are placed in Proved with Proved Undeveloped status for now, subject to transfer to Proved Developed in 2 years (or in Year 28) when the project is expected to be completed and put on-stream.

Table 4.10—Assessment using Decline Curve Analysis (Production Decline Period): Estimates of Project EURs and Reserves under Peripheral Waterflood only

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves Category: Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Oil	MMSTB	**518.9**	**518.9**	**518.9**
		% OIIP	34.0%	34.0%	34.0%
	- Raw Gas	Bscf	**295.8**	**295.8**	**295.8**
Original Oil In-Place (OIIP)		MMSTB	**1,525**	**1,525**	**1,525**
Recovery Factors Calculated[1]		% OIIP	46.0%	49.0%	54.0%
Recoverable Oil (EUR)	- Original	MMSTB	**701.5**	**747.3**	**823.5**
	- Remaining*	MMSTB	**182.6**	**228.4**	**304.6**
Initial Solution Gas-Oil Ratio (R_{si})		scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas		Btu/scf	1,350	1,350	1,350
Original Gas In-Place (GIIP)		Bscf	**869.3**	**869.3**	**869.3**
Recoverable Raw Gas (EUR)	- Original	Bscf	**399.9**	**426.0**	**469.4**
		MMBOE[2]	93.1	99.1	109.3
	- Remaining*	Bscf	**104.1**	**130.2**	**173.6**
		MMBOE[2]	24.2	30.3	40.4

[1] As a ratio of "direct estimates of project EURs under peripheral water injection" and "the project OIIPs, if available".
[2] Calculated using an average conversion factor of 5.8 MMBtu per BOE
* Estimated Oil and Raw Gas Reserves categories of **1P, 2P** and **3P**, respectively.

Table 4.10a summarizes the resulting EURs and reserves categories for the peripheral waterflood with artificial lift project as they were recalculated using the increased recovery efficiencies of 51%, 54%, and 59% of the OIIPs. The estimates were considered to have a slightly reduced degree of uncertainty relative to those obtained under the peripheral waterflood project only (refer to Table 4.10).

It may be important to point out the following qualifications about the oil example project producing under peripheral water injection:

1. As summarized in Table 4.10, the low, best, and high project EURs and Reserves are estimated directly. Although it was not necessary to know the latest estimates of respective OIIPs, it would have been definitely desirable. They were not available at the time. For a relative illustrative purpose, the best estimate of 1,525 MMSTB was used to show the recoverable estimates in terms of percent OIIP as well, and to report in respective figures and tables.
2. Since last assessment using reservoir simulation models, the project had produced another 120 MMSTB, bringing the total to 518.9 MMSTB (34% of OIIP) in 26 years, drilled and analyzed 15 additional new wells, and obtained numerous well tests thereby reducing uncertainty in the new estimates. The EURs represented relative waterflood recovery efficiencies of 46%, 49%, and 54% of this single OIIP estimate, respectively and correspond to project economic lives (at around 3 MBOD) estimated to be 78, 96 and 127 years, respectively. Long economic and/or operation project lives such as these should not be assumed without proper consideration and documentation. In this example the estimates were considered valid because:
   - The best or 2P estimate of 228.4 MMSTB (or remaining reserves) represents only 15% OOIP or about 30% of the 747.3 MMSTB EUR (see Table 4.10).
   - In actual practice, for projects with long-life reserves exceeding 100 years, depending on the sustainable future growth in worldwide demand for oil, the project's economic life will most likely vary between 50 and 70 years as a natural consequence of the higher depletion rates, which are not only required to meet the expected target production rates, but also result from implementation of the approaching planned artificial lift using ESPs and EOR projects. They are needed to both accelerate production (e.g., higher depletion rates) and increase ultimate recovery.

The incremental 7% OOIP oil recovery by artificial lift using ESPs (discussed earlier under Reservoir Simulation Methods) was revised downward to 5% OOIP to further ensure reasonable confidence and to bring the overall project recovery to 54% OOIP for the "best scenario." Similarly, these additional reserves are placed in Proved Undeveloped status for now, subject to Proved Developed status in 2 years (or in Year 28), when the project is expected to be completed and put on-stream.

Table 4.10a summarizes the resulting EUR's and reserves categories for the peripheral waterflood with artificial lift project recalculated using the increased recovery efficiencies of the peripheral waterflood by a constant 5% OIIP to 51%, 54%, and 59% of the OIIPs.

Table 4.10a—Assessment using Decline Curve Analysis (Production Decline Period): Estimates of Project EURs and Reserves Under Peripheral Waterflood with ESPs

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves Category: Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Oil	MMSTB	**518.9**	**518.9**	**518.9**
		% OIIP	34.0%	34.0%	34.0%
	- Raw Gas	Bscf	**295.8**	**295.8**	**295.8**
Original Oil In-Place (OIIP)		MMSTB	**1,525**	**1,525**	**1,525**
Assigned Recovery Factors[1]		% OIIP	51.0%	54.0%	59.0%
Recoverable Oil (EUR)	- Original	MMSTB	**777.8**	**823.6**	**899.8**
	- Remaining*	MMSTB	**258.9**	**304.7**	**380.9**
Initial Solution Gas-Oil Ratio (R_{si})		scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas		Btu/scf	1,350	1,350	1,350
Original Gas In-Place (GIIP)		Bscf	**869.3**	**869.3**	**869.3**
Recoverable Raw Gas (EUR)	- Original	Bscf	**443.3**	**469.4**	**512.9**
		MMBOE[2]	103.2	109.3	119.4
	- Remaining*	Bscf	**147.5**	**173.7**	**217.1**
		MMBOE[2]	34.3	40.4	50.5

[1] Under peripheral water injection (see Table 4.10), supplemented with field-wide installed artificial lift using ESPs.
[2] Calculated using an average conversion factor of 5.8 MMBtu per BOE
* Estimated Oil and Raw Gas Reserves categories of **1P, 2P** and **3P**, respectively.

Similarly, supported further by the full performance of a second analog CO_2 miscible pilot project nearby with a realized recovery efficiency of about 20% OIIP, it was judged prudent to revise the incremental recovery efficiencies (assigned earlier under Reservoir Simulation Methods) downward by 2% to 13%, 16%, and 20% OIIP, respectively, bracketing the uncertainty for the planned CO_2 miscible project (scheduled to be on-stream by Year 32). The respective Contingent Resources categories of 1C, 2C, and 3C are summarized in **Table 4.10b**.

Table 4.10b—Assessment of Contingent Resources (Production Decline Period): EURs under a Planned CO_2 Miscible Project

Measured and Estimated Parameters	Units	Bases and Estimates by Resource Category: Low Estimate	Best Estimate	High Estimate
Original Oil In-Place (OIIP)	MMSTB	**1,525**	**1,525**	**1,525**
Initial Solution Gas-Oil Ratio (R_{si})	scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas	Btu/scf	1,350	1,350	1,350
Recovery Factor[1]	% OIIP	13%	16%	20%
Recoverable Oil*	MMSTB	**198.3**	**244.0**	**305.0**
Recoverable Raw Gas*	Bscf	**113.0**	**139.1**	**173.9**
	MMBOE[3]	26.3	32.4	40.5

[2] Under a CO_2 Miscible Flood based on the results of two implemented anolog CO_2 Pilot Projects.
[3] Calculated using an average conversion factor of 5.8 MMBtu per STB of crude oil.
* Estimated Oil and Gas Contingent Resources categories of **1C, 2C** and **3C**, respectively.

Modern Decline Analysis (MDA). Similar to TDA, the objective of MDA is also to determine the best-fit values of constants n and D_i to the observed production rate trend for a well, a number of wells or the entire reservoir. While not illustrated in this particular example oil recovery project, advances in computing have facilitated the application of MDA using type-curve analysis and nonlinear regression techniques. Among many available in the literature,

these following two methods are judged to be significantly different and may be used to analyze PPTs using MDA:

1. *Fetkovich Type-Curve Analysis* (Fetkovich 1980 and Fetkovich et al. 1987).
2. *Hsieh et al. Dual Exponent Power Function Model* (Hsieh et al. 2001). PS-CIM (2004) provides a procedure for using spreadsheet software analysis with automatic curve-fitting options to use and apply the Hsieh et al. (2001) method.

Examples for and discussion of these and other methods of both TDA and MDA can also be found in various published articles by Long and Davis (1988), Mannon and Porter (1989), and COGEH Volume 2 (2005).

1. *Other Production Performance Trend Analyses.* There are other well-established production performance analyses that may be used to predict recoverable volumes based on trends exhibited for a well and/or a reservoir even before the production rate begins to decline. These reservoir drive specific analyses are briefly discussed by Cronquist (2001). Salient points of these methods may be summarized as follows:
2. Cumulative Gas Production vs. Oil Production Trends: For oil reservoirs with solution-gas drive, a semi-log plot of log G_p vs. N_{pt} may develop a trend that could be extrapolated to estimate oil recovery with the maximum G_p being equal to original solution gas in-place (GIIP = R_{si} x OIIP).
3. Water Cut or Water/Oil Ratio (WOR) vs. Cumulative Production Trends: These performance trends have been found particularly useful in analyzing an oil reservoir with waterdrive or producing with down-dip water injection and pattern waterflood. The established trend is extrapolated to economic water cut (f_w) or WOR to estimate ultimate recovery under the prevailing production method over which the trend has been established. It may be useful to note the following reported observations:
   - A semi-log plot of "log f_w (or f_o) vs. N_{pt}" trend may turn down at small values f_o but earlier for light oils and later for viscous oils (Brons 1963).
   - A semi-log plot of (WOR+1) and total fluids withdrawal (F_p) vs. time (t) may help define oil rate trend (Purvis 1985). It is reported that a semi-log plot of "(WOR+1) vs. N_{pt}" tends to be linear at WOR's less than 1 and therefore may help define performance trends at low values of WOR or water cuts.
   - Ershaghi and Omoregie (1978) and Ershaghi and Abdassah (1984) recommended that a plot of $[1/f_w - ln(1/f_w - 1)]$ vs. N_{pt} should be linear. However, they noted that due to the inflection point of the f_w vs. S_w curves, the method will work only at higher water-cuts when $f_w > 50\%$.

It logically follows that one should use Purvis-type performance trend analysis for reservoirs with low water-cuts, and the Ershaghi et al.-type for those with high water-cuts exceeding 50%. Finally, it must be emphasized that although the significant portion of semi-log plot of (k_{rw}/k_{ro}) vs. S_w is linear, the floodout performance of wells and reservoirs are also governed by the rock heterogeneity and the combined impact of gravity, viscous and capillary forces.

Actual PPT analyses require a thorough understanding of their semitheoretical technical bases and the well-established and widely used methods and procedures. However, the correct application of these procedures is not straightforward. One could easily and incorrectly obtain an excellent match, but end up with inaccurate reserves. COGEH Volume 2 (2005) provides the following advice on this very point: "The choice of the best-estimate case reserves, which represents the 2P reserves estimate, must consider the quality of the fit, the uniqueness of the fit,

the range of expected exponents, and the reasonableness of the reserves or life. Caution must be used however in relying on computer generated best-fits, because there is always reservoir uncertainty and late time behavior, which may change decline rates and exponents in the future."

Production performance trends are not only reservoir specific but also depend on the specific reservoir management and production practices. Any significant change in these practices could easily shift and change the previously established decline trends and invalidate their extrapolations. Therefore, proper application of these procedures, to a large extent, depends on the experience and skill levels of the professional evaluators and their ability to judge the reasonableness of results obtained by comparing them to known analogs and/or other performance-based methods.

4.3 Summary of Results

Consistent with PRMS guidelines on petroleum resources and reserves definitions, classification, and categorization, different deterministic assessment methods and procedures have been used to estimate oil and raw gas resources and reserves for an example oil project. The project retraces its E&P life cycle, starting from the exploration (pre- and post-discovery stages) and appraisal phase and going through all three stages (including initial development) of its production phase (refer to Figs. 4.1 and 4.1a). It covers 5-year appraisal and initial development period after the initial discovery followed by an actual production history of 26 years.

Results of project's OIIPs and EURs of oil resources and reserves estimated using Volumetric and Analogous Methods during its Exploration and Appraisal Phase and Initial Development Period are summarized in **Fig. 4.11**.

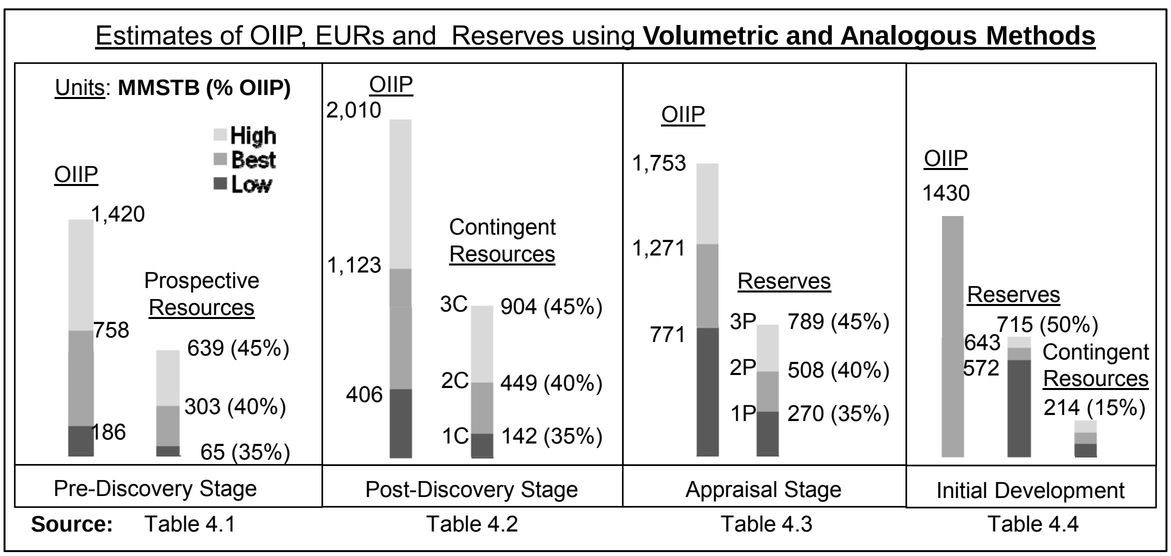


Fig. 4.11— Project Resources and Reserves Assessment during Exploration and Appraisal Phase.

Similarly, the results of estimated project OIIPs, EURs, and Reserves using performance-based methods at three different periods during its production phase are presented in **Table 4.11.** Finally, based on these project OIIPs and the results of nearby analog pilot projects and supported by a reservoir simulation study carried out for the example oil project, the estimated respective Contingent Resources under a planned CO_2 Miscible Project are summarized in **Table 4.12.** A close examination of Fig. 4.11, Tables 4.11 and 4.12 should provide a reasonable picture

of how estimates of project in-place and recoverable quantities (reserves and/or resources) could change over its E&P life cycle.

Table 4.11—Reserves Assessment Using Performance-Based Methods
Estimates of Project OIIPs, EURs and Reserves During Production Phase

Assessment Method	Units	Estimates under Waterflood Performance only			Estimate under Waterflood and Artificial Lift Performance		
		Low	Best	High	Low	Best	High
Material Balance (MB) Analyses (Source: Table 4.6)							
Depletion Stage		*Early Production Stage with 8 years of actual production performance*					
Cumulative Production	MMSTB	220.8	220.8	220.8			
(An indication of Project Maturity)	% OOIP	17.0%	13.8%	11.0%			
Original Oil In-Place (OIIP)	MMSTB	**1,300**	**1,600**	**2,000**			
Recovery Factor (%OIIP)	% OOIP	40%	45%	50%			
Recoverable Oil (EUR)	MMSTB	**520**	**720**	**1,000**			
Oil Reserves	MMSTB	**299**	**499**	**779**			
Reservoir Simulation Model (RSM) Studies (Source: Tables 4.8 and 4.8a)							
Depletion Stage		*Early Decline Stage with 16 years of actual production performance*					
Cumulative Production	MMSTB	399.0	399.0	399.0	399.0	399.0	399.0
(An indication of Project Maturity)	% OOIP	27.8%	26.2%	23.0%	27.8%	26.2%	23.0%
Original Oil In-Place (OIIP)	MMSTB	**1,434**	**1,525**	**1,739**	**1,434**	**1,525**	**1,739**
Recoverable Oil (EUR)	MMSTB	**573**	**686**	**869**	**674**	**793**	**991**
Implied Recovery Factor (%OIIP)	% OOIP	40%	45%	50%	47%	52%	57%
Oil Reserves	MMSTB	**174**	**287**	**470**	**275**	**394**	**592**
Production Performance Trend (PPT) Analysis (Source: Tables 4.10 and 4.10a)							
Depletion Stage		*Late Decline Stage with 26 years of actual production performance*					
Cumulative Production	MMSTB	518.9	518.9	518.9	518.9	518.9	518.9
(An indication of Project Maturity)	% OOIP	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%
Original Oil In-Place (OIIP)	MMSTB	**1,525**	**1,525**	**1,525**	**1,525**	**1,525**	**1,525**
Recoverable Oil (EUR)	MMSTB	**702**	**747**	**824**	**778**	**824**	**900**
Implied Recovery Factor (%OIIP)	% OOIP	46%	49%	54%	51%	54%	59%
Oil Reserves	MMSTB	**183**	**228**	**305**	**259**	**305**	**381**

Table 4.12—Assessment of Contingent Resources
Estimates of Project OIIPs and EURs During Production Phase

Assessment Method	Units	Bases and Estimates by Resource Category (under a Planned CO_2 Miscible Project)		
		Low	Best	High
Material Balance (MB) and Analogous Methods (Source: Table 4.6)				
Depletion Stage: *Early Production Stage*		*8 years of production performance under Peripheral Waterflood and results of one analog CO_2 Pilot.*		
Cumulative Production	MMSTB	220.8	220.8	220.8
(An indication of Project Maturity)	% OOIP	17.0%	13.8%	11.0%
Original Oil In-Place (OIIP)	MMSTB	**1,300**	**1,600**	**2,000**
Recovery Factor (%OIIP)	% OOIP	5%	10%	15%
Recoverable Oil (EUR)	MMSTB	**65**	**160**	**300**
Reservoir Simulation Model (RSM) and Analogous Methods (Source: Table 4.8b)				
Depletion Stage: *Early Decline Stage*		*16 years of production performance under Peripheral Waterflood and the results of two analog CO_2 Pilots (only one fully realized).*		
Cumulative Production	MMSTB	399.0	399.0	399.0
(An indication of Project Maturity)	% OOIP	27.8%	26.2%	23.0%
Original Oil In-Place (OIIP)	MMSTB	**1,434**	**1,525**	**1,739**
Recovery Factor (%OIIP)	% OOIP	15%	18%	22%
Recoverable Oil (EUR)	MMSTB	**215**	**275**	**382**
Single OIIP Estimate and Analogous Methods (Source: Table 4.10b)				
Depletion Stage: *Late Decline Period*		*26 years of production performance under Peripheral Waterflood and fully realized results of two analog CO_2 Pilots.*		
Cumulative Production	MMSTB	518.9	518.9	518.9
(An indication of Project Maturity)	% OOIP	34.0%	34.0%	34.0%
Original Oil In-Place (OIIP)	MMSTB	**1,525**	**1,525**	**1,525**
Recovery Factor (%OIIP)	% OOIP	13%	16%	20%
Recoverable Oil (EUR)	MMSTB	**198**	**244**	**305**

As a concluding remark, it may be beneficial to reiterate the commonly practiced development and production strategy for projects with long-life reserves similar to our example oil project. Because of the availability of many development opportunities in excess of their development needs, oil reservoirs have been developed at relatively low annual depletion rates from 2 to 5% of EUR initially by many Middle East producers. That is why the full reservoir development (drilling of all well-spacing units) typically requires 20 to 30 years to complete, and extends the economic lives beyond 100 years. Having the leverage to practice a low reservoir depletion strategy and continuous drilling to maintain the initially established plateau production rate as long as possible provides significant benefits including the opportunity to take better advantage of new technological advancements to maximize the ultimate recovery and keep the unit development and production costs at significantly lower levels than those prevalent elsewhere.

Key takeaways from this chapter are as follows:

1. Petroleum resources assessment is and must be a continuous ongoing technical process supported by good practices and collaborative efforts across many disciplines.
2. Petroleum resources assessment should use the methods most suitable for analyzing the data available, including static geoscientific and engineering as well as dynamic actual production performance, and be carried out by a collaborative multidisciplinary team of expert evaluators consisting of geoscientists and engineers.
3. Assessment of subsurface petroleum resources is complex and subject to many uncertainties in static and dynamic reservoir parameters coupled with regulatory, operational and economic uncertainties. Although exceptions will continue to exist, the quantity of reliable data and degree of certainty in the estimates of PIIP and EUR are expected to increase over time.
4. Irrespective of project maturity and the amount and quality of performance data available, the degree of certainty in resource estimates largely depends on the ability of experienced reserves evaluation professionals not only to know the most appropriate methods to use, but also to exercise prudent judgment, ensuring the reasonableness and validity of these estimates by always comparing them with those estimated using different methods and/or with the known analog reservoirs.
5. Use of the full PRMS classification and categorization matrix provides a standardized framework for characterizing the estimates of marketable hydrocarbon volumes according to their associated risks and uncertainties.

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Chapter 5

Probabilistic Reserves Estimation

Wim J.A.M. Swinkels

5.1 Introduction

Understanding and managing the range of uncertainty in reserves and resources estimation are important aspects of the business of exploration and production of oil and gas. Oil and gas professionals want to capture this uncertainty in order to

- Make development plans that can cover the range of possible outcomes
- Provide a range of production forecasts to evaluate the expected outcome of their ventures
- Measure exploration, appraisal, and commercial risks
- Ensure that they can handle an unfavorable outcome (i.e., that they have an economic project, even if the low case materializes)
- Understand and communicate the confidence level of their reserves estimate

Approaches to handle uncertainty in resource estimates can be seen on a scale from completely deterministic to fully probabilistic as follows:

1. *The Deterministic Method*—A single value is used for each parameter, resulting in a single value for the resource or reserves estimate. The estimated volumes can be classified as Proved, Probable, or Possible in the incremental approach, or 1P, 2P, or 3P in the cumulative approach described in the PRMS, depending on the level of uncertainty. Each of these categories can be related to specific areas or volumes in the reservoir.
2. *The Scenario Method* (sometimes called *Realizations Method*)—This is essentially an extension of the Deterministic Method. In this case, a range of possible deterministic outcomes or scenarios is described. Usually, this collection of scenarios is then translated into a pseudoprobability curve. The scenario method combines elements of the deterministic approach and of the full probabilistic method.
3. *The Probabilistic Method*—The statistical uncertainty of individual reservoir parameters is used to calculate the statistical uncertainty of the in-place and recoverable resource volumes. Often a stochastic (e.g., Monte Carlo) method is applied to generate probability functions by randomly sampling input distributions. Such functions lend themselves readily to various quantitative risk analysis and decision-making methods. Probability levels of the total recoverable volume can then be related to 1P, 2P, and 3P reserve categories, or the corresponding resources categories, using the Petroleum Resources Management System (PRMS) guidelines (SPE 2007). In many cases, there is no one-to-one relation between one of these outcomes and a physical volume or area in the reservoir.

This chapter focuses on the last two of these three approaches, which both have a probabilistic nature, as opposed to the first approach, which is deterministic. Increasingly, industry and regulatory bodies are accepting the use of these methods; see for example, the modernized US Securities and Exchange Commission rules (US SEC 2008).

The value of the probabilistic and scenario methods in the business process is that

- Both describe the full range of uncertainty and reveal upsides and downsides
- They easily allow calculation of the value of information of various activities
- Both allow calculation of effects of interdependent uncertainties
- They provide a good interface with decision support and financial modeling methods
- Both methods can easily be applied across the boundary between exploration and production activities

We will briefly describe the deterministic method, then we will discuss the scenario approach, and finally we will address issues in the application of probabilistic methods.

5.2 Deterministic Method

The deterministic method uses a single value for each parameter, based on a well-defined description of the reservoir, resulting in a single value for the resource or reserves estimate. Typically, three deterministic cases are developed to represent either low estimate (1P or 1C), best estimate (2P or 2C), or high estimate (3P or 3C), or Proved, Probable, and Possible estimates. Each of these categories can be related to specific areas or volumes in the reservoir and a specific development plan.

Advantages of the deterministic method are

- The method describes a specific physical case; physically inconsistent combinations of parameter values can be spotted and removed.
- The method is direct, easy to explain, and manpower efficient.
- The estimate is reproducible.
- Because of the last two advantages, investors and shareholders like this method, and it is widely used to report Proved Reserves for regulatory purposes.

A feature and potential weakness of the deterministic method is that it handles each reserves category in isolation and does not quantify the likelihood of the mid, high, and low case.

5.3 Scenario Method

The scenario method describes a range of possible outcomes for the reservoir, which are consistent with the observed data. A single, physically consistent outcome within this range with its estimated in-place volume is called a subsurface realization. For the purpose of obtaining a recovery factor, we can then define a development scenario for each subsurface realization and subsequently book recoverable volumes in the appropriate PRMS categories. The collection of scenarios can also be translated into a pseudoprobability curve by assigning associated chances of occurrence. This method combines elements of the deterministic approach and of the full probabilistic method.

Multiple realizations of the subsurface should be

- Based on ranked uncertainties. For this purpose we first have to specify and rank the main uncertainties.
- Internally consistent (i.e., a realization should consist of parameter values or sets of conditions that can physically exist together).
- Associated with a probability of occurrence (but not necessarily equally probable).
- Related to a technically sound development option.

When using PRMS, the Proved Reserves are a high-confidence commercial case within the set of scenarios (i.e., a realization that results in a reserves number at the low end of the range).

The scenario method can also be used with each branch representing an individual simulation run (history-matched, if production history exists). By assigning probabilities to these branches, it is possible to define appropriate low (1P or 1C), best (2P or 2C), and high (3P or 3C) estimates from the set of simulation runs. Because this is not strictly a probabilistic method, it is not necessary to select outcomes at precisely the probability equivalents of these categories.

Various methods are available to represent and visualize a set of realizations. The two most important ones are the probability-tree method and the use of scenario matrices.

5.3.1 Probability-Tree Representation of the Scenario Method. When using probability trees to represent scenarios, each branch in the tree represents a set of discrete estimates and associated probability of occurrence, as shown in the relatively simple example in **Fig. 5.1.**

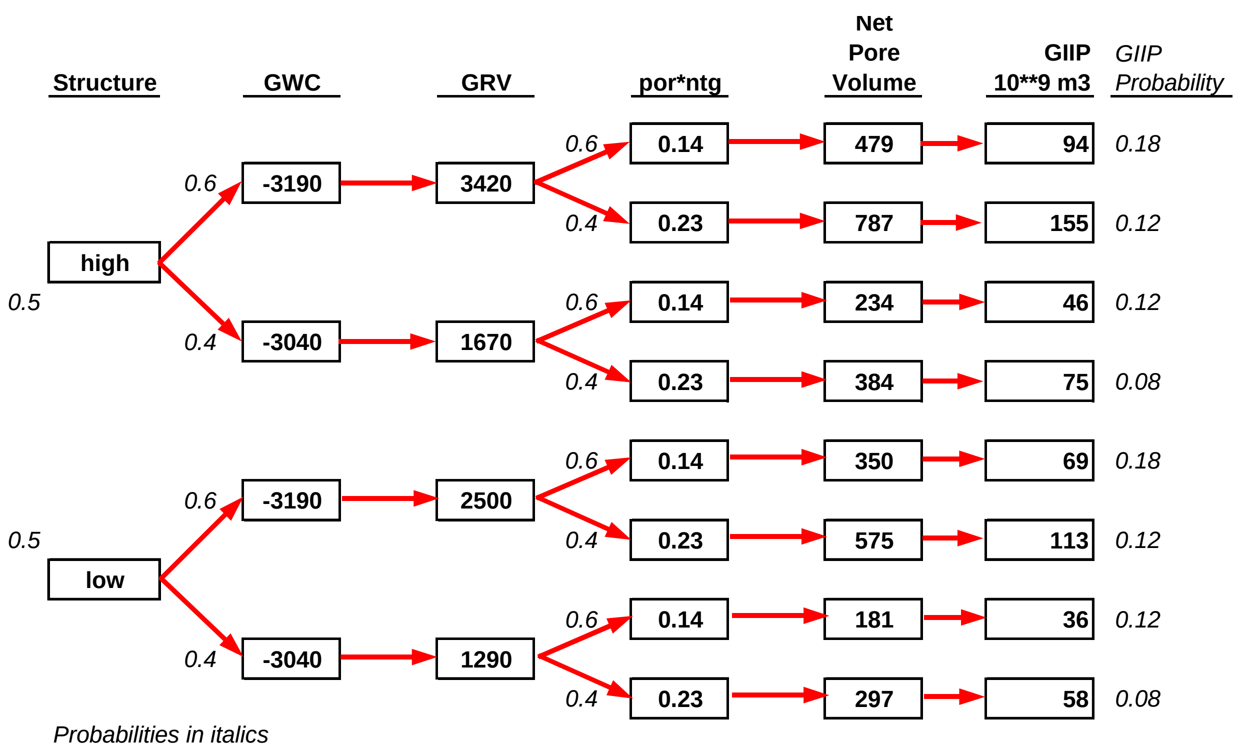

Fig. 5.1—Probability-tree example. (GRV=gross rock volume; GWC=gas/water contact).

Each end branch in this tree is the result of a possible route along the branching points in the tree and hence represents a specific subsurface realization, for which an in-place volume [gas initially in place (GIIP) in this case] can be calculated. The example shows that the branches are associated with different probabilities, and thus a combined probability can be calculated for each endpoint. By combining the endpoint GIIP values and their cumulative probabilities, this tree also can be used to generate a cumulative probability curve, which is provided in **Fig 5.2,** for the example in Fig. 5.1. In this curve, the 90, 50, and 10% probability values can be easily identified. In this example, a GIIP estimate of about 40 x 10^9 m^3 has a probability of 90% to be exceeded.

Obviously such a tree can straightforwardly handle dependencies between probabilities on the branching points.

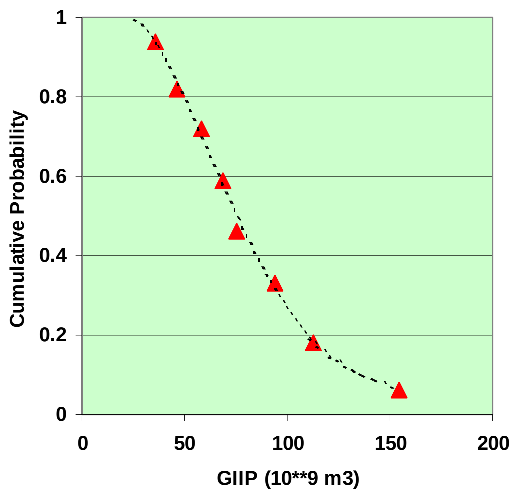

Fig. 5.2—Cumulative probability density function (PDF) constructed from probability tree.

5.3.2 Matrix Representation of the Scenario Method. The realization matrices method to represent subsurface realizations and development concepts is more qualitative but often richer in content than the probability-tree method described above. The example in **Fig. 5.3,** modified from a recent project, shows various reservoir aspects that are represented by columns. Each cell in the columns describes a possible outcome. A realization is the consistent combination of a set of possible outcomes. The example also shows that realizations can be described according to a specific theme (e.g., in this case a "High-STOIIP/Low-Drainage" case is represented by triangles in the diagram, while the hexagons represent a scenario characterized by high residual saturation, strong aquifer, and low drainage).

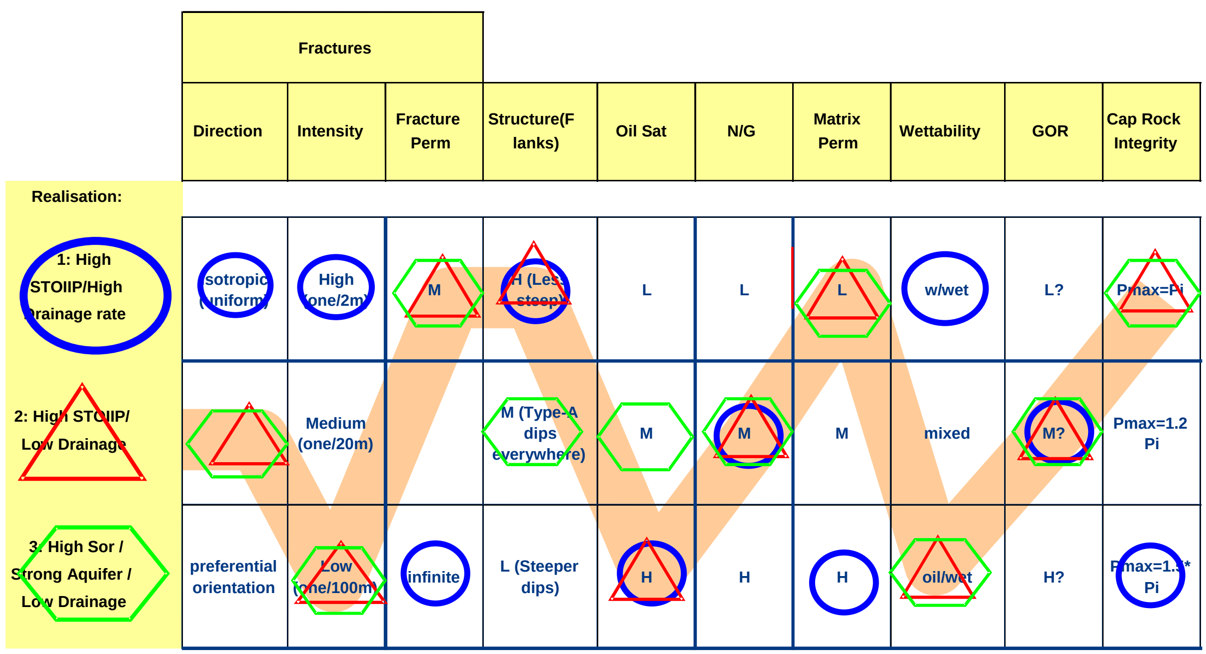

Figure 5.3—Example of scenario method.

The scenario matrix is useful for generating scenarios that cover a wide range of possible outcomes and hence can play an important role in project-framing exercises. This representation does not allow as much quantitative treatment of probabilities as the scenario tree method. For an example see O'Dell and Lamers (2005).

5.3.3 Strengths and Weaknesses. The scenario method combines the strengths of probabilistic (stochastic sampling) and deterministic approaches. Its strong points are

- It allows generation of subsurface realizations made up of consistent sets of parameters.
- It is a useful approach to identify development concepts.
- Development concepts can be tested against all possible reservoir outcomes.
- It can be helpful in defining targets for appraisal (through value-of-information analysis).
- It provides an auditable method to identify the selected reserves or resources category outcomes.

A weakness of the scenario method is the limited number of scenarios that can usually be handled, with the risk of undersampling the range of possibilities. Assigning a probability to each scenario relies heavily on geological and petroleum engineering judgment. Both of these shortcomings are sometimes tackled by using experimental design methods, as described by Al Salhi et al. (2005).

5.4 Probabilistic Method

In the probabilistic method, we use the full range of values that could reasonably occur for each unknown parameter (from the geosciences and engineering data) to generate a full range of possible outcomes for the resource volume. To do this, we identify the parameters that make up the reserves estimate and then determine a so-called probability density function (PDF). The PDF describes the uncertainty around each individual parameter based on geoscience and engineering data. Using a stochastic sampling procedure, we then randomly draw a value for each parameter to calculate a recoverable or in-place [e.g., stock-tank oil initially in place (STOIIP)] resource estimate. By repeating this process a sufficient number of times, a PDF for the STOIIP or recoverable volumes can be created. This Monte Carlo procedure is schematically shown in **Fig. 5.4.**

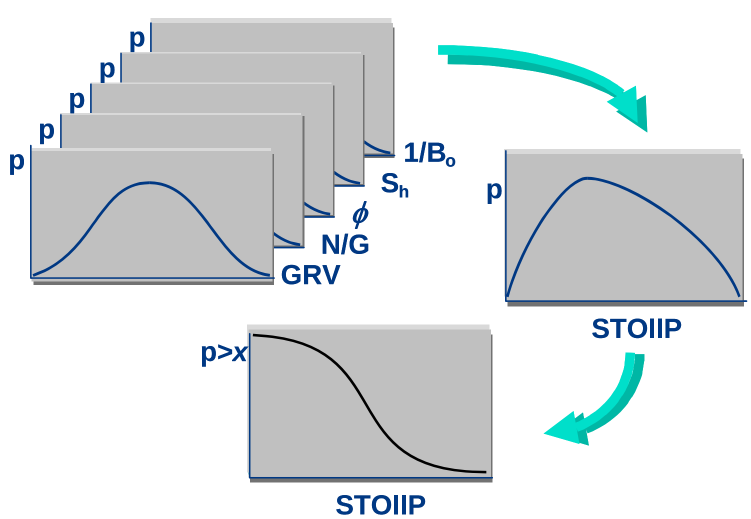

Fig. 5.4—Monte Carlo approach to volumetrics.

Dependencies between parameters often exist and must be represented in the probabilistic estimation of recoverable volumes. Commonly encountered positive correlations are between net-to-gross gas saturation and porosity in clastic reservoirs. An obvious negative correlation exists between the oil and gas volumes in a gas-capped oil reservoir. It should be noted that the resultant PDF for the recoverable resources is often asymmetrical.

It is important to remove physically impossible realizations from the model because they will inappropriately skew the range of outcomes. A good practice is to select a realization that represents a "typical" 1P or 2P case and to supplement each probabilistic assessment with discrete realizations for the low, mid, and high cases. This ensures that one is clear about the development scenario that the probabilistic estimate represents and should guard against allowing unrealistic cases into the assessment. It should be noted that probabilistic estimates for an accumulation will differ depending on the development scenario selected.

For fields where production data exists, the workflow includes the additional step of history matching. A result of this workflow is a group of equally probable history-matched models created by a combination of parameters, using for instance genetic algorithms and evolutionary strategy to match the production history.

5.4.1 Volumetric Parameters and Their Uncertainty Distribution. Uncertainty in volumetric estimates of petroleum reserves and resources is associated with every parameter in the equations.

Gross Rock Volume (GRV). Usually, the most important contribution to overall uncertainty is in the GRV of the reservoir—just how big is it? This uncertainty may be related to

- Lack of definition of reservoir limits from seismic data
- Time-to-depth conversion in seismic observations
- Dips of the top of the formation
- Existence and position of faults
- Whether the faults are sealing to hydrocarbon migration and production

The GRV depends critically on the height of the hydrocarbon column because the volume of a reservoir anticline increases roughly proportionally with the cube of the column. Typical reporting requirements (US SEC 2008) for Proved Reserves recognize this sensitivity by limiting the rock volume to that above the lowest known hydrocarbons (LKH) unless otherwise indicated by definitive geosciences, engineering, or performance data.

Rock Properties: Net-to-Gross and Porosity. The uncertainty associated with the properties of the reservoir rock originates from the variability in the rock. It is determined through petrophysical evaluation, core measurements, seismic response, and their interpretation. While petrophysical logs and measurements in the laboratory may be quite accurate, the samples collected may be representative only for limited portions of the formations under analysis. A core 4 in. 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 precise 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 to condition one or several alternative (uncertain) interpretations.

Fluid Properties. For fluid properties, a few well-chosen samples may provide a representative selection of the fluids. The processes of convection and diffusion over geologic times have generally ensured a measure of chemical equilibrium and homogeneity within the reservoir, although sometimes gradients in fluid composition are observed.

Sampling and analysis may be a significant source of uncertainty. Reservoirs with initial gradients in fluid composition or where phase changes have occurred will be affected by production. Here, samples may be unrepresentative of the initial fluids and they may be misinterpreted easily. Hence, fluid definition under such conditions is less certain than in virgin reservoirs. Additionally, sampling may be affected by acquisition methodology, such as recombination procedures in surface sampling, and fluid properties may also be impacted by other factors, such as storage, which can alter original reservoir conditions.

Recovery Factor (RF). Recovery is based on the execution of a project and affected by the shape and the internal geology of the reservoir, its properties and fluid contents, and the development strategy. If a reservoir can be described in sufficient detail, then numerical models can be made of the effects of well and drainage-point density and location, fluid displacement, pressure depletion, and their associated production and injection profiles. Realistic alternatives, conditioned by available information and consistent with the definitions, may be modeled to assess the uncertainties. If a reservoir is poorly defined, material balance calculations or analog methods may be used to arrive at an estimate of the range of RFs. Uncertainty ranges in the RF can often be based on a sensitivity analysis.

Selecting Distribution Functions for Individual Parameters. In probabilistic resource calculations, it is the task of the estimator to specify a PDF that fits the information available. Modern tools (such as spreadsheet-based or other commercially available statistical software) allow for a wide choice of PDFs (normal, log-normal, triangular, Poisson, etc.).

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

- Make a conscious decision on range and shape of the input distributions for the volumetric calculation on the basis of direct reservoir and geoscience information or appropriate analogs.
- The distributions must be applied only in the range for which they usefully reflect the underlying uncertainty. Avoid distributions that extend into infinity. Ensure that distributions do not become negative or exceed unity for parameters expressed as fractions or ratios, such as porosity, net-to-gross, saturation, or recovery efficiency.
- The most generic PDFs to describe the uncertainty of the mean are normal and log-normal distributions. Their disadvantage is the infinite tail, which can lead to unrealistic scenarios. One solution is to apply truncation at meaningful values; however, if truncation significantly impacts the overall shape of the PDF, then it is probably more appropriate to use another PDF as the starting point.
- Recall that the range of values required is that which represents the evaluator's uncertainty in the value of the mean, rather than the distribution of the data itself.
- Do not confuse the three measures of centrality (expectation or mean, mode, and median) when defining the distribution.
- Be aware of what the low and high value estimates represent: extremes (such as minima and maxima (P100/P0) or some other probability value (such as P95/P05, P90/P10, etc.).
- The PDF of a sum of log-normal distributions tends toward a normal distribution. As a result, a product of independent factors, whose logarithms are of the same magnitude, tends toward

a log-normal distribution. Examples of entities that are strongly affected by products are the reserves of an accumulation and the permeability of a porous system.

- The PDF of the 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 the independent quantities are not of the same magnitude, the sum and its PDF will be dominated by the largest ones.

Many practitioners approximate PDFs with triangular distributions, particularly when data are limited and the range is narrow. In cases where a probability distribution cannot be determined easily, a uniform distribution is sometimes used. Such distributions may be considered coarse approximations of reality. However, uncertainty ranges of the resulting volumes are more influenced by mean values and standard deviations than they are by the shape of the distributions of the individual parameters that make up the estimate.

The most 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. As a general principle, the less the information, the wider the range. It should be emphasized that distributions to be used in a probabilistic analysis routine, even if measured data are available, should properly describe the uncertainty of the specific input parameters being represented. For example, the porosity distribution from core or logs is conceptually different from the distribution of the average porosity in the reservoir. Therefore, the use of existing data distributions as observed in the existing wells is not valid. **Fig. 5.5** illustrates an example. In this example some of the core plugs have 0% porosity. Obviously 0% porosity cannot be used as the low value in the distribution of average fieldwide porosity if it is known that average porosity is always above zero. A further discussion of the differences between distributions of the raw data and of the reservoir average is provided in Cronquist (2001).

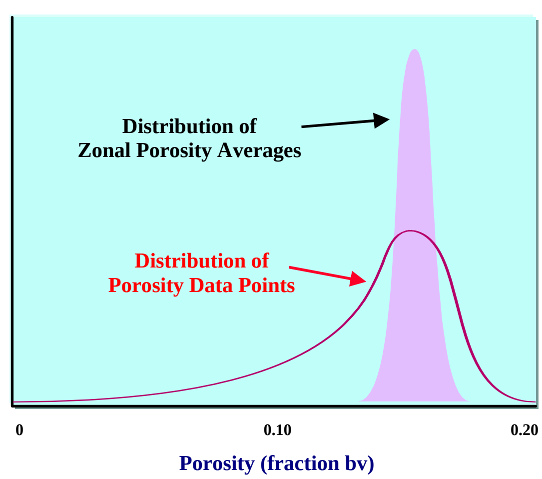

Fig. 5.5—Frequency distributions of porosity.

The known distribution of available data should be considered only as the starting point to define the PDF for reservoir parameters. If cutoffs are applied to the reservoir parameters (e.g., if net sand has a 5% porosity cutoff), then these should be reflected in the reservoir parameter PDF.

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, after cutoffs, can be used as a starting point. If only scarce data are at hand, then the range should be defined and turned into a distribution. Always keep in mind that the distribution function should describe the distribution of the reservoir-averaged parameter value. **Table 5.1** provides typical ranges of uncertainty in the most common reservoir parameters.

TABLE 5.1—SOME RESERVOIR PARAMETERS AND TYPICAL RANGES OF UNCERTAINTY

	Range	Source
GRV	+/– 30%	3D Seismic
		2D Seismic
Net-to-Gross	+/– 20%	Well logs
Porosity from logs	+/– 15%	Logs
Porosity from cores	+/– 10%	Cores
Hydrocarbon saturation	+/– 20%	Well logs
Dip	+/– 10%	Dipmeter
	+/– 30%	Seismic
Formation volume factor (B_o or B_g)	+/– 5%	PVT test

Note: Ranges are a percentage of the actual measurement, not e.g., porosity percentage points.
Warning: The values in this table are typical ranges provided to use for comparison with your actual parameter ranges. Do not use as default uncertainty ranges.

5.4.2 Performance Methods: Parameters and Their Uncertainty Distribution. When sufficient production performance information is available, reserves can be assessed by using performance-based methods, such as decline curve analysis (DCA). In classical DCA, the uncertainty in the estimated ultimate recovery is mainly caused by the selected decline model (exponential, hyperbolic, or harmonic) and the selected matching or regression period.

A possible approach to arrive at a probabilistic estimate using performance-based methods is by using the hyperbolic decline equation:

$$q = \frac{q_i}{\left(1 + b d_i t\right)^{\frac{1}{b}}}$$

and matching on the hyperbolic decline constant b, as well as the initial nominal decline rate d_i. Since exponential decline (b=0) and harmonic decline (b=1) are limiting cases of the hyperbolic decline, this eliminates the problem of selecting a decline model. By varying b, d_i, and the matching period within reasonable limits, a distribution for the resulting ultimate recovery can be obtained, from which Proved, Probable, and Possible Reserves can be derived. Other approaches have been explored (Cheng et al. 2005).

Combining Risk and Uncertainty. PDFs resulting from the methods described previously can be combined with risk factors, which will result in typical shapes for different situations on both sides of the exploration/production boundary. **Fig. 5.6** shows cumulative risked PDFs for resources in five different situations. First of all, there are four curves that intersect the y-axis at a value below one. For these cases, there is a finite probability that the STOIIP is 0 (i.e., these curves describe prospects for which it is not certain that they contain oil). The intersection point with the y-axis is the probability of success (PoS), as used in exploration situations. The curve that intersects the y-axis at Probability 1, describes a discovered oil accumulation, with a range of uncertainty and PoS=1. In more detail, the figure shows the following:

- Relatively poor prospect; volume is small and PoS is also limited.
- Speculative prospect; small probability of a large volume.
- Either/or prospect; in case of success there is a relatively well-defined volume.
- Small confident prospect; PoS is relatively large, mean volume in the success case is in the order of 30 million bbl.
- Discovery; in this example case the P10, or the upside, is almost twice the P50, the P90 value is some 60% of the P50.

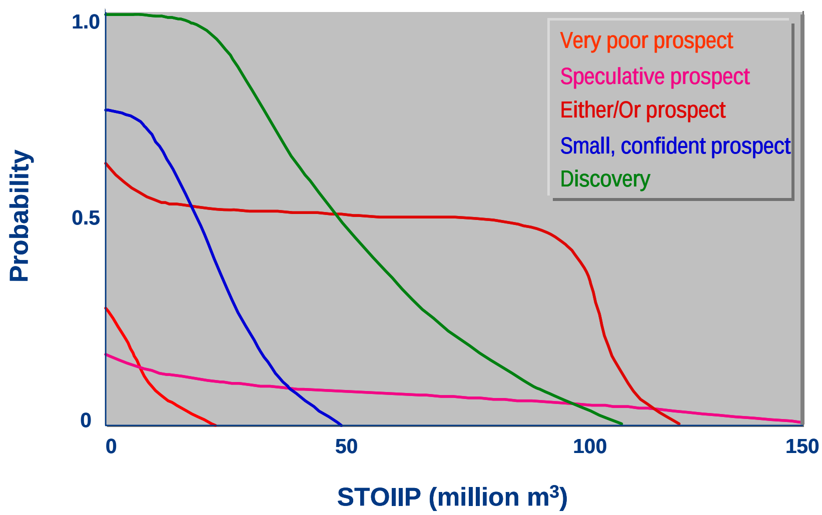

Fig. 5.6—PDFs.

5.4.3 Strengths and Weaknesses. Strengths of the probabilistic method include

- The uncertainty range of the result can be derived from basic parameter uncertainty ranges
- Easily lends itself to numerical treatment
- Can be applied throughout the business cycle from exploration to production
- Naturally links in with value-of-information work
- Allows capture of the range of outcomes when insufficient detailed data are available

Weaknesses, on the other hand, are

- Can lead to extensive, complicated, and sometimes ineffective calculation work
- Categories (e.g., P90, P50, P10) may not correspond to specific physical areas or volumes when simple Monte Carlo methods are used. In cases where geological and simulation

models are used to do the analysis, the models and parameters used for the P90, P50, and P10 scenarios can be identified.

- The PDF of basic parameters is not always known and technical judgment has to be applied
- Dependencies between parameters are even more difficult to assess.

5.5 Practical Applications

The probabilistic approach to resource estimation can be applied usefully to other economic and engineering tasks, such as resource categorization, experimental design, and value-of-information calculations.

5.5.1 Resource Categorization. Under PRMS, when the range of uncertainty in recoverable volumes is represented by a probability distribution, then low, best, and high estimates are defined as follows:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate [Proved (1P) for Reserves, 1C for Contingent Resources].
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate [Proved + Probable (2P) for Reserves, 2C for Contingent Resources].
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate [Proved + Probable + Possible (3P) for Reserves, 3C for Contingent Resources].

Although the most probable value of the distribution is the mode, common industry practice (as described in the PRMS) is to use the median (P50) as the best technical estimate for a single entity (reservoir or zone).

5.5.2 Experimental Design. Experimental design is a well-known set of statistical methods that are helpful in generating the scenarios or cases required to efficiently cover all possible outcomes of the reservoir or field development at hand. Steps in the evaluation typically include the following:

1. Define the set of parameters and their ranges.
2. Perform a sensitivity analysis and select the parameters that have the most impact on the result.
3. Calculate the reserves for a limited number of realizations of the model. These realizations are based on combinations of parameters determined by an experimental design procedure.
4. Use the results of this limited number of model runs to generate a so-called response function, or response surface, using regression techniques.
5. Use the PDFs of the input parameters to generate the PDF of the response function in a stochastic sampling (e.g., Monte Carlo) process.

Experimental design is particularly useful when the analysis is based on performance data, such as material balance or reservoir simulation. A description of this method is provided in van Elk et al. (2000), and an illustrative example is described by Al Salhi et al. (2005).

5.5.3 Value of Information. The goal of appraisal is to reduce uncertainty, and it is necessary to address the value of the additional information gained against cost. In the appraisal example represented by **Fig. 5.7,** the curve for the STOIIP estimation has a gentle slope before appraisal, indicating a wide distribution of possible values. After appraisal, the slope is much steeper, indicating that the range of possible answers has been narrowed. Even if the outcome is unfavorable (i.e., the post-appraisal curve is below the economic minimum), the appraisal activity has delivered value by preventing unnecessary investments. A post-appraisal curve that is in the economic realm will allow for a more focused development.

This narrowing of possible answers allows the design of a more cost-effective development, provided that the post-appraisal range of STOIIP exceeds some economic threshold. The increased cost-effectiveness of the development is the value of the information (VoI) gained by the appraisal. As long as the appraisal cost is lower than this VoI, further appraisal is necessary.

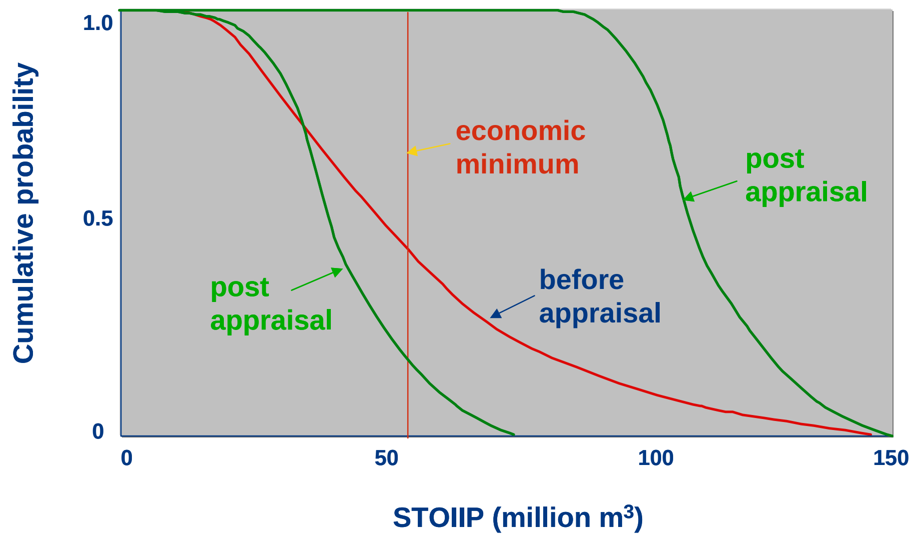

Fig. 5.7—Value of information.

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Definitions and Rules

Probability	The extent to which an event is likely to occur measured by the ratio of the number of occurrences to the whole number of cases possible.[5] 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 PDF (C_{df}); Survival Function (S_f)	To each possible value of a variable, a C_{df} (S_f) 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 three 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 of statistical distributions can be added arithmetically in aggregation
Mode, or Most Probable Value	The mode is the most probable value. It is the reserves quantity where the PDF has its maximum value.
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: $s^2 = \frac{\sum_{i=1}^{n}\left(x_i - \mu_i\right)}{n} = \int_a^b \left(x-\mu\right)^2 f(x)dx$

[5]New Concise Oxford Dictionary

	where x = reserve, μ = mean, and $f(x)$ = PDF. It is convenient to square the differences because this avoids the cancelling of positive and negative values. 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	Describes the spread of a variable around its mean value. It is defined as the square root of the variance.

Chapter 6

Aggregation of Reserves

Wim J.A.M. Swinkels

6.1 Introduction

In reserves and resources estimation, estimates are based on performance evaluations and/or volumetric calculations for individual reservoirs or portions of reservoirs. These estimates are summed to arrive at estimates for fields, properties, and projects. The uncertainty of the individual estimates at each of these aggregation levels may differ widely, depending on geological setting and maturity of the resource. This cumulative summation process is usually referred to as "aggregation" (SPE 2007).

Adding up estimates, or ranges of estimates, with such different levels of uncertainty can be impacted by the purpose for which the estimate is required.

Oil companies, considering long-term performance of their assets, will use the "best estimate" of the volumes for investment purposes; this generally is based on the sum of Proved plus Probable (2P) volumes. They work on the assumption that in the long run, the portfolio of their best estimates will be realized, with the downside in one case compensated for by the upside in another situation. However, it is best practice that reserve estimates always be reported as a range (1P/2P/3P or, in the case of Contingent Resources, 1C/2C/3C). Where assessments are based on deterministic methods, summations are arithmetic and by category. Where probabilistic assessments are available, companies may aggregate probabilistically to the field/property/project level, but subsequent summations are generally arithmetic. For internal portfolio analyses, companies may use fully probabilistic methods, with risking applied where appropriate.

Investors, accountants, and utilities will usually require a high level of certainty and concentrate on the Proved (1P) volumes, or to a lesser extent, the Proved plus Probable (2P) volumes. Gas contracts are typically based on Proved Reserves, which adds a strong business incentive to the accurate determination (and summation) of Proved Reserves. Long-term gas contracting is sometimes based on Proved plus Probable Reserves where there is a large gas resource that is most economically developed over the life of the gas contract.

Accountants may use the ratio of production to Proved Developed Reserves or other reserves categories as the basis for depreciating or depleting the cost of acquiring and developing reserves over time as the reserves are produced. In some areas, the ratio of production to Proved plus Probable Reserves (including any Undeveloped Reserves) is used as the basis for depreciation. Depreciating the cost of investments has an impact on business profits and indicators as return on average capital employed (ROACE). For these calculations, accountants require the reserves to be assessed at the level at which the investments apply.

Thus, reported aggregates of reserves and resources not only encompass variations in associated uncertainties, but also require a detailed portfolio cash flow analysis to understand the value they represent.

Sec. 6.2 addresses some general technical issues in reserves aggregation. The discussion on the aggregation of reserves also addresses 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 uncertainty decreases with an increasing number of independent units available. The implications of the resulting uncertainty reduction in a diverse portfolio, also called the portfolio effect, will be discussed in Sec. 6.3.

Sec. 6.4 discusses aggregation over reserves categories, and the use of scenario methods for reserves aggregation is shown in Sec. 6.5, followed in Sec. 6.6 by a few notes on normalization and standardization of volumes. Sec. 6.7 summarizes the chapter in a few simple guidelines.

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

6.2.1 Reservoir Performance. The best estimate of ultimate recovery (EUR) can be derived through volumetric methods or through extrapolation of well performance in mature fields [e.g., by decline curve analysis (DCA)]. In applying DCA methods, good industry practice is to work from the lowest aggregation level (e.g., wells or completions) upwards, comparing both individual and reservoir- or field-level analysis. Performance extrapolation at the reservoir level can lead to a higher EUR than the sum of the extrapolated well decline curves for that reservoir for many reasons. A summation of individual-well-level DCA may not adequately address catastrophic failures, such as wellbore or completion damage. Also, the comparison of individual-well DCAs to a field-level DCA will highlight small, systematic biases that could otherwise be undetectable at the low level of anaylsis.

One reason for this may be that aggregating from individual-well decline curves does not capture the effect that shutting in a well can sometimes give, an extra economic life to the surviving wells in the reservoir. Another problem, which is specific to gas fields, is that the *p/z* plot per well often 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.

This effect is aggravated if we use a 1P estimate for the well extrapolations. If we sum the individual well results into a reservoir-level estimate, then we assume full dependence (i.e., that all wells will develop their low case simultaneously). There always will be some dependency for wells in the same reservoir because they have the same geological formation, drive mechanism, mode of production, etc., but disregarding the fact that the well results have some statistical independence may result in overly conservative estimates at the reservoir level for the sum of high confidence estimates.

Two approaches have been proposed to avoid the effect of arriving at too low aggregates for P1 (or C1) volumes when adding low cases:

1. Apply decline analysis at the reservoir level.
2. Statisticaly add Proved estimates from well level to reservoir level.

Method 1: Performance Extrapolation and DCA at the Reservoir Level. The first approach, performance extrapolation at the reservoir level is, along with the individual well DCAs, an obvious and necessary supporting part of the performance analysis. In cases where reliable production data at the well level are not available, DCA analysis at a higher level of aggregation (e.g., platform, plant, production station, or reservoir) may be the only basis for the performance extrapolation. Another condition that calls for a higher-level DCA is the occurrence of strong interference effects between neighboring wells.

Performance extrapolation at the reservoir level has a number of pitfalls:

- The performance will include the effects of ongoing drilling, development, and maintenance activities.
- The aggregate may include wells at different stages of decline, with different GORs, etc.
- It has been shown that for multiwell aggregates, the decline will be dominated by the high-rate wells, which may lead to over- or underestimation of the reserves.

Discussion of these issues in DCA are provided by Harrell et al. (2004) and Purves in his chapter (PS-CIM 1994) on DCA methods.

Method 2: Statistical Aggregation of Well-Level Proved Estimates. Another approach to compensate for arithmetic addition of high-confidence estimates may be to apply a form of statistical addition. This has other pitfalls:

- Well-level Proved estimates are often mutually dependent because of common aquifers, formation heterogeneity, facilities, operation constraints, etc. If independence is assumed, it is up to the reserves evaluator to justify this assumption.
- The proposed methods often rely on statistical simplifications (e.g., the assumption of normal distributions for the reserves estimates).

It should be noted that the above problems are avoided when using simulation models to capture reservoir performance. However, often DCA is the method of choice because of its independence from various modeling assumptions.

6.2.2 Correlations Between Estimates. One of the major reasons why summation of reserves, particularly Proved Reserves, sometimes leads to complications is that many parameters in the reserves calculation are dependent upon each other. This leads to further dependencies between individual reserves estimates for reservoir blocks, reservoirs, or subreservoirs, 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 reasons for dependency between reservoirs of a geological (fault location, contact height), methodological (similar interpretation methods), or personal (same optimistic geologist for a number of reservoirs) nature, as classified in **Table 6.1.**

Rigorous methods for evaluating measures of dependency and correlation matrices are discussed in van Elk, Gupta, and Wann (2008).

An example of a positive relation between two estimates can be illustrated with the area-vs.-depth plot of a field shown in **Fig. 6.1,** 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.

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 prerequisite 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).

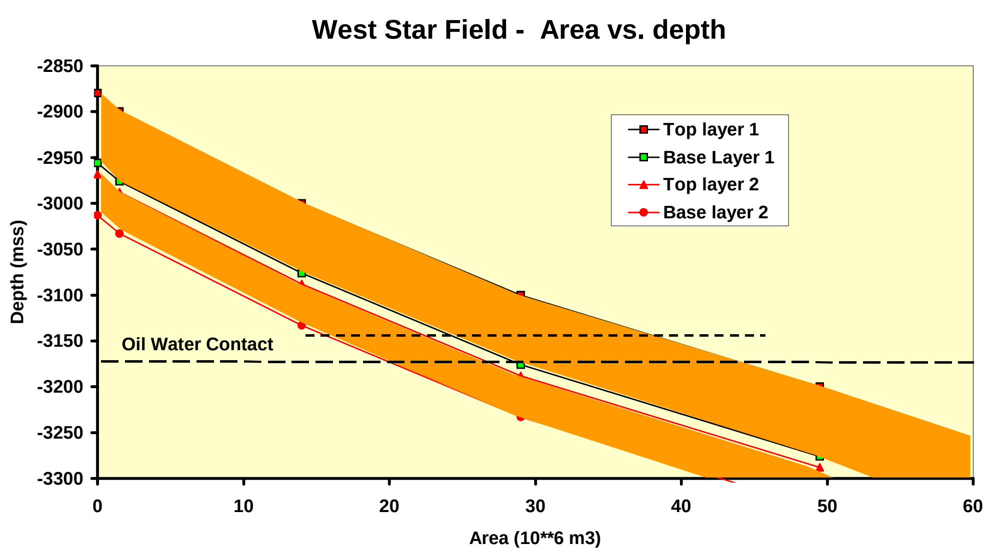


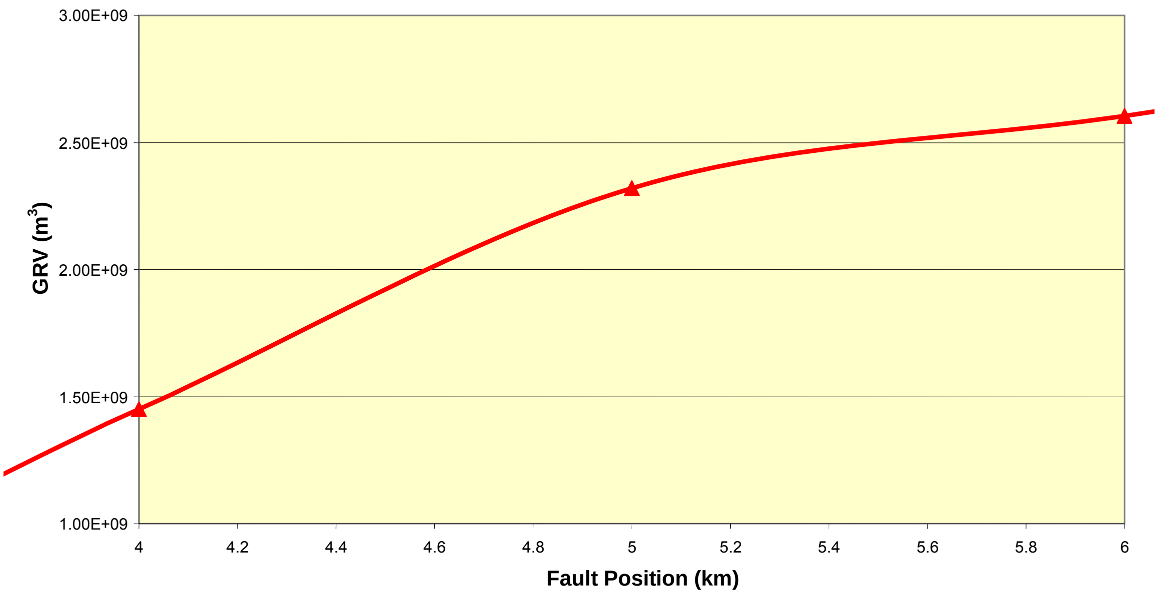
Fig. 6.1—West Star field area vs. depth.

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

A negative correlation occurs when there is uncertainty about the location of a fault between two noncommunicating 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 in the fault location. The impact of this uncertainty can be represented by a relation between the fault position and the GRV of the two blocks, Blocks A and B, as **Fig. 6.2** illustrates.

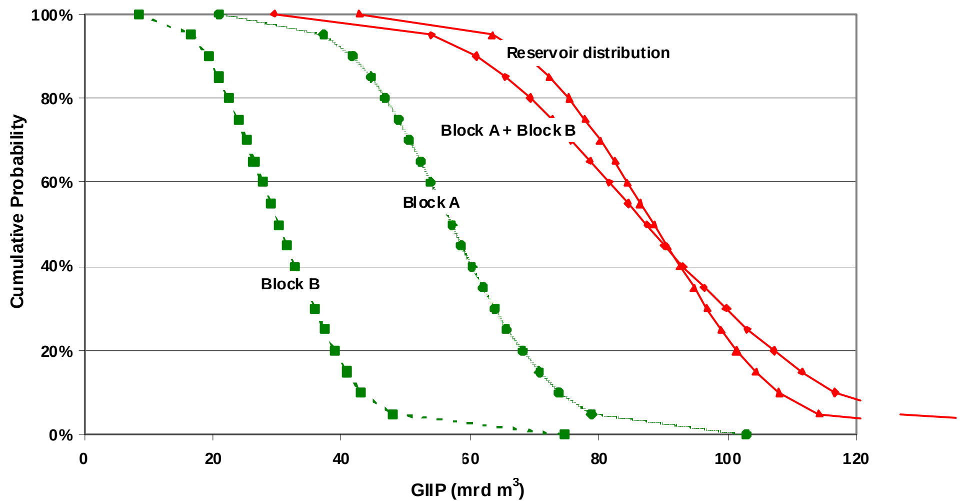
Figure 6.2—GRV of Fault Block A as a Function of Fault Position



Calculating the gas initially in place (GIIP) is now possible 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 Proved 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 **Fig. 6.3,** which shows the cumulative probability curves of Blocks A and B. The figure also shows the arithmetic sum of the two blocks (curve Block A + Block B) 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 at the 90% level derived for the full reservoir.

Figure 6.3—Probability Distribution—Reservoir Blocks A and B



Another commonly encountered negative correlation is the situation in an oil reservoir with a gas cap, where solution gas below the gas/oil contact (GOC) is estimated separately. If there is an uncertainty in the GOC depth, then there is a negative correlation between the gas reserves that are carried above and below the GOC. [There is also, of course, a negative correlation between oil reserves and gas-cap reserves. Unless information is available, such as detailed fluid properties, to guide the placement of the GOC, it is usually appropriate to assume that the volume above the highest known oil is occupied by the lower-value product (usually gas).]

Adding up the best estimate, or 2P, values makes good sense to arrive at the combined value 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 stochastic procedure (using a spreadsheet add-in such as Crystal Ball™ or @Risk™, for example) can be used to arrive at the resultant distributions for GIIP and reserves at the field level.

6.2.3 Levels of Aggregation. As discussed above, summation of Proved Reserves in a statistical way will often result in different volumes than the straightforward “bookkeeping” arithmetic summation. Theoretically, the probabilistic summation can go up to the highest levels of aggregation. Many companies and organizations now appear comfortable with the idea of adding probabilistically up to the field level for specific purposes, provided dependencies are handled properly.

The PRMS (SPE 2007) recommends that reserves figures should not incorporate statistical aggregation beyond the field, property, or project level, an approach that has been followed by others in the industry (SEC 2008).

A field containing different reservoir blocks (layers, pools, accumulations) can be fiscally ring fenced 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 summation 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 be of interest only to the small group of professionals involved in portfolio management in the larger companies.

It should be noted that if only deterministic estimates are available, the only option is to use arithmetic summation. The discussion of statistical aggregation only applies if we have a probabilistic analysis (or convert scenarios to quantitative probabilities).

6.3 Adding Proved Reserves

6.3.1 Pitfalls of Using Arithmetic (Dependent) Addition of Proved Reserves. 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, PRMS interprets reasonable certainty as a 90% probability (P90) of meeting or exceeding the quoted value (SPE 2007). The Proved Reserves represent a high-confidence (i.e., 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 may result in much less than the expected hydrocarbon recovery.

Whenever oil investors or companies add Proved Reserves of several reservoirs arithmetically, they underestimate the aggregated value of their assets. This is because the upsides on most reserves estimates will more than compensate for the downsides on the 10% underperforming assets in the portfolio. This will certainly happen if the estimates of the volumes are independent of each other. For this reason, most companies will rely more on the 2P numbers than on the high-confidence 1P estimates for business planning purposes.

In daily life, we are aware of this when we try to spread our risks and avoid, for example, putting all our investments in one particular asset. For instance, a company committing a number of gas fields to a contract seems unnecessarily conservative in assuming that, ultimately, each field will produce only 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 (1998)]. For the same reason, arithmetic addition of the 3P values of individual reservoirs will overestimate the real upside of the combined asset.

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 is sometimes 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 that is caused by the diversity of their portfolios. This may be true for larger oil and gas companies as well as for governments. Aggregates derived in this way are outside the scope of the PRMS and other classification systems.

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 summation 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."

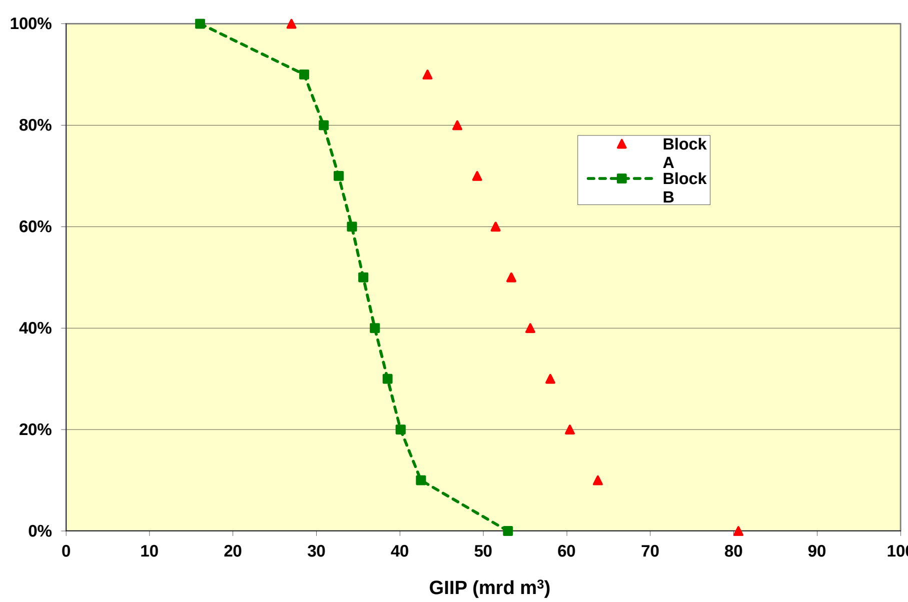
6.3.2 Arithmetic or Dependent Summation. Arithmetic summation is the usual straightforward way of adding volumes and thus of aggregating reserves. Let us look at two gas-bearing reservoir blocks, A and B, with the dimensions in **Table 6.2.**

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

With the range and PDF of these paramters, we can construct a probability distribution of the individual blocks as shown in **Fig. 6.4,** with the cumulative probability of exceeding a given volume on the vertical axis.

Figure 6.4—Probability Distribution Reservoir—Blocks A and B



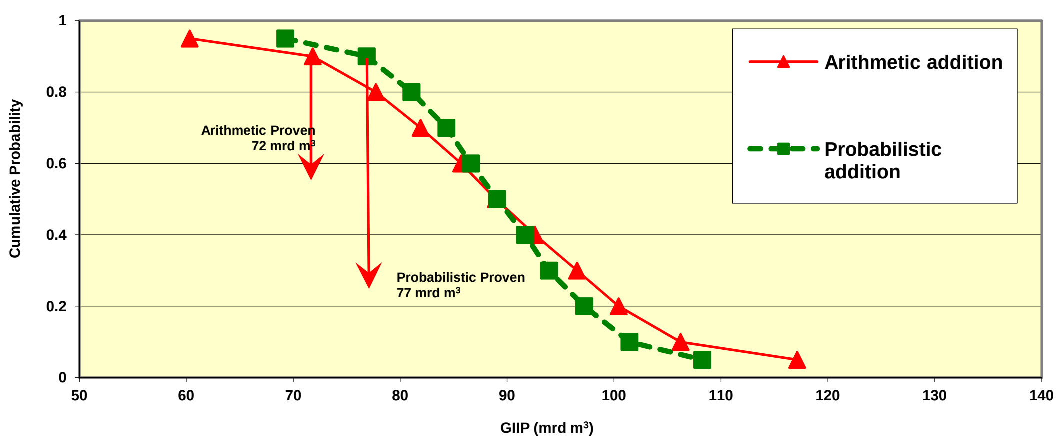
Note that for the sum of the Proved Reserves in Table 6.2, we have taken the arithmetic sum of two Proved numbers, both of which have a 90% probability of being met or exceeded. In fact, by adding these, we assume complete dependency between the two cases; i.e., we assume that if the low side of one case materializes, the same thing will happen with the other case. In this way, we arrive at a potentially pessimistic number for the Proved GIIP, representing the situation that both blocks turn out to be relatively disappointing. However, this could 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. Even the bias introduced by the same subsurface team, applying the same methods, working on two reservoir blocks may introduce a positive correlation.

6.3.3 Probabilistic or Independent Summation. If the reservoir volumes of the two blocks are deemed to be truly independent of each other, we can still calculate the sum of the mean[6] values by straightforward summation. 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 optimistic outcomes in one block compensate for the disappointing outcomes in the other block. This results in a cumulative distribution curve for the combined GIIP that is steeper (i.e., has a smaller spread) than the curve for the arithmetically added volumes, as shown in Fig. 6.5. This tendency of the uncertainty range to narrow is a statistical phenomenon that will always be observed if we stochastically add up quantities that have independent statistical distributions.

Applying this approach and making the assumption of complete independence, 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 using arithmetic summation. In situations where gas contracts are based on Proved 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 Sec. 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.

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[6] The mean is used in this discussion as it is the only statistical function that is correctly additive across distributions. However, it should be recalled that the definitional "best estimate" case is represented by the median 2P (P50) number.

In the last mentioned method, we approach the uncertainty of the estimate for a reservoir volume by Δ_I = Mean − Proved. We can then calculate the uncertainty for the sum of Reservoirs A and B using the relation $\Delta^2{}_{1+2} = \Delta^2{}_1 + \Delta^2{}_2$.

This method is an approximation that holds only for symmetric distributions, but it has the strong advantage of being easy to calculate. It is very suitable for estimating an upper limit for the effects of probabilistic summation. 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, summation and fully independent, or probabilistic, summation of Proved Reserves. Most practical situations 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 (1998). They describe the probabilistic summation 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 (mean) levels. The Proved Reserves per field are defined as the volume that has a 90% chance of being met or exceeded. Adding these volumes arithmetically results in a volume of Proved Reserves across the project that is 15% lower than the stochastically combined P90. 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 by applying the following procedure:

1. The areas of dependence are tabulated for 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 PDF.
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 summation. Not

taking the dependencies between the fields into account, the increase would have been 15% over the straightforward arithmetic summation.

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 semiquantitative 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 can 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 estimation 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 Classes

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 EUR targets for existing and newly discovered fields as well as for untested opportunities and identify which activity—exploration, appraisal, development, further study, or new technology development—is required to achieve these targets. As explained in Chap. 2, various classes of resource volumes can be defined in this process.

The volumes 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 significant differences

in the criteria associated with the classification"[7] that comprise the risk of accumulations not achieving commercial production. In general, this means that the different resources classes should not be included into an aggregate volume. However, a common practice to assess a total portfolio of assets is the use of "risked volumes" calculated by multiplying mean success volumes (MSVs) by the probability of success (POS). POS includes both geological chances (presence of hydrocarbons) and probability of commercial development. This is usually deemed to be applicable for a large portfolio of independent projects.

In adding up such volumes, a meaningful total can be defined only by adding the risked volumes (POS x 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. If such an approach is taken, it is strongly recommended that the resource class components are identified separately and not to report just one single number.

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 approach to aggregate reserves 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), for 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. **Table 6.3** gives low, median, and high STOIIP for the sands.

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

[7] PRMS Sec. 4.2.1.1

To construct a scenario tree for this situation, we have taken the low, median, and high values of STOIIP with equal probability 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 (**Fig. 6.6**).

Scenario Approach

Low Degree of Dependency

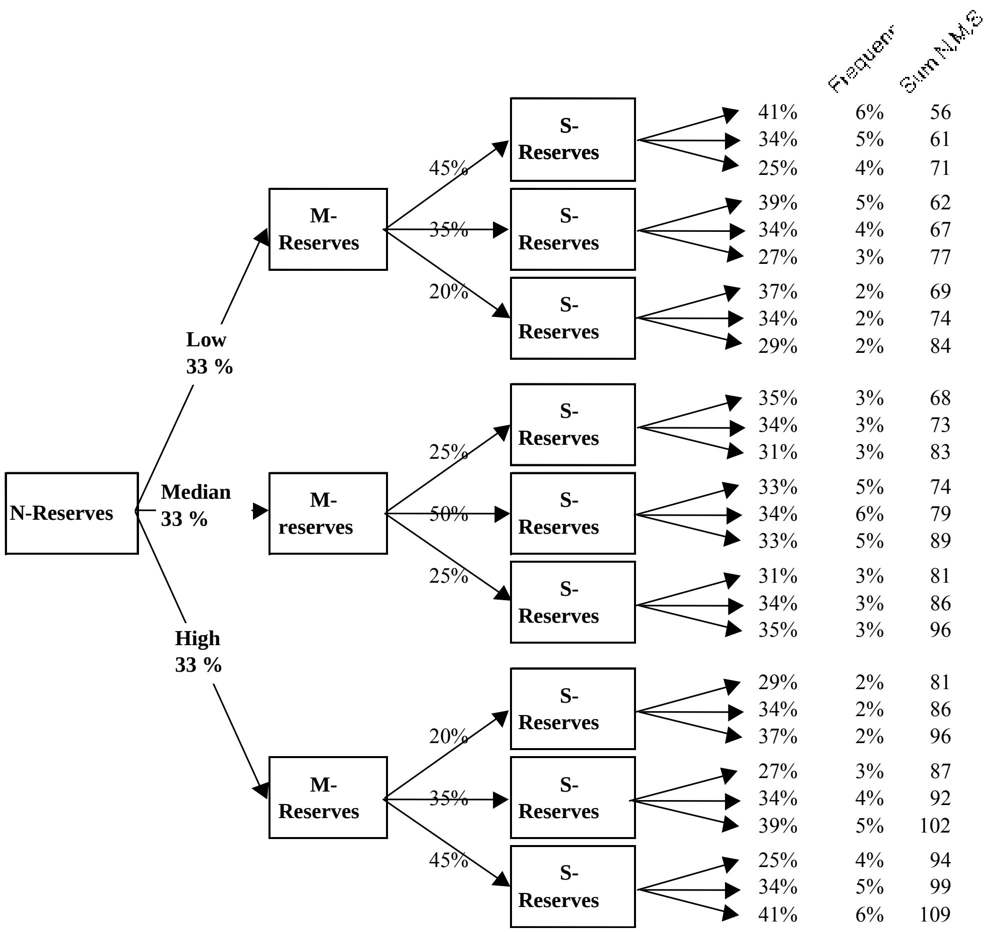

Fig. 6.6—Scenario Tree.

As can be seen in Fig. 6.6, there is some correlation between the occurrence of low, high, and median cases for each of the sands (i.e., the probability that the M-sands have a high value are higher than if the N-sands are high, etc.). 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 values in this example are not the same as the Proved values for the sands because they are not the 90% probability point in the cumulative probability curve. The probability of the branches and the dependencies between these probabilities, as represented in the tree, should reflect the understanding of the geological processes at work. The

resulting STOIIP distribution can then be used as a building block for a resource assessment in PRMS. A plot of these figures is provided in Sec. 6.5.3.

6.5.2 Example of Dependent Reservoir Elements. In this second example, 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 in the N-sands will increase the likelihood of a high volume in the other sands. We assume that geological parameters, such as porosity or net-to-gross pay play a secondary role and disregard them to keep the number of branches limited. **Fig. 6.7** shows the scenario tree for this case.

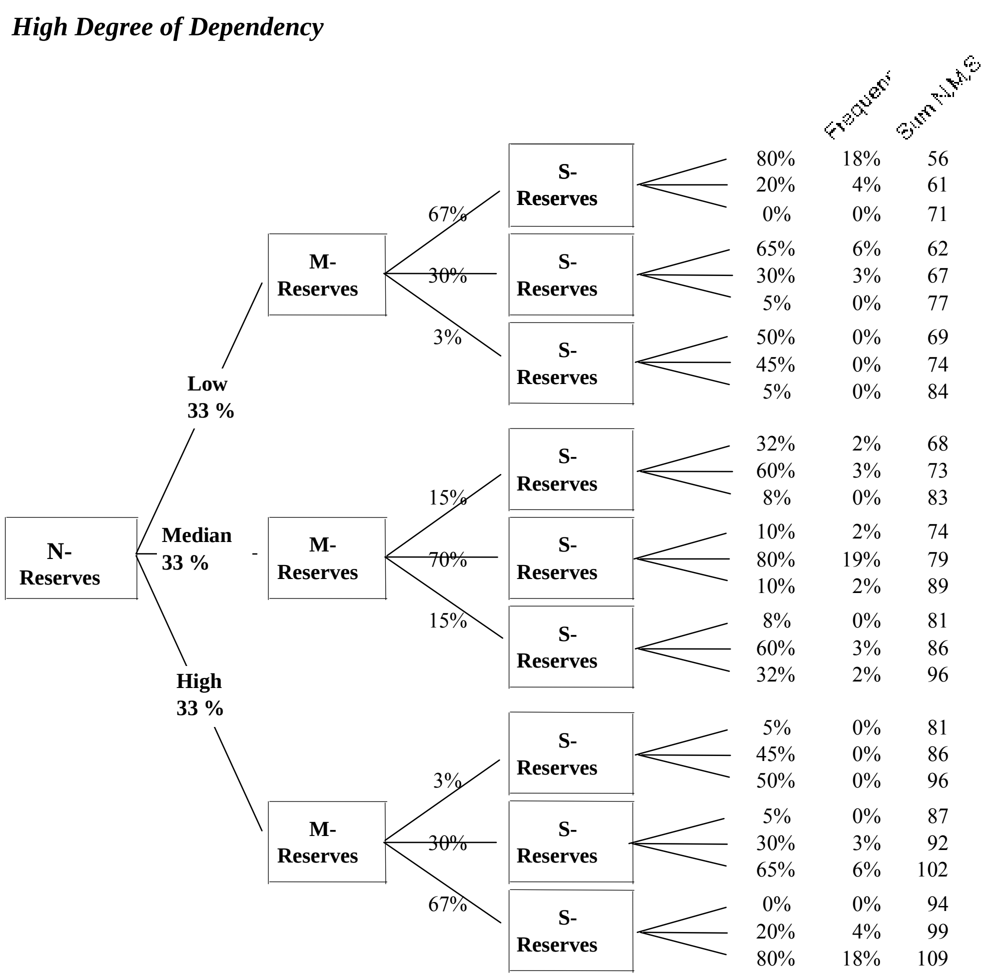

Fig. 6.7—Scenario tree with high degree of dependent reservoir elements.

In the scenario tree in Fig 6.7, the dependency 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. A plot of these figures is provided in Sec. 6.5.3.

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 pseudoprobability curves for each of the three cases by sorting and calculating cumulative probabilities. **Fig. 6.8** shows the results. This analysis now results in the summations of the three sands shown in **Table 6.4.**

Figure 6.8—Cumulative Probability Curve

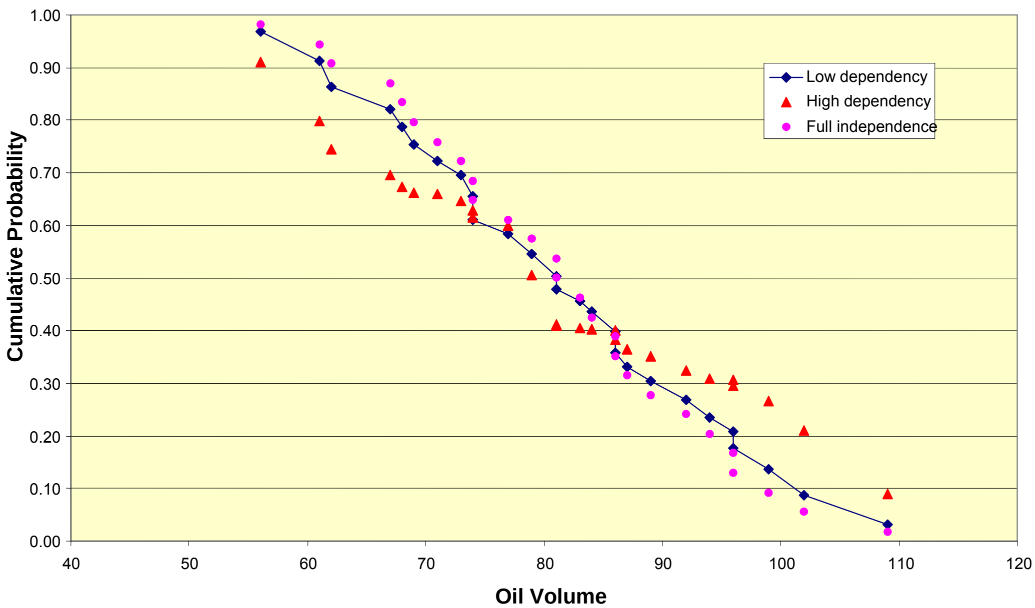

TABLE 6.4—PROBABILISTIC ADDITION WITH VARYING DEGREES OF DEPENDENCY, STOIIP				
	P85 = Low	P50 = Median	P15 = High	Expectation = Mean
M-sands	17	23	30	23.3
N-sands	29	41	54	41.3
S-sands	10	15	25	16.7
Independent sum	67	81	96	81.3
Low-dependence sum	64	81	98	81.2
High-dependence sum	59	79	105	81.1
Fully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

As expected, the mean 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.

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 to the chance factors in the scenario tree.

6.5.4 Comparing Scenario Trees and Correlation Methods. We now have discussed two methods for handling dependencies in aggregating volumes: the use of matrices to describe correlation between parameters (in Sec. 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 and properly interpreted only if there is no doubt of their meaning. On a global basis, there may be variations in specifications so that for aggregations to be meaningful, we need to normalize volumes. Under PRMS, reserves and resources are measured at the custody transfer point at pressure and temperature, for which agreed values are used. This may lead to small differences between reported volumes in different unit-of-measurement 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, 1 atm (760 mm Hg); m^3 or bbl at 60°F, 14.7 psia). Local deviations from this convention exist where sales gas is measured and reported in other units.

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. 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:

Field gas is usually reported at the composition and 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., the volume at normalized gross heating volume (GHV) of, for example, 9500 kcal/Nm^3].

6.7 Summary—Some Guidelines

1. In summing 2P reserves values, arithmetically add the deterministic estimate of volumes.
2. Arithmetic summation of Proved Reserves for independent units leads to a conservative estimate for the Proved total. Methods and tools are available to determine a more realistic value (Monte Carlo, probability trees, and customized tools) for summation of independent distributions.
3. Adding Proved Reserves probabilistically without fully accounting for dependencies could overstate the Proved total.
4. In calculating reserves volumes from well-performance extrapolation or DCA, always work up from the lowest aggregation level (e.g., well or string). Adding up Proved Reserves from well-based DCA estimates may lead to overly conservative estimates of reserves at the reservoir level of aggregation; hence, always check with an overall reservoir performance extrapolation. Also, carefully review the "history-to-forecast" interface to make sure that the methodology has not introduced any discontinuities.
5. PRMS allows probabilistic aggregation up to the field, property, or project level. Typically, for reporting purposes, further aggregation uses arithmetic summation by category. Fully probabilistic aggregation of a company's total reserves and risked Contingent and Prospective Resources may be used for portfolio analysis.
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 can often be applied.
7. When adding volumes, make sure they have a common standard of measurement (pressure/temperature, calorific value).

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Chapter 7

Evaluation of Petroleum Reserves and Resources

Yasin Senturk

7.1 Introduction

The valuation process is about determining value. Commercial evaluation of petroleum reserves and resources is a process by which the value of investing in existing and planned petroleum recovery projects is determined. These results are used to make internal company investment decisions regarding commitment of funds for commercial development of petroleum reserves. Based on a companywide comparative economic analysis of all alternative opportunities available, the company continues to make rational investment decisions to maximize shareholders' value. Results may also be used to support public disclosures subject to regulatory reporting requirements.

These guidelines are provided to promote consistency in project evaluations and the presentation of evaluation results while adhering to PRMS (SPE 2007) principles. In this context, a project evaluation will result in a production schedule and an associated cash flow schedule; the time integration of these schedules will yield an estimate of marketable quantities (or sales) and future net revenue [or net present value (NPV) using a range of discount rates, including the company's]. The estimation of value is subject to uncertainty due not only to inherent uncertainties in the petroleum in place and the efficiency of the recovery program but also in the product prices, the capital and operating costs, and the timing of implementation. Thus, as in the estimation of marketable quantities, the resulting value estimates should also reflect a range of outcomes.

Petroleum resources evaluation requires integration of multidisciplinary "know-how" in both the technical and the commercial areas. Therefore, evaluations should be conducted by multidisciplinary teams using all relevant information, data, and interpretations.

7.2 Cash-Flow-Based Commercial Evaluations

Investment decisions are based on the company's view of future commercial conditions that may impact the development feasibility (commitment to develop) based on production and associated cash flow schedules of oil and gas projects. Commercial conditions reflect the assumptions made both for financial conditions (costs, prices, fiscal terms, taxes) and for other factors, such as marketing, legal, environmental, social and governmental. Meeting the "commercial conditions" includes satisfying the following criteria defined in PRMS Sec. 2.1.2 for classification as Reserves:

- A reasonable assessment of the future economics of such production projects meeting defined investment and operating criteria, such as having a positive NPV at the stipulated hurdle discount rate.

- A reasonable expectation that there is a market for all or at least some sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental, and other social and economic concerns will allow for the actual implementation of the recovery project evaluated.
- Evidence to support a reasonable timetable for development.

Where projects do not meet these criteria, similar economic analyses are performed, but the results are classified under Contingent Resources (discovered but not yet commercial) or Prospective Resources (not yet discovered but development projects are defined assuming discovery). Value of petroleum recovery projects can be assessed in several different ways, including the use of historical costs and comparative market values based on known oil and gas acquisitions and sales. However, as articulated in PRMS, the guidelines herein apply only to evaluations based on discounted cash flow (DCF) analysis.

Consistent with the PRMS, the calculation of a project's NPV shall reflect the following information and data:

- The production profiles (expected quantities of petroleum production projected over the identified time periods).
- The estimated costs [capital expenditures (CAPEX) and operating expenditures (OPEX)] associated with the project to develop, recover, and produce the quantities of petroleum production at its reference point (SPE 2007 and 2001), including environmental, abandonment and reclamation costs charged to the project, based on the evaluator's view of the costs expected to apply in future periods.
- The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods, including that portion of the costs and revenues accruing to the entity.
- Future projected petroleum production and revenue-related taxes and royalties expected to be paid by the entity.
- A project life that is limited to the period of entitlement or reasonable expectation thereof (see Chapter 10) or to the project economic limit.
- The application of an appropriate discount rate that reasonably reflects the weighted average cost of capital or the minimum acceptable rate of return (MARR) established and applicable to the entity at the time of the evaluation.

It is important to restate the following PRMS guidance: "While each organization may define specific investment criteria, a project is generally considered to be economic if its best estimate (or 2P) case has a positive net present value under the organization's standard discount rate."

7.3 Definitions of Essential Terms

Understanding of essential definitions and well-established industry practices is necessary when generating and analyzing cash flows for any petroleum recovery project. These include current and forecast economic conditions, economic limit, and use of appropriate discount rate for the corporation.

7.3.1 Economic Conditions. Project net cash flow (NCF) profiles can be generated under both current and future economic conditions as defined in the PRMS. Consistent DCF analyses and resource evaluations may be conducted using the definitions of economic cases or scenarios:

Forecast Case (or Base Case): DCF Analysis Using Nominal Dollars. The "forecast case"(or "base case") is the standard economic scenario for reserves evaluations. Economic evaluation underlying the investment decision is based on the entity's reasonable forecast of "future economic conditions," including costs and prices expressed in terms of nominal (or then-current) monetary units that are expected to exist during the life of the project. Such forecasts are based on changes to "current conditions" projected to any year (t). Estimates of any project cash flow component (price or cost) expressed in terms of base-year or current-year dollars are escalated (to account for their specific annual inflation rates or escalation rates) to obtain their equivalent value in terms of nominal dollars (also known as then-current dollars, or dollars of the day) at any year (t) over its economic life by using the following simple relationship:

$$\text{Nominal \$ } (t) = (\text{Current-Year \$})\, EF_{kt} = (\text{Current-Year 2010 \$})\,(1+E_k)^t \qquad (7.1)$$

where

$$EF_{kt} = (1 + E_k)^t \qquad (7.1a)$$

and EF_{kt} is the escalation factor (or the cumulative overall multiplier) at any time t, which ranges from t = 0 (zero or current-year) to $t = n$ (project's economic life in years) for any price or cost component (k = 1, 2, 3…) of project cash flows.
E_k = average and constant annual escalation rate or goods/products and services specific inflation rate (in fraction) for any price and cost component (k) over the entire project life (t = 0 to n). Although generally expressed and used as annual rates, these rates can be expressed over any time period provided that other data are also expressed in the same time unit.

Note that for simplicity alone, periodic escalation rate, E_k, is assumed to remain constant for any individual price or cost component (k = 1, 2, 3, . .) over the entire project life. (Unless specified explicitly, the monetary unit is assumed to be US dollars, designated by $).

Constant Case (or Alternative Case. *DCF Analysis Using Current-Year Dollars.* The "constant case" is an alternative economic scenario in which current economic conditions are held constant throughout the project life. PRMS defines current conditions as the average of those that existed during the previous 12 months, excluding prices defined by contracts or property specific agreements.

PRMS recommended reserves evaluation under Constant Case requires each price and cost component of project cash flows to be expressed in terms of current-year dollars. Evaluation under the Forecast Case uses project cash flows that are expressed in terms of nominal dollars. **Table 7.1** illustrates how an example average crude price of USD 50/bbl in current-year 2010 dollars can be expressed in terms of nominal dollars in Years 2011 through 2012 using Eq. 7.1.

Table 7.1—Oil Price in Different Dollar Units

	Crude Price ($/bbl)	
Year (t)	Current-Year 2010 $	Nominal $ *
2010	**50.0**	**50.00**
2011	50.0	52.00
2012	50.0	54.08

Escalated "Current-Year 2010 $" prices using an annual price escalation rate of 4%.

For escalation of prices and costs, readers can also refer to SPEE Recommended Evaluation Practices (2002). However, companies may run several additional economic cases based on alternative cost and price assumptions to assess the sensitivity of project economics to uncertainty in forecast conditions.

7.3.2 Economic Limit. The economic limit calculation based on forecast economic conditions can significantly affect the estimate of petroleum reserves volumes. SPE recommends using industry standard guidelines for calculating economic limit and associated operating costs required to sustain the operations. For definitions of revenue, costs and cash flow terms used here, readers should refer to Sec. 7.4.1.

Economic limit is defined as the production rate beyond which the net operating cash flows (net revenue minus direct operating costs) from a project are negative, a point in time that defines the project's economic life. The project may represent an individual well, lease, or entire field. Alternatively, it is the production rate at which net revenue from a project equals "out of pocket" cost to operate that project (the direct costs to maintain the operation) as described in the next paragraph. For example, in the case of offshore operations, the evaluator should take care to ensure that the estimated life of any individual reserves entity (as in a well or reservoir) does not exceed the economic life of a platform in the area capable of ensuring economic production of all calculated volumes. Therefore, for platforms with satellite tiebacks, the limit of the total economic grouping should be considered. Scenario or probabilistic modeling can be used to check the most likely confidence level of making such an assumption.

Operating costs, defined and described in detail in Sec. 7.4.1 and also described in PRMS, should be based on the same type of projections (or time frame) as used in price forecasting. Operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated. In other words, only those cash costs that will actually be eliminated if project production ceases should be considered in the calculation of economic limit. Operating costs should include property-specific fixed overhead charges if these are actual incremental costs attributable to the project and any production and property taxes but (for purposes of calculating economic limit) should exclude depreciation, abandonment and reclamation costs, and income tax, as well as any overhead above that required to operate the subject property (or project) itself. Under PRMS, operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue enhancement approaches, such as sharing of production facilities, pooling maintenance contracts, or marketing of associated nonhydrocarbons. Interim negative project net cash flows may be accommodated in short periods of low product prices or during temporary major operational problems, provided that the longer-term forecasts still indicate positive cash flows.

7.3.3 Discount Rate. The value of reserves associated with a recovery project is defined as the cumulative discounted NCF projection over its economic life, which is the project's NPV. Project NCFs are discounted at the company's discount rate (also known as the MARR desired for and expected from any investment project), which generally reflects the entity's weighted average cost of capital (WACC). Different principle-based methods used to determine company's appropriate discount rate can be found in Campbell et al (2001) and Higgins (2001).

Finally, it may be useful to restate the following PRMS guidance relevant to the petroleum resources evaluation process:

- Presentation and reporting of evaluation results within the business entity conducting the evaluation should not be construed as replacing guidelines for subsequent public disclosure under guidelines established by external regulatory and government agencies and any current

or future associated accounting standards. Consequently, oil and gas reserves evaluations conducted for internal use may vary from that used for external reporting and disclosures due to variance between internal business planning assumptions and regulated external reporting requirements of governing agencies. Therefore, these internal evaluations may be modified to accommodate criteria imposed by regulatory agencies regarding external disclosures. For example, criteria may include a specific requirement that, if the recovery were confined to the technically Proved Reserves estimate, the constant case should still generate a positive cash flow at the externally stipulated discount rate. External reporting requirements may also specify alternative guidance on "current economic conditions."

- There may be circumstances where the project meets criteria to be classified as Reserves using the forecast case but does not meet the external criteria for Proved Reserves. In these specific circumstances, the entity may record 2P and 3P estimates without separately recording Proved. As costs are incurred and development proceeds, the low estimate may eventually satisfy external requirements, and Proved Reserves can then be assigned.
- While the PRMS guidelines do not require that project financing be confirmed prior to classifying projects as Reserves, financing may be another external requirement. In many cases, loans are conditional upon the project being economic based on Proved Reserves only. In general, if there is not a reasonable expectation that loans or other forms of financing (e.g., farm-outs) can be arranged such that the development will be initiated within a reasonable time frame, then the project should be classified as Contingent Resources. If financing is reasonably expected but not yet confirmed, and financing is an external requirement for reporting in that jurisdiction, the project may be internally classified as Reserves (Justified for Development), but no Proved Reserves may be reported.

7.4 Development and Analysis of Project Cash Flows

This section describes how project cash flows are developed. Definitions of different cash flow terms are followed by an overview of its major components (production rates, product prices, capital and operating costs and other key definitions of ownership interests, royalties, and international fiscal agreements), including the uncertainties (or accuracy) associated with them that change over time. The next subsection provides the technical basis and a brief description of how project DCFs analysis is carried out to establish its value.

7.4.1 Definitions and Development of Project Cash Flows. The cash-flow valuation model estimates money received (revenue) and deducts all royalty payments, costs (OPEX and CAPEX), and income taxes, yielding the resulting project NCFs. Detailed definitions, basis, and description of the key project cash-flow components are provided amply for in Campbell et al. (2001), Newendorp and Schuyler (2000), and Schuyler (2004). However, even though some terms may not exist or new terms may appear in different countries, in the basic and simplified format that works in any country, the project annual NCF at any year t can be expressed in terms of the following relationship:

$$\mathrm{NCF}(t) = \mathrm{REV}(t) - \mathrm{ROY}(t) - \mathrm{PTAX}(t) - \mathrm{OPEX}(t) - \mathrm{OH}(t) - \mathrm{CAPEX}(t) - \mathrm{ITAX}(t) + \mathrm{TCR}(t) \quad (7.2)$$

All affected annual terms above are expressed in applicable working interest (WI) portions are defined as follows:

NCF(t) = NCF,
REV(t) = revenue = annual production rate (t) times price (t),
ROY(t) = royalty payments = REV(t) times effective royalty rate (t),

PTAX(t) = production tax payments = [REV(t) - ROY(t)] times effective production tax rate (t),
OPEX(t) = OPEX (includes all variable and fixed expenses),
OH(t) = overhead expense (includes all fixed expenses related to management, finance and accounting and professional fees, etc.),
CAPEX(t) = capital expenditures (tangible and intangible),
ITAX(t) = income tax payments = taxable income (t) times effective income tax rate (t), and
TCR(t) = tax credits received.
Note that the use of word "effective" in the above terms is meant to represent the composite rate of several applicable factors. For example, production taxes in the US may include severance and ad valorem taxes, and income tax may include federal and state taxes. It does not mean to eliminate the need for their inclusion and calculations separately.

To complete the process of generating the project annual net cash flows given by Eq. 7.2, net revenue, taxable income and income tax payments during any year t are given by the following definitions:

- Calculation of annual net revenue (NREV):

$$\mathrm{NREV}(t) = \mathrm{REV}(t) - \mathrm{ROY}(t) - \mathrm{PTAX}(t) \qquad (7.2a)$$

- Calculation of annual taxable income (TINC):

$$\mathrm{TINC}(t) = \mathrm{NREV}(t) - \mathrm{OPEX}(t) - \mathrm{OH(t)} - \mathrm{EXSI}(t) - \mathrm{DD\&A}(t) - \mathrm{OTAX}(t) \qquad (7.2b)$$

where new annual terms not defined previously are
NREV(t) = net revenue defined by Eq. 7.2a,
TINC(t) = taxable income defined by Eq. 7.2b,
EXSI(t) = expensed investment capital,
DD&A(t) = capital recovery or allowance in terms of depreciation, depletion and amortization (of allowed nonexpensed investment capital), and
OTAX(t) = other tax payments.

- Calculation of annual ITAX:

$$\mathrm{ITAX(t)} = \mathrm{TINC\ (t)} \bullet \mathrm{ITR\ (t)} \qquad (7.2c)$$

where the ITR(t) is the annual effective income tax rate of the corporation.

The revenue and costs components of any term described above (including all other relevant economic and commercial terms) must be accounted for when deriving project NCF even if they are defined differently by each entity (e.g., company or government). Definitions of these terms may differ from country to country due to the fiscal arrangements made between operating companies and host governments, which allocate the rights to develop and operate specific oil and gas businesses. Common forms of international fiscal arrangements are concessions (through royalties and/or taxes) and contracts as described in Chapter 10 and elsewhere (Campbell et al. 2001 and Seba 1998). In general, these agreements define how project costs are recovered and profit is shared between the host country and the operator. Detailed knowledge of these governing rules (in royalty, tax, and other incentives) is critical for a credible project reserves assessment and evaluation process.

Although the generation of these annual project cash-flow components is straightforward, the accuracy of the estimates (magnitude and quality) is dependent on the property-specific input

data and forecasting methods used (deterministic or probabilistic) and the expertise of and effective collaboration among the multidisciplinary valuation team members.

Each component of project NCF terms (such as production rate, product price, CAPEX, OPEX, inflation rate, taxes, and interest rate) briefly described in Eq. 7.2 has some uncertainty that changes over time. The terms with significant impact on project NCF are briefly reviewed below.

Reserves and Production Forecasts. The uncertainty in reserves and associated production forecasts is usually quantified by using at least three scenarios or cases of low, best and high. For many projects, these would be the 1P, 2P, and 3P reserves. They could have been generated deterministically or probabilistically. Many companies, even if the reserves uncertainty is quantified probabilistically, choose specific reserves cases (as opposed to a Monte Carlo cash-flow approach) to run cash flows because this allows a clear link between reserves and associated development scenarios and costs. In projects with additional Contingent Resources and exploration upside, companies frequently layer these forecasts on top of the Reserves. This can lead to overly optimistic evaluations unless the appropriate risks of discovery and development are applied correctly.

Product Prices. It is important to use the appropriate product prices taking into account the crude quality or gas heating value. Whatever the method of predicting future oil prices (be it forward strip or internal company estimates), the differential with a recognized marker crude (such as West Texas Intermediate or Brent) should be applied. Ideally, it is best to use actual historical oil price differentials. For new crude blends, a market analyst should review a sample assay. If the oil is being transported through a pipeline with other crude, the average price for the blend should be considered, and the evaluator should understand whether a crude banking arrangement exists or not to allow individual crudes to receive separate price differentials based on quality (usually API gravity and sulfur content).

For gas, it is important to look at the final sales gas composition after liquids processing to ensure that the correct differentials are being applied. Each byproduct (e.g., propane, butane, and condensate) should be evaluated with the appropriate price forecast. Shrinkage of the raw gas caused by removing liquids and the presence of nonhydrocarbon gases such as CO_2 should be accounted for. Fuel gas requirements should be subtracted from the sales gas reserves.

The transportation costs for both oil and gas should be identified either as part of the operating costs or as a reduction of the sales price if the sales point is not at the wellhead.

Project Capital Costs. The major components of CAPEX for a typical oil and gas development project are land acquisition, exploration, drilling and well completion, surface facilities (gathering infrastructure, process plants, and pipelines), and abandonment.

Drilling and completion well costs are categorized in terms of tangible (subject to depreciation allowance) and intangible (expensed portion and portion subject to amortization) well costs.

Surface facility costs are subjected to facility-specific depreciation allowances used in calculating taxes and various incentives.

Total capital investment cost required for any process equipment (or plant with several units of equipment) is generally recognized under four categories (Clark and Lorenzoni 1978 and Humphreys and Katell 1981). *Direct costs include* all material and labor costs associated with a purchased physical plant or equipment and its installation. They include the costs of all material items that are directly incorporated in the plant itself as well as those bulk materials (such as foundation, piping, instrumentation, etc.) needed to complete the installation. *Indirect costs*

represent the quantities and costs of items that do not become part of, but are necessary costs involved in, the design and construction of process equipment. Indirect costs are generally estimated as "percentage of direct costs." Indirect costs are further subcategorized as engineering, constructor's fee (covering administrative overhead and profit), field labor overhead (FLOH), miscellaneous others and owner's costs (such as land, organization, and startup costs). Engineering indirects include the costs for design and drafting, engineering and project management, procurement, process control, estimating and construction planning. FLOH includes costs of temporary construction consumables, construction equipment and tools, field supervision and payroll burden, etc. *Miscellaneous others* include freight costs, import duties, taxes, permit costs, royalty costs, insurance and sale of surplus materials. *Contingency* is included to allow for possible redesign and modification of equipment, escalated increases in equipment costs, increases in field labor costs, and delays encountered in startup. Finally, *working capital* is needed to meet the daily or weekly cost of labor, maintenance, and purchase, storage and inventory of field materials.

Equipment sizing and pricing requires a reasonably fixed basic design for budget estimates and a detailed design for definitive estimates. For equipment sizing and design of oil and gas handling facilities (in addition to contractor or company-developed standard and analogous designs), the readers may review a fine reference by Arnold and Stewart (1989, 1991).

There are two fundamental approaches to project cost estimating, the "top-down" and the "bottom-up." The top-down approach uses historical data from similar engineering projects to estimate the costs for the current project by revising and normalizing these data for changes in time (inflation or deflation), production size, or plant capacity and location and other factors (such as activity level, weight, and energy consumption). It uses a simple "percentage-of-cost basis" established from the review of historical or current data. The bottom-up approach is a more detailed method of cost estimating and requires a detailed design that breaks down the process plant equipment into small, discrete, and manageable parts (or units). The smaller unit costs are added together (including other associated costs) to obtain the overall cost estimate for the process equipment and the plant.

As illustrated by **Fig.7.1**, a typical project development life (for surface facilities, plants, or pipelines) encompasses the four phases of initial planning and evaluation, designing and engineering (conceptual and detailed), construction, and startup, which could take several years to complete. It represents a series of steps leading to decision points (or gateways) at the end of each phase where cost estimates are made to determine whether it is economically viable to proceed to the next step or project phase.

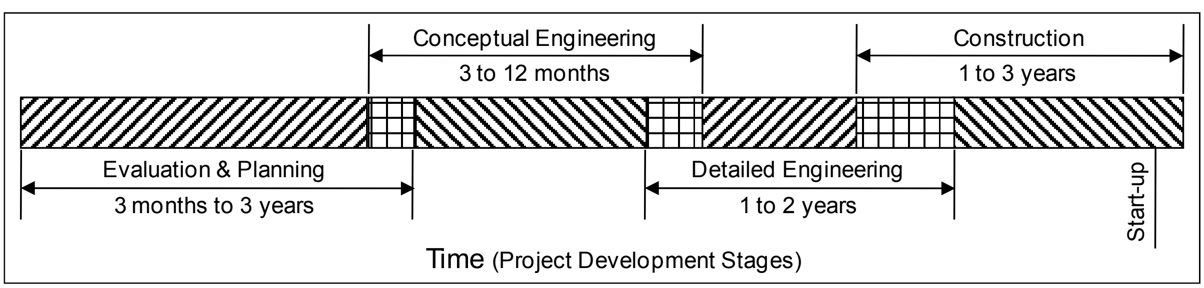

Fig. 7.1—Typical project phases [adapted from Clark and Lorenzoni (1978)].

Although they may be known or defined by different names, the American Association of Cost Engineers (Humphreys and Katell 1981) recommends three basic categories of project cost

estimates according to detail and accuracy required by their intended use (during project phases illustrated in Fig. 7.1), which are approximately defined as follows:

- *Order of magnitude estimate* is considered accurate within - 30% to + 50%. Based on cost-capacity curves and ratios, this cost estimate is made during the initial planning and evaluation stage of a project, and used for investment screening purposes.
- *Preliminary estimate* is considered accurate within - 15 to + 30%. Based on flow sheets, layouts, and equipment details, the semidetailed cost estimate is made during the conceptual-design stage of a project, and is used for budget proposal and expenditure approval purposes.
- *Definitive estimate* is considered accurate within - 5 to + 15%. Based on detailed and well-defined design and engineering data (with complete sets of specifications, drawings, equipment data sheets, etc.), this estimate is made during the detailed engineering and construction stage of a project and is used for procurement and construction.

Project Operating Costs. Similar to capital costs, estimation and treatment of OPEX in various categories could also be important for the purpose of calculating tax and project profitability. Estimates of OPEX in base-year, or current-year, dollars are generally based on an analogous operations, adjusted for the production capacity, manpower, and appropriate cost-escalation (or cost-component specific inflation) rates. Operating cost estimates are generally performed on a unit-of-production, monthly, or annual basis.

OPEX are generally recognized under five categories (Humphreys and Katell 1981). *Direct costs* are considered to be dependent on production and include variable and semivariable components. At production shutdowns (with zero production or throughput), direct costs are generally represented at a reasonable minimum basis of about 20% or greater of the semivariable costs estimated for an operation at full capacity. *Indirect costs* are considered independent of production and include plant overhead, or burden, and fixed costs such as property taxes, insurance and depreciation. *General and administration expenses (G&A),* or simply *overhead expenses,* are those costs incurred above the factory or production level and are associated with home office or headquarters management. This category includes salaries and expenses of company officers and staff, central engineering, research and development, marketing and sales costs, etc. *Distribution costs* are those operating and manufacturing costs associated with shipping the products to market, like pipelines for crude oil, gas sales, and natural gas liquids. They include the cost of containers and packages, freight, operation of pipelines, terminals, and warehouses or storage tanks. *Contingencies* constitute an allowance made in an operating cost estimate for unexpected costs or for error or variation likely to occur in the estimate. A contingency allowance is just as important in the OPEX as it is in the CAPEX. However, it must be pointed out that companies may define and categorize their operating costs differently and may not even include some of the components in their project economic analysis.

Other Key Terms and Definitions. *Ownership Interest* represents the share, right, or title in property (a lease, concession, or license), project, asset, or entity. The most commonly known type of ownership (or economic) interests are: WI, net WI, mineral interest, carried interest, back-in interest, and reversionary interest.

Royalties are the payments made to the landowner or the mineral interest owner for the right to explore and produce petroleum after a discovery**.** They are made to the host government or mineral owner (lessor) in return for depletion of the reservoirs and granting the producer (lessee/contractor) access to the petroleum resources. 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. Some agreements provide for the royalty to be taken only in kind (e.g., in terms of production) by the royalty owner.

Royalty Interest is a mineral interest that is not burdened with a proportionate share in investment and operating costs. Royalty owners are responsible for their share of production and ad valorem taxes (i.e., taxes imposed based on production value and/or value of equipment necessary to produce petroleum). Royalty interest may also be defined as the share of minerals reserved in money, or in kind, free of expense, by the owner of mineral interest or a fee received when leasing the property to another party for exploration and production.

Overriding royalty interest is a fraction of wellhead production owned free of any cost obligation. It is an economic interest created in addition to the royalty stated in the basic lease.

International Fiscal Arrangements made between the producer and the host government may include concession agreements, joint venture agreements and contracts (production sharing and service [refer to Chap. 10, PRMS (SPE 2007), Campbell et al. (2001), and Seba (1998)].

7.4.2 Analyzing Project Cash Flows and Establishing Value. The generally accepted figure of merit or value for any petroleum recovery project is defined by cumulative discounted NCF or the NPV generated over its economic (or contractual) life cycle illustrated by **Fig. 7.2.**

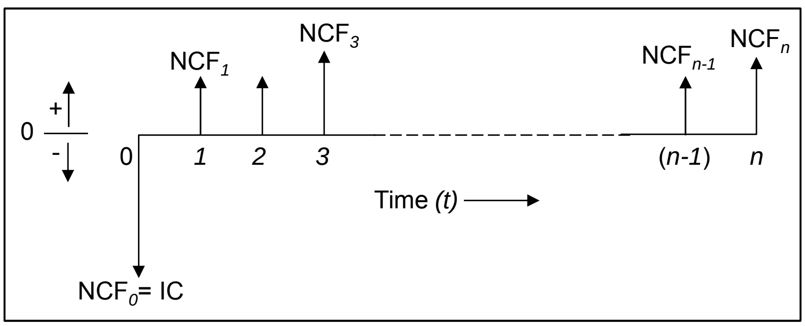

Fig. 7.2—A typical project net cash flow diagram.

The value of any project can be expressed mathematically by the following DCF-based valuation model or the NPV equation:

$$\mathrm{NPV}(t,\mathrm{MARR}) = \sum_{t=0}^{n} \frac{\mathrm{NCF}_t}{(1+\mathrm{MARR})^t} = \sum_{t=0}^{n} \mathrm{NCF}_t \bullet \mathrm{DF}_t \qquad (7.3)$$

and can also be rewritten in the following open form:

$$\mathrm{NPV}(t,\mathrm{MARR}) = \mathrm{NCF}_0 + \mathrm{NCF}_1 \bullet \mathrm{DF}_1 + \mathrm{NCF}_2 \bullet \mathrm{DF}_2 + .. + \mathrm{NCF}_n \bullet \mathrm{DF}_n \qquad (7.3a)$$

where

NCF_t = annual year-end NCF (revenue minus cost) at any year (t) ranging from 0 to n and

NCF_0 = the initial investment capital (IC) made as a single lump sum in the first or "0" year-end for the most projects. However, for large projects, the initial CAPEX profile does span more than one year and thus, the NCF_t's for (t) ranging from initial (0) to say (m) years would be negative during these early years. They are actually spent as nominal dollars during these earlier m years and are also equivalent to their future value (FVI) assumed to be spent only in zero-year (or current-year) as a lump-sum initial investment capital (IC or NCF_0) and can now be defined as follows:

$$IC = NCF_0 = FVI(t, \text{MARR}) = \sum_{t=0}^{m} \text{IC}_t (1 + \text{MARR})^t = \sum_{t=0}^{m} \text{IC}_t / \text{DF}_t \qquad (7.3b)$$

This manipulation is necessary not to discount future project cash flows for another *m* years and thus provide the same comparative basis for all projects included in a company's investment portfolio. As a result, each project will show the positive cash flow in the actual year where revenue begins, and this ensures consistent discounting of future cash flows among all competing investment projects. Variables in Eqs. 7.3 through 7.3b are defined as follows:

MARR = Minimum attractive rate of return desired or the company's annual discount rate,
t = time starting from zero (0) or current-year to (*n*) years in the future,
n = project economic (or contractual) life in years,
m = number of years (usually 2 to 5 for megaprojects) during which initial project capital is actually spent,
DF_t = discount factor at any year (t) defined as follows:

$$\text{DF}_t = 1/[1+\text{MARR}]^t \text{ for the year-end cash receipts} \qquad (7.3c)$$

$$\text{DF}_t = 1/[1+\text{MARR}]^{(t-0.5)} \text{ for the mid-year cash receipts} \qquad (7.3d)$$

Eqs. 7.3 through 7.3c assume project annual NCFs are received only at year-end. However, if they are received at mid-year then the appropriate discount factor (DF_t) defined by Eq. 7.3d must be used. For discounted cash-flow analysis, readers can also refer to SPEE (2002).

According to PRMS guidelines, a discovered petroleum development project is considered commercial and its recoverable quantities are classified as Reserves when its evaluation has established a positive NPV and there are no unresolved contingencies to prevent its timely development. If the project NPV is negative and/or there are unresolved contingencies preventing the project implementation within a reasonable time frame, then technically recoverable quantities must be classified as Contingent Resources.

Finally, in addition to project NPV described above, there are other important measures of profitability [such as the internal rate of return, profitability index (dollar generated per dollar initially invested), payout time, or payback period] that are routinely used in project economic evaluations (Campbell et al. 2001, Higgins 2001, Newendorp and Schuyler 2000, Seba 1998, and COGEH 2007).

7.5 Application Example

A relatively small but prolific international oil field (with its associated gas) is jointly owned by several independent North American producers. The company in this example evaluation has a one-third WI ownership in the property.

The PRMS guidance on evaluations states that: "While each organization may define specific investment criteria, a project is generally considered to be 'economic' if its 'best estimate' (2P or P50 in probabilistic analysis) case has a positive NPV under the organization's standard discount rate. It is the most realistic assessment of recoverable quantities if only a single result were reported." Therefore, it is judged to be prudent and useful to generate the results of economic evaluation reserves for this example petroleum-development project using production profiles based on the low estimate (Proved, or 1P), the best estimate (Proved *plus* Probable, or 2P), and the high estimate (Proved *plus* Probable *plus* Possible, or 3P) of oil reserves. Moreover, similar to reserves assessment using probabilistic approach in Chapter 5, an economic evaluation of

these three scenarios may also be carried out using stochastic (probabilistic) decision analysis, which is briefly described at the end of this chapter, including its application to the PRMS Forecast Case economic evaluation of the example oil project.

7.5.1 Basic Data and Assumptions. The example petroleum recovery project is developed at an initial annual depletion rate of about 11% of the respective estimated ultimate recovery (EUR) values of 1P, 2P, or 3P Reserves. The project has been producing under an effective pressure maintenance scheme supported by downdip water injection. **Fig. 7.3** presents oil production profiles based on the low (1P), best (2P), and high (3P) estimates of oil reserves (i.e., the company's WI share only).

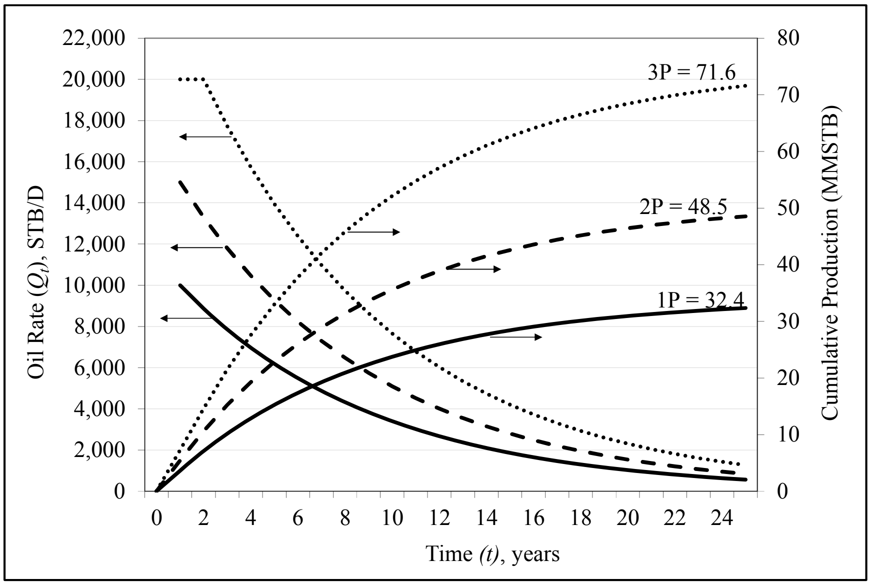

Fig. 7.3—Example Evaluation: Production rate profiles and reserves.

It is important to emphasize that production profiles are independently developed based on different oil initially in-place (OIIP) estimates and hence the reserves categories represent the low, best, and high scenarios. **Table 7.2** summarizes key parameters defining current and future economic conditions.

Table 7.2—Example Evaluation: Key Economic Parameters

	Estimate
Current Economic Conditions:	
Current-year 2010 Oil Price ($/bbl)	60
Current-year 2010 Gas Price ($/MMBtu)	5
Future Economic Conditions (beyond the current-year 2010 and over the project life):	
Average Annual Product Price & Cost Escalation Rates (%)	
Oil Prices	3%
Gas Prices	3%
Operating Expenditures (OPEX)	3.5%
Capital Expenditures (CAPEX)	4%
Average Annual Inflation Rate (f)	3%
Average Nominal Discount Rate (ANDR)	10%

Furthermore, **Table 7.3** summarizes the cost estimates and other relevant company-specific data assumed and necessary to carry out the example oil project evaluation for all three reserves scenarios.

Key economic assumptions and project cost estimates (Tables 7.2 and 7.3) are considered reasonable. Although the quality of input data is very important for assessment of reserves volumes and project value, it does not impact the methodology of the evaluation process described here.

Table 7.3—Example Evaluation: Basic Reserves and Cost Data

Type of Basic Data Required	*The Low Estimate* (1P)	*The Best Estimate* (2P)	*The High Estimate* (3P)
Oil Reserves (MMSTB)	32.4	48.5	71.6
Solution GOR (scf/STB)	600	600	600
Solution Gas Reserves (Bscf)	19.4	29.1	42.9
Gross Heating Value of Gas (Btu/scf)	1,330	1,330	1,330
Initial Oil Rate (MSTB/D)	10	15	20
Initial Investment Capital, IC (MM$)	140	180	230
Annual Future Expenses and Capital (2010 MM$)			
- OPEX	8	10	12
- CAPEX (only in 5th/10th/15th years)	8	12	18
Effective Royalty Rate	20%	20%	20%
Effective Production Tax Rate	10%	10%	10%
Declining Balance Depreciation Rate	25% per year	25% per year	25% per year
Effective Income Tax Rate	35%	35%	35%

Finally, based on the project basic economic data summarized in Tables 7.2 and 7.3, the projected oil and gas production rates, and forecasts of product prices and costs, the cash flow development process (described in Sec. 7.4) is used to generate the relevant project NCF projections over its 25-year economic life for the following two PRMS economic scenarios:

- *Forecast Case (Base Case) Economic Scenario:* All project cash flows are expressed in terms of nominal dollars calculated by escalating the project cash flows in terms of current-year 2010 dollars using the appropriate annual price and cost escalation and inflation rates in Table 7.2.
- *Constant Case (Alternative Case) Economic Scenario:* Project cash flows are expressed in terms of current-year 2010 dollars, and all future annual price and cost escalation and inflation rates are assumed to be zero during the entire project life of 25 years.

It is a good practice to test for the economic limit as a project approaches the end of its productive life. In this example, the net cash flows for the three profiles remain positive at the end of the 25 year project period.

7.5.2 Summary of Results. Due to its relatively small size and the availability of analog projects completed in the same producing area, the project is expected to be completed by a reputable contractor in less than 18 months from its approval. It is further assumed that contract drilling rigs and the off-the-shelf design details on the required gas/oil separator, water injection plants, and related pipelines are readily available. **Fig. 7.4** illustrates the example project's CAPEX profiles for the initial investment spent in terms of 2010 dollars during 2 years for these three reserves scenarios evaluated.

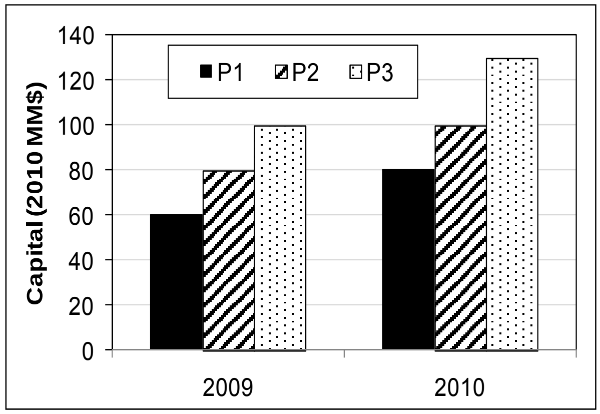

Fig. 7.4—Evaluation Example: Expenditure profiles of initial capital investment.

The value of the example petroleum project owned by an independent producer (with a one-third WI) is evaluated using its appropriate annual discount rate assumed to be at 10%/yr.

Based on development of three plausible reserves estimates and associated production profiles presented in Fig. 7.3, discounted annual and cumulative NCF profiles under PRMS Forecast Case and Constant Case assumptions can be generated for each reserves scenario. **Fig. 7.5** illustrates these profiles only for the 2P reserves scenario.

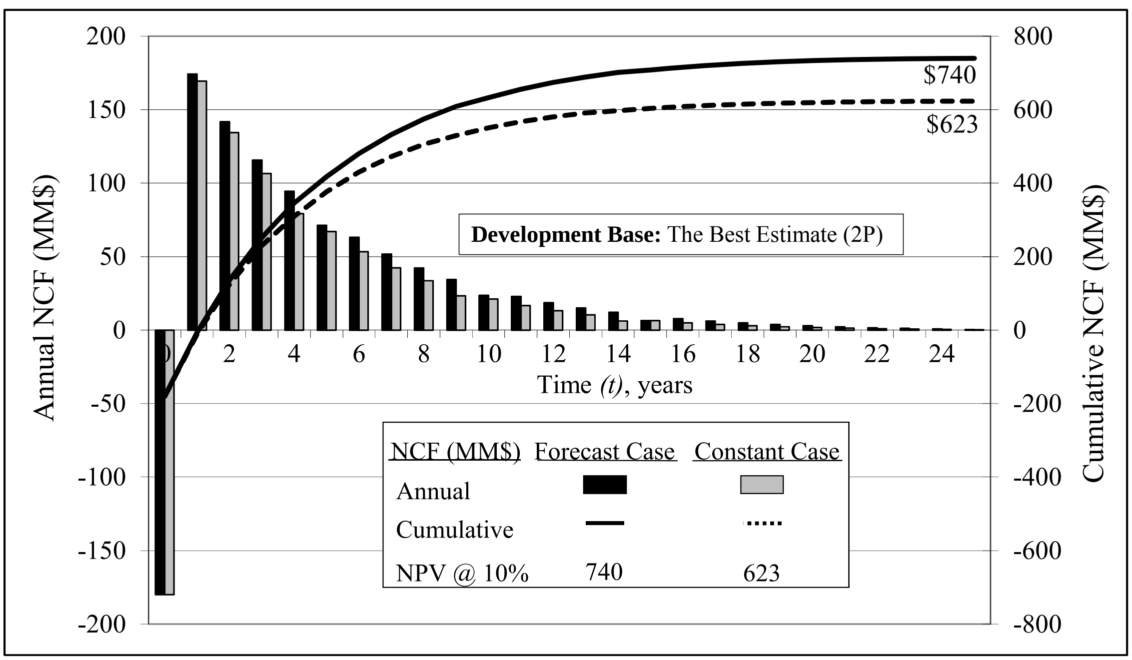

Fig. 7.5—Evaluation example using the best reserves estimate (2P): Discounted Net Cash Flow (NCF) projections (million $) at 10%.

Table 7.4 provides a comparative summary of results based on 1P, 2P, and 3P reserves scenarios and associated project profitability measures estimated under both economic cases.

Table 7.4—Evaluation Example: Basis and Estimated Project Profitability Measures

Key Parameters (in 2010 $'s)	*The Low Estimate* (1P)	*The Best Estimate* (2P)	*The High Estimate* (3P)
Oil Reserves (MMSTB)	32.4	48.5	71.6
Associated Gas Reserves (Bscf)	19.4	29.1	42.9
Initial Oil Rate (MSTB/D)	10	15	20
Initial Investment Capital, IC (MM$)	140	180	230
Value of Petroleum Reserves or Net Present Value, NPV @ 10%			
Forecast Case	467	740	1,139
Constant Case	392	623	958
DCF Rate of Return, DCF-ROR (%):			
Forecast Case	81%	96%	107%
Constant Case	76%	90%	101%
Profitability Index ($ Returned per $ Initially Invested):			
Forecast Case	4.3	5.1	6.0
Constant Case	3.8	4.5	5.2

As summarized in Table 7.4, the project's NPV profit (or value of its petroleum reserves) estimated using the Forecast Case (with higher project NCFs in nominal dollars) is determined to be greater than that obtained using the Constant Case (with lower project NCFs expressed in current-year 2010 dollars) when both project NCFs are discounted at the same company annual nominal discount rate of 10%.

Under the price and cost estimates (including their future projections) and assumptions used, the example petroleum project is determined to be a very attractive investment opportunity for the corporation with an estimated annual DCF rate of return exceeding 75% for all economic scenarios studied, providing a substantial margin of safety (or degree of certainty) over the desired annual MARR of 10%. However, whether this particular project is finally included in the company's current investment portfolio or not will strictly depend on both the relative economic merits of other competing investment opportunities and the amount of investment capital available.

Finally, **Fig. 7.6** shows the results of a sensitivity analysis in a typical tornado diagram form:

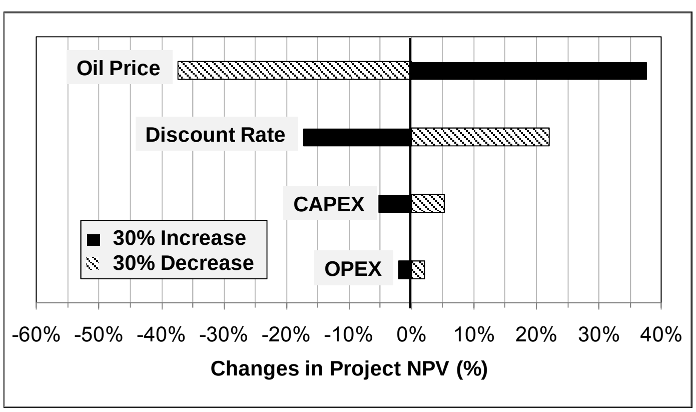

Fig. 7.6—Results of sensitivity analysis.

The tornado diagram illustrates the impact on project NPV (based on 2P scenario) of predefined constant ± 30% (positive and negative percent) changes in major cash-flow components, including the discount rate. Similar charts also could be constructed to illustrate the sensitivity of other project profitability measures, such as rate of return, profitability index, and payout time, etc. Sensitivity analysis clearly demonstrates that project NPV is more sensitive to revenue (oil price and similarly to production rate) than it is to costs, especially the operating costs. A constant ± 30% change in the selected major parameters would change this example project NPV (also approximately valid for the development of any reserves or resources category) as follows:

- Oil price (and production rate) would change it by ± 37%, with a direct relationship.
- Other parameters impact the NPV inversely, as expected [e.g., (+) changes resulting in (–) changes in NPV and vice versa]. It follows that
  - Discount rate would change it by -17% and +22%, respectively,
  - CAPEX would change it by -5% and +5%, respectively, and
  - OPEX would change it by -2% and +2%, respectively.

However, although impact of capital, and especially the operating expenditures, on project economics appears to be relatively minor, the need for consistency and accuracy in their estimates cannot be overemphasized as they are routinely used to estimate company's unit annual development and operating costs (in $/bbl) both on a project and a companywide basis.

7.5.3 Decision Analysis Based on Expected Value (EV) Concept (Campbell et al. 2001, Newendorp and Schuyler 2000, Schuyler 2004). Decision analysis is a structured process based on a clear objective(s) and criteria that are used to evaluate, compare, and make rational decisions on many definable problems, including investment projects.

In *deterministic analysis*, investment decisions are generally made by evaluating and comparing the project NPVs in a portfolio of projects competing for capital funds. In the Forecast Cases of the example recovery project, NPV was deterministically estimated to be about USD 467 million, USD 740 million and USD 1,139 million, respectively, for the 1P, 2P, and 3P estimates of petroleum reserves.

In *stochastic analysis,* on the other hand, the EV concept is used to probabilistically estimate project profitability measures. EV is the probability-weighted value of all possible outcomes, which is the sum of all outcome values X_i times their respective probabilities of occurrence $p(x_i)$ [where subscript (i) could range from 1 to n], and can be mathematically expressed by

$$EV = \sum X_i \bullet p\,(x_i) \tag{7.4}$$

where the summation is taken over (n) outcomes irrespective of whether the outcomes represent different categories of petroleum resources, monetary values, DCF rates of return or any other values of a random occurrence.

Two most common methods used to stochastically assess petroleum resources and/or evaluate project economics are briefly described below.

Decision Tree Analysis (DTA). Using Eq. 7.4 at each successive node, DTA can be used to derive the *expected monetary value (EMV)* of the project at any discount rate (or MARR)**,** which now replaces the project NPV deterministically determined earlier (see Eqs. 7.3), as follows:

$$EMV@\ MARR = \sum EMV_i \bullet p\,(x_i) \tag{7.5}$$

where EMV_i represent the EMV for i^{th} outcome, etc.

In the simplest possible application of DTA and for illustration purpose only, let us assume that the deterministically estimated incremental project reserves with varying degrees of uncertainty and their associated NPVs have average probabilities of occurrence of 97% (for Proved), 70% (for Probable instead of being ≥ 50% as a range for 2P, etc), and 30% (for Possible). They represent generalized approximations, or "weighting factors," that are valid for the majority of cases using a log-normal "cumulative probability distribution curve," which is also known as an "expectation curve" (EC). The expected (or mean) value for any random variable is equivalent to and defined by the area under its specific EC. Therefore, using Eqs. 7.4 and 7.5, the *expected reserves value* (ERV) and the EMV for the example petroleum project can be calculated as follows:

ERV = (0.97) x32.2 + (0.7) x (48.5-32.2) + (0.3) x (71.6-48.5) = 50.1 MMSTB

EMV at 10% = (0.97) x 467 + (0.7) x (740-467) + (0.3) x (1,139-740) = USD 763 million

These expected values would approach their best estimates or 2P values (of 48.5 MMSTB and USD 740 million for the Forecast Case) if their expectation curves were normally distributed.

Monte Carlo Simulation (MCS) Technique. It uses a simple sampling technique that amounts to integrating Eq. 7.4. It is based on the DCF model defined by Eq. 7.3. and specific probability distribution curves similar to those presented in **Fig. 7.7,** which are defined for each key random variable with significant ranges of uncertainty.

In a simplified cash-flow model, project NCF at any time (t), defined earlier by Eq. 7.2 and required by Eqs. 7.3 through 7.3b, may be expressed in terms of these key probabilistic (or random) variables as

$$NCF_t = [\text{Volume}(t) - \text{Royalty}(t)]\,(t) \times \text{Price}\,(t) - \text{CAPEX}\,(t) - \text{OPEX}(t) - \text{Taxes}\,(t) \quad (7.6)$$

Uncertainty around each random variable in Eq.7.6 may be represented by one of the following common probability-density functions (or probability distribution curves) presented in Fig.7.7. The selection of a distribution curve appropriate for any random variable should be based on the judgments of the subject-matter experts.

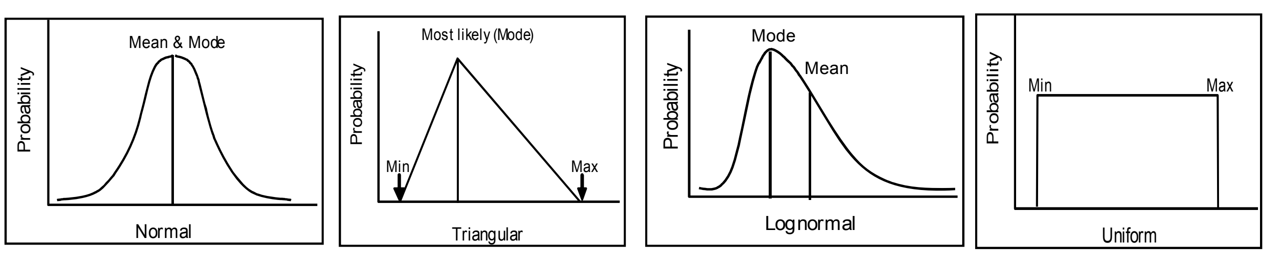

Fig. 7.7—Common probability distribution curves.

Selecting and using the probability distribution curve [or probability-density function (PDF)] appropriate for each random variable and accounting for other fixed input parameters in the cash-flow model (see Eqs. 7.3 and 7.6), MCS sampling technique randomly generates the estimates of project annual NCFs over the study period and the resulting single EMV at each trial. After hundreds or thousands of trials, it can generate the project NCF profiles representing different confidence bands, associated EMVs, and hence the resulting EMV profile (or profiles for other profitability measures as well). Results are usually presented in terms of both PDFs

(approximately bell-shaped distribution curves) and ECs, as illustrated for the EMV profiles of the example evaluation project on the right side of **Fig. 7.8.**

Based on the assumptions made and input data (given in terms of probability distribution curves and as fixed parameters illustrated in the left side of Fig.7.8) used for the example petroleum project, the data for the simulated EMV profiles are generated by using the MCS technique and plotted in the right side of Fig. 7.8. As a result, the stochastically established P90, P50, and P10 values of the project EMVs (discounted at 10%) for the Forecast Case are estimated to be about USD 500, USD 705, and USD 995 million, respectively. They compare with the deterministic NPVs (also discounted at 10%) of about USD 467 million (1P), USD 740 million (2P), and USD 1,139 million (3P), respectively. Moreover, the mean monetary value of the project (EMV at 10%), is equivalent to the area under either of its EMV profiles shown on the right side of Fig. 7.8 and is estimated to be USD 846 million as compared with USD 763 million estimated using DTA (or EV analysis) applied to deterministic estimates. It must be noted that only the mean values of probabilistic estimates (Reserves or associated EMVs) may be added together among projects (refer to Chapter 6 for more details).

It is important to point out that MCS technique provides the evaluator with a significant advantage over the deterministic analysis using the scenario approach and especially over traditional sensitivity analysis. MCS provides not only the project's expected profitability measures like EMV, expected DCF rate of return, and expected profitability index etc., but also their profiles over a wide range of uncertainties quantified in terms of PDFs and ECs similar to the ones presented for the example project's EMV on the right side of Fig. 7.8.

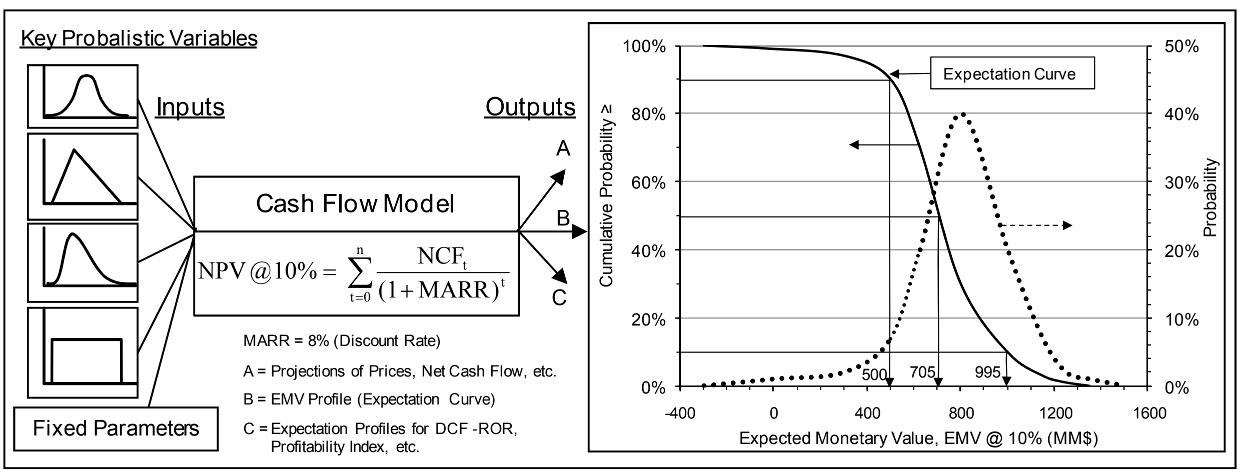

Fig. 7.8—Example evaluation: Project's EMV profiles generated by the MSC technique.

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Chapter 8

Unconventional Resources Estimation

8.1 Introduction

Phil Chan

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

- Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition (typically with each accumulation bounded by a down-dip contact with an aquifer) that is significantly affected by hydrodynamic influences such as the buoyancy of petroleum in water. The petroleum is recovered through wellbores and typically requires minimal processing prior to sale.
- Unconventional resources exist in hydrocarbon accumulations that are pervasive throughout a large area and that are generally not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Such accumulations require specialized extraction technology, and the raw production may require significant processing prior to sale.

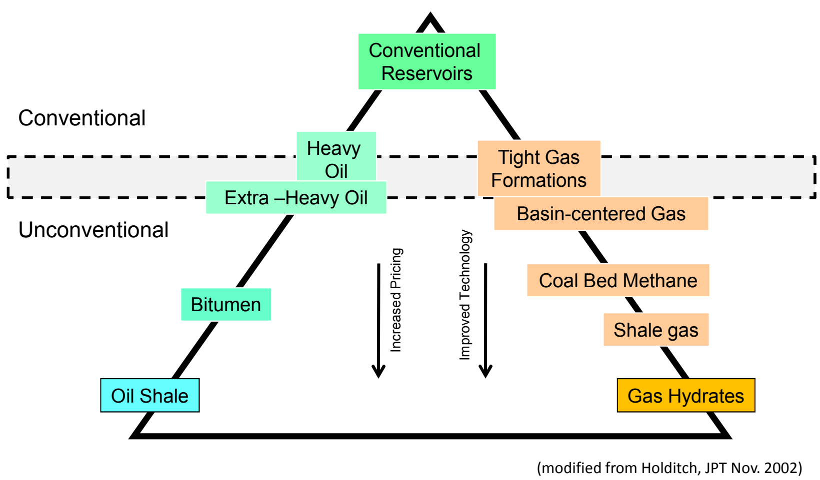

Fig. 8.1—Resource triangle.

The relationship of conventional to unconventional resources is illustrated by a resource triangle **(Fig. 8.1).** Heavy oil and tight gas formations straddle the boundary; nonetheless, both present challenges in applying the assessment methods typically used for conventional accumulations.

Very large volumes of petroleum exist in unconventional reservoirs, but their commercial recovery often requires a combination of improved technology and higher product prices. Industry analysts project that unconventional liquids reservoirs (excluding oil shale) may contain 4.8 trillion bbl initially-in-place. Oil shales may add another 1 to 3 trillion bbl. The in-place

estimates for unconventional gas accumulations range up to 30,000 Tscf (excluding gas hydrates) vs. 2,800 Tscf produced to date. Estimates for gas hydrates vary widely between 60,000 and 700,000 Tscf; however, no commercial recovery methods have yet been developed to extract these in-place volumes.

8.1.1 Assessment and Classification Issues. The Petroleum Resources Management System (PRMS) resources definitions, together with the classification system, are intended to be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, the extraction method applied, or the degree of processing required. However, specialized techniques often are employed in assessing in-place quantities and evaluating development and production programs of unconventional resources.

Estimations of recoverable resource quantities must include an estimate of the associated uncertainty expressed by allocation to PRMS categories using the same low/best/high methodology as for conventional resources. Typically, the assessment process begins with estimates of original-in-place volumes. Thereafter, portions of the in-place quantities that may be potentially recovered by identified development techniques are defined. In some cases, there are no known technical methods of recovery and the in-place volumes are classified as Unrecoverable.

As in conventional accumulations, undiscovered recoverable volumes are classed as Prospective Resources and are estimated contingent on their discovery and commercial development. PRMS recognizes that the hydrocarbon type and/or the reservoir may not support a flowing well test but the accumulation may be classed as Discovered based on other evidence (e.g., sampling and/or logging).

It is not uncommon to recognize very large areas where prior drilling results have identified the presence of a Discovered resource type that, based on analogs, has production potential. Where technically feasible, recovery techniques are identified, but when economic and/or other commercial criteria are not satisfied (even under very aggressive forecasts), estimates of recoverable quantities are classified as Contingent Resources and subclassified as Development Not Viable. If the recovery processes have been confirmed as not technically feasible, the in-place volumes are classified as Discovered/Unrecoverable. As the play and technologies mature and development projects are better defined, portions of estimated volumes may be assigned to the Contingent Resources subclasses that recognize this progressive technical and commercial maturity. Typically, Reserves are only attributed after pilot programs have confirmed the technical and economic producibility and after capital is allocated for development.

In many cases, the raw production must be further processed to yield a marketable product. Integrated development/processing projects include the cost of the processing and related facilities in the project economics. In other cases, the raw production is sold to a third party (at a reduced price) for further processing. In either case, development economics are highly dependent on the capital and operating costs associated with complex processing facilities.

As a result of their recent emergence as commercial ventures, the publicly available literature on the standard assessment methods and the illustrative examples for unconventional resources is limited. In addition, these accumulations are often pervasive throughout a very large area and are developed with high-density drilling; probabilistic assessment techniques may be more applicable than in conventional plays. While the authors have quoted some “rules of thumb” on drainage areas and drilling spacing unit offsets related to reserves categorization, it must be recognized that our overall goal is to assign appropriate confidence to commercial producibility; this relationship may be much more complex than in conventional reservoirs.

The following sections by different authors provide an overview of each resource type and preliminary information on evaluation approaches. It is envisioned that these sections will be updated and expanded in future editions.

8.2 Extra-Heavy Oil
8.3 Bitumen
8.4 Tight Gas Formations
8.5 Coalbed Methane
8.6 Shale Gas
8.7 Oil Shale
8.8 Gas Hydrates

8.2 Extra-Heavy Oil

John Etherington

8.2.1 Introduction. Crude oil may be divided into categories based on density and viscosity. Heavy crude oil is generally defined as having a density in the range of 10 to 23° API with a viscosity that is typically less than 1,000 cp. Although heavy crude oil is often recovered in thermal EOR projects, it is typically not a continuous accumulation and often does not require upgrading. Therefore, heavy crude is defined herein as Conventional Resources regarding assessment methods and classification under PRMS guidelines. Extra-heavy oil density is less than 10° API with a viscosity ranging from 1,000 to 10,000 cp. While mobility is limited, accumulations typically have defined oil/water contacts and exhibit normal buoyancy effects. Extra-heavy oil is herein classified as unconventional resources because it typically requires upgrading.

About 90% of the world's known accumulations of extra-heavy oil are in the Orinoco Oil belt of the Eastern Venezuelan basin, with over 1.3 trillion bbl initially-in-place (Dusseault 2008). Depending on technology developments and associated economics, ultimate recoverable volumes are estimated at 235 billion barrels (Dusseault 2008).

8.2.2 Reservoir Characteristics—Risk and Uncertainty. Individual sand bodies in the Orinoco accumulations range in thickness up to 150 ft. The majority of oil-bearing beds are 25 to 40 ft thick, with high porosity (27 to 32%), good permeability (up to 5 darcies), and good lateral continuity (Dusseault 2001). The major uncertainties are fault compartmentalization and water encroachment.

In the Orinoco Oil belt, cold production of extra-heavy oil is normally achieved through multilateral (horizontal) wells that are positioned in thin but relatively continuous sands, in combination with electric submersible pumps and progressing cavity pumps. Horizontal multilateral wells maximize the borehole contact with the reservoir. Extra-heavy oil mobility in the Orinoco Oil Belt reservoirs is typically greater than that of bitumen in the Alberta sands because of higher reservoir temperatures, greater reservoir permeability, higher gas/oil ratio, and the lower viscosity of extra-heavy oil. The recovery factor for an extra-heavy oil cold-production project in the Orinoco Oil belt is estimated to be approximately 12% of the in-place oil. While upside secondary recovery with thermal projects is forecast, these incremental volumes would be classed under PRMS as Contingent Resources until pilots are complete and thermal projects are sanctioned.

The majority of Orinoco production is diluted and transported to the Caribbean coast for upgrading prior to sale; thus, economics must incorporate upgrading costs either as integrated projects or through reduced pricing at the field-level custody-transfer point.

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8.3 Bitumen

John Etherington

8.3.1 Introduction. Natural bitumen is the portion of petroleum that exists in the semi-solid or solid phase in natural deposits. It usually contains significant sulfur, metals, and other nonhydrocarbons. Natural bitumen generally has a density less than 10° API and a viscosity greater than 10,000 cp measured at original temperature in the deposit and at atmospheric pressure on a gas-free basis. In its natural viscous state, it is normally not recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Near-surface deposits may be recovered using open-pit mining methods.

Bitumen accumulations are classified as unconventional because they are pervasive throughout a large area and are not currently affected by hydrodynamic influences such as the buoyancy of petroleum in water. This petroleum type requires upgrading to synthetic crude oil (SCO) or dilution with light hydrocarbons prior to marketing.

The largest known bitumen resource is in western Canada, where Cretaceous sands and underlying Devonian carbonates covering a 30,000-sq mile area contain over 1,700 billion bbl of bitumen initially-in-place (Alberta Energy Resources Conservation Board 2009). Current commercial developments are confined to the oil sands. Depending on assumed technology developments and associated economics, estimates of technically recoverable volumes range from 170 to more than 300 billion bbl (Alberta Energy Resources Conservation Board 2009).

According to the World Energy Council (2007), outside of Canada, 359 natural bitumen deposits are reported in 21 countries. The total global volumes of discovered bitumen initially-in-place are estimated at 2,469 billion bbl.

8.3.2 Reservoir and Hydrocarbon Characteristics. Individual sand beds in the western Canada oil sands can form thick and continuous reservoirs of up to 250 ft with a net/gross ratio of over 80%. More often, there are a stacked series of 50- to 150-ft thick sands with intervening silts and clays. It is common for the sands to have high porosity (30–34%) and permeability (1–5 darcies). The sand grains are often floating in bitumen with minor clay content. Western Canadia oil sands may contain a mixture of bitumen, extra-heavy oil, and heavy oil, whose properties differ between and within reservoirs.

8.3.3 Extraction and Processing Methods. Two general processes are used to extract the western Canada bitumen: open-pit surface mining and various subsurface in-situ recovery methods.

In surface mining, the overburden is removed and the oil sands are excavated with very large "truck and shovel" operations. The oil sands are transported to a processing plant where the ore

is subjected to a series of hot water froth floatation and/or solvent processes to separate the sand and bitumen. At current economics, typically about 4 tonnes of material are mined to recover 2 tonnes of oil sand ore, which yields 1.2 bbl of bitumen. While the process can recover more than 95% of the bitumen in the sand, the intermixing of clays and the mine-layout requirements combine to yield approximately an 80% recovery factor. Surface mining is typically considered where the depth to the top of the oil sands is less than 215 ft. In Canada, approximately 34 billion bbl is considered recoverable with current surface-mining technology (Alberta Energy Resources Conservation Board 2009). If all expansions and planned new projects proceed, the total production from mined bitumen could increase from 600,000 BOPD in 2009 to 1,200,000 BOPD by 2012.

Bitumen that is too deep for surface mining is typically produced using in-situ thermal recovery processes similar to those used in heavy oil projects. In general, such projects require a reservoir depth in excess of 500 ft to provide an impermeable cap to contain the required steam pressure that provides adequate reservoir energy and temperature. In cyclic steam operations, a volume of steam is injected into a well, some period of time (soak time) is allowed to pass, and then the bitumen, whose viscosity has been significantly reduced by the high-temperature steam, is produced from the same well. This process can be repeated multiple times in the same well and the recovery efficiency in these projects is typically estimated to be 25 to 30% of the oil initially-in-place.

Most of the new in-situ projects employ a process termed steam-assisted gravity drainage (SAGD) using a pair of vertically offset horizontal wells. The upper wellbore is used for steam injection, creating an expanding steam chamber. The thermally mobilized bitumen drains into the lower wellbore from which it is produced. A typical project uses well pairs with horizontal lengths of 2,500 to 3,500 ft, and the injector is placed about 15 ft above the producer. The wells are drilled in patterns from pads consisting of 5 to 10 well pairs spaced 300 to 500 ft apart. Expected production rates are 800 to 2,000 BOPD per well. Recovery efficiencies range from 40 to 75% of oil initially-in-place (Etherington and McDonald 2004).

In Canada, the total rate from all current and planned in-situ projects is forecast at 1,500,000 BOPD. Research on improved in-situ processes continues, including use of vaporized solvent rather than steam to decrease bitumen viscosity (VAPEX), a combination of steam and solvents called ES (expanding solvent)-SAGD, and a modified fireflood technology. Firefloods are processes for extracting additional oil by injecting compressed air into the reservoir and burning some of the oil to increase the flow rate and recovery.

8.3.4 Assessment Methods—Risks and Uncertainties. Bitumen, due to its density and immobile character, may require different methods to delineate deposits and estimate in-place volumes than those used for other conventional oil assessments. Conventional production decline and material balance calculations do not apply.

For surface mine planning, a closely spaced grid of core holes is required to support a detailed volumetric assessment. The total cores are analyzed in laboratories to determine the weight percent of bitumen, which is typically 10 to 14 wt% (equivalent to 65 to 89% S_o). The Alberta Energy Resources Conservation Board (2001) has published criteria for reporting mineable resources. The Reserves classification is usually tied to the core grid spacing that defines continuity. For example, Proved Reserves may require a 1,600-ft grid (61-acre spacing) while Probable Reserves would be assigned to areas with a 3,200-ft grid (247-acre spacing). Thickness and condition of overburden, and volume allowances on the lease for mine layout and

tailing ponds are examples of key factors affecting mine economics that would likely be unfamiliar to engineers focused on conventional reservoirs.

The assessment methods for in-situ bitumen-production operations require close well spacing and core analysis but are supplemented by high-resolution 3D-seismic and complete-wireline log suites. Thermal processes, such as SAGD, are sensitive to reservoirs with associated gas and/or top or bottom water zones that may act as potential thief zones. Water zones rob the steam chamber of energy otherwise available to heat the bitumen and result in higher operating costs and poorer oil recoveries.

8.3.5 Commercial Issues. Raw bitumen is marketed at a discount to conventional petroleum at prices ranging from 25 to 85% of West Texas Intermediate (WTI) benchmark prices depending on oil quality and seasonal demand. Thus, many projects include integrated or third party upgrading to yield Synthetic Crude Oil (SCO) that is valued at prices approximating WTI crude. Bitumen operations are energy intensive and associated greenhouse gases are typically much greater than for conventional operations. As such, any legislation that taxes emissions may negatively impact the economics of bitumen projects.

8.3.6 Classification Issues. Similar to improved-recovery projects in conventional reservoirs, Reserves attribution requires "successful testing by a pilot project, or the operation of an installed program in the reservoir, that provides support for the engineering analysis on which the project or program was based." The difference in bitumen projects is that there may be no preceding "primary" production upon which to base improved recoveries. However, as more SAGD projects have come on-stream, the performance results in adjacent analog reservoirs may be accepted to help underpin the booking of undeveloped reserves.

Under PRMS, to be classed as Reserves, owners must have committed to an approved development plan including facilities to produce, process, and transport the products to established markets. It would be difficult to apply all classical petroleum reserves criteria such as oil/water contacts and offset-well pressure response to unconventional deposits like the Canadian oil sands. The appropriate assessment methods may be a hybrid of those applied to conventional petroleum reservoirs and to mining deposits.

In Canada, the Society of Petroleum Evaluation Engineers (SPEE) has created the Canadian Oil and Gas Evaluation Handbook (COGEH 2007) that is referenced for technical guidance in Canada's petroleum disclosure rules. COGEH Vol. 3 provides more-detailed best practices for bitumen reserves and resources assessment and classification.

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8.4 Tight Gas Formations

Roberto Aguilera

8.4.1 Introduction. The US Gas Policy Act of 1978 required in-situ gas permeability to be equal to or less than 0.1 md for the reservoir to qualify as a tight gas formation (TGF) (Kazemi 1982, Aguilera and Harding 2007). For purposes of this section, the definition is expanded such that a TGF is "a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores" (Holditch 2006). The industry generally divides TGFs into (1) basin-centered gas accumulations (BCGA), also known as continuous gas accumulations (Law 2002; Schmoker 2005) and (2) gas reservoirs that occur in low-permeability, poor-quality reservoir rocks in conventional structural and stratigraphic traps (Shanley et al. 2004). Both types of accumulations can be treated within the PRMS guidelines given the following minor glossary amendment: "Unconventional TGF resources can exist in petroleum accumulations that are pervasive throughout a large area and that are generally, but not always, affected by hydrodynamic influences."

8.4.2 Resource Potential. The tight gas initially-in place (TGIIP) in the US lower 48 states is estimated at 5,000 Tscf (Holditch 2006). The estimated recoverable resource is 350 Tscf, which represents only 7% of the TGIIP. The TGIIP in Canadian TGFs is estimated at 1,500 Tscf (Canadian Society for Unconventional Gas, Masters 1984). Application of the same recovery estimate of 7% presented above leads to a resource of 105 Tscf. The bulk of tight gas resources in Canada is stored in a BCGA in the Western Canadian Sedimentary basin (WCSB). Globally, the gas resource in TGFs is conservatively estimated at over 15,000 Tscf (Aguilera et al. 2008).

8.4.3 Reservoir and Hydrocarbon Characteristics. The primary definition used in this report assumes that TGFs, including sandstones and carbonates, are characterized by permeabilities of less than 0.1 md. The hydrocarbons in these rocks are primarily methane with some impurities, but there are also occurrences of associated gas condensate.

Permeability is not the only factor that plays a role in gas production from tight gas reservoirs. A cursory examination of the pseudo steady-state, radial flow equation illustrates that gas rate is a function of many other physical factors, including pressure, fluid properties, reservoir and surface temperatures, net pay, drainage and wellbore radius, skin, and the non-Darcy constant (Holditch 2006). Furthermore, a tight gas reservoir can be deep or shallow, high or low pressure, high or low temperature, naturally fractured, contained within a single layer or in multiple layers (Holditch 2006), continuous BCGA without a water leg (Law 2002; Schmoker 2005), or with characteristics of a conventional trap under hydrodynamic influences (Shanley et al. 2004; Aguilera et al. 2008). To succeed and improve recoveries from TGFs, it is necessary to identify the location and preferential orientation of natural fractures, to distinguish clearly between water and gas-bearing formations, to efficiently drill into and stimulate multiple

zones,and to enhance the connectivity between wells and their associated drainage volumes (Kuuskra and Ammer 2004).

Continuous gas accumulations, or BCGAs, are defined (Schmoker 2005) by the US Geological Survey as "those oil or gas accumulations that have large spatial dimensions and indistinctly defined boundaries, and which exist more or less independently of the water column." In addition, they commonly have low matrix permeabilities, are in close proximity to reservoir rocks, have low recovery factors (Schenk and Pollastro 2002), and are visualized as "a collection of gas charged cells." All of these cells are capable of producing gas, but their production capabilities change from cell to cell, with the highest production being obtained from cells with connected natural fractures and/or higher matrix permeabilities.

There are four key elements that define a BCGA:

- Abnormal pressure
- Low permeability (generally ≤ 0.1 md)
- Continuous gas saturation
- No down-dip water leg

If any one of these elements is missing, the reservoir cannot be treated as a continuous gas accumulation. Note that lithology is not part of the four requirements listed above; the same four elements have been reported for both clastic and carbonate reservoirs.

Conventional Tight Gas Traps. An opposite view to the concept of continuous gas accumulations discussed in the previous section has been presented by Shanley et al. (2004). These authors state explicitly that "low-permeability reservoirs from the Greater Green River basin (GGRB) of southwest Wyoming are not part of a continuous-type gas accumulation or a basin-center gas system in which productivity is dependent on the development of enigmatic sweet spots. Instead, gas fields in this basin occur in low-permeability, poor-quality reservoir rocks in conventional traps."

The model Shanley et al. use to explain their theory is called "permeability jail." The concept was developed originally by A. Byrnes of the Kansas Geological Survey based on laboratory work conducted at room conditions and at 4,000 psi overburden stress (Shanley et al. 2004). The "permeability jail" concept indicates that a range of saturations exist, within which the relative permeabilities to gas and water are equal to zero; that is, the relative permeabilities do not cross each other as in the case of conventional reservoirs.

The controversy over whether these accumulations are basin-centered or in low-permeability conventional traps is important because the estimates of gas-in-place volumes and mobile gas are much larger in a basin that contains a BCGA instead of discrete conventional traps.

8.4.4 Assessment Methods. The integration of geoscience and engineering aspects are of paramount importance in exploring for and assessing TGFs. Folding, faulting, natural fracturing, in-situ stresses, multilayer systems, mineralogy and petrology, connectivity and continuity, permeability barriers, and interbedded coals and shales are just some of the aspects that must be taken into account when evaluating TGFs (Aguilera et al. 2008). These are affected by the dominating tectonics, which in the case of the Rocky Mountain basins are wrench/extensional, while in the Western Canadian Sedimentary basin they are compressional (Zaitlin and Moslow 2006).

Exploration methods focus on how to locate swarms of natural fractures, positive closures, and "sweet spots" of higher matrix permeability. Once these are located and natural fracture orientations are determined, wells are drilled in a way that intercepts the natural fractures. Inducing formation damage must be avoided as much as possible, which generally implies the

use of underbalanced drilling. However, even if the reservoir is not damaged, stimulation(s) of the TGF will likely be required to establish commercial production. To be Commercial under PRMS guidelines, in addition to technical development feasibility, the project must include economic, legal, environmental, social and governmental viability.

Seismic velocity reductions can indicate zones of high porosity, while variations in seismic velocity with direction (azimuthal anisotropy) can be related to fractures in the rocks. Wide azimuth seismic acquisition and processing techniques allow the detection of natural fractures, which appear as wavy or sinusoidal reflectors on the seismic data. The recognition of fractures, slots (Byrnes et al. 2006a and 2006b), and the best porosities allows optimum positioning of drilling targets and, consequently, a reduction in capital and operating costs (Aguilera and Harding 2007; BP 2008).

This 3D-seismic approach has been used in a large-scale survey in the Wamsutter gas field in Wyoming (USA), which covers an area of around 4,000 km^2. The reservoir section has a thickness of approximately 600 m and is made up of thousands of very thin gas pay zones. It is also being used for evaluation of tight gas sands in the In Amenas and In Salah fields in Algeria and in the Khazzan and Makarem gas fields in Oman (BP 2008).

Ant tracking (Pedersen et al. 2002) is another approach that offers hope for locating fracture swarms. The technique has been found to be useful for automatic determination of fault surfaces from conditioned fault-enhancing attributes. In those instances where the fractures are fault related, the method can provide indirect indications of where the fractures are located.

An integrated approach using shear wave splitting, P-wave azimuthal velocity anomalies, cores, image logs, and geomechanical methods (Billingsley and Kuuskraa 2006) has proven useful for locating natural fractures in three distinct geologic settings and tight gas basins in the US: the Piceance and Wind River basins in the Rocky Mountains, and the Anadarko basin in western Oklahoma. Under favorable conditions, this technology allows fracture density and apertures to be estimated. This technology has been reported to improve ultimate recoveries significantly in lenticular gas plays of the Rulison field in the Piceance basin from 0.9 Bcf/well in 1956–1972 to 2.0 Bcf/well more recently. The number of dry holes has also dropped from 45% to a low percentage (Billingsley and Kuuskraa 2006).

Hydrodynamic studies must be conducted to determine if the TGF is over- or underpressured, whether it has a down-dip water leg, if it is continuously gas saturated, and what the approximate size of the TGF is. This work is useful in determining whether the TGF is a continuous accumulation (BCGA) or a conventional structural or stratigraphic low-permeability trap. This work is also very important in planning the development strategy of the reservoir. If the TGF is a continuous gas accumulation, large problems with water production probably will not be an issue. However, if the hydrodynamic study shows the presence of a down-dip water leg, it is reasonable to anticipate that eventually there will be water production problems.

Although porosities are lower in TGFs, this does not necessarily translate into lower calculated gas saturations. The reason for this is that there are lower values of the Archie cementation exponent, *m,* in TGFs resulting from the presence of fractures and slot pores (Aguilera 2008). The recovery efficiency, however, would be lower than in a conventional gas reservoir due to the low matrix permeabilities.

An excellent and valuable compilation of rock properties for the Mesaverde Group has been published by Byrnes et al. (2006a, 2006b) for the Green River, Piceance, Powder River, Sand Wash, Uinta, Washakie and Wind River basins in the Rocky Mountains region of the US. Included in their work are routine in-situ porosity, permeability, and grain-density

measurements, along with special core analyses, including cementation and saturation exponents, cation exchange capacities, mercury injection capillary pressures, drainage critical gas saturations, thin sections, and core descriptions. Ideally, the same type of information should be collected for all TGFs, along with the most recent generation of well logs, including image logs and nuclear magnetic resonance (NMR) logs.

The work of Byrnes et al. (2006a, 2006b) also shows that the value of m becomes smaller as porosity decreases. They relate the low values of m to the presence of slot pores in TGFs, and state that "this pore architecture is similar to a simple fracture that exhibits cementation exponents near $m = 1$." The slot porosity can be visualized as grain bounding fractures that result from uplifting and cooling (Billingsley and Kuuskra 2006).

Well testing, planning, and analysis require specialized methods because of the very low permeabilities of TGFs. Methods for single- (Lee 1987) and dual-porosity reservoirs (Shahamat and Aguilera 2008) are available for this purpose. The special signature of gas production decline can be analyzed with specialized techniques (Arevalo-Villagran et al. 2006; Palacio and Blasingame 1993) that under favorable circumstances permit estimating permeability and volumes of gas-in-place with a flowing-gas material balance (Rahman et al. 2006). Specific-purpose type curves can be developed in some instances based on the tight gas production-decline history of TGFs. Given that well spacing is smaller in tight gas reservoirs than in conventional reservoirs, single-well simulators can provide reasonable results.

Decline-curve analysis using normalized gas rates can provide good results for estimating performance, if wells have been producing for several years. If normalization is not possible because of the lack of pressure data, hyperbolic declines can be used with generally reasonable results. In this case, it is important to constrain the forecasted production time so that estimates of ultimate recovery are not skewed by very long production periods (a guideline is to consider a maximum of 30 years).

The TGF can act in some cases as a gas storage facility, while in other cases (e.g., in a conglomerate) it can act as the commercial delivery medium to the wellbore. This happens sometimes in the WCSB of Canada, with the Cadomin conglomerate feeding the wellbore. As the Cadomin pressures drop, the Nikanassin tight sandstone starts feeding gas into the higher permeability conglomerate (Zaitlin and Moslow 2006).

8.4.5 Drilling, Completion, and Stimulation Issues. Intercepting natural fractures requires knowledge of fracture(s) strike and dip. The accepted concept in TGFs is that the well must be drilled perpendicular to the open fractures. If more than one set of open fractures is present, a properly designed slanted, horizontal, or multilateral wellbore can maximize gas production and recovery by intersecting as many fracture sets as economically possible.

In conventional drilling, the mud weight is chosen to exceed the reservoir pressure to avoid potential blowouts. In TGFs, however, mud invasion can result in large values of skin factor because these formations are highly susceptible to damage. The problem is exacerbated because of the complex geology of TGFs, which includes natural fracturing (causing fluid leakoff and potential sand screenouts), folding and faulting (resulting in high stresses that could make initiation of the hydraulic fractures difficult or impossible), and channel sands and interbedded coals and shales (resulting in leakoff into cleats or unexpected fracture-propagation paths).

As a result, underbalanced drilling appears as a reasonable approach for drilling TGFs. In underbalanced drilling, the usual mud is replaced by fluids, such as inert gases and foams, to make the hydrostatic pressure exerted on the reservoir smaller than the reservoir pressure. This eliminates fluid invasion through the fractures and, consequently, minimizes damage to the tight

gas formation. Downhole sensors near the drill bit gather and send information to the surface, which permits the bit to be steered through the best portions of the reservoir, improving the probability of success (Bennion et al. 1996).

Unfortunately, underbalanced drilling is not a panacea in TGFs because it can sometimes induce severe nonanticipated damage. Some of the potential problems include (Craig et al. 2002) fluid retention, adverse rock/fluid and fluid/fluid interactions, countercurrent imbibition effects, glazing and mashing, condensate dropout, and entrainment from rich gases, fines mobilization, and solids precipitation.

Hydraulic fracturing jobs (single or multistage) are necessary in most cases in TGFs, even when drilling slanted or horizontal wells. However, water retention is a big problem in some TGFs. As a result, many potential fracturing solutions have been attempted in the past, including fluids such as pure oil, CO_2 energized oil, and cross-linked water-based poly-emulsion and water-based foam (Rahman et al. 2006; Craig et al. 2002).

8.4.6 Processing and Marketing. A general observation based on experience is that where there is "conventional gas," there is also "tight gas" (Aguilera et al. 2008). Furthermore, "tight-sand accumulations should occur in all or nearly all petroleum provinces of the world" (Salvador 2005). As a result, the processing and marketing of tight gas could proceed hand in hand with that of conventional gas. Stranded gas, both from conventional and unconventional reservoirs (including TGFs), requires special handling and economic considerations due to the very large investments required. In all cases the PRMS guidelines would still apply.

8.4.7 Commercial Issues. Economic considerations have to take into account special drilling, stimulation, and completion practices; and long transient-flow periods that can last for several years and even decades in some cases prior to finding any reservoir boundary or discovering the production effect of an offset well. A larger number of wells per unit area are always required in TGFs compared to conventional reservoirs. In order to move some of the huge tight gas resources into reserves, efforts need to focus on many technological improvements that have the potential to reduce costs and increase gas production rates. The handling of liquids, even in continuous accumulations without down-dip water, is an important consideration that must be taken into account when producing TGFs in order to optimize production.

8.4.8 Classification and Reporting Issues. The PRMS (classification, categorization, and definitions) is generally applicable to TGFs, but given the characteristics of TGFs discussed previously, there are some differences with respect to conventional reservoirs that should be highlighted, including the following:

1. In spite of low porosities, the volume of gas initially-in-place (GIIP) is generally much larger in tight gas reservoirs located in BCGAs compared with conventional reservoirs. In fact, the continuity of BCGAs suggests that the volume of gas they contain is very large. To avoid being overly optimistic (Schmoker 2005), the "assessment scope needs to be constrained from that of crustal abundance to resources that might be recoverable in the foreseeable future." The gas volume of a BCGA would initially be classified as total PIIP in the PRMS guidelines. At a smaller scale it could be divided between Discovered PIIP and Undiscovered PIIP. Although there would be little doubt about the existence of the TGF, the uncertainties associated with the presence of natural fractures, higher matrix permeability, low values of water saturation, and the size of individual well drainage areas will all affect whether the accumulation can progress from Prospective Resources to Contingent Resources and Reserves.

2. The gas recovery efficiency, as a percentage of the total GIIP in the entire BCGA without a water leg, is generally much lower (less than 10%) than in a conventional reservoir. However, the gas recovery efficiency from a given property (lease or license area or study area) located in a sweet spot within the continuous accumulation can reach 50% or more. The bulk of the resources are categorized initially as Contingent Resources but can move very rapidly to Reserves, if the project's commercial threshold is met. For a given property, it is also important to remember that generally a small percentage of the wells will contribute to the bulk of the gas production. This is sometimes known as the "20-80 rule," whereby 20% of the wells produce 80% of the gas.
3. With detailed geoscience, engineering, and economic data, this estimate could be classified into Reserves (category 1P, 2P, and/or 3P) and Contingent Resources (category 1C, 2C, and/or 3C). The undiscovered gas can be classified as Prospective Resources (category low, best, and/or high).
4. Once a project satisfies the required commercial risk criteria, if the foreseeable future is within the suggested guideline of maximum 5 years, the associated Contingent Resources can be classified as Reserves.
5. Well spacing is smaller in TGFs, compared with conventional reservoirs. Generally, the smaller spacing is the result of infill drilling when commercial production has been established in offset wells but there are no indications of well-interference. A good example is the Jonah field in Wyoming that started at a 160-acre well spacing and is now down to less than 10 acres per well. The infill wells are an incremental project (or projects) that adds GIIP and reserves with time. By contrast, in conventional reservoirs, GIIP remains relatively constant with time and the 1P, 2P and 3P reserves tend to converge, with the 2P remaining approximately constant, the 3P decreasing, and the 1P increasing with time.

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8.5 Coalbed Methane

C.R. Clarkson and G.J. Barker

8.5.1 Introduction. Coal is defined as a "readily combustible rock containing more than 50% by weight and more than 70% by volume of carbonaceous material formed from compaction and induration of variously altered plant remains similar to those in peaty deposits" (Schopf 1956). Coalbed methane (CBM), variously referred to as natural gas from coal (NGC, Canada) or coalseam gas (CSG, Australia), is generated either from methanogenic bacteria or thermal cracking of the coal. Since much of the gas generated in coal can remain in the coal, primarily because of sorption of gas in the coal matrix, coal acts as both the source rock and the reservoir for its gas. Exploration for and exploitation of CBM resources requires knowledge of the unique coal-fluid storage and transport processes as well as special processes (well completions and operations) required to extract commercial quantities of gas.

8.5.2 Global Potential. CBM resources worldwide are immense, with estimates exceeding 9,000 Tscf (Jenkins and Boyer 2008). The primary producing countries include the US, Canada, and Australia. More than 40 countries have evaluated the potential of CBM. The US has the most mature production, with commercial production starting in the 1980s. US production of CBM in 2009 was approximately 1.9 Tscf.

8.5.3 CBM Characteristics. CBM reservoirs are generally naturally-fractured, and the majority of gas storage is by way of sorption because of the immense internal surface area provided by organic matter within the coal matrix. The transport of natural gas and water to the wellbore is dictated primarily by the natural-fracture system. The coal matrix has a very low permeability, and the mechanism of gas transport is generally considered to be due to diffusion (concentration-driven flow). Gas diffuses from the coal matrix into the natural fractures and moves under Darcy flow to the wellbore. The production profiles of CBM reservoirs are unique and are a function of a variety of reservoir and operational factors.

The primary mechanisms for gas storage in CBM reservoirs are: (1) adsorption upon internal surface area, primarily associated with organic matter, (2) conventional (free-gas) storage in natural fractures, (3) conventional storage in matrix porosity, and (4) solution in bitumen and formation water. Note that the term "sorption" is used here to encompass adsorption of gas on the internal surface area of coal and solvation of gas by liquid/solids in the coal matrix—when sorption isotherms are measured in the laboratory for establishing gas content, these mechanisms of storage are typically not distinguished. Generally, free-gas is negligible compared to sorbed gas storage and is usually ignored in CBM reservoirs because of low fracture-pore volumes and high water saturations. The exception is for some dry CBM reservoirs, in which free-gas storage

may be more significant (Bustin and Clarkson, 1999; Bustin and Bustin, 2009). Solution gas is also usually ignored.

Sorbed gas storage is by far the most important storage mechanism in most CBM reservoirs. High-rank coals have surface areas on the order of 100 to 300 m^2/g, whereas conventional reservoirs typically have surface areas < 1 m^2/g. Most of the gas-accessible surface area of the coal matrix is associated with organic matter whose pore structure is generally dominated by microporosity, which are pores that are < 2 nanometers in diameter (Sing et al. 1985). The controls on CBM-matrix pore structure include thermal maturity (rank), organic matter content, and coal composition (Bustin and Clarkson 1998). The immense ratio of surface area to volume in the coal matrix means that a large surface area is exposed to attract gas molecules through molecular forces (dispersion and electrostatic) that in turn cause adsorption to occur.

The adsorption of CBM-reservoir gases is thought to be primarily physical vs. chemical, meaning that molecular interaction is weak and reversible. Gas is stored in a near-liquid-like state, with a higher density than compressed gas at typical reservoir temperatures and pressures. The controls upon sorption, in addition to the organic matter pore structure, include: pressure, temperature (Levy et al. 1997), moisture (Joubert et al. 1973), thermal maturity (rank) (Levy et al. 1997), mineral matter content (grade) (Mavor 1996), organic matter composition (Clarkson and Bustin 1999), and gas composition (Hall et al. 1994). Sorption on coal is a nonlinear function of pressure and has been modeled using a variety of empirical and theoretical equations. By far the most commonly applied single-component and multicomponent gas adsorption model for coal is the Langmuir isotherm (Mavor 1996). The Langmuir equation can be used to estimate coal-gas content if the coalseams are saturated (i.e., the in-situ gas content is equal to the in-situ storage capacity), the reservoir pressure and gas composition are accurately known, the free-gas and solution-gas storage are negligible, and the average coal composition of the reservoir is known.

The primary mechanisms governing gas flow in coals include pressure-driven flow (modeled with some form of Darcy's law) through the fractures and concentration-driven flow (modeled with some form of Fick's law) through the coal matrix. Gas and water flow to the wellbore through a well-defined natural-fracture system called "cleats." Cleats generally exist as an orthogonal set; that is, they are perpendicular to each other and also perpendicular (or nearly so) to the bedding planes. The "face" cleat is better developed and more continuous than the "butt" cleat, which terminates into the face cleat. Other, subordinate ("tertiary") fractures may also occur (Mavor 1996).

Flow in the fractures is often modeled using some form of Darcy's law, modified in some instances to account for two-phase flow (gas + water) and non-Darcy flow effects. Note that if coals are undersaturated (i.e., the in-situ gas content is less than the in-situ storage capacity), they will need to be dewatered before gas saturation develops in the fractures. In this case, single-phase flow of water will occur through the fractures until the critical desorption pressure is reached. If the coals are saturated (in-situ gas content = sorbed gas content), then two-phase flow of gas will occur from the start of production. Absolute permeability in coal is highly dependent upon the existence, frequency, orientation (relative to current in-situ stresses), height, and degree of mineral in-filling in the natural-fracture set (Laubach et al. 1998). A common model for describing cleat porosity and permeability in coal is the matchstick model (Seidle 1992). The permeability is extremely sensitive to fracture aperture, with which it has a cubic relationship. Any process acting to modify the cleat aperture will have a strong effect on absolute permeability.

In coal reservoirs, two physical processes will act to change the physical dimension of the fracture apertures: (1) changes in effective stress and (2) matrix shrinkage. Note that fines migration may also act to reduce fracture apertures. With Process 1, because the fracture pore volume is highly compressible with pore volume compressibilities typically on the order of 10^{-4} psi^{-1}, increases in effective stress because of pore-pressure depletion can cause the fracture apertures to decrease in width, which in turn causes a reduction in absolute permeability. In some coal reservoirs, Process 2 will cause the absolute permeability to increase with depletion, because the coal matrix will shrink during desorption, causing an increase in fracture apertures.

Several analytical models (Palmer 2009) have been developed that predict permeability changes as a function of (1) effective stress and (2) matrix shrinkage/swelling. Other important controls on fluid flow through the fracture system include relative permeability effects (changes in effective permeability to gas and water during dewatering), reservoir pressure, pressure drawdown, and fluid properties. For some CBM reservoirs, gas properties will change during depletion not only because of changes in reservoir pressure, but also as a result of gas composition changes caused by adsorption behavior. For example, in the Fruitland coal fairway of the San Juan basin, the initial gas composition contained a significant amount of CO_2 (10 mol% or more in some areas), which has increased during reservoir depletion to greater than 20%. This occurs because coal has a greater affinity for CO_2 than methane, so it gives up CO_2 in greater amounts as the reservoir is depleted.

The coal matrix provides a source of gas to the fractures. If the fracture density is great enough, and/or the diffusion coefficient is large enough, the matrix may be assumed to be in equilibrium with the fractures and desorption may be modeled as an instantaneous release of gas to the fractures. Also, assuming that the pressure in the fracture system dictates the sorbed gas content in the matrix, an equilibrium sorption isotherm equation, such as the Langmuir equation, can be used to model the matrix desorption.

In cases where the fractures are more widely spaced and/or the diffusion coefficient is small, then desorption from the matrix to the fractures is not instantaneous, and may need to be modeled using either a pseudo steady-state formulation (using an average gas concentration in the coal matrix that is not equal to that at the fracture face) or a nonsteady-state formulation, in which concentration gradients in the matrix are modeled. In either case, some form of Fick's law for concentration-driven flow (diffusion) is used to model matrix transport.

Because of the unique storage and transport mechanisms associated with CBM reservoirs, CBM wells can exhibit unusual gas-production profiles. The production characteristics of a CBM well exhibiting two-phase flow are illustrated using an example from the San Juan basin **(Fig. 8.2).**

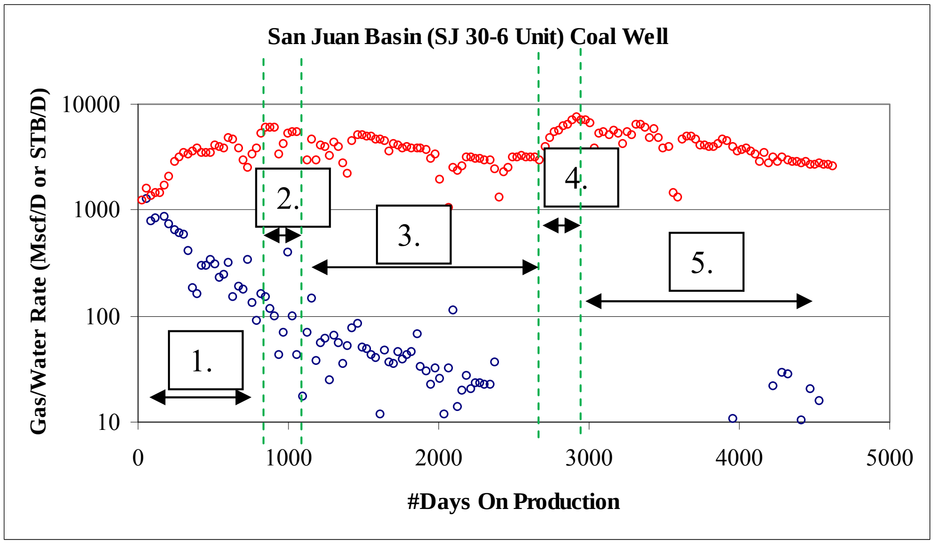

Fig. 8.2—Production profile for CBM well (Fruitland coal) in the San Juan basin. Red markers indicate gas production, blue markers represent water production.

In this example, during the early dewatering period (1), gas production inclines primarily as the result of an increase in the effective permeability to gas. Flowing pressures are also rapidly decreasing during this period, which is referred to as the "negative decline" period. Once the well has contacted no-flow boundaries (in this case, probably created by offsetting wells), the well reaches a peak rate (2) and starts to exhibit a normal decline (3). Note that conventional decline curves cannot be fit to this dataset until several months after peak production is reached (> 1,000 days after first production). A disturbance in the well-production profile occurs at around 2,700 days because of a rapid lowering of backpressure associated with the installation of compression (possibly coupled with restimulation). This rapid backpressure decrease causes an additional change in effective permeability to gas caused by an alteration of near-wellbore water saturation and, possibly, absolute permeability (caused by matrix-shrinkage effects). These changes result in a short negative-decline period (4). Lastly, a terminal-decline period occurs (5) when, once again, a decline curve may be fit to the data.

Some dry coal wells, such as those in the Horseshoe Canyon play in Alberta, exhibit a more conventional decline profile, analogous to shallow gas wells. In the Fruitland coal of the San Juan basin, wells only a few miles from each other may exhibit production characteristics that are drastically different. Care must, therefore, be taken in the selection of analog reservoirs and wells for reserves estimation.

8.5.4 Exploration and Development Considerations. Play- and prospect-analysis tools developed for conventional reservoirs are not directly applicable to CBM or shale reservoirs (Haskett and Brown 2005; Clarkson and McGovern 2005). The variability of key CBM-reservoir properties from basin-to-basin and even field-to-field necessitates a more stochastic approach to CBM exploration. Failure to reach commercial CBM production is often related to lack of permeability, resulting in subeconomic rates. Sweet spots can occur in CBM plays due to enhanced natural fracturing and 3D-seismic techniques are currently being adapted to identify these enhanced permeability areas (Hyland et al. 2010).

For CBM exploration and appraisal, a key step is the design of the pilot program (Roadifer, 2009). Uncertainties associated with production forecasting include relative permeability, absolute permeability, and the effect of stress and desorption on permeability during depletion, permeability anisotropy, and multilayer effects. It is for these reasons that pilots are needed particularly for undersaturated coal reservoirs, where interior wells are bounded by exterior wells to accelerate dewatering. The interior wells need to achieve significant (commercial) gas rates, and effective permeability to gas must be established before reserves bookings can be contemplated. The pilots need to be designed to reduce the uncertainty in key reservoir parameters and to test various completion/drilling technologies to determine which are most cost-effective.

The unique CBM properties also impact later-stage development planning. The two-phase flow nature of most CBM plays means that well spacing, well geometry and well orientation should be designed to accelerate dewatering, which will, in turn, increase effective permeability to gas, initiate gas production, and reduce the time to peak gas production. Care must be taken, however, not to overdrill or overdevelop, leading to pure acceleration with infill drilling. Critical data gathered during the exploration phase, such as gas contents, isotherm data, pressures (flowing and shut-in) and effective/absolute permeability data must continue to be collected during early and sometimes mature stages of development because of the heterogeneity (vertical and lateral) of CBM plays. Collection of these key data is necessary to informed development and business decisions.

Surface operations must also be planned carefully to account for production behavior. Facilities must be designed to dewater coal wells (artificial lift) and to gather, transport (trucking or water-gathering system), and treat (subsurface or surface disposal) large amounts of water, particularly in the early life of a field. Compression must be considered to assist with early dewatering and to optimize well performance. Additionally, because of the potential for evolving gas compositions during depletion, facilities may be needed to scrub nonhydrocarbon gases (such as carbon dioxide) to meet market specifications.

8.5.5 Commercial Issues. A primary consideration for commerciality is the resource size, related to the thickness and gas content of the coals. Depth of the coal is an important factor affecting both gas content (through pressure and temperature) and absolute permeability, which generally decreases with depth due to the stress-sensitivity of the coal fracture apertures. Commercial production of CBM is generally limited to depths < 4,000 ft for this reason. Factors affecting the timing of first significant gas production (above the economic limit rate in order to pay out operating costs)—such as degree of undersaturation—will impact commerciality. Commerciality will also be affected by factors controlling time to peak production and peak gas rate, such as effective permeability to gas, which changes with saturation and reservoir pressure.

In CBM projects, it is important that (1) infrastructure is sufficient to gather and dispose of high initial-water volumes; (2) sufficient compression is installed to improve CBM recovery and

assist with well dewatering; (3) artificial lift is planned for and included in operating costs; (4) facilities are designed to scrub nonhydrocarbon gas from produced gas to meet market specification (where applicable); and (5) regulatory concerns are addressed.

8.5.6 Unique Assessment Methods/Issues. Methods for the assessment of CBM resource/reserves have been adapted largely from techniques developed for conventional reservoirs. Four general methods are applied:

- Volumetric
- Material balance
- Production data analysis (PDA)
- Reservoir simulation

The appropriate application of these methods depends on the phase of development of the CBM reservoir. Although both volumetric and simulation methods can be applied at all stages of development, their accuracy will improve with increased data availability. Material balance, decline curve, and PDA methods can only be applied after a significant amount of production, flowing pressure, and shut-in pressure data become available.

Volumetrics. Volumetric estimates of CBM reserves is the simplest method, as well as the most potentially error prone, because of the uncertainty in basic parameters such as recovery efficiency and parameters in the total gas initially in-place (TGIIP) calculation [such as bulk volume of the reservoir (*Ah*), and in-situ gas content]. Estimated ultimate recovery (EUR) may be obtained from TGIIP simply by multiplying TGIIP by recovery efficiency (*Rf*). The most commonly used form of the GIIP equation for coal is (Zuber 1996)

$$G_i = Ah\left(\frac{43560\phi_f\left(1-S_{wi}\right)}{B_{gi}} + 1.3597\overline{\rho}_c\overline{G}_c\right) \quad \text{..........}(8.1)$$

where

G_i = GIIP, Mscf

A = reservoir area, acres

h = reservoir thickness, ft

ϕ_f = natural-fracture porosity, dimensionless, fraction

S_{wi} = initial water saturation in the natural fractures, dimensionless, fraction

B_{gi} = initial gas formation volume factor, Rcf/Mscf

1.3597 = conversion factor

$\overline{\rho}_c$ = average in-situ coal-bulk density corresponding to the average in-situ coal composition, g/cm^3

$\overline{G}_c$ = average in-situ coal-gas content corresponding to the average in-situ coal composition, scf/ton.

The primary modification to the conventional GIIP equation has been the inclusion of adsorbed gas content, which requires specialized field- and lab-based techniques to ascertain. Adsorbed gas cannot be directly detected in-situ using current petrophysical methods. Recently (Lamarre and Pope 2007), however, a downhole technique based upon Raman spectroscopy was introduced that may hold promise for gas-in-place determination, if certain rigid conditions are met. Raman spectroscopy can be used to measure gas in solution (produced water) from which the partial pressure of methane is obtained. If it can be assumed that the partial pressure of methane in the coal is equivalent to gas in solution, and if a representative coal isotherm is

available, the gas content of the coal can be determined (Lamarre and Pope 2007). Carlson (2006) introduced a technique to establish the critical desorption pressure (CDP) of undersaturated coals through estimation of bubble point pressure of the water, which they demonstrate to be equal to CDP.

In the derivation of Eq. 8.1, it is assumed that only gas sorbed in the coal matrix and free-gas stored in the natural-fracture system are contributing to the gas-in-place. In general, the sorbed gas content within the coal matrix is the dominant contribution to gas-in-place, and free-gas storage in both the matrix and the fractures is generally considered to be negligible.

It is very difficult to obtain an accurate value for coal-gas content ($\overline{G}_c$), mainly because of the heterogeneity of the coal and the difficulty in the use of well-logging to infer gas content. Fortunately, the Gas Research Institute (GRI) has published excellent guidelines (e.g., McLennan et al. 1995) on the proper assessment of in-situ gas content. Recent advances have been discussed by Clarkson and Bustin (2010).

Both inorganic and organic fractions of coal affect coal density ($\overline{\rho}_c$). Coal seam bulk densities are related to the volume fraction of each of these components. Because coal contains more than 70 vol% (50 wt%) of organic matter by definition, it is easy to detect coals using openhole density logs. Historically, an upper limit of 1.75 g/cm^3 has been used as a cutoff in the identification of coal on the density log, believed to be in part related to the above definition of coal. However, as pointed out by Mavor and Nelson (1997), using this definition may exclude the contribution of other organic-rich materials (i.e., carbonaceous shales) from the total gross-thickness calculation. One approach to include them is to establish the coal bulk-density upper limit at zero adsorbed gas content. Using this approach for Fruitland coal samples, the upper density limit obtained was consistent with those cited by Mavor and Nelson (1997) (2.1 to 2.5 g/cm^3).

The reservoir thickness (h) is intended to be coal thickness, after a density cutoff has been applied. For each coal reservoir, this may be best estimated using a density cutoff corresponding to zero adsorbed gas content. In the absence of quality density log data, other wireline logs may be used to estimate coal thickness. Neutron-porosity logs, which can be run in cased hole, may be used because coals generally have neutron porosities of > 40%. Gamma ray logs must be used in parallel with other logs, because although gamma ray responses in coal are generally low, this depends on the uranium content of the coal.

The reservoir area (A) may correspond to artificial or natural boundaries at the well, field, play, or basin scale. Artificial boundaries include ownership, survey limits, or well interference (Mavor 1996). Natural boundaries include coal pinchouts, faults, permeability changes, lateral facies changes, and other geologic variability. Individual coal seams are so thin, it is often difficult to resolve them and identify their boundaries with 3D seismic. Well-production-data analysis, material-balance calculations, and simulation history matching may be used to infer drainage volumes, which, when combined with volumetric information, can be used to estimate drainage areas.

In Eq. 8.1, the porosity term refers to natural fracture porosity (ϕ_f), which is difficult to determine quantitatively from core analysis as discussed by Mavor (1996). Initial water saturation in the fracture system (S_{wi}) is similarly difficult to ascertain from core techniques and is commonly assumed to be 100%. In most commercial CBM reservoirs, fracture porosity (generally < 1%) tends to contribute little to the total gas storage, and some error in the estimate will, therefore, not have a material impact on estimates of GIIP. However, given that this porosity is initially filled with water, the practical aspect of having 2% fracture porosity instead

of 1% fracture porosity is that twice as much water will have to be moved to dewater the reservoir.

There are several approaches to estimating R_f (Zuber 1996):

1. Adsorbed gas content calculated at initial (desorption pressure) and abandonment conditions using the adsorption isotherm
2. Analogy
3. Reservoir simulation

Material Balance. A number of material-balance equations have been developed that include adsorbed gas storage (King 1993; Jenson and Smith 1997; Seidle 1999; Clarkson and McGovern 2001; Ahmed et al. 2006), but the degree of complexity of the equations increases as free-gas (or compressed-gas) storage, water and pore volume compressibility, and water production and encroachment are accounted for. The method developed by King (1993) remains the most rigorous, although the equations may be difficult to apply in practice because of the need for iterative calculations. Since 1997, starting with Jensen and Smith's (1997) work, approximations have been developed that ease the use of material balance for CBM reservoirs, without necessarily sacrificing significant accuracy.

Production Data Analysis. The most abundant data collected for CBM reservoirs is gas- and/or water-production data, so it is logical to maximize the use of these data for reserves estimates. Advanced production-data-analysis methods (i.e., production type curves and flowing material balance) have similarly been adapted to include adsorbed gas storage, and very recently have been modified to include more-complex CBM-reservoir behavior, such as two-phase flow (gas + water), nonstatic absolute permeability (caused by effective stress changes or matrix shrinkage), and multilayer effects (Clarkson et al. 2007; Clarkson et al. 2008; Clarkson 2009; Clarkson et al. 2009). Maturing CBM fields and recent simulation studies have provided some guidelines for the appropriate use of empirical production-analysis techniques such as Arps decline curves for dewatered or dry CBM reservoirs. A comprehensive study by Rushing et al. (2008) used constant flowing pressure numerical simulation to investigate the impact of many CBM reservoir properties on decline characteristics.

Reservoir Simulation. Reservoir simulation includes the use of analytical and numerical flow models that are "calibrated" by history-matching, well production, and flowing and static (shut-in) pressures, and are then used to forecast single or multiwell production under a variety of operational and development scenarios. A variety of commercial simulators now exist for analyzing CBM-reservoir behavior, including many aspects of the storage and transport mechanisms unique to CBM. Reservoir simulation may be performed at the single- or multiwell level. In either case, for reserves-booking purposes, reservoir simulators must be properly calibrated to existing well performance using proper constraints on static and dynamic data.

8.5.7 Classification and Reporting Issues (Barker 2008). The current practices to classify CBM resources often use an incremental approach to delineation and development, similar to that used in the mining industry and the "well spacing" concepts traditionally applied in the petroleum sector. The basis for this approach is that uncertainty increases as the distance to known well control increases resulting in a progression from Proved to Probable to Possible Reserves. Under these concepts, all the Developed reserves are Proved and Undeveloped reserves may be Proved, Probable or Possible. However, there may be no explicit evaluation of the range of uncertainty in recovery efficiency for a project. Consequently, CBM projects often see large reserves growth provided that the overall area is prospective and there is a tendency to grow reserves toward a 3P value.

This approach can result in a significantly different reserves maturation profile over time than that experienced in the conventional petroleum industry where the reserves are based on uncertainty in recovery for the applied project and are expected to trend towards the 2P value. Moreover, it is important that a direct link between the applied project and the resource estimate is maintained to ensure compliance with the project-based principles of the PRMS. The following summarizes the current practices in defining the resource areas:

Contingent Resources. Demonstrated by drilling, testing, sampling and/or logging hydrocarbon gas content (e.g., coal sample or gas flow) and coal thickness sufficient to establish the existence of a significant quantity of potentially moveable hydrocarbons (i.e., there should be data indicating sufficient permeability for flow within the coal seam). Gas rates may be undemonstrated or uneconomic, gas composition may or may not support marketability, significant distance from existing well locations that have demonstrated commercial potential, outside coal fairway or acceptable depth limits (typically 200 to 1000 m) may require as yet unproven well technology, (e.g., untried stimulation techniques or horizontal/multilateral wells), outside areas that can be accessed legally (e.g., protected land), development plan immature or subeconomic, market not assured, lack of approvals.

Reserves. Demonstrated commercial production potential (pilot test), marketable gas composition and commercial gas content and thickness (coal sample, gas sample), depth within accepted economic limits within coal fairway (e.g., 200 to 1000 m depending on the area), development plan feasible, economically viable, market exists, firm commitment to develop within a reasonable time frame, approvals existing or imminent.

Proved Developed. Applies to the nominal drainage area for producing or nonproducing wells that are proven to have commercial quantities of recoverable gas. Well spacings will vary depending on the region. Typical drainage areas per well are reported to be 80 to 320 acres (Jenkins and Boyer 2008) and up to 550 acres in the Fairview/Spring Gully fields, Bowen Basin, Australia (King, June 2008).

Proved Undeveloped. Well spacing rules—distance from Proved Developed location (typically 1 spacing, in some instances this may be increased to 2 well spacings if the permeability is high and regional experience justifies good lateral continuity of the coals).

Probable. Well spacing rules—distance from Proved location (typically 2 well spacings, but this may be extended to greater distances between Proved areas if coal geology, coal quality, and local experience permits).

Possible. Well spacing rules—distance from Probable location (typically 2 well spacings, may be extended to greater distances if coal geology, coal quality, and local experience permits or constrained by geological/geographical limits).

The current conventions are also illustrated diagrammatically in **Fig. 8.3**. The 200 m and 1000 m depth contours are shown, which for this example are intended to represent the vertical limits of anticipated commercial production. These rules of thumb may be modified by experience or additional data (e.g., pressure data from observation wells, which supports continuity over distances and larger well drainage areas).

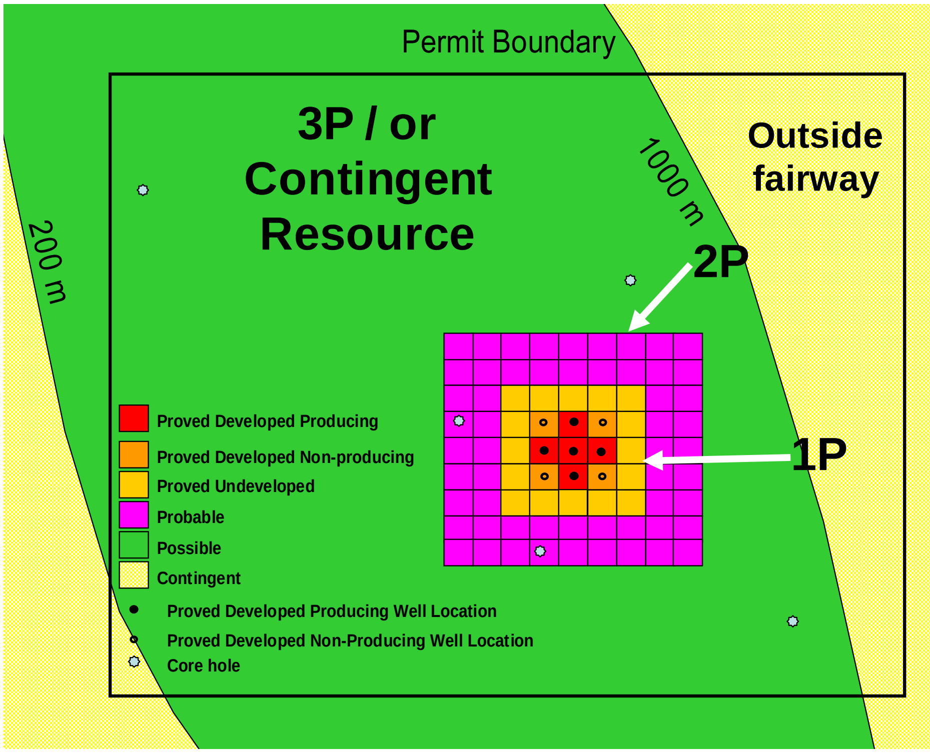

Fig. 8.3—Conceptual 1P 2P and 3P Areas used in the CBM Industry (Barker 2008).

Comments on Current Practice. The current practices have several implications. In the initial period of appraisal or development, substantial 2P reserves growth is often seen because the full resource potential may not have been captured and/or disclosed. This is understandable since coal properties can vary substantially over short distances and sufficient data needs to be gathered to develop confidence in the recovery estimates away from known data. Area is used as the main variable in recoverable volume uncertainty. The rate of conversion to 1P reserves implies that what is termed 2P and 3P must have much higher confidence levels than one would expect compared to conventional reserves estimates. Some practitioners will have sufficient confidence in the geological and engineering data to "bracket" areas together and so accelerate this conversion.

In the absence of any further modifying information, using the typical well spacing conventions, each Proved Developed well can "prove up" a further 8 Proved Undeveloped and 40 Probable locations[8]. The full area can be categorized as 2P reserves if 1/49 (approximately 2%) of the total planned wells were to be successfully drilled and placed on production at commercial rates. This is premised on establishing that this well group is located in the coal fairway in terms of laterally continuous coal thickness and sufficient gas content and permeability.

[8] A practice called "bracketing" or "rubber-banding" is also used with this method that enables areas larger than that associated with the well spacing conventions to be categorised in a higher confidence resource class and/or category. For example, Probable areas located adjacent to or between Proved areas may be deemed Proved if, based on the judgment of the evaluator, there is sufficient certainty in reservoir continuity and coal properties. Similarly, Possible areas located adjacent to or between Probable areas may be deemed Probable, and the same principles can apply to Contingent Resource areas.

The full area can be categorized as 1P Reserves after drilling 1/9 (i.e., 11%) of the planned development wells assuming an even spacing. At this point, all the original Probable and Possible Reserves have been converted into Proved Reserves. This implies that there is very little uncertainty in the estimate of recovery, which given the nature of CBM, is unlikely for projects of any reasonable scale. As a result, the reserves tend to approach the 3P estimate over time and as wells get drilled. It is also not unusual to see growth in the 3P component as Contingent and Prospective Resources are converted to Reserves.

The booking of CBM reserves based on the traditional incremental "well spacing" approach has advantages in that it is a predictable rules-based system, but the following issues should be considered in its application:

- It is typically based on a "best estimate" outcome for wells in all reserves category and relies primarily on area to provide a range of uncertainty in the outcome.
- The defined project applied will need to include development and appraisal of the Probable and Possible areas to define the ultimate project limits for Reserves to be claimed over these areas. The definition of the project required to develop the 1P, 2P, or 3P scenario may have a vastly different scale of investment and market requirements, which has implications for project approvals and the potential exists for noncompliance with the project-based principles within PRMS. If Reserves are claimed, they must have the necessary degree of operator commitment.
- The approach may not clearly separate risk (i.e., the likelihood of commercial production being realized from a given project) and uncertainty (i.e., the uncertainty in the amounts that will actually be recovered from the applied project).

Application of the PRMS using an uncertainty-based cumulative approach could provide a better indication of the risks associated with successive expansion projects proceeding and the uncertainty associated with the recovery of each project. Another advantage of approaching the problem in this fashion is that the uncertainty analysis lends itself to probabilistic assessment should this be required, which may yield additional insight.

Each project will have special circumstances and data availability with regards to technical merits of the project, maturity of the management approvals, marketing certainty, etc., that will guide the classifications and volume assignments.

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8.6 Shale Gas

Creties Jenkins

8.6.1 Introduction. Shale gas is produced from organic-rich mudrocks, which serve as a source, trap, and reservoir for the gas. Shales have very low matrix permeabilities (hundreds of nanodarcies), requiring either natural fractures and/or hydraulic-fracture stimulation to produce

the gas at economic rates. Shales have diverse reservoir properties, and a wide array of drilling, completion, and development practices are being applied to exploit them. As a result, the process of estimating resources and reserves in shales needs to consider many different factors and remain flexible as our understanding evolves.

8.6.2 Resource Potential. The Potential Shale Gas Committee (Potential Gas Agency 2008) estimates that there are 616 Tscf of technically recoverable shale gas resources in the US. An estimate by the INGAA Foundation (Vidas and Hugman 2008) places recoverable shale gas resources at 385 Tscf for the US and 131 Tscf for Canada. A study in 2001 (Kawata and Fujita 2001) estimated that the total initially-in-place shale gas resource base for the world is 16,103 Tscf. Shale gas currently represents nearly 10% of total US gas production and has been growing rapidly over the past few years. This has fueled work to find and develop similar reservoirs around the world.

8.6.3 Reservoir Characteristics. Shales are complex rocks that exhibit submillimeter-scale changes in mineralogy, grain size, pore structure, and fracturing. In thermogenic shale gas reservoirs (like the Barnett shale), the organic matter has been sufficiently cooked to generate gas, which is held in the pore space and sorbed to the organic matter. In biogenic shale gas reservoirs (like the Antrim shale) the organic matter has not been buried deep enough to generate hydrocarbons. Instead, bacteria that has been carried into the rock by water has generated biogenic gas that is sorbed to the organics. TOC (Total Organic Content) values are high in biogenic shales (often > 10 wt%), but relatively low (> 2 wt%) in thermogenic shales where most of the TOC has been converted to hydrocarbons.

A common feature of productive thermogenic shale gas plays is brittle reservoir rock containing significant amounts of silica or carbonate and “healed” natural fractures. Relative to more clay-rich rock, the brittle rock shatters when hydraulically fracture stimulated, which maximizes the contact area. Thermogenic shales are often referred to as “fracturable” shales instead of “fractured” shales. In contrast, biogenic shales are commonly less brittle and rely on the existence of open natural fractures to provide conduits for water and gas production. A comprehensive suite of data are needed to fully characterize shale gas reservoirs in terms of their geochemistry, geology, geomechanics, fluid properties, fracture characteristics, and well performance. **Table 8.1** summarizes these data.

TABLE 8.1—DATA NEEDED TO FULLY CHARACTERIZE SHALE GAS RESERVOIRS	
Data	**Usage**
TOC	Provides an indication of source-rock richness and sorption capacity.
Gas content	Includes the volumes of desorbed, lost, and residual gas obtained from the desorption of core. It is an indicator of the in-situ sorbed gas content.
Sorption isotherm	A relationship, at constant temperature, describing the volume of gas that can be sorbed to a shale as a function of pressure.
Gas composition	Used to quantify the percentage of methane, carbon dioxide, nitrogen, ethane, etc. in the desorbed gas. Used to build composite sorption isotherms.
Rock-eval pyrolysis	Assesses the petroleum-generative potential and thermal maturity of organic matter in a shale sample.
Mineralogical analyses	Determines bulk and clay mineralogy using petrography, X-ray diffraction, scanning electron microscopy, and similar techniques.
Vitrinite reflectance	A value indicating the amount of incident light reflected by the vitrinite maceral. It is a fast and inexpensive means of determining thermal maturity.
Core description	Visually captures lithology, bedding, fracturing, grain size variations, etc.
3D seismic	Used to determine interwell shale properties including lateral extent, thickness, faulting, and those areas with higher gas saturation and brittleness.
Kerogen types	Used to assess whether rocks are Type I (oil-prone), II (mixed), or III (coal).
Routine core analysis	Includes total porosity, fluid saturations, bulk density, and matrix permeability (via pressure pulse testing on crushed samples).
Conventional logs	SP, GR, resistivity, microlog, caliper, density, neutron, sonic, and temperature logs are run to provide thickness, porosity, matrix, and sorbed gas saturations.
Special logs	May include image logs (fractures), NMR logs (free water, bound water, gas saturation), pulsed neutron and geochemical tools (mineralogy), dipole sonic (geomechanical properties), spectral GR (clay types), etc.
Pressure-transient tests	Pressure buildup or injection fall-off tests to determine static reservoir pressure, permeability, skin factor, and to detect fractured-reservoir behavior.
Geomechanical properties	Young's modulus and Poisson's ratio for determining shale brittleness, stress orientations and magnitudes to predict fracture growth.
Microseismic	Used to assess hydraulic fracture geometries and stimulated reservoir volumes.
Fracture diagnostics	Treating pressures, closure stress, pumped volumes, flowback volumes, etc. to determine the quality of a fracture stimulation.
Gas, water rates	Captured daily (preferably) to assess individual well behavior.
Bottomhole pressures	Preferably recorded in closely-spaced increments (every 10 min) early in well life; can also use surface pressures with wellbore-fluid gradients.
Tracer surveys	Chemical or radioactive tracers to assess which fracture stages are contributing.
Facilities	Variations in line pressure, etc., that affect producing well rates.
Rate-transient analysis	Decline analysis tool that analyzes production rates and pressures using various methods to assess EUR, GIP, drainage area, etc.
Numerical modeling	Helpful in understanding reservoir mechanisms, predicting early well behavior, and estimating EURs and recovery factors.
Decline-curve analysis	Traditionally used to forecast well performance. More reliable later in well life (after a few years) due to uncertainties regarding *b*-factor values.
Analogs	May be useful to estimate EURs and recovery factors if a strong correlation exists between key reservoir parameters of subject and analog reservoir.

8.6.4 Well Performance. Wells have produced gas from shales since the 1820s, and many studies have been carried out over the past 30 years to understand and predict their performance. Thermogenic shale gas reservoirs exhibit steep initial declines of 30 to 80% or more in the first year, followed by a flattening characterized by a decline exponent (*b*-factor) greater than 1.0.

This decline behavior is evidence that wells are in transient flow. This may persist for many years depending upon well spacing and permeability. Because the permeability is so low in these reservoirs, it may be tens of years before pressures begin to decrease substantially away from hydraulic fractures. As a result, even though up to half the gas initially-in-place in thermogenic shale gas reservoirs may be sorbed gas, only a small fraction of this gas will be produced over the life of the well.

Thermogenic shale gas reservoirs are generally found at depths greater than 3,000 ft, and production is dominated by dry gas held in the pores of the shales. Initial gas rates for fracture-stimulated horizontal wells are typically greater than 1 MMcf/D with corresponding EURs of more than 1 Bcf. Shales that are thermally immature (in the oil or wet-gas window) generally have lower IPs and EURs due to relative permeability effects and the difficulties related to moving liquids through the very small pore throats. Biogenic shale gas reservoirs tend to have significantly lower production rates and EURs than thermogenic shales because of their shallow depths, lower gas initially-in-place, and the need to dewater the fractures before producing the sorbed gas.

8.6.5 Drilling and Development. The most important factor behind the rapid expansion in shale gas development has been advances in drilling and completions technology. Most notable among these are the use of (1) horizontal drilling, (2) light-sand slickwater fracs, and (3) microseismic. The impact of these techniques on gas production has been dramatic. Fracture-stimulated horizontal wells in the Barnett are expected to produce about 3.8 times as much gas over their lifetime as fracture-stimulated vertical wells, based on a comparison of median well EURs (Frantz et al. 2005).

These drilling and completion techniques have been adapted and applied to multiple shale gas developments including Fayetteville, Woodford, Marcellus, and Haynesville. Lateral well lengths have increased along with the number of stimulation stages that are pumped. It is now common for laterals to be 5,000 ft long and contain 15 to 20 fracture stages, which substantially increases the contacted reservoir volume and accelerates drainage. Microseimic is used to monitor the stimulations to understand fracture geometries and estimate the stimulated reservoir volume.

Laterals are drilled parallel to each other and oriented perpendicular to the maximum compressive stress. Typical patterns in a section (640 acres) range from 4 wells (160-acre spacing) to 8 wells (80-acre spacing) with some pilot projects containing wells spaced at 40 acres. The choice of well spacing depends on multiple factors including gas-in-place, permeability, and the volume of rock contacted by hydraulic fractures. Laterals are commonly landed in the most brittle intervals of the shale to more easily initiate fractures and more intensely fracture-stimulate the rock. Care is taken to avoid structural complexities including faults with significant displacement and vertically adjacent water-productive units.

8.6.6 Commercial Issues. The greatest successes in shale gas development are realized by companies that acquire large acreage positions at low cost in locations that eventually become the core area of a shale gas play. Work begins by assessing the available data and establishing a lease position in a prospective area. This is followed by the drilling of numerous appraisal wells and pilot projects, at a total cost that often exceeds USD 100 million, to assess whether shale gas development will be commercial. Once this is demonstrated, a viable play requires billions of additional dollars to drill and complete hundreds of development wells. The cost for these can range from USD 2 to 3 million for a well in the Barnett shale to more than USD 8 million for a well in the Haynesville shale.

Because the development of any new shale gas play requires climbing up the learning curve, it is likely that the earliest wells will deliver some of the poorest results. As a result, well economics may be marginal until technological innovation, increases in operational efficiency, and economies-of-scale increase production rates and drive down costs. Gas prices also play a critical role because low prices not only reduce revenue but also reduce available capital, which slows the pace of development and further diminishes the present value of the project.

Wells in thermogenic shale gas reservoirs produce at very high initial rates and decline rapidly. This is due to multiple factors, including a reduction in reservoir pressure near the wellbore, a reduction in permeability as pore pressure decreases, and reductions in fracture conductivity resulting from proppant crushing, proppant embedment, and fines migration. Because many wells produce more than half of their total gas within the first two years, drilling must expand continuously to increase the field gas rate. In shale gas reservoirs dominated by sorbed gas, such as the Antrim shale, production may be delayed because of dewatering and more closely-spaced wells may be needed to accelerate this process.

In the early years of development it may not be possible to gather sufficient data to understand well spacing, drainage areas, and interference issues because wells are drilled at a wide spacing (often one well per section) just to hold acreage. As infill drilling proceeds, these issues can be addressed, and it may be advisable to restimulate or redrill early wells using what has been learned during the initial phase of development.

Initial gas rates and EURs for shale gas wells are highly variable and difficult to predict, with values often varying by one to two orders-of-magnitude across any given area. Because of the log-normal distribution of individual well EURs, the top 5% of wells drilled are critical to the overall economic success of any project. The goal is to understand what makes these wells so successful and to replicate this in succeeding wells.

8.6.7 Classification of Shale Gas Prospective and Contingent Resources. Shale gas resources may be estimated deterministically or probabilistically, with best practice being to use both methods. Prior to discovery, these techniques can be used to generate low, best, and high estimates of prospective gas resources, which are commonly risked by a chance of discovery (Pg) and a chance of commerciality (Pc). The difference between the low and high estimates will likely be very large, reflecting the uncertainty in both gas-in-place volumes and recovery factors. Data available for this task could include 2D seismic data and information such as logs, cuttings, mudlogs, and/or cores from wells that passed through the shale on the way to deeper horizons.

Prospective Resources can become Contingent Resources once a well is drilled and a discovery is made. According to PRMS, a discovery requires that the collected data establish the existence of a significant quantity of potentially moveable hydrocarbons. This definition reflects the expansive nature of PRMS, whereby accumulations such as tar sands may be discovered without flowing oil to the surface. For shales, there are several criteria that should be considered before an accumulation is declared to be "discovered." The first is a well test, which may require fracture stimulation that produces enough gas to the surface to be of commercial interest. The second is core and log data that provide convincing evidence of a significant volume of moveable hydrocarbons. The third is identification of a commercially-productive analog with sufficient similarity to the subject reservoir to conclude that it should be able to produce gas at comparable rates and recoveries. It is the combined weight of these three criteria that is important, which means, for example, if the gas flow rate is thousands of cubic feet per day, then the evidence from core, logs, and analogs needs to be more compelling than if the gas flow rate is millions of cubic feet per day.

Once the discovery is made, the next decision is whether a project can be defined using existing technology or technology under development (see Section 2.3). If not, then the accumulation should be classified as Discovered Unrecoverable Resources. Initially, Contingent Resources may be placed in the "economic status undetermined" category while wells are being drilled to evaluate the commercial potential of the play. Contingent Resources should only be assigned to this category while an ongoing evaluation is taking place. During this time, contingencies that impede production (such as poor reservoir properties or completions) and/or contingencies that impede development (such as low gas prices or insufficient capital) may be recognized. If it is clear that these cannot be overcome, the resources need to be assigned to the Unrecoverable or Not Viable subclass.

After a sufficient number of wells have been drilled to demonstrate that the project is technically feasible and a development plan has been generated, economics can be run to determine whether the project should be placed in the marginal or submarginal Contingent Resources category. Because projects at this stage have a chance of failure, evaluators can express the degree of commercial risk by describing the specific contingencies, quantifying the chance of commerciality, and/or assigning an appropriate Project Maturity subclass (see Section 2.5). Once the gas has been shown to be commercially recoverable under defined conditions for a given project, and there is a commitment to proceed with development, shale gas Contingent Resources can be classified as Reserves.

Since shale gas plays extend beyond the limits of conventional traps, the decision regarding how far away from existing well control Contingent Resources should be assigned can be difficult. Two guidelines that should be applied in this work are (1) information from seismic data showing that the shale is a continuous accumulation of similar character extending away from well control and is not cut by a sealing fault, and (2) indications that reservoir properties from wells that bound the Contingent Resources area are sufficiently similar to those of the discovery well that their well performance is expected to be similar.

8.6.8 Classification of Shale Gas Reserves. The most common way to assign Proved Reserves and Developed Producing Reserves in shale gas reservoirs is through the use of decline-curve analysis. Horizontal wells start out with a steep initial decline that eventually flattens, often after a year or more of production. This flattening continues until some terminal decline rate is attained (commonly less than 5 to greater than 10%), which is extrapolated to the economic limit. The shape of the decline curve often is based on comparisons of the subject well to similar wells either in the same shale gas reservoir or in analogous shale gas reservoirs.

A key drawback in the use of decline curves is the uncertainty associated with projecting well performance in early time. For example, in the Haynesville shale, a well that initially produces at a rate of 18 MMcf/D may decline to less than 3 MMcf/D after a year of production. Depending on how much the decline curve is projected to flatten beyond this first year, the *b*-factor can range from 0 (exponential) to 1.5 (super-harmonic), and the associated reserves can vary by a factor of two. In these circumstances, it may be reasonable to use a conservative decline to assign Proved Reserves, and less conservative declines to assign Developed Probable and Possible Reserves.

To help reduce the uncertainty associated with these early forecasts, rate-transient analysis and numerical modeling techniques can be applied. Both of these approaches require high-frequency rate and bottomhole-pressure data from producing wells, and detailed information about the hydraulic fracture stimulation. Other techniques, such as material balance, do not work very well because the permeability is so low that it is not possible to obtain accurate static

reservoir pressures. No matter which forecasting technique is used, it is good practice to compare the resulting EURs to the original gas in place volumes to ensure that the resulting recovery factors are reasonable.

The assignment of Proved Undeveloped Reserves to offset well locations requires reasonable certainty that these locations will be economically productive and that the reservoir is laterally continuous with the drilled Proved locations. Lateral continuity is generally not a problem, unless the shale is cut by a fault, but the large variability in individual well IPs and EURs can make the assignment of PUDs problematic at distances beyond one development spacing unit from a producing well. In general, if there is consistency in the initial rates and estimated ultimate recoveries of producing wells, then it seems reasonable to assign PUDs at a distance of two or perhaps three development spacings from these wells as long as these PUD locations are bounded by other PDP wells. If there are a large number of PDP wells (at least 50 to 100), then it may be possible to apply the statistical techniques described in SPEE Monograph 3 (2010) to assign PUDs to a much larger area between PDP wells.

Undeveloped Probable and Possible Reserves may be assigned to well locations beyond PUDs using type curves derived from producing wells. The choice of which type curve to use depends on a number of factors including area, permeability-thickness, lateral length, and completion effectiveness. In practice, it seems reasonable to assign Probable Reserves to 2 to 3 drilling locations beyond PUDs, and Possible Reserves to 2 to 3 drilling locations beyond the Probable Reserves area. However, in making these assignments, a number of factors need to be considered including (1) the amount of well control, (2) whether reserves are being assigned between existing wells or beyond existing wells, (3) whether the geological and petrophysical data indicate that reservoir properties are similar in the Proved, Probable, and Possible areas, and (4) whether discontinuities such as potentially sealing faults are present. For reporting purposes, according to PRMS, shale gas reserves can be statistically aggregated up to the field, property, or project level. Beyond this level, PRMS recommends using arithmetic summation by reserves category, which may result in very conservative Proved Reserves estimates and very optimistic 3P reserves estimates due to the portfolio effect. Operators should also be cautious in relying on aggregations if they are supported only by type curve approaches to forecasting individual wells.

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8.7 Oil Shale

John Etherington

8.7.1 Introduction. Oil shales are fine-grained sedimentary rocks (shale, siltstone, and marl) containing relatively large amounts of organic matter (known as "kerogen") from which significant amounts of shale oil and combustible gas can be extracted by destructive distillation.

The organic matter in oil shale is composed chiefly of carbon, hydrogen, oxygen, and small amounts of sulfur and nitrogen. It forms a complex macromolecular structure that is insoluble in common organic solvents (versus bitumen that is soluble). Because of its insolubility, the kerogen must be retorted at temperatures of about 500°C to convert it into oil and gas. Oil shale differs from coal in that the organic matter in coal has a lower atomic H:C ratio and the organic matter to mineral matter ratio of coal is much greater.

Global oil shale in-place resources are conservatively estimated at 2.8 trillion bbl. The largest known deposit is the Green River oil shale in the western US, with an estimated 1.5 trillion bbl of oil originally-in-place. Other important deposits include those of Australia, Brazil, China, Estonia, Jordan, and Morocco (World Energy Council 2007).

8.7.2 Production Methods and Assessment Issues. All current commercial extraction projects use surface mining techniques. Oil shales of Estonia are used directly as fuel for power generation and in cement plants. China and Brazil also have significant oil shale production. Brazil has developed the world's largest surface oil shale pyrolysis retort and 2009 production was about 3,600 BOPD.

Despite very significant research investments in the Colorado Piceance basin deposits since the 1970s, there is no current commercial production. Initial pilots were based on surface mining and associated retort facilities. Typical yields were < 1 bbl of hydrocarbon liquids per tonne of shale. Environmental issues include the disposal of large amounts of processed shale with associated contaminants and the potential contamination of groundwater.

Recent research has focused on the potential for in-situ conversion process using various methods to concentrate heat in the reservoir. The assessment techniques are similar to the mapping of facies and organic content as employed in shale gas assessments. Assuming that the current production/processing costs do not support economic projects under near-term product price forecasts, estimated recoverable volumes for identified deposits would be classified as Contingent Resources—Development Not Viable.

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8.8 Gas Hydrates

John Etherington

8.8.1 Introduction. Gas hydrates are naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cagelike structure,

or "clathrate." At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates form when gases, mainly biogenic methane produced by microbial breakdown of organic matter, combine with water at low temperature and high pressure.

8.8.2 Resource Potential. Because of its large gas-storage capacity, gas hydrates are thought to represent an important future source of natural gas. They bind immense amounts of methane within seafloor and Arctic sediments. The worldwide amount of methane in gas hydrates is considered to exceed 10,000 gigatonnes of carbon. This is about twice the amount of carbon held in all fossil fuels on earth. Other estimates are quoted as 700,000 Tscf (Collett et al. 1971) in-place. The Mackenzie River delta in northern Canada contains some of the most concentrated deposits. A number of other countries such as Russia, the US, India, Japan, and China also have substantial marine gas-hydrate deposits.

8.8.3 Production Methods and Assessment Issues. Theoretical production methods involve either depressurization or downhole heating, but the technology to support commercial production has yet to be developed. Research projects are underway using exploration seismic techniques, petrophysical assessment methods, and experimental production. Selected areas have mapped significant gas hydrate accumulations penetrated while targeting deeper conventional reservoirs. Such accumulations may be classified as Contingent Resources—Development Not Viable, or as Currently Unrecoverable in-place volumes.

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Chapter 9

Production Measurement and Operational Issues

Satinder Purewal

9.1 Introduction

An underlying principle within PRMS (SPE 2007) is that reserves and resource quantities will be reported in terms of the sales products in their condition as delivered from the applied development project at the custody transfer point. This is defined as the "reference point." The objective is to provide a clear linkage between estimates of subsurface quantities, measurements of the raw production, sales quantities, and the product price received. PRMS provides a series of guidelines to promote a consistent approach in all types of projects.

9.2 Background

The following discussion provides context for application of PRMS guidelines regarding the linkage of production measurement to resource estimates in both conventional and unconventional resource projects.

Fig. 9.1 illustrates typical oil and gas production with local or lease processing; the SPE historical guidance on measurement points was built around such a model with roots in small-scale onshore gas operations.

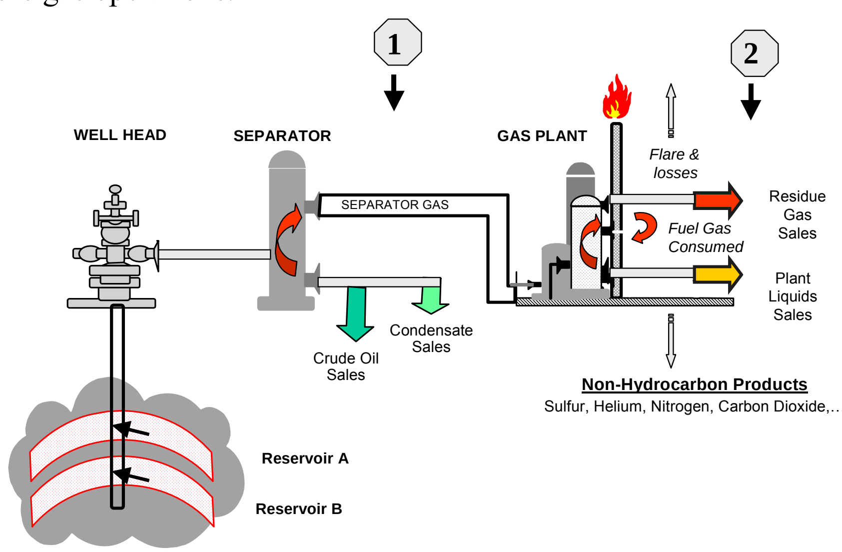

Figure 9.1—Reference points in a typical oil and gas operation.

A measurement reference point must be clearly defined for each project. It is typically the sales point or where custody transfer of the product occurs. For conventional oil and gas

operations, the measurement point can vary. In many operations, it is at the exit valve of the lease separator (Point 1 in Fig. 9.1). Where gas plants are involved as part of an integrated project, the measurement point is typically at the plant outlet (Point 2 in Fig. 9.1).

Volumes of oil, gas, and condensate are adjusted to a standard temperature and pressure defined in government regulations and/or in product sales contracts. Liquid sales products may be measured as volumes (e.g., barrels of oil with associated density) or in terms of their mass (e.g., tonnes of oil). Natural gas is measured in volumes (e.g., cubic feet or cubic meters) and typically sold on a heating-value basis (e.g., Btu). Products are further specified by their quality and composition (e.g., sweet light crude, less than *X*% sulfur).

There is a wide range of complexity in processing facilities. “Local plants” may range from a simple dehydration unit to a sulfur-recovery plant to a liquefied natural gas (LNG) complex or a bitumen upgrader. The “plant” may be physically located on the producing property or may be a considerable distance away connected by a pipeline.

The following levels of processing are recognized:

- **Level 1:** Volumes undergoing purification and physical separation (e.g., separation of condensate and natural gas liquids (NGLs) and removal of sulfur from sour gas with subsequent sale of residual dry gas).
- **Level 2:** Volumes requiring more extensive treatment (e.g., upgrading by coking), where chemical changes are induced but no nonreservoir quantities are added. Inert gas and contaminants are also removed in the process.
- **Level 3:** Volumes undergoing significant chemical change or where nonreservoir quantities are added (e.g., hydrotreating that adds hydrogen using catalysts to rechain the hydrocarbon molecule). Inert gas and contaminants are also removed in the process.

In Level 1 projects, the processing is primarily physical separation, and outlet quantities are portions of the original reservoir petroleum; thus, resource measurements should be given in terms of the outlet products (Point 2 in Fig. 9.1). If natural gas is sold before extraction of liquids (wet gas), resource estimates are given in terms of that volume. Any further processing beyond this reference point, including additional liquid recoveries (e.g., in “straddle plants”) are not to be reflected in resource quantities.

Typically, a product sales contract (or pipeline constraints) sets maximum limits on the nonhydrocarbon “contaminants” content on natural gas deliveries. The volume sold may include some small fraction of nonhydrocarbons (H_2S, CO_2) as long as that fraction does not exceed specifications. Then the resource volumes captured in PRMS categories and classifications would be estimated including the same nonhydrocarbon content as in the sales gas.

In the case of LNG plants, while significant purification and associated fuel-use shrinkage is involved, there is no intent to chemically alter the gas but only to change its physical state for transportation. Inert gases and contaminants that must be removed during processing are part of shrinkage. If condensate or NGLs are extracted during processing and reported, the gas volume should be adjusted accordingly. Volumes must be adjusted downward for plant fuel consumption. While output is measured in tons of LNG, associated reservoir estimates are stated in terms of equivalent purified/shrunk volume of gas.

Levels 2 and 3 may both be considered upstream manufacturing processes. The actual custody transfer point in integrated upstream projects depends on the legal structure and contract terms. Where the same corporate entity shares in both the upstream and downstream operations, it may be necessary to establish the custody transfer point arbitrarily. Production streams should be physically measured at the plant inlet, or quantities may be estimated from the outlet products

to account for shrinkage (including fuel usage) and additives. For example, in bitumen-upgrading operations, whereas the coking process involves significant shrinkage, the addition of hydrogen results in a volume gain. The synthetic oil delivered at the plant outlet is the final upstream sales product. Where the custody transfer is deemed to be at the upgrader inlet, a virtual inlet price may be derived through a netback calculation.

This technical analysis must be combined with royalty treatment, regulatory guidance, and accounting to ascertain the logical measurement point for stating resource quantities. In cases of fully integrated extraction and processing operations, transfer prices should be calculated to value quantities correctly at the designated measurement point.

A further issue is the treatment of the nonhydrocarbons; that is, whether they are contaminants (with disposal costs and/or no net sales value) or byproducts (e.g., sulfur or helium) that can be sold to produce additional income. There is general industry agreement that these nonhydrocarbons in excess of sales specifications are not included in resources quantity estimates; however, income generated by their sale can be used to offset expenses to extract and process the associated hydrocarbons (subject to applicable regulatory guidance) when determining economic producibility for PRMS classifications.

Some disclosure jurisdiction may require separate reporting of heavy oil from light/medium crude. It is not intended to prescribe here granularity of reporting by the oil and gas industry.

9.3 Reference Point

Reference point is a defined location in the production chain where the produced quantities are measured. It is typically the point of sale, and where custody transfer takes place between the buyer and seller. Quantitative transfer across the reference point over a fixed period of time defines sales production volumes.

The reference point may be defined by relevant accounting regulations to ensure that the reference point is the same for both the measurement of reported sales quantities and for the accounting treatment of sales revenues. This ensures that sales quantities are stated according to their delivery specifications at a defined price. In integrated projects, the appropriate price at the reference point may need to be determined using a netback calculation.

Sales quantities are equal to raw production less nonsales quantities, being those quantities produced at the wellhead but not available for sales at the reference point. Nonsales quantities include hydrocarbons consumed as fuel, flared, or lost in processing plus nonhydrocarbons that must be removed before sale. Each of these may be allocated using separate reference points, but when combined with sales, they should sum to raw production. Sales quantities may need to be adjusted to exclude components added in processing but not derived from raw production. Raw production measurements are necessary and form the basis of engineering calculations (e.g., production performance analysis) based on total reservoir voidage.

9.4 Lease Fuel

In hydrocarbon production operations, in-field produced natural gas is often used for plant operation, mostly for power generation. Substantial savings 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.

Data records of consumption for fuel, flare, and other operational requirements need to be kept for operational and reservoir monitoring purposes. These data may also be required by regulatory bodies.

Internationally, the gas (or crude oil) consumed in lease operations is usually treated as shrinkage and is excluded from sales quantities; thus under PRMS, it would normally not be included in reserves and resource estimates.

Some jurisdictions allow gas volumes consumed in operations (CiO) to be included in production and reserves because they replace alternative sources of fuel that would be required to be purchased in their absence. The value of the fuel used is considered to offset the revenue and operating costs and hence does not fall into either category. Incidental flared gas is not included in production or reserves. Gas that is used 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 that the volume of gas CiO is included.

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

9.5 Associated Nonhydrocarbon Components

If nonhydrocarbon 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 as produced includes a proportion of CO_2, the pipeline may accept sales gas with a limited CO_2 content. For example, if produced gas has 4% CO_2 and the pipeline will accept up to 2% CO_2, then it is acceptable to design facilities to deliver sales gas to that specification. Thus, the sales gas volume would include 2% CO_2 and reserves dedicated to that pipeline would be estimated including 2% CO_2. In the case where CO_2 must be extracted before sale, and the sales gas contains only hydrocarbon gases, then all categories of reserves should reflect only the hydrocarbon gases that will be sold.

The treatment of gas and crude oil containing H_2S is generally handled in a similar fashion. For gas containing small quantities of H_2S, this 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 treatment. Whereas for LNG and processes involving compression where the dangers following stress-cracking-embrittlement are important, the H_2S must always be totally removed and therefore should be excluded from reserves.

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

Under PRMS, the volumes of nonhydrocarbon byproducts cannot be included in any reserves or resources classification, but the revenue generated by the sale of the nonhydrocarbon byproducts may be used to offset project operation expenses, potentially allowing for the recognition of additional reserves resulting from a lower economic limit. In some cases, revenue from byproducts such as helium or sulfur can be very significant.

9.6 Natural Gas Reinjection

Gas can be injected into a reservoir for a number of reasons and under a variety of conditions. Gas may be reinjected into reservoirs at the original location for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes and be included as reserves. Gas is routinely processed in commingled facilities and redistributed for reinjection, but to retain its reserves status, these volumes should not have moved past the field's reference point as

described in 9.3. If reinjected 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 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. Normally, these volumes are not included in any PRMS reserves category. 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.

Third parties may also purchase gas to be used in a reservoir different from where it is produced 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 would not be considered as reserves. It should be accounted for as inventory. When produced, the gas would not contribute toward 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 toward field production. Once the inventory gas has been re-produced, further gas production would be drawn against the reserves 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 reserves.

9.7 Underground Natural Gas Storage

Natural gas may be produced from a field and transported through pipelines and injected into an underground storage (UGS) reservoir for production at a later date. UGS can be used to meet fluctuations in gas demand profile, which is subject to the seasonal cycle. UGS may also reduce flaring by storing the gas for later use rather than burning off the evolved gas from the produced crude stream. The revenue stream from the produced volumes sold should account for the molecules produced and then stored in another reservoir according to the contracts in place between the various owners.

9.8 Production Balancing

9.8.1 Production Imbalances (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 an overlift or an underlift situation. Based on the production-matching of 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.

9.8.2 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/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.

Some points to consider in gas-balancing arrangements:

- In gas swaps, early production from one field may be traded with later production from another field.
- Take or pay gas means that the production has to be paid for even if it is not "taken" (i.e., produced).

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.

9.9 Shared Processing Facilities

It is not uncommon in gas production operations that several fields may be grouped to supply gas to a central processing facility (gas plant) to remove nonhydrocarbons and recover liquids. Where a company has an equity interest in one or more of the contributing gas fields and also in the processing facility, the allocation of dry gas and NGLs back to the fields (and reservoirs) for estimation of reserves can be complex. While not addressed specifically in PRMS, the basic principle that reserves estimates must be linked to sales products applies. Thus, by measuring the volumes and components of the gas stream leaving each lease and the equity share in the lease, the company can calculate its share of the sales products for purposes of reserves. This share is not affected by the company's actual equity interest in the gas plant as long as it is greater than zero. If the company has no equity interest in the facility, it is treated as a straddle plant and reserves are estimated in terms of the wet gas and the nonhydrocarbon content accepted at the lease outlet. The allocation of revenues is subject to the contractual agreement among the lease and plant owners.

When the plant ownership and lease working interest are different, booking may be an issue. This can be highly complex, but some general points are captured in the following:

1. If the plant is associated with unit production and is unit owned, book residual plus liquids.
2. If the plant is 100% owned by the company sending produced volumes to the facility, then that company books the volumes processed by the plant as residual plus liquids.

3. If the contract directly stipulates the retention, by the producer, of products through plant processing, then the volumes are booked according to contract.
4. If plant ownership and lease ownership interests are different, and existing contracts do not conclusively specify product allocation, the issues may be complex. In this case, where the trail is not clear, the booking of wet gas is recommended. The asset team responsible for handling the produced stream is afforded, however, the opportunity to present information that describes a specific instance in which the booking of residual plus liquids is reasonable and adheres to applicable contract terms. Where processed volumes are significant, this reconciliation is required.

9.10 Hydrocarbon Equivalence Issues

9.10.1 Gas Conversion to Oil Equivalent. Converting gas volumes to an oil equivalent is customarily performed 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 (STP) 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 60°F and 14.696 psia (1 atm). Standard conditions in the metric system are 15°C and 1 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 std m^3 and Nm^3 to scf or vice versa, as the conversion factors are different depending on the temperature and gas composition. For std m^3, the factor is generally 35.3*xxx*, and for Nm^3, the conversion factor is normally 37.*xxx* (the last three places vary according to the effect of gas composition on compressibility behavior).

A common gas conversion factor for intercompany comparison purposes is 1 bbl of oil equivalent (BOE) = 5.8 thousand standard cubic feet (Mscf) of gas at STP (15°C and 1 atm).

Another factor in use, presumably rounded from the above, is 1 BOE = 6 Mscf.

Derivation of the Conversion Factor. First, some facts:

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

From **Fig. 9.2,** an approximate 35°API oil has a heat content of some 5.8 million Btu/bbl. Thus,

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

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 1,000 Btu/scf (37.3 MJ/m^3) at STP (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 is wet or has a calorific value materially different to 1,000 Btu/scf), it is necessary to calculate a conversion factor for all fields in the portfolio on the basis of 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 used 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 std m^3 of gas per 1 std m^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 1,000 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 (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.

Another approach for calculation of gas reserves in terms of BOE is described below:

Depending on the type of crude oil and the quality of gas produced from a reservoir, the BOE factor may vary significantly. It may be possible to estimate BOE factor for each reservoir separately and then average-weight it with reserves figure to be used for conversion of gas reserves number in terms of oil equivalent.

If calorific values of gas volumes are not available at gas sales point, multistage PVT experimental data on gas liberation process as per separation conditions of the field gathering system may be used. The first step is to calculate the weighted average gross calorific value of gas based on composition obtained for each stage of separation of gas.

The mole fraction of each component of gas for particular separation pressure obtained from the multistage PVT study is then multiplied by standard properties of gross calorific value of the respective component obtained from standard gas properties chart (Gas Processors Suppliers Association gas properties chart may be used). The calorific value for each component is added, to obtain the gross calorific value of gas for that particular stage of separation pressure.

- The calorific value for each component in each stage is summed up to obtain the Gross Calorific Value for that stage of separation

  Σ(Component CV) = Gross Stage CV(*)

- Total calorific value for the gas is then obtained by average weighting the gas obtained from each stage with Gas Oil Ratio (GOR) numbers obtained from the same multistage PVT data from the experiment.

  Avg. Wt. Gross CV = (Stage 1 CV × GOR_1 + Stage 2 CV × GOR_2 + ...
  + Stage n CV × GOR_n) (*)(*)

  $GOR_1 + GOR_2 + ... + GOR_n$

The calorific value obtained using these formulas can be cross-checked by taking actual calorific value measurements of some gas samples from the sales point.

The calorific value obtained by the process described above can be used for estimating BOE with a more customized approach, by taking into consideration the crude oil characteristics of the same reservoir (API and Heating value). This will enhance the reporting of gas in terms of oil equivalent, as a change in BOE factors affects the overall volume of gas in terms of oil.

TABLE 9.1—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, Sec. 6.6.

9.10.2 Liquid Conversion to Oil Equivalent. Regulatory reporting usually stipulates that liquid and gas hydrocarbon reserves volumes be 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 correlation between the Btu heat content of crudes, condensates, fuel oils, and paraffins in **Fig. 9.2** 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).

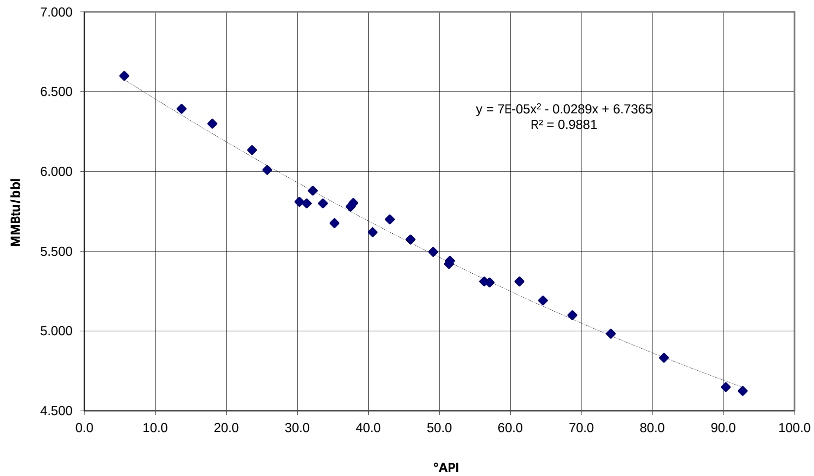

Fig. 9.2—Btu content of crudes, condensates, fuel oils, and paraffins. (Graph provided through personal communication with Chapman Cronquist.)

References

McMichael, C.L. and Spencer, A. 2001. Operational Issues. *Guidelines for the Evaluation of Petroleum Reserves and Resources*, Chap. 3, SPE, Richardson, Texas, USA.

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Chapter 10

Resources Entitlement and Recognition

Elliott Young

10.1 Foreword

This chapter is an update to Chapter 9 of *Guidelines for the Evaluation of Petroleum Reserves and Resources* published by SPE in 2001. Drawing heavily on the original text, it has been updated to reflect refinements in generally accepted industry practices commonly used when determining entitlement to production and recognizable quantities of reserves and resources under a range of agreement types and fiscal terms. It is not the intent of SPE, or the cosponsors of the Petroleum Resources Management System (PRMS) (SPE 2007), to comment on the individual disclosure regulations promulgated by specific government agencies regarding entitlement to production or the ability to report reserves. As a consequence, emphasis has been placed on principles for reserves and resources recognition under PRMS and determination of net quantities, rather than specific government regulations, financial reporting guidelines, or the classification of Reserves and Contingent Resources into the various certainty categories of PRMS.

10.2 Introduction

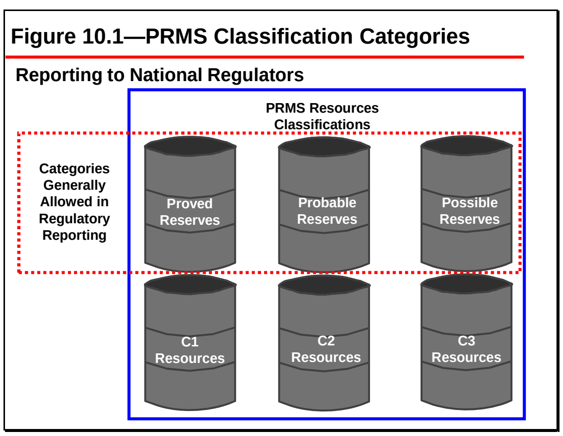
The ability to discover, develop, and economically produce hydrocarbons is the primary goal of the upstream petroleum industry. Aggressive competition, ever-sharpening scrutiny by the investment community, and volatility in product prices drive companies to search for attractive new exploration and producing venture opportunities that will add the greatest value for a given investment. As a consequence, contracts and agreements for these opportunities are becoming increasingly complex, further increasing the focus on the ability to recognize reserves and resources.

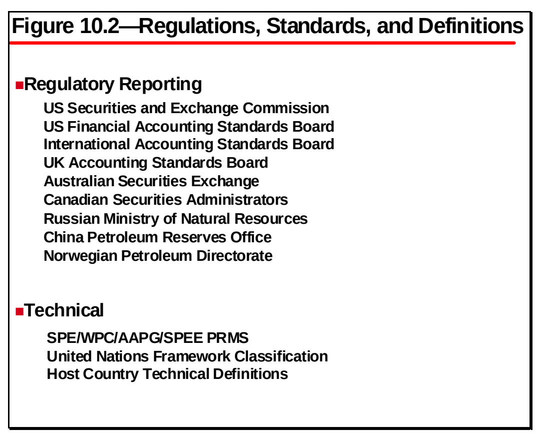
Production-sharing and other nontraditional agreements have become popular given the flexibility they provide host countries in tailoring fiscal terms to fit their sovereign needs while enabling contracting companies to recover their costs and achieve a desired rate of return. However, actual agreement terms, including those that relate to royalties or 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 and resources recognition and reporting under the more common fiscal systems being used throughout the industry. The various types of production-sharing, service, and other types of common contracts are reviewed to illustrate their impact on recognition and reporting of oil and gas reserves and resources in the context of the PRMS framework.

Oil and gas reserves and resources 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 and resources inventories and the value of externally reported, project-related reserves that are added each year, many companies are reluctant to undertake a project that does not provide the opportunity to report reserves.

10.3 Regulations, Standards, and Definitions

In defining reserves, it is important to distinguish between the specific regulations that govern the reporting of reserves externally and internal company use for technical and business-planning purposes. The term "reserves" is used throughout the industry but has many different and often conflicting meanings. The explorationist may refer 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 term. One of the key strengths of PRMS is the framework it provides to clarify what is being referred to. In any assessment, the basis used, assumptions, and purpose for which reserves and resources are recognized and reported must be defined. **Fig. 10.1** summarizes the PRMS reserves and resources categories with the reserves categories that many government regulatory agencies allow in required disclosures. **Fig. 10.2** (SPE 1979; Martinez et al. 1987; SPEE 1998) provides a summary of the more widely recognized regulatory reporting agencies, standards, and technical definitions.





10.3.1 Host Government Regulations. Numerous national regulatory bodies have developed regulations and standards for reporting oil and gas reserves within their respective countries (Martinez et al. 1987; *SEC Guidelines, Rules, and Regulations* 1993; FASB 1977; APPEA 1995; UK Oil Industry Accounting Committee 1991; Johnston 1994). These standards provide detailed descriptions of the categories of reserves to be reported, required supporting information, and the format to be used for the disclosures. However, these standards and regulations do not generally provide much guidance on the type or extent of rights to the underlying resource or production that is required for reporting. For some unique types of agreements, it may not be clear whether a company is even entitled to report the related reserves. This is particularly the case with

agreements in which reserve ownership and control resides, by law, with the host country rather than with the contracting party. Analysis of the key elements and fiscal terms of these contracts and comparison to those in more widespread use is a good approach to determine whether reserves and resources can be recognized and subsequently reported.

PRMS recognizes the concept of an economic interest as the basis for recognizing and reporting reserves and resources. To determine when an economic interest exists, many companies have referred to the SEC Section S-X, Rule 4-10b, "Successful Efforts Method" (US SEC 1993) [or Financial Accounting Standard 19 (FASB 1977)]. While Rule 4-10b was revised in the 2008 SEC rule modernization, the fundamental principles contained in the definition of a mineral interest provide a very useful framework and criteria for establishing when an interest in a property exists and guidance on when reserves and resources can be recognized under PRMS and government regulations:

> 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.

10.4 Reserves and Resources Recognition

Regulation SEC Section S-X, Rule 4-10b can be summarized into elements that support and establish an economic interest and the ability to recognize reserves and resources. These include the following:

- The right to extract oil or gas
- The right to take produced volumes in kind or share in the proceeds from their sale
- Exposure to market risk and technical risk
- The opportunity for reward through participation in producing activities

In addition, the regulation establishes specific elements that do not support an economic interest and preclude the recognition of reserves and resources. These include the following:

- 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 an interest in the minerals

Note that the US Financial Accounting Standards Board (Topic 932) permits reporting of Proved Reserves received under long-term supply agreements with governments, provided that the enterprise wishing to report the reserves participates in the operation or otherwise serves as the

operator. Applying PRMS to this type of agreement, recoverable amounts could be classified as Reserves and/or Resources depending on project maturity and technical certainty.

The right to extract hydrocarbons and the exposure to elements of risk and the opportunity for reward are key elements that provide the basis for recognizing reserves and resources. Many companies use these elements to differentiate between agreements that would allow reserves to be recognized and reported to regulatory agencies from those purely for services that would not allow recognition of reserves and resources. Risks and rewards associated with oil and gas production activities stem 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 generally sufficient to fulfill the requirements of risk and reward and allow reserves to be reported. It should also be noted that the ability or obligation to report reserves to regulatory agencies does not necessarily imply ownership of the underlying resources.

10.4.1 Taxes and Reserves. In general, net working interest reserves and resources are recognized in situations where there is an economic interest, and after deduction for any royalty owed to others. 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 volume components. The summation of the cost and profit volumes that the contractor will receive through the term of the contract represents the reserves and resources that the contractor is entitled to. In many instances, these agreements may also contain clauses that provide that host country income taxes will be paid by the government or the national oil company on behalf of the contractor. While details on the specific hydrocarbons produced and revenues that are used to fund the payments are not usually specified in the agreement, they are inferred to come from the government's share of production. By virtue of the economic interest that the contractor has in these additional volumes, common practice is to include the related quantities in the contractor's share. This also typically requires reporting of the value related to the tax payment that is received in the financial reporting statements.

10.4.2 Royalties and Reserves. Royalties are typically paid to the owner of the mineral rights in exchange for the granting of the rights to extract and produce hydrocarbons. Royalties are a form of a nonoperating interest in the underlying hydrocarbons that is free and clear of all exploration, development, and operating costs. They are generally a fixed percentage or may have some form of a sliding scale basis. Royalty volumes that are payable either in-kind or in monetary terms to the owner of the mineral rights are normally excluded from net reserves and resources. However, in many agreements and/or fiscal systems, the wording that describes this obligation may be in the language of the host country and may not translate well into English. As a consequence, the defined payments or obligation may, in reality, be an additional form of tax. While there are no published standards to differentiate between royalties and taxes, examination of the specific attributes and the intent of the payment or obligation in comparison to other established and recognized royalties and taxes is one approach often used to make the distinction. For example, if the obligation is based on project profitability rather than a defined interest, or costs are deductible from the obligation, an argument can be made that the obligation

has attributes of a tax rather than a royalty. Where the payment is concluded to be a tax, the related reserves and resources are included in amounts recognized by the contractor.

10.4.3 Mineral Property Conveyances. A mineral interest in a property may be conveyed to others to spread risks, to obtain financing, to improve operating efficiency, or for tax benefits. Some types of conveyances are essentially financial arrangements or loans and do not carry with them the ability to recognize or report reserves or resources. Other forms may involve the transfer of all or a part of the rights and responsibilities of operating a property or an operating interest and the ability to recognize reserves or resources. While intended for US SEC reserves reporting, the following text from the US Financial Accounting Standards Board, Standard 19 (FASB 1977), (paragraph 47a) provides useful guidance on when reserves and resources may be recognized in PRMS categories.

a) 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 reserves estimates and production shall be reported as those of the purchaser of the production payment and not of the seller.

If an agreement satisfies the requirements of FASB Standard 19, Paragraph 47a, the purchaser of a production payment is able to recognize the related reserves and resources and would be permitted to externally report the related reserves per applicable regulatory agency regulations. However, if the agreement is purely a financial arrangement or loan, the purchaser would not be able to recognize reserves and resources or report them externally. Production payments have been widely used as a hedging vehicle in periods of price volatility.

10.5 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 for determining when reserves or resources can be recognized under the wide variety of these contracts. The purpose of this section is to expand on the text contained in PRMS 3.3.2 by providing more detailed information for the various agreement types noted and to promote consistency in the recognition of reserves and resources under them. The focus is on the specific elements of the agreements that enable recognition of reserves and resources but not on the classification into specific PRMS certainty categories.

This section follows the classification system template proposed by Johnston (Johnston 1994; Johnston 1995; McMichael and Young 1997) as shown in **Fig. 10.3.** 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 reserves and resources and report them to

regulatory agencies is shown in **Fig. 10.4** (McMichael and Young 1997). Key aspects of each type of agreement are summarized in **Table 10.1** (McMichael and Young 1997).

Figure 10.3—Classification of Petroleum Fiscal Systems

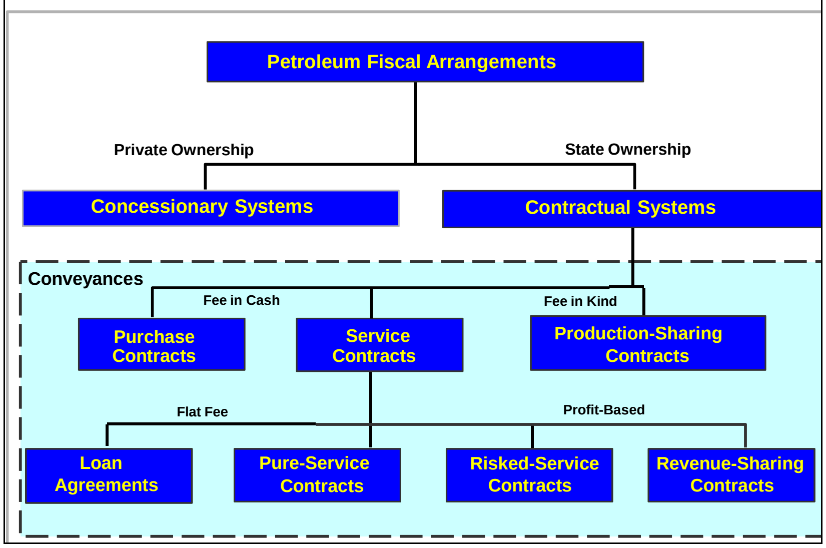


Figure 10.4—Spectrum of Petroleum Fiscal Systems

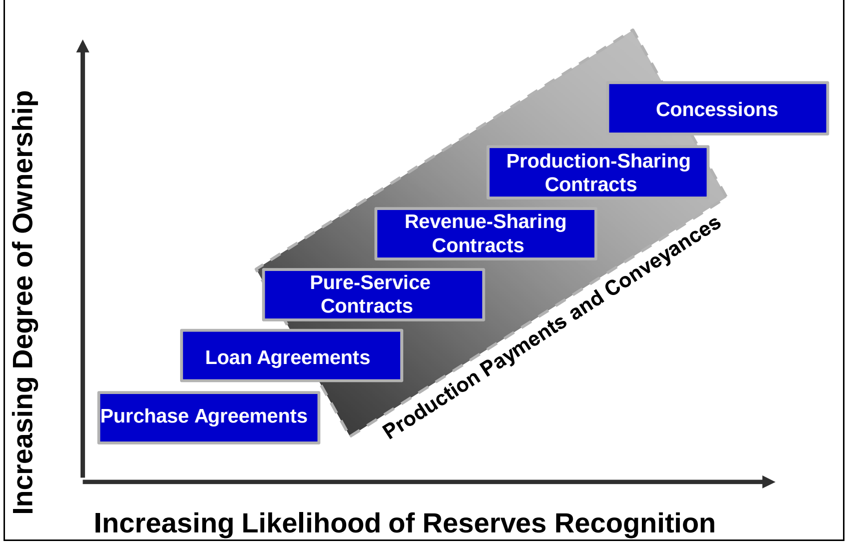


Table 10.1—Contract Summary

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

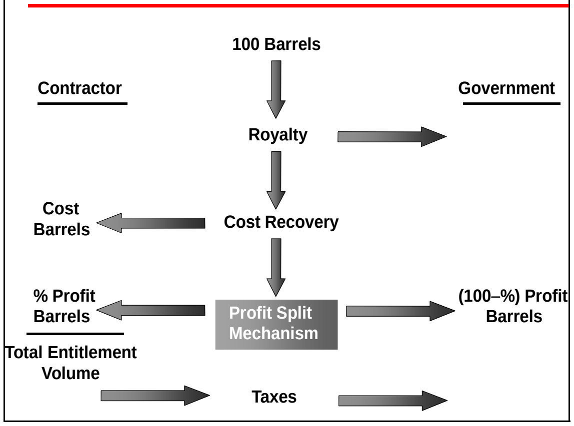
10.5.1 Concessions, Mineral Leases, and Permits. Historically, leases and concessions have been the most commonly used agreements between oil companies and governments or mineral owners. In such agreements, the host government or mineral owner grants the producing company the right to explore for, develop, produce, transport, and market hydrocarbons or minerals within a fixed area for a specific amount of time. The production and sale of hydrocarbons from the concession are then typically 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 recognized by the upstream contractor. Ownership of the reserves producible over the term of the agreement is normally taken by the company. However, as described in PRMS 3.3.3, volumes recoverable after the term of the contract would normally be classified as resources and be contingent on the successful negotiation of an agreement extension. If the contract contained provisions for extension and the likelihood of extension was judged to be reasonably certain, additional reserves would likely be recognized for the length of the extension period, provided requirements for project commitment and funding were satisfied.

10.5.2 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 of the underlying resource is almost always retained by the host government. However, the contractor normally receives title to the prescribed share of the volumes as they are produced. Subject to technical certainty, reserves in one or more of the PRMS categories based on cost recovery plus a profit element for hydrocarbons that are recoverable under the terms of the contract are typically recognized by the

contractor. Resources may also be recognized for future development phases where project maturity is not sufficiently advanced or for possible extensions to the contract term where this would not be a matter of course.

Under a production-sharing contract, the contractor's entitlement to production generally decreases with increasing prices because a smaller share of production is required to recover investments and costs. These agreements commonly contain terms that reduce entitlement as production rate (production tranches) and/or cumulative production increases ("*R*" factors). **Fig. 10.5** is a schematic indicating the distribution of yearly project production between contractor and government. As in the case of a concession, volumes recoverable after the term of the contract would normally be classified as Resources unless the contract contained provisions for extension and there was continued commitment to the project.

Figure 10.5—Example Production-Sharing Contract



10.5.3 Revenue-Sharing/Risked-Service Contracts. Revenue-sharing contracts are very similar to the production-sharing contracts described earlier, with the exception of contractor remuneration. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production. The contractor has an economic or revenue interest in the production and hence can recognize reserves and resources. 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 sales revenues. Also similar to a production-sharing contract, resources may be recognized for future development phases or possible extensions to the contract term.

Fig. 10.6 is a schematic of the distribution of yearly project revenue between contractor and government. 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 and has rights and obligations and bears risks similar to those in the previously noted agreement types.

Figure 10.6—Example Revenue-Sharing Contract

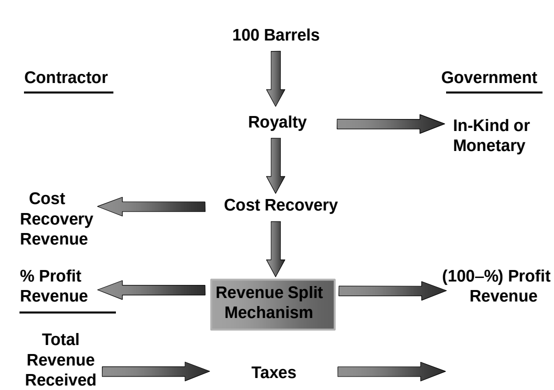
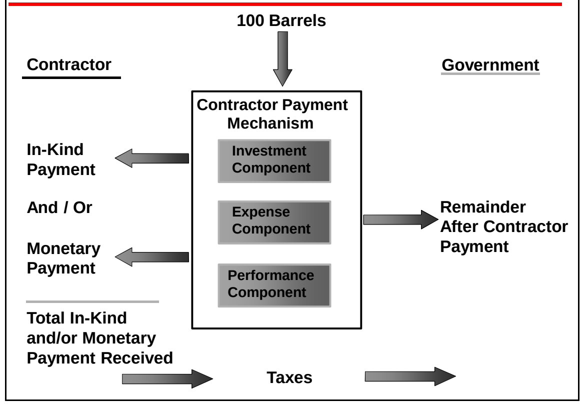


Figure 10.7—Example Risked-Service Contract

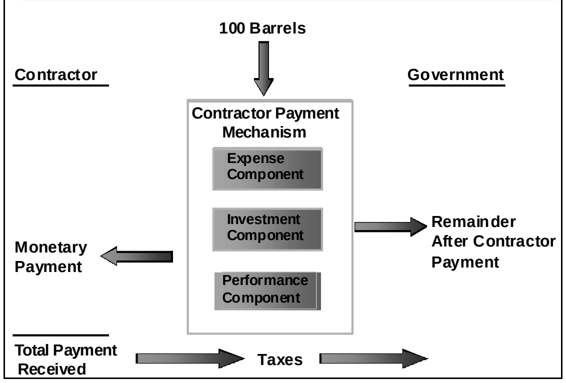


Reserves and resources recognized under PRMS and those reported to regulatory agencies would be based on the economic interest held or the financial benefit received, as shown in **Fig. 10.7.** Depending on the specific contractual terms, the reserves and resources equivalent to the value of the cost-recovery-plus-revenue-profit split are normally reported by the contractor.

10.5.4 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 metrics. In many cases, payments are made from government general revenue accounts to avoid a direct linkage with field operations.

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 normally have exposure to production volume or market price; consequently, reserves and resources are not usually recognized under this type of agreement. The service company may, however, have an obligation to report gross (total working interest basis) reserves and resources to the host countries' regulatory agencies. **Fig. 10.8** is a schematic of the distribution of yearly project revenue between contractor and government.

Figure 10.8—Example Pure-Service Contract



10.5.5 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 typically 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 and resources would not be recognized in any PRMS categories by the lender under this type of agreement.

10.5.6 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 of 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 monetary terms and would not enable recognition of reserves and resources under PRMS. 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. Reserves and resources would be recognized under PRMS by the purchaser. The ability to report reserves to applicable government agencies may be permissible; however, the specific accounting standards for the jurisdiction should be consulted for appropriate treatment.

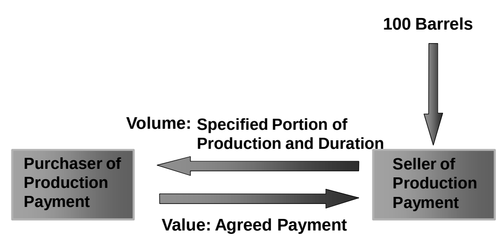
10.5.7 Carried Interests. A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the preproduction costs of another party (the carried party) on a license in which both own a portion of the working interest. This arises when the carried party 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 property becomes productive, 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. The carrying party normally recognizes the additional production received in one or more of the PRMS reserves categories. If project maturity is not sufficient to classify the amounts as Reserves, the PRMS resources categories would be used according to the agreed reimbursement terms.

10.5.8 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 and resources through production, it does not convey the right to extract, nor does it convey a financial interest in the reserves. Consequently, reserves and resources would not be recognized under PRMS for this type of agreement.

10.5.9 Production Payments and Conveyances. In addition to the contracts and agreements noted previously, there is a wide range of arrangements that have features of property trades, loans, and production purchase contracts. These are more commonly called production payments and conveyances and provide terms where assets are transferred between participants, assets are pooled, or loans are provided in return for the right to purchase volumes. In certain specific cases, as described in Sec. 10.4.3, reserves and resources may be recognized by the purchaser of the production payment. **Fig. 10.9** gives an example of a typical conveyance.

Figure 10.9—Example Conveyance—Production Payment



10.6 Example Cases

10.6.1 Base-Case Example. The following example illustrates the approach used to calculate reserves and resources under a nonconcessionary production-sharing agreement. In this example, the contractor develops and operates the field and is entitled to a share of production that is based on cost recovery and profit share components. The contractor takes his share of product in-kind. The contractor does not have ownership of the underlying resources being produced but does earn an economic interest by virtue of the exposure to technical, financial, and operational risks and is therefore able to recognize reserves and resources for the project under PRMS. Due to the difficulty in predicting prices, this example uses a base case oil price of USD 60 and sensitivity cases USD 10 above and below this price. While these are unlikely to represent the actual prices

in effect, they do provide a good illustration of how entitlement and contract terms respond to prices changes.

The base case is a 500-million-bbl oil field, of which 400 million bbl, for the purposes of this example, are reflected in the PRMS Proved Reserves category. The contract provides for an initial exploration period, with the contract term lasting 20 years from the start of production. The general field data are summarized in **Table 10.2**.

Table 10.2—Example Field

Field Information Summary

Field Size	500 million bbl
Production During PSC	400 million bbl
Exploration Cost	$450 million
Drilling Cost	$600 million
Development Cost	$750 million
Fixed Operating Cost	$1,800 million ($90 MM/yr)
Variable Operating Cost	$4.55 / bbl

The production forecast is based on the Proved Reserves, while the remaining 100 million bbl is captured as PRMS 1C and 2C resources. These resources are related to a potential contract extension. In this simplified example, no additional drilling is required; therefore, there are no Probable or Possible Reserves to migrate to the Proved category. However, in actual field development, a portion of the reserves would likely be captured in the Probable (and perhaps Possible) PRMS reserves categories, depending on supporting information and technical certainty.

For example, some Probable (or Possible) Reserves may be captured for better-than-expected recovery or perhaps for undrilled blocks where technical certainty was not sufficient to classify the reserves as Proved. In this instance, modeling two cases, one for the Proved plus Probable flow streams and a separate model for the Proved-only case, will give the Probable Reserves entitlement by difference. **Table 10.3** shows the project production forecast and full-life cost summary.

Table 10.3—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	300	0	0	0	0	300
2	2.7	150	105	120	90	12	477
3	11.5	0	369	180	90	52	691
4	19.9	0	276	300	90	90	756
5	30.4	0	0	0	90	138	228
6	33.3	0	0	0	90	152	242
7	34.5	0	0	0	90	157	247
8	34.7	0	0	0	90	158	248
9	31.3	0	0	0	90	142	232
10	28.1	0	0	0	90	128	218
11	25.3	0	0	0	90	115	205
12	22.8	0	0	0	90	104	194
13	20.5	0	0	0	90	90	183
14	18.5	0	0	0	90	84	174
15	16.6	0	0	0	90	76	166
16	14.9	0	0	0	90	68	158
17	13.5	0	0	0	90	61	151
18	12.1	0	0	0	90	55	145
19	10.9	0	0	0	90	50	140
20	9.8	0	0	0	90	45	135
21	8.8	0	0	0	90	40	130
Total	400.0	450	750	600	1800	1820	5420

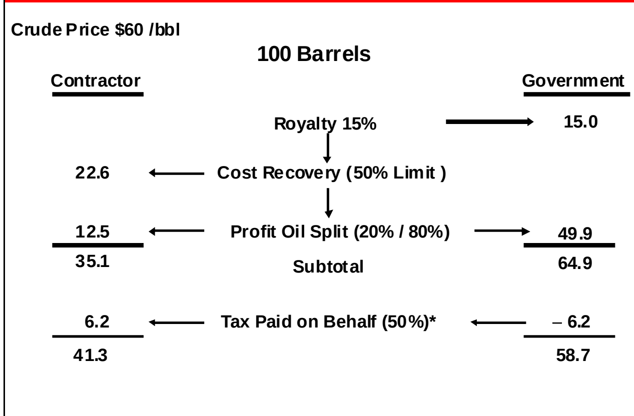
Production startup is midyear in the second year of the project and builds to a peak rate of 95,000 BOPD (34.7 million bbl annualized) in the eighth year. Project exploration costs are USD 450 million for exploratory drilling. The total development costs are USD 1,350 million for both project facilities and development drilling. Operating costs comprise a fixed cost of USD 90 million per year and a variable cost of USD 4.55/bbl.

The contractor's share of reserves and resources will be evaluated in the following with evaluation for the effect of price and alternative tax treatment on recognizable reserves.

10.6.2 Production-Sharing Contract Terms—Normal Tax Treatment. The example contract contains many common contractual terms affecting the industry today. These include 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.

Fig. 10.10 shows the general terms of the contract. 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.

Figure 10.10—Production-Sharing Contract (PSC) Base Case



* Taxes may be paid by Government on behalf of Contractor in some PSCs. Depending on specific terms, the payments may be treated as a tax credit or a revenue gross-up. In this example: Taxable income = (Profit Share)

10.6.3 Contractor 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. Table 10.3 shows the anticipated production, investment, and cost profiles for the project. The calculation of the contractor's revenue entitlement for the peak year with 34.72 million bbl of production is shown in **Table 10.4.** At USD 60/bbl, the gross revenue from 34.72 million bbl in Year 8 is USD 2,083 million. At a royalty rate of 15%, the government would receive as royalty 5.2 million bbl valued at USD 312 million (before cost recovery or profit split). The remaining USD 1,771 million would remain for cost recovery and profit split according to the terms of the contract. In the production-sharing contract, revenue available for cost recovery is limited to 50% after royalty, or USD 886 million. Costs and expenses for the year total USD 248 million, including costs carried forward from previous years. The yearly costs are fully recoverable. In the 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 USD 305 million, or 20% of the available revenue after royalty and costs. The contractor's revenue entitlement is the sum of the contractor's cost recovery and profit.

Table 10.4—Project Cost and Profit-Share Schedule

Year	Total Revenue ($Million)	Net Revenue after Royalty ($Million)	Recoverable Costs ($Million)	Costs Carried Forward ($Million)	Contractor Recovered Costs ($Million)	Available for Profit Sharing ($Million)	Contractor Profit Share ($Million)	Contractor Cost + Profit Share ($Million)	Contractor Share %	Contractor Entitlement (Mbbls)
1	0	0	300	300	0	0	0	0	n/a	0.00
2	161	137	477	709	69	69	14	82	51	1.37
3	687	584	691	1,108	292	292	58	351	51	5.84
4	1,192	1,014	756	1,357	507	507	101	608	51	10.14
5	1,824	1,550	228	810	775	775	155	930	51	15.50
6	1,999	1,699	242	202	850	850	170	1,020	51	16.99
7	2,069	1,759	247	0	449	1,310	262	711	34	11.85
8	2,083	1,771	248	0	248	1,523	305	553	27	9.21
9	1,875	1,594	232	0	232	1,362	272	505	27	8.41
10	1,688	1,434	218	0	218	1,216	243	461	27	7.69
11	1,519	1,291	205	0	205	1,086	217	422	28	7.04
12	1,367	1,162	194	0	194	968	194	387	28	6.45
13	1,230	1,046	183	0	183	862	172	356	29	5.93
14	1,107	941	174	0	174	767	153	327	30	5.46
15	996	847	166	0	166	681	136	302	30	5.03
16	897	762	158	0	158	604	121	279	31	4.65
17	807	686	151	0	151	535	107	258	32	4.30
18	726	617	145	0	145	472	94	240	33	3.99
19	654	556	140	0	140	416	83	223	34	3.71
20	588	500	135	0	135	366	73	208	35	3.46
21	530	450	130	0	130	320	64	194	37	3.24
Total	24,000	20,400	5,420	n/a	5,420	14,981	2,996	8416	35	140.27

In the base case, the calculated average contractor cost plus profit share value in Year 8 is USD 553 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, the contractor is obligated to pay income tax out of his share, which amounts to USD 152 million at the tax rate of 50%.

10.6.4 Contractor Reserves Calculations. The preceding 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. The crude price may vary over the year and the method for calculating the price for each settlement period is normally defined in the agreement. For the purposes of this example, the crude price is assumed to be fixed at USD 60/bbl. The contractor's crude entitlement is equal to the profit share before tax plus cost recovery oil divided by the crude price. For Year 8, with crude at USD 60/bbl, the contractor's entitlement is 9.2 million bbl. In this example, this would be reflected in the PRMS Proved Reserves category. In an actual field development, part of these entitlement volumes may be sourced from portions of the reservoir that are not considered Proved at the time of classification, as noted in Sec. 10.6.1. In this situation, the non-Proved portion would be reflected in the PRMS Probable (or Possible) categories until reclassification to Proved is justified.

This calculation provides only the contractor's share of the annual 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 to determine future annual entitlements. The contractor's reserves are obtained by the summation of the estimated annual volume entitlements over the remaining life of the project. Table 10.4 shows the forecasted entitlements from project initiation to the end of the contract term. They were calculated with the forecasted production schedule, exploration and drilling costs, the anticipated project investment

schedule, and the forecasted operating expense through the term of the agreement. For this case, the contractor's Proved PRMS Reserves are estimated at 140 million bbl, or 35% of the total project Proved Reserves of 400 million bbl.

In the example case, prices and profit splitting were held constant over the period and the effect of the recovery of initial capital investments can be seen on the effective net entitlement interest. At the onset of production, entitlement (economic) interest is approximately 51% and declines over the next several years to a low of 27% in Year 8. The entitlement interest then increases to 37% by the end of the term. This increase is due to the natural decline in the production rate and the need to have a greater portion of the production to reimburse fixed operating costs. In general, production-sharing contract entitlements are highest at the point of first production and tend to decrease as a project becomes cost current. Entitlements tend to increase as costs increase and prices decline; however, many agreements contain "*R*" terms and/or stepwise tranches that tend to reduce the profit share allocation to the contractor over time. These take many different forms, but generally tend to be related to cumulative production or cumulative reimbursements or to higher production rates.

10.6.5 Crude-Price Sensitivity. Contractor reserves are sensitive to the assumed production schedule, crude-price projections, and cost forecasts. The most volatile of these factors is the crude price. **Table 10.5** demonstrates the relationship between crude price and contractor reserves. For a USD 10/bbl increase in crude price, the contractor's reserves decrease from 140 million to 130 million bbl. Such swings in reserves can be expected when prices are volatile. A number of other commonly used financial metrics have also been included in Table 10.5 to illustrate how they also change with price. Subject to specific pricing requirements in the production-sharing-contract agreement, the ability to use average prices over a year, as provided by PRMS, helps dampen price-related reserves changes. The contractor's actual ultimate recovery will, however, be determined by the weighted average crude price over the project life.

Table 10.5—Base Case, Oil Price, and Tax Sensitivity

	Low Case $50 Oil Price		Base Case $60 Oil Price		High Case $70 Oil Price	
Parameter Measured	Normal Tax	Carried Tax	Normal Tax	Carried Tax	Normal Tax	Carried Tax
Reserves (million bbl)	155	178	140	165	130	156
Cost of Finding & Dev. ($/bbl)	$11.63	$10.12	$12.83	$10.89	$13.85	$11.52
Profit/bbl ($/bbl)	$14.97	$19.53	$21.36	$27.20	$28.29	$35.30
Production Costs ($/bbl)	$23.40	$20.35	$25.81	$21.91	$27.86	$23.18
Net Production Income ($/bbl)	$7.48	`$13.02	$10.68	$18.13	$14.14	$23.53
NPV@10%(FASB) ($MM)	$87	$493	$260	$788	$419	$1070
SMOG/BBL ($/bbl)	$0.56	$2.78	$1.86	$4.77	$3.23	$6.85
Contractor IRR	11.9%	18.8%	15.7%	24.3%	19.5%	29.6%

10.6.6 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 economics but has no impact on the reserves 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. If the tax payment is a purely financial arrangement and the payments cannot be attributed to a portion of the government's production revenues, an economic interest would not exist; therefore, no additional reserves would be recognized by the contractor. In this case, the carried tax reserves will equal those obtained in the normal tax case, as shown in Table 10.5.

If under the terms of the contract the contractor derives a benefit from and has an economic interest in the government's share of hydrocarbon volumes used to fund the tax payments, those volumes may be considered as the contractor's reserves. Table 10.5 shows the impact on both the project financial indicators and reserves. The contractor's cost recovery and profit share are computed in the standard fashion, but would now include the economic benefit related to the taxes paid on behalf of the contractor. With a tax-paid-on-behalf arrangement, the contractor's base-case Proved Reserves would increase by 25 million to 165 million bbl. In an actual field development, part of these additional entitlement volumes may be sourced from portions of the reservoir that are not considered Proved at the time of classification. As discussed previously, the non-Proved portion would be reflected in the PRMS Probable (or Possible) category until reclassification to Proved is justified.

10.6.7 Reserves Sensitivity. The preceding reserves calculation illustrates the general approach that 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, with relatively stable prices and the relationship between project costs and project revenues 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 corrections would be applied when accounts are trued-up for actual production and realizations on the regular intervals prescribed in the agreement.

10.6.8 Assessing Other Categories of Reserves and Resources. In the production-sharing-contract example case, 100 million bbl was noted to be related to the potential extension of the original contract agreement. If significant additional new investments were required to produce this volume and/or there was some doubt that the agreement would be extended, the related volume would most likely be categorized as a Contingent Resource in one or more of the 1C, 2C, or 3C scenarios, depending on the level of technical certainty. There may also be a question of whether the same or different terms will apply to the extension. Consequently, judgment must be used when estimating the entitlement interest that will be used to determine the net share of PRMS resources potentially available to the contractor.

In a different scenario, if the 100 million bbl were related to potentially higher recovery efficiency from the reservoir within the original term, and no additional debottlenecking or development investments were required, the volume could be classified as Probable (and/or Possible) Reserves (assuming appropriate technical certainty). To determine the effective net interest for this Probable increment, a two-step process is commonly used. In the first step, the Proved flowstream is evaluated using the production-sharing-contract model described in the preceding subsections. In the second step, the forecast Proved plus Probable flowstream is then evaluated with the production-sharing-contract model and the results from the Proved case are subtracted. This provides the entitlement and revenues related to the discrete Probable

component. This approach can be used with multiple categories and in cases where additional investments may also be required. It may also be used where there are multiple fields being developed within the same production-sharing-contract ring fence.

10.7 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 whether there is an opportunity to recognize reserves and resources for internal use, regulatory reporting, or public disclosure. Particular care should be taken 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 and a useful framework for determining when a mineral interest in hydrocarbon reserves and resources exists. These criteria can be used to supplement PRMS to help determine when an economic interest in hydrocarbons exists, allowing reserves and resources to be recognized and reported. However, the distinction between when reserves and resources can or cannot be recognized 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 entitlement (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. The treatment of taxes and the accounting procedures used can also have a very significant impact on the reserves and resources recognized and production reported from these contracts.

Given the complexity of these types of agreements, determination of the net company share of hydrocarbons recognized for each PRMS classification requires economic modeling of the flowstreams with the related costs and investments for each cumulative PRMS classification (1P, 2P, 3P and 1C, 2C, 3C). The net amount for each discrete PRMS category can then be determined by difference from the model results (i.e., net Probable Reserves = 2P – 1P).

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Reference Terms

Note: The column USED IN THESE GUIDELINES provides the chapter where the term is used (first number) and the number of times the term appears in that chapter (number after the period). For example, 4.12 means the term appears in Chapter 4 and is used 12 times.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
1C	2007 – 2.2.2	1.1, 2.8, 4.12, 5.3, 6.1, 8.1, 10.3	Denotes low estimate scenario of Contingent Resources.
2C	2007 – 2.2.2	1.1, 2.6, 4.12, 5.3, 6.1, 8.1, 10.3	Denotes best estimate scenario of Contingent Resources.
3C	2007 – 2.2.2	1.1, 2.4, 4.12, 5.3, 6.1, 8.1, 10.2	Denotes high estimate scenario of Contingent Resources.
1P	2007 – 2.2.2	1.1, 2.13, 4.18, 5.6, 6.4, 7.9, 8.8, 10.2	Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves.
2P	2007 – 2.2.2	1.1, 2.15, 4.25, 5.6, 6.7, 7.18, 8.10, 10.2	Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves.
3P	2007 – 2.2.2	1.1, 2.12, 4.20, 5.5, 6.2, 7.11, 8.11, 10.1	Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves.
Accumulation	2001 – 2.3	2.22, 3.6, 4.9, 5.3, 6.3, 8.37	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	2007 – 3.5.1 2001 – 6	1.1, 2.1, 4.1, 5.1, 6.26, 8.1	The process of summing reservoir (or project) level estimates of resource quantities to higher levels or combinations such as field, country, or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Approved for Development	2007 – Table I	2.4	All necessary approvals have been obtained; capital funds have been committeed, and implementation of the development project is underway.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Analogous Reservoir	2007 – 3.4.1	2.3, 4.1	Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.
Assessment	2007 – 1.2	1.2, 2.11, 3.6, 4.60, 5.2, 6.3, 7.5, 8.23, 10.1	See Evaluation.
Associated Gas		7.2, 8.2	Associated Gas is a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas.
Barrels of Oil Equivalent (BOE)	2001 – 3.7	4.12, 9.13	See Crude Oil Equivalent.
Basin-Centered Gas	2007 – 2.4	8.2	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas saturated reservoirs, and lack of a downdip water leg.
Behind-pipe Reserves	2007 – 2.1.3.1	none—no occurrences	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. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Best Estimate	2007 – 2.2.2 2001 – 2.5	2.5, 4.36, 5.2, 6.5, 7.9, 8.1	With respect to resource categorization, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
Bitumen	2007 – 2.4	1.1, 8.29, 9.2	See Natural Bitumen.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Buy Back Agreement		none—no occurrences	An agreement between a host government and a contractor under which the host pays the contractor an agreed price for all volumes of hydrocarbons produced by the contractor. Pricing mechanisms typically provide the contractor with an opportunity to recover investment at an agreed level of profit.
Carried Interest	2001 – 9.6.7	7.1, 10.3	A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the preproduction costs of another party (the carried party) on a license in which both own a portion of the working interest.
Chance	2007 – 1.1	2.36, 4.6, 5.1, 6.4, 8.4	Chance is 1- Risk. (See Risk.)
Coalbed Methane (CBM)	2007 – 2.4	8.49	Natural gas contained in coal deposits, whether or not stored in gaseous phase. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. (Also termed Coal Seam Gas, CSG, or Natural Gas from Coal, NGC.)
Commercial	2007 – 2.1.2 and Table I	1.1, 2.66, 3.1, 4.5, 5.2, 6.2, 7.10, 8.40	When a project is commercial, this implies that the essential social, environmental, and economic conditions are met, including political, legal, regulatory, and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.
Committed Project	2007 – 2.1.2 and Table I	none—no occurrences	Projects status where there is a demonstrated, firm intention to develop and bring to production. Intention may be demonstrated with funding/financial plans and declaration of commerciality based on realistic expectations of regulatory approvals and reasonable satisfaction of other conditions that would otherwise prevent the project from being developed and brought to production.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Completion		4.7, 6.2, 7.2, 8.9	Completion of a well. The process by which a well is brought to its final classification—basically dry hole, producer, injector, or monitor well. A dry hole is normally plugged and abandoned. A well deemed to be producible of petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir. Various methods are utilized to establish this connection, but they commonly involve the installation of some combination of borehole equipment, casing and tubing, and surface injection or production facilities.
Completion Interval		none—no occurrences	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	2001 – 9.6.1	7.3, 10.7	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an enterprise. The enterprise is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned.
Condensate	2001 – 3.2	4.16, 7.1, 8.2, 9.10	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from natural gas liquids (NGL) in two respects: 1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and 2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensate. Compare to Natural Gas Liquids (NGL)
Conditions	2007 – 3.1	2.1, 3.9, 4.6, 5.3, 6.4, 7.17, 8.6, 9.6, 10.1	The economic, marketing, legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated (also termed Contingencies).

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Constant Case	2007 – 3.1.1	7.11	Modifier applied to project resources estimates and associated cash flows when such estimates are based on those conditions (including costs and product prices) that are fixed at a defined point in time (or period average) and are applied unchanged throughout the project life, other than those permitted contractually. In other words, no inflation or deflation adjustments are made to costs, product prices, or revenues over the evaluation period.
Contingency	2007 – 3.1 and Table 1	2.4, 7.1	See Conditions.
Contingent Project	2007 – 2.1.2	none—no occurrences	Development and production of recoverable quantities has not been committed due to conditions that may or may not be fulfilled.
Contingent Resources	2007 – 1.1 and Table I	2.27, 3.2, 4.29, 5.3, 6.2, 7.4, 8.18, 10.1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.
Continuous-Type Deposit	2007 – 2.4 2001 – 2.3	8.1	A petroleum accumulation that is pervasive throughout a large area and which is not significantly affected by hydrodynamic or buoyancy influences. Such accumulations are included in Unconventional Resources. Examples of such deposits include "basin-centered" gas, shale gas, gas hydrates, natural bitumen and oil shale accumulations.
Conventional Crude Oil	2007 – 2.4	none—no occurrences	Crude Oil flowing naturally or capable of being pumped without further processing or dilution [see Crude Oil and compare to Synthetic Crude Oil (SCO)].
Conventional Gas	2007 – 2.4	8.3	Conventional Gas is a natural gas, trapped by buoyancy, occurring in a normal porous and permeable reservoir rock, either in the gaseous phase or dissolved in crude oil, and which technically can be produced by normal production practices.
Conventional Resources	2007 – 2.4	1.1, 8.3	Conventional resources exist in discrete petroleum accumulations related to localized geological structural features and/or stratigraphic conditions, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Conveyance	2001 – 9.6.9	10.11	Certain transactions that are in substance borrowings repayable in cash or its

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
			equivalent and shall be accounted for as borrowings and may not qualify for the recognition and reporting of oil and gas reserves.
Cost Recovery	2001 – 9.6.2, 9.7.2	10.21	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the gross production stream. The contractor normally receives payment in oil production and is exposed to both technical and market risks.
Crude Oil	2001 – 3.1	4.2, 7.1, 8.3, 9.9	Petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. Crude Oil may include small amounts of nonhydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Crude Oil Equivalent	2001 – 3.7	none—no occurrences	Conversion of gas volumes to their oil equivalent, customarily done on the basis of the nominal heating content or caloric value of the fuel. 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) = 5,600–6,000 standard cubic feet of gas. (Also termed Barrels of Oil Equivalent.)
Cumulative Production	2007 – 1.1	4.27, 7.1, 10.2	The sum of production of oil and gas to date (see also Production).
Current Economic Conditions	2007 – 3.1.1	7.3	Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve a defined averaging period. The SPE guidelines recommend that a one-year historical average of costs and prices should be used as the default basis of “constant case” resources estimates and associated project cash flows.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Cushion Gas Volume		none—no occurrences	With respect to underground natural gas storage, the gas volume required in a storage field for reservoir management purposes and to maintain adequate minimum storage pressure for meeting working gas volume delivery with the required withdrawal profile. In caverns, the cushion gas volume is also required for stability reasons. The cushion gas volume may consist of recoverable and nonrecoverable in-situ gas volumes and/or injected gas volumes.
Deposit	2007 – 2.4	5.1, 8.14	Material that has accumulated due to a natural process. In resource evaluations it identifies an accumulation of hydrocarbons in a reservoir (see Accumulation).
Deterministic Estimate	2007 – 3.5	2.2, 3.1, 6.2, 7.1	The method of estimation of Reserves or Resources is called deterministic if a discrete estimate(s) is made based on known geoscience, engineering, and economic data.
Developed Reserves	2007 – 2.1.3.2 and Table II	3.1, 6.1, 8.1	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 compared to the cost of a well. Developed Reserves may be further subclassified as Producing or Non-Producing.
Developed Producing Reserves	2007 – 2.1.3.2 and Table II	2.1, 8.1	Developed Producing Reserves are expected to be recovered from completion intervals that 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.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Developed Non-producing Reserves	2007 – 2.1.3.2 and Table II	2.1	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells that were shut in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are also those expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Development not Viable	2007 – 2.1.3.1 and Table I	2.6, 8.3	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Development Pending	2007 – 2.1.3.1 and Table I	2.4	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity subclass that reflects the actions required to move a project toward commercial production.
Development Plan	2007 – 1.2	1.1, 2.12, 3.2, 4.5, 5.2, 6.1, 8.4, 9.1	The design specifications, timing, and cost estimates of the development project that can include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation and marketing. (See also Project.)
Development Unclarified or on Hold	2007 – 2.1.3.1 and Table I	2.3	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity subclass that reflects the actions required to move a project toward commercial production.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Discovered	2007 – 2.1.1	2.10, 4.5, 5.1, 6.1, 7.3, 8.8	A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. (See also Known Accumulations.)
Discovered Petroleum Initially-in-Place	2007 – 1.1	none—no occurrences	Discovered Petroleum Initially-in-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Discovered Petroleum Initially-In-Place may be subdivided into Commercial, Sub-Commercial, and Unrecoverable, with the estimated commercially, recoverable portion being classified as Reserves and the estimated subcommercial recoverable portion being classified as Contingent Resources.
Dry Gas	2001 – 3.2	8.1, 9.2	Natural gas remaining after hydrocarbons liquids have been removed prior to the Reference Point (see definition). The dry gas and removed hydrocarbon liquids are accounted for separately in resource assessments. It should be recognized that this is a resource assessment definition and not a phase behavior definition. (also called Lean Gas)
Dry Hole	2001 – 2.5	4.2, 8.1	A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Economic	2007 – 3.1.2 2001 – 4.3	2.14, 4.22, 5.6, 6.2, 7.46, 8.25, 9.2, 10.8	In relation to petroleum Reserves and Resources, economic refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation.
Economic Interest	2001 – 9.4.1	7.2, 10.12	An Economic Interest is possessed in every case in which an investor has acquired any Interest in mineral in place and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return of his capital.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Economic Limit	2007 – 3.1.2 2001 – 4.3	4.27, 7.10, 8.3, 9.1	Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative.
Entitlement	2007 – 3.3	1.1, 7.1, 9.4, 10.30	That portion of future production (and thus resources) legally accruing to a lessee or contractor under the terms of the development and production contract with a lessor.
Entity	2007 – 3.0	5.1, 7.10, 9.1, 10.1	A legal construct capable of bearing legal rights and obligations. In resources evaluations this typically refers to the lessee or contractor which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Estimated Ultimate Recovery (EUR)	2007 – 1.1	4.85, 5.1, 6.2, 7.1, 8.12	Those quantities of petroleum that are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.
Evaluation	2007 – 3.0	1.4, 2.15, 3.2, 4.4, 5.2, 6.1, 7.42, 8.5, 10.1	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. Projects are classified and estimates of derived quantities are categorized according to applicable guidelines. (Also termed Assessment.)
Evaluator	2007 – 1.2, 2.1.2	2.2, 4.5, 5.1, 6.1, 7.5, 8.2	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including Reserves and Resources and attributed value estimates.
Exploration		2.8, 3.4, 4.8, 5.6, 6.4, 7.3, 8.7, 10.16	Prospecting for undiscovered petroleum.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Field	2001 – 2.3	1.1, 2.7, 3.18, 4.8, 5.4, 6.52, 7.6, 8.15, 9.19, 10.14	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. The term may be defined differently by individual regulatory authorities.
Flare Gas	2007 – 3.2.2	9.1	Total volume of gas vented or burned as part of production and processing operations.
Flow Test	2007 – 2.1.1	none—no occurrences	An operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test).
Fluid Contacts	2007 – 2.2.2	3.2, 4.1	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	2007 – 3.1.1	7.15	Modifier applied to project resources estimates and associated cash flow when such estimates are based on those conditions (including costs and product price schedules) forecast by the evaluator to reasonably exist throughout the life of the project. Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Forward Sales	2001 – 9.6.6	10.1	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.
Fuel Gas	2007 – 3.2.2	4.1, 7.1, 9.1	See Lease Fuel.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Gas Balance	2007 – 3.2.7 2001 – 3.10	none—no occurrences	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.
Gas Cap Gas	2001 – 6.2.2	none—no occurrences	Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of Associated Gas.
Gas Hydrates	2007 – 2.4	1.1, 8.9	Naturally occurring crystalline substances composed of water and gas in which a solid water lattice accommodates gas molecules in a cagelike structure, or clathrate. At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Because of this large gas-storage capacity, gas hydrates are thought to represent an important future source of natural gas. Gas hydrates are included in unconventional resources, but the technology to support commercial production has yet to be developed.
Gas Inventory		none—no occurrences	The sum of Working Gas Volume and Cushion Gas Volume in underground gas storage.
Gas/Oil Ratio (GOR)	2007 – 3.4.4	4.1, 6.1, 7.1, 8.1, 9.7	Gas to Oil Ratio (GOR) in an oil field, calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ration (R_s); produced gas/oil ratio (R_p); or another suitably defined ratio of gas production to oil production.
Gas Plant Products		none—no occurrences	Gas Plant Products are natural gas liquids (or components) recovered from natural gas in gas processing plants and, in some situations, from field facilities. Gas Plant Products include ethane, propane, butanes, butanes/propane mixtures, natural gasoline and plant condensates, sulfur, carbon dioxide, nitrogen, and helium.
Gas-to-Liquids (GTL) Projects		none—no occurrences	Projects using specialized processing (e.g., Fischer-Tropsch synthesis) to convert natural gas into liquid petroleum products. Typically these projects are applied to large gas accumulations where lack of adequate infrastructure or local markets would make conventional natural gas development projects uneconomic.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Geostatistical Methods	2001 – 7.1	none—no occurrences	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of masses of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool; specifically related here to resources estimates, including the definition of (all) well and reservoir parameters in 1, 2, and 3 dimensions and the resultant modeling and potential prediction of various aspects of performance.
High Estimate (Resources)	2007 – 2.2.2 2001 – 2.5	2.10, 4.27, 5.3, 7.4, 8.2	With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Highest Known Hydrocarbons	2007 – 2.2.2.	4.1	The shallowest occurrence of a producible hydrocarbon accumulation as interpreted from some combination of well log, flow test, pressure measurement, and core data. Hydrocarbons may or may not extend above this depth. Modifiers are often added to specify the type of hydrocarbons (for instance, “highest known gas”).
Hydrocarbons	2007 – 1.1	2.1, 3.2, 6.1, 8.7, 9.2, 10.14	Chemical compounds consisting wholly of hydrogen and carbon.
Improved Recovery (IR)	2007 – 2.3.4	2.1, 8.2, 10.1	Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called Enhanced Recovery.)
Injection	2001 – 3.5 2007 – 3.2.5	3.6, 4.36, 5.1, 7.2, 8.4, 9.4	The forcing, pumping, or free flow under vacuum of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Justified for Development	2007 – 2.1.3.1 and Table I	2.5, 7.1	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained. A project maturity subclass that reflects the actions required to move a project toward commercial production.
Kerogen		8.3	Naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil or gas upon subjection to heat and pressure. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called natural bitumen). (See also Oil Shales.)
Known Accumulation	2007 – 2.1.1 2001 – 2.2	2.1, 3.2, 8.1	An accumulation is an individual body of petroleum-in-place. The key requirement to consider an accumulation as “known,” and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons.
Lead	2007 – 2.1.3.1 and Table I	2.1	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A project maturity subclass that reflects the actions required to move a project toward commercial production.
Lease Condensate		none—no occurrences	Lease Condensate is condensate recovered from produced natural gas in gas/liquid separators or field facilities.
Lease Fuel	2007 – 3.2.2	9.1	Oil and/or gas used for field and processing plant operations. For consistency quantities consumed as lease fuel should be treated as part of shrinkage. However, regulatory guidelines may allow lease fuel to be included in Reserves estimates. Where claimed as Reserves, such fuel quantities should be reported separately from sales and their value must be included as an operating expense.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Lease Plant		none—no occurrences	A general term referring to processing facilities that are dedicated to one or more development projects and the petroleum is processed without prior custody transfer from the owners of the extraction project (for gas projects, also termed “Local Gas Plant”).
Liquefied Natural Gas (LNG) Project		9.2	Liquefied Natural Gas projects use specialized cryogenic processing to convert natural gas into liquid form for tanker transport. LNG is about 1/614 the volume of natural gas at standard temperature and pressure.
Loan Agreement	2001 – 9.6.5	10.5	A loan agreement is typically used by a bank, other 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.
Low/Best/High Estimates	2007 – 2.2.1, 2.2.2	1.1, 2.5, 3.1, 4.9, 5.1, 7.2, 8.2	The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes at varying degrees of uncertainty (using the cumulative scenario approach) for an individual accumulation or a project.
Low Estimate	2007 – 2.2.2 2001 – 2.5	2.4, 4.18, 5.2, 7.5	With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons	2007 – 2.2.2.	3.1, 5.1	The deepest occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, or core data.
Marginal Contingent Resources	2007 – 2.1.3.3	2.1	Known (discovered) accumulations for which a development project(s) has been evaluated as economic or reasonably expected to become economic but commitment is withheld because of one or more contingencies (e.g., lack of market and/or infrastructure).
Measurement	2007 – 3.0	4.4, 5.4, 6.3, 8.1, 9.14	The process of establishing quantity (volume or mass) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Mineral Interest	2001 – 9.3	7.4, 10.6	Mineral Interests in properties including (1) 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; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and (3) 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).
Monte Carlo Simulation	2001 – 5 2007 – 3.5	2.3, 6.2, 7.1	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum volumes).
Natural Bitumen	2007 – 2.4	2.1, 8.3	Natural Bitumen is the portion of petroleum that exists in the semisolid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other nonhydrocarbons. Natural Bitumen has a viscosity greater than 10,000 milliPascals per second (mPa.s) (or centipoises) measured at original temperature in the deposit and atmospheric pressure, on a gas-free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural Bitumen generally requires upgrading prior to normal refining. (Also called Crude Bitumen.)
Natural Gas	2007 – 3.2.3 2001 – 6.6, 9.4.4	1.1, 4.3, 8.4, 9.8	Natural Gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural Gas may include some amount of nonhydrocarbons.
Natural Gas Inventory		none—no occurrences	With respect to underground natural gas storage operations “inventory” is the total of working and cushion gas volumes.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Natural Gas Liquids (NGL)	2007 – A13 2001 – 3.2, 9.4.4	4.2, 6.1, 7.1, 9.3	A mixture of light hydrocarbons that exist in the gaseous phase at reservoir conditions but are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus (the main constituent of condensates).
Natural Gas Liquids to Gas Ratio		none—no occurrences	Natural gas liquids to gas ratio in an oil or gas field, calculated using measured natural gas liquids and gas volumes at stated conditions.
Net-back	2007 – 3.2.1	none—no occurrences	Linkage of input resource to the market price of the refined products.
Net Profits Interest	2001 – 9.4.4	none—no occurrences	An interest that receives a portion of the net proceeds from a well, typically after all costs have been paid.
Net Working Interest	2001 – 9.6.1	10.2	A company's working interest reduced by royalties or share of production owing to others under applicable lease and fiscal terms. (Also called Net Revenue Interest.)
Non-Hydrocarbon Gas	2007 – 3.2.4 2001 – 3.3	4.1, 9.12	Natural occurring associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium. If nonhydrocarbon 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.
Non-Associated Gas		none—no occurrences	Non-Associated Gas is a natural gas found in a natural reservoir that does not contain crude oil.
Normal Production Practices		none—no occurrences	Production practices that involve flow of fluids through wells to surface facilities that involve only physical separation of fluids and, if necessary, solids. Wells can be stimulated, using techniques including, but not limited to, hydraulic fracturing, acidization, various other chemical treatments, and thermal methods, and they can be artificially lifted (e.g., with pumps or gas lift). Transportation methods can include mixing with diluents to enable flow, as well as conventional methods of compression or pumping. Practices that involve chemical reforming of molecules of the produced fluids are considered manufacturing processes.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Offset Well Location		8.4	Potential drill location adjacent to an existing well. The offset distance may be governed by well spacing regulations. In the absence of well spacing regulations, technical analysis of drainage areas may be used to define the spacing. For Proved volumes to be assigned to an offset well location, there must be conclusive, unambiguous technical data that supports the reasonable certainty of production of hydrocarbon volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the lowest known hydrocarbon.
Oil Sands		8.7	Sand deposits highly saturated with natural bitumen. Also called “Tar Sands.” Note that in deposits such as the western Canada “oil sands,” significant quantities of natural bitumen may be hosted in a range of lithologies including siltstones and carbonates.
Oil Shales	2007 – 2.4	8.13	Shale, siltstone, and marl deposits highly saturated with kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil).
On Production	2007 – 2.1.3.1 and Table 1	2.4, 3.2, 4.2, 7.3, 8.2	The development project is currently producing and selling petroleum to market. A project status/maturity subclass that reflects the actions required to move a project toward commercial production.
Operator		2.1, 4.2, 7.1, 8.2, 10.1	The company or individual responsible for managing an exploration, development, or production operation.
Overlift / Underlift	2007 – 3.2.7 2001 – 3.9	9.5	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 may 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.
Penetration	2007 – 1.2	2.1	The intersection of a wellbore with a reservoir.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Petroleum	2007 – 1.0	1.12, 2.11, 3.1, 4.31, 5.3, 7.28, 8.18, 9.1, 10.4	Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain nonhydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, nonhydrocarbon content could be greater than 50%.
Petroleum Initially-in-Place	2007 – 1.1	2.2	Petroleum Initially-in-Place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Crude Oil-in-place, Natural Gas-in-place and Natural Bitumen-in-place are defined in the same manner (see Resources). (Also referred as Total Resource Base or Hydrocarbon Endowment.)
Pilot Project	2007 – 2.3.4, 2.4	2.5, 4.6, 8.3	A small-scale test or trial operation that is used to assess the suitability of a method for commercial application.
Play	2007 – 2.1.3.1 and Table 1	2.1, 8.15	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. A project maturity subclass that reflects the actions required to move a project toward commercial production.
Pool		3.5, 6.1	An individual and separate accumulation of petroleum in a reservoir.
Possible Reserves (P3)	2007 – 2.2.2 and Table 3	1.1, 2.5, 4.1, 5.1, 10.4	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Primary Recovery		2.1, 4.1	Primary recovery is the extraction of petroleum from reservoirs utilizing only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	2007 – 2.2.1	2.19, 3.1, 5.44, 6.23, 7.16, 8.1	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
			cases possible. SPE convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)
Probabilistic Estimate	2007 – 3.5	5.3, 7.1	The method of estimation of Resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	2007 – 2.2.2 and Table 3	1.1, 2.4, 6.2, 8.3, 10.3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Production	2007 – 1.1	1.1, 2.13, 3.12, 4.151, 5.12, 6.10, 7.44, 8.89, 9.42, 10.78	Production is the cumulative quantity of petroleum that has been actually recovered over a defined time period. While all recoverable resource estimates and production are reported in terms of the sales product specifications, raw production quantities (sales and nonsales, including nonhydrocarbons) are also measured to support engineering analyses requiring reservoir voidage calculations.
Production-Sharing Contract	2007 – 3.3.2 2001 – 9.6.2	10.33	In a production-sharing contract 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 incurred investment from production, subject to specific limits and terms. Ownership is retained by the host government; however, the contractor normally receives title to the prescribed share of the volumes as they are produced.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Profit Split	2001 – 9.6.2	10.7	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor is entitled to a share of the remaining profit oil or gas. The contractor receives payment in oil or gas production and is exposed to both technical and market risks.
Project	2007 – 1.2 2001 – 2.3	1.2, 2.184, 3.2, 4.172, 5.5, 6.12, 7.158, 8.59, 9.10, 10.47	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 in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity 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 resources for that project. (See also Development Plan.)
Property	2007 – 1.2 2001 – 9.4	2.1, 3.6, 6.3, 7.9, 8.3, 9.1, 10.11	A volume of the Earth's crust wherein a corporate entity or individual has contractual rights to extract, process, and market a defined portion of specified in-place minerals (including petroleum). Defined in general as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prorationing		none—no occurrences	The allocation of production among reservoirs and wells or allocation of pipeline capacity among shippers, etc.
Prospect	2007 – 2.1.3.1 and Table 1	2.4, 4.3, 5.9, 8.1, 10.1	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Prospective Resources	2007 – 1.1 and Table 1	1.1, 2.16, 3.2, 4.8, 6.2, 7.1, 8.5	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Proved Economic	2007 – 3.1.1	none—no occurrences	In many cases, external regulatory reporting and/or financing requires that, even if only the Proved Reserves estimate for the project is actually recovered, the project will still meet minimum economic criteria; the project is then termed as "Proved Economic."

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Proved Reserves	2007 – 2.2.2 and Table 3	1.1, 2.4, 4.2, 5.3, 6.24, 7.5, 8.4, 9.1, 10.7	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and underdefined economic conditions, operating methods, and government regulations. 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. Often referred to as 1P, also as “Proven.”
Purchase Contract	2001 – 9.6.8	10.4	A contract to purchase oil and gas provides the right to purchase a specified volume of production at an agreed price for a defined term.
Pure-Service Contract	2001 – 9.7.5	10.5	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 expenses for 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.
Range of Uncertainty	2007 – 2.2 2001 – 2.5	2.28, 3.1, 4.3, 5.4, 6.2, 8.2	The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. (See Resource Uncertainty Categories.)
Raw Natural Gas	2007 – 3.2.1	4.2	Raw Natural Gas is natural gas as it is produced from the reservoir. It includes water vapor and varying amounts of the heavier hydrocarbons that may liquefy in lease facilities or gas plants and may also contain sulfur compounds such as hydrogen sulfide and other nonhydrocarbon gases such as carbon dioxide, nitrogen, or helium, but which, nevertheless, is exploitable for its hydrocarbon content. Raw Natural Gas is often not suitable for direct utilization by most types of consumers.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Reasonable Certainty	2007 – 2.2.2	4.3, 6.2, 8.1	If deterministic methods for estimating recoverable resource quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered.
Reasonable Expectation	2007 – 2.1.2	7.3	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur.
Reasonable Forecast	2007 – 3.1.2	7.1	Indicates a high degree of confidence in predictions of future events and commercial conditions. The basis of such forecasts includes, but is not limited to, analysis of historical records and published global economic models.
Recoverable Resources	2007 – 1.2	2.1, 5.1, 6.1, 8.1	Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations.
Recovery Efficiency	2007 – 2.2	2.4, 4.19, 5.1, 8.7, 10.1	A numeric expression of that portion of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage.
Reference Point	2007 – 3.2.1	7.1, 9.13	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions prior to custody transfer (or consumption). Also called Point of Sale or Custody Transfer Point.
Reserves	2007 – 1.1	1.15, 2.63, 3.16, 4.106, 5.22, 6.68, 7.50, 8.53, 9.37, 10.112	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	2001 – 2.3	1.1, 2.15, 3.68, 4.208, 5.35, 6.55, 7.2, 8.143, 9.16, 10.3	A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rocks/formations and is characterized by a single-pressure system.
Resources	2007 – 1.1	1.10, 2.5, 3.4, 4.15, 5.5, 6.6, 7.7, 8.17, 9.2, 10.66	The term “resources” as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
			"unconventional" (see Total Petroleum Initially-in-Place). (In basin potential studies, it may be referred to as Total Resource Base or Hydrocarbon Endowment.)
Resources Categories	2007 – 2.2 and Table 3	4.8, 5.1, 10.2	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability, contractual changes)
Resources Classes	2007 – 1.1, 2.1 and Table 1	6.1	Subdivisions of Resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and subclasses and/or quantitatively by associating a project's estimated chance of reaching producing status.
Revenue-Sharing Contract	2001 – 9.6.3	10.3	Revenue-sharing contracts are very similar to the production-sharing contracts described earlier, with the exception of contractor payment. With these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Reversionary Interest		7.1	The right of future possession of an interest in a property when a specified condition has been met.
Risk	2001 – 2.5	2.24, 3.3, 4.3, 5.6, 6.23, 7.1, 8.7, 10.23	The probability of loss or failure. As "risk" is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.
Risk and Reward	2001 – 9.4	10.2	Risk and reward associated with oil and gas production activities stems primarily from the variation in revenues due to 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 cost, price, and political or other economic factors.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Risked-Service Contract	2007 – 3.3.2 2001 – 9.7.4	10.4	These agreements are very similar to the production-sharing agreements with the exception of contractor payment, but risk is borne by the contractor. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	2007 – 3.3.1 2001 – 3.8	7.16, 9.1, 10.16	Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. 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. Some agreements provide for the royalty to be taken only in kind by the royalty owner.
Sales	2007 – 3.2	2.6, 4.3, 6.3, 7.9, 9.38, 10.3	The quantity of petroleum product delivered at the custody transfer (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities. All recoverable resources are estimated in terms of the product sales quantity measurements.
Shut-in Reserves	2007 – 2.1.3.2 and Table 2	none—no occurrences	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.
Solution Gas		4.28, 6.3, 7.1, 8.2	Solution Gas is a natural gas that is dissolved in crude oil in the reservoir at the prevailing reservoir conditions of pressure and temperature. It is a subset of Associated Gas.
Sour Natural Gas	2001 – 3.4	none—no occurrences	Sour Natural Gas is a natural gas that contains sulfur, sulfur compounds, and/or carbon dioxide in quantities that may require removal for sales or effective use.
Stochastic Estimate	2001 – 5	2.1, 6.6	Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Subcommercial	2007 – 2.1.2	2.2	A project is Subcommercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. Discovered subcommercial projects are classified as Contingent Resources.
Submarginal Contingent Resources	2007 – 2.1.3.3	2.1	Known (discovered) accumulations for which evaluation of development project(s) indicated they would not meet economic criteria, even considering reasonably expected improvements in conditions.
Sweet Natural Gas	2001 – 3.3	none—no occurrences	Sweet Natural Gas is a natural gas that contains no sulfur or sulfur compounds at all, or in such small quantities that no processing is necessary for their removal in order that the gas may be sold.
Synthetic Crude Oil (SCO)	2001 – A12, A13	8.2	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. SCO may contain sulfur or other nonhydrocarbon compounds and has many similarities to crude oil.
Taxes	2001 – 9.4.2	7.15, 8.1, 10.14	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Uncertainty	2007 – 2.2	2.1, 4.1	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Total Petroleum Initially-in-Place	2007 – 1.1	2.2	Total Petroleum Initially-in-Place is generally accepted to be all those estimated quantities of petroleum contained in the subsurface, 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. Also termed “Original-in-Place” or “Hydrocarbon Endowment.”

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Uncertainty	2007 – 2.2 2001 – 2.5	2.50, 3.17, 4.28, 5.30, 6.20, 7.8, 8.18, 9.1	The range of possible outcomes in a series of estimates. For recoverable resource assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Unconventional Resources	2007 – 2.4	1.1, 8.6	Petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also referred to as "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrate, natural bitumen (tar sands), and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders).
Undeveloped Reserves	2001 – 2.1.3.1 and Table 2	2.4, 6.1, 8.2	Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.
Unitization		none—no occurrences	Process whereby owners group adjoining properties and divide reserves, production, costs, and other factors according to their respective entitlement to petroleum quantities to be recovered from the shared reservoir(s).
Unproved Reserves	2001 – 5.1.1	none—no occurrences	Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
Unrecoverable Resources	2007 – 1.1	8.1	That portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are estimated, as of a given date, not to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data are acquired.
Upgrader	2007 – 2.4	9.2	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil (SCO). While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Well Abandonment		4.3, 7.3	The permanent plugging of a dry hole, an injection well, an exploration well or a well that no longer produces petroleum or is no longer capable of producing petroleum profitably. Several steps are involved in the abandonment of a well: permission for abandonment and procedural requirements are secured from official agencies; the casing is removed and salvaged if possible; and one or more cement plugs and/or mud are placed in the borehole to prevent migration of fluids between the different formations penetrated by the borehole. In some cases, wells may be temporarily abandoned where operations are suspended for extended periods pending future conversions to other applications such as reservoir monitoring, enhanced recovery, etc.
Wet Gas	2001 – 3.2 2007 – 3.2.3	4.2, 8.1, 9.3	Wet (Rich) gas is natural gas from which no liquids have been removed prior to the reference point. The wet gas is accounted for in resource assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resource assessment definition and not a phase behavior definition.
Working Gas Volume		none—no occurrences	With respect to underground natural gas storage, Working Gas Volume (WGV) is the volume of gas in storage above the designed level of cushion gas that can be withdrawn/injected with the installed subsurface and surface facilities (wells, flow lines, etc.) subject to legal and technical limitations (pressures, velocities, etc.). Depending on local site conditions

TERM	REFERENCE*	USED IN THESE GUIDELINES	DEFINITION
			(injection/withdrawal rates, utilization hours, etc.), the working gas volume may be cycled more than once a year.
Working Interest	2001 – 9	7.1, 9.3, 10.4	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

*2001 Guidelines for the Evaluation of Reserves and Resources
2007 Petroleum Resources Management System

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Applications Document Committees

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Applications Document Review Process Summary (2009–11)

A review process for these *Guidelines* was formally adopted at the October 2009 SPE Oil and Gas Reserves Committee (OGRC) meeting. Chapter Editing Committees were formed for each chapter, with expert members procured from all the stakeholder societies. Clear mandates and timelines were established for finalization and review of the chapters. Each Chapter Editing Committee worked with the chapter author(s) to incorporate comments and endorse the revised chapter. A Steering Committee, chaired by Satinder Purewal, oversaw the process.

When each Chapter Editing Committee completed and endorsed its chapter, the Chairman sent the chapter to the Steering Committee Chairman, who circulated it for comment within the Steering Committee. Any comments from the Steering Committee were incorporated with consultation of the Chapter Editing Committee. All chapters were completed in draft form and posted on an online site accessible to all reviewers and authors. Final edits were made and incorporated into one document, which was edited by SPE staff for consistency, language, and clarity. This document was posted on the SPE website from 15 December 2010 to 15 March 2011 for industry review and comment. Prominent notice of the posting appeared on the home page at www.SPE.org.

All comments received by SPE were circulated to the Chapter Editing Committees and the Steering Committee. The comments were discussed at the April 2011 OGRC meeting. Each Chapter Editing Committee worked with the author(s) for inclusion of relevant comments. Finalized chapters, endorsed by the Chapter Editing Committees and by the OGRC were combined into a single document. The Reference Terms were updated to ensure consistent references to the text, as several chapters (e.g., Chaps. 3 and 8) had changed since the draft was published on the SPE website in December.

The final document was sent to the SPE Board of Directors for review and approved on 26 June 2011. Approval from the endorsing societies (AAPG, SPEE, SEG, and WPC) was obtained 19 October 2011. The document was published on the SPE website on 1 November 2011.

ADDENDUM - CORRECTIONS TO THIS DOCUMENT

The following corrections have been made since the original publication in November 2011.

Page	Original Text	Corrected Text	Date
5, Line 6	Chap. 7 covers commercial evaluations, including a discussion on public disclosure and regulatory reporting under existing regulations.	Chap. 7 covers commercial evaluations.	July 2012
66, Line 1	…parameters D_i and *n*.	…parameters D_i and *b*.	July 2012
84, Line 18	If a reservoir is poorly defined, material balance calculations or analog methods may be used to arrive at an estimate of the range of RFs. Uncertainty ranges in the RF can often be based on a sensitivity analysis. If a reservoir or project is poorly defined, material balance calculations or analog methods may be used to arrive at an estimate of the range of RFs. Uncertainty ranges in the RF can often be based on a sensitivity analysis.	If a reservoir is poorly defined, material balance calculations or analog methods may be used to arrive at an estimate of the range of RFs. Uncertainty ranges in the RF can often be based on a sensitivity analysis.	July 2012
119, Eq. 7.3d	$DF_t = 1/[MARR]^{(t\text{-}0..5)}$	$DF_t = 1/[MARR]^{(t\text{-}0.5)}$	July 2012
134, Line 15	…industry generally divides TGFs into (1) basic-centered gas accumulations (BCGA)…	…industry generally divides TGFs into (1) basin-centered gas accumulations (BCGA)…	July 2012