Guidelines for Application of the Petroleum Resources Management System

English- Chinese Version

Sponsored by:

Society of Petroleum Engineers (SPE)
American Association of Petroleum Geologists (AAPG)
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Society of Petroleum Evaluation Engineers (SPEE)
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Guidelines for Application of the Petroleum Resources Management System

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Preface

The Guidelines for Application of the Petroleum Resources Management System (hereinafter referred to as the "Guidelines") was sponsored jointly by the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE) and Society of Exploration Geophysicists (SEG) and published in November 2011. It currently serves as a major specification and guidelines for the petroleum resources management and evaluation practice in global industry. In this Guidelines, from the perspective of systematic engineering on the petroleum resources management, the background and nationals for the guidelines are introduced, PRMS definitions, classification and categorization are further expounded, technical Principles and applications of the key methodologies used in resources and reserves evaluation are illustrated based on typical examples, and a series of important theoretical and practice issues associated with resources management, assets evaluation and reporting are discussed as well. As the Guidelines is rich in content and practical, application examples universal and applicable, it has been widely adopted and applied in the global oil industry, and also accepted by the U.S. Securities and Exchange Commission (SEC) as an important supporting basis for its new "modernization of oil and gas reporting" rules. The Guidelines in English-Chinese version is of great significance to further promote PRMS' global application. It is not only a very useful working hand book for Chinese speaking petroleum engineers and geologists, but also a helpful reference textbook for young petroleum scholars in petroleum universities.

The translation work has been guided by the SPE oil and gas reserves committee, supported by the Department of Mineral Resources Protection and Supervision of the Ministry of Natural Resources of China, and contributed by experts mainly from China National Oil and Gas Exploration and Development Company Ltd. (CNOOC), Research Institute of Petroleum Exploration and Development (RIPE) and Petroleum Industry Press (PIP). All above contributions are sincerely acknowledged. If there is any misleading translation existing in the Chinese version of the Guidelines, the original English version shall prevail. You are also welcome to feedback comments and guide our work in the coming future.

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CHAPTER 1

Introduction
1.1 Rationale for New Application 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:

- 1] Consistency
- 2] Transparency
- 3] 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:

1) Estimation of Petroleum Resources Using Deterministic Procedures (Chap.4)

2) 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 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 therefore, only a high-level overview could be given. Detailed sections on coiled tubing and shale gas are included. The intent is to expand this chapter and add details on heavy oil, bitumen, tight gas, and shale gas 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 to 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 times 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 SEG and PRMS in the formal approval process. The list also includes the International Accounting Standards Board (IASB) and the American Petroleum Institute (API).
AAPG created in 1917; SPE was founded in 1922 and became an autonomous society in 1957; WPC was founded 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
CHAPTER 1 Introduction

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.
第 2 章
CHAPTER 2

Petroleum Resources Definitions, Classification, and Categorization Guidelines

James G. Ross 著，刘合年、吴蕾 译
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 Figure 2.1.
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

每一个项目可以根据其成熟度或所处状态

大致对应于其商业几率划分为三大类别：储量、条件资源量和远景资源量，还可以进一步划分亚类。另一方面，项目的预计可采销量的不确定性范围至少根据低估值、最佳估值和高估值三个可能结果来进行表征。

若一个项目能满足商业性要求，则可以给项目核定储量，并将其估算可采销量的三个评估结果分别确定为1P、2P、和3P。持有条件资源量的项目可对应分级为1C、2C和3C。而远景资源量则使用术语低估值、最佳估值和高估值。该系统还可以按增量法分级和报告证实储量、概算储量和可能储量，而不是用1P、2P和3P情景法。

过去，如第1章所述，项目成熟度和可采量不确定性情形之间存在一定的交叉叠合（因而易混淆）。例如，可能储量的核定可以是未来可能实施的开发项目反映项目的成熟度。也可以是一个已启动或已实施项目的潜在可采量的增量反映可采量的不确定性。本《石油资源管理系统》已消除了这种混淆。因此，清晰地认识到项目划分和储量/资源量分级的根本区别是非常重要的。

2.2 定义项目

PRMS 是一个基于项目的系统。项目 “体现了油气聚集体与决策进程的关联，包括预算资金的分配。一个项目可以是单个油气藏或油气田的开发，亦或是一个在产油气田的增产开发，也可以是共享地面设施的多个油气田的综合开发。一般而言，一个单一项目体现了特定的成熟度水平，以决策项目是否继续推进即投入资金，并得到相应的估算可采量范围”

一个项目可视为一个投资机会。管理决策则是对可用资金、投资成本以及预期投资收益按价值核算所构成投资组合的选择或放弃。项目
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 its 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:

1. 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.

(2) 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.

(3) 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.

(4) 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.

(5) 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.

(6) 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.

(7) 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 4.

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 Figure 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
CHAPTER 2 Petroleum Resources Definitions, Classification, and Categorization Guidelines

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 Figure 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), it is the company's responsibility to assess the uncertainty associated with the estimated quantities. The range of uncertainty is intended to reflect a range of quantities potentially recoverable from an accumulation (or group of accumulations) for a specific, defined project.
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

一些非常成熟的项目, 其技术不确定性相对较小。在 PRMS 中, 不确定性的范围是由项目评估结果的低估值、最佳估值和高估值 3 个情景来表征。对于不同类别的项目, 所采用的术语也有所不同。但不管成熟度如何, 其基本原则是相同的。总之, 如果该项目满足储量类别所需要的所有条件, 则低估值、最佳估值和高估值就可以分别确认为证实储量1P, 证实储量+概算储量2P 和证实储量+概算储量+可能储量3P。相应地，对应条件资源量类别的术语分别是1C, 2C 和3C。而远景资源量则使用术语“低估值”“最佳估值”和“高估值”。

基于确定性评估方法或者概率法可以得到上述三个估值。如第4章和第5章所述, 对于这两种方法之间的关系, PRMS 强调:

“确定法评估结果是概率法评估结果分布范围中的一个离散值”

此外, 资源估值的不确定性最好表述为一系列可能结果的分布范围。当然, 如果要求报告一个代表性结果, 则认为最佳估值是可采量最具有现实意义的评估结果。在使用确定情景法或概率法评估时, 一般认为最佳估值表示的是证实与概算估算之和。2P”

领悟 PRMS 应用的关键点在于: 拟定一个特定项目的可采量为储量，条件资源量或远景资源量完全基于该项目成熟度/状态的评估。如第2.3节所述，相对而言，将储量再划分为1P，2P和3P或相应增量；则完全基于对项目开采量的不确定性考量；条件资源量和远景资源量的情况类似。因此, 在 PRMS 系统中, 如果项目满足储量类别的条件, 则总是应存在一个低估值。1P, 一个最佳估值2P, 和一个高估值3P。除非是非常特殊的情况，例如1P证实储量，估值为零的情形。

尽管评估可以采用确定法或概率法，或多情景法，但如果要得到可对比的结果，遵循的基本
(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 P90 and P10 outcomes are typically selected for the low and high estimates.

2. In the probabilistic method, probabilities actually correspond to ranges of outcomes, rather than to a specific scenario. The P90 estimate, for example, corresponds to the situation whereby there is an estimated 90% probability that the correct answer lies somewhere between the P90 and the P0 (maximum) outcomes. Obviously, there is a corresponding 10% probability that the actual Reserve will be between the P90 and the P100 (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.

(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 or high value 3P reserves even though actual recoverable reserves, the probability that real recoverable reserves are less than the 1P value may be less than 50%. However, as SPE 2001 states, for very mature producing projects, it may be considered that the distribution of uncertainty is very small. Therefore, the correct answer will more likely exceed the 1P estimate than the 2P or 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 than the 2P or 3P estimates. Therefore, the correct answer will more likely exceed the 1P estimate than the 2P or 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 than the 2P or 3P estimates.
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.

2.5.1 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).

2.5.2 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.

2.5.3 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

2.5.1 确定(情景)法

在这种方法中，设计了三个单独的情景来表示可采量的低估值、最佳估值和高估值。这些情景必须反映参数组合的现实性，并需特别小心以确保油气藏属性均值。如平均孔隙度不确定性合理的范围，并考虑属性的相关性。例如，岩石总体积的高估值可能会与较低的平均孔隙度相关联。一般来说，用组合中每个输入参数的低值来确定低估值情景结果是不恰当的，因为这种组合并不代表一个实际存在的低估值情景，而更接近可能结果的绝对最低值。

2.5.2 确定(增量)法

确定(增量)法广泛应用于陆上成熟地区，特别是按井距部署的区域。通常，证实已开发储量可核定在已钻井的井距控制区域内。证实未开发储量可核定在相邻一个井距与产层连通性度高区域。概算和可能储量则可核定到更远、置信度较低的区域。上述储量增量，如概算储量是单独估算的，而不是定义一个证实储量+概算储量情景。这种情形下，需要特别注意的是，一般要正确定义项目，例如，区分已计划井位和潜在井位。二是确保适当表述了所有不确定性，包括采收率。

2.5.3 概率法

通常，概率法的应用是采用蒙特卡洛分析。在这种情况下，由用户定义输入参数的不确定性分布以及它们的关系。然后在这些假定的输入参数组合基础上用蒙特卡洛分析技术得到一个结果分布。如上所述，运算模型的每一次迭代计算代表的都是一个离散的确定性情景。然而，每次迭代计算是由软件完成的，而不是用户来确定参数的组合。运算很多次不同的可能组合通常几千次，是为了得到可能结果范围的完整概率分布，并从中选择出三个代表性结果，如P90、P50和P10。也可以应用油藏随机建模的方法。
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., P90, P50 and P10). Stochastic reservoir modeling methods may also be used to generate multiple realizations.

### 2.5.4 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 P90, P50 and P10 (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.

来产生多个实现

2.5.4 多情景法

多情景法是一种结合确定性、概率法的综合方法。在这种情况下，由用户设置大量离散的确定性情景，也许 100 个或更多，并为每一个可能的输入参数赋予概率。例如，可考虑三个可能的深度转换模型，根据用户对每个模型的相对可能性来赋予其概率。每个情景会得到一个单独的确定性结果而每个输入参数概率的叠加就可得到该情景/结果的概率。如果有足够多的情景，可通过实验设计技术来补充。就可以建立一个完整的概率分布，从中选择三个特定情景，例如，最接近 P90、P50 和 P10 的确定性情景。

2.6 商业风险与披露数量

在石油资源管理系统 PRMS 中，商业风险可以定量地表述为商业几率，并定为两个风险因素的乘积：

1. 潜在油气聚集体实现石油发现的几率也称为“发现几率”
2. 一旦发现，该油气聚集体将实现商业开发的几率称为“开发几率”

由于储量和条件资源量只归属于已发现的油气聚集体，因此其发现几率为 100%。而商业几率则等于开发几率。此外，如前文所述，对于一个即将核定储量的项目而言，其进一步商业开发的几率应该非常高。若存在商业风险，也非常小。因此，在储量的评估和报告中，商业风险一般都忽略不计。

当然，对有条件资源量或远景资源量的项目而言，商业风险可能很高。应认真考量与记录。对于远景资源量，已有相对多行业实践，但对于条件资源量，似乎对其商业风险的认识尚不一致。首先，我们看看远景资源量的行业实践经验情况。发现几率的评估是基于形成一个油气聚集体所需的要素、烃源岩、圈闭、运移等出现的几率。
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 P90 of the risked success-case distribution (or any other probability level other than the mean itself) by multiplying an unrisked success-case P90 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.

另外，还要评估“发现”在规模上的潜在不确定性。通常，这种评估是假设在可能发现的不确定性分布范围，由于该分布可能包含一些低于商业项目经济界限的结果。高于经济界限部分的概率可作为开发几率。再与发现几率相乘就得到商业几率。然后重新计算“成功案例”即发现规模大于最小经济油田规模的结果分布。

由于远景资源量一般不对外披露，因此公司都建立了各自独有的内部系统来记录风险与预期结果之间的关系。一般来说，一个结果数值确定，应该是风险后的平均值或者风险后的平均有效体积。即大于最小经济油田规模。其风险就是商业几率，而均值就是取自成功案例的可采量分布。需要注意的是，从数学角度来看，成功案例风险前的P90与商业几率相乘来计算成功案例风险前的P90，或任何其他概率值是无效的。

对于条件资源量，很容易假定一个类似远景资源量评估的过程——根据可采量估值高于最低经济界限的概率来确定一个“成功案例”结果。但这样做是不对的。

一旦获得一个发现，并评估出其技术可采量范围，若当前存在任何或有因素使该项目无法划归为商业项目，那么该项目的可采量应被确定为条件资源量。若该或有因素完全是技术性的，例如环境审批方面的问题，一般其估算可采量的不确定性不会因为该或有因素的消除而受到影响。一旦该或有因素被消除，理论上而言，条件资源量1C、2C和3C应直接升级为1P、2P和3P储量。当然，前提是条件资源量的其他条件都能满足。且计划的开发项目没有任何变化。在这个案例中，商业几率就是获得环境许可的概率。然而，另一种可能阻碍开发决策的或有因素是1C资源估算量太小，不足以启动该项目，即使2C资源量经济可行，这种情况并不少见。例如，某公司首先通过测算表明，项目的2C资源
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 Figure 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.

Figure 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

可辅以商业几率的定量评估，如第2.6节所述，项目成熟度不同水平之间的界限可能对应于内部公司的项目“决策点”。因此，为公司决策过程与资源分类组合特征之间建立了直接的关联关系。该关联关系也将相应地有助于为商业几率分配适当的量化风险因子。

评估师也可以采用其他可替代的亚类和项目成熟度调节因子来契合自己的决策过程，但商业几率增加的理念应该是支撑整个分类系统应用和资产管理的一个重要驱动因素。需要注意的是，就量化而言，图2.1和图2.2中所示的“商业几率”在纵轴上并不代表线性比例。例如，一个条件资源量项目若被核定为“开发不可行”，
CHAPTER 2 Petroleum Resources Definitions, Classification, and Categorization Guidelines

This does not mean that its commerciality will be lower than that of 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 Figure 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 the chance of commerciality. If the subclasses in Figure 2.2 are adopted, the following general guidelines should be considered in addition to those documented in Table 1 of PRMS:
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.

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.

(6) 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 determine 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.

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.

Table 2.1 Relationship between Project Maturity Sub-classes and Reserves Status

<table>
<thead>
<tr>
<th>Project Maturity Sub-classes</th>
<th>Reserves Status</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Developed Producing Reserves</td>
<td>Developed Non-Producing Reserves</td>
</tr>
<tr>
<td>On Production</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Approved for Development</td>
<td>×</td>
<td>✓</td>
</tr>
<tr>
<td>Justified for Development</td>
<td>×</td>
<td>×</td>
</tr>
</tbody>
</table>

In the absence of project maturity subclasses, reserves status
subdivisions can lead to the mixing of two different types of
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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 2.2):

<table>
<thead>
<tr>
<th>Project Maturity Subclass</th>
<th>Additional Sub-classification</th>
<th>Economic Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Development Pending</td>
<td>Pending</td>
<td>Marginal Contingent Resources</td>
</tr>
<tr>
<td>Development Unclarified or On Hold</td>
<td>On Hold</td>
<td>Undetermined</td>
</tr>
<tr>
<td>Development not Viable</td>
<td>not Viable</td>
<td>Sub-marginal Contingent Resources</td>
</tr>
</tbody>
</table>

2.9 经济状态

第三种可选用的次级划分方式是按经济状态将条件资源量项目进一步划分为边际的或者次边际的。此外，PRMS 提示，评价工作尚未结束之前，未确定最终商业几率的时机并不成熟，此时项目经济状态为“未确定”是可以接受的。与选用储量状态进行次级划分一样，按经济状态进行次级划分也可以单独应用或与项目成熟度亚类划分联合应用。

总的来说，这两种可选用方式之间的近似关系如表 2.2 所示。

Table 2.2 Relationships between Project Maturity Subclass and Economic Status

<table>
<thead>
<tr>
<th>项目成熟度亚类</th>
<th>其他次级划分</th>
<th>经济状态</th>
</tr>
</thead>
<tbody>
<tr>
<td>待开发</td>
<td>待定</td>
<td>边际条件资源量</td>
</tr>
<tr>
<td>开发未明确或延迟开发</td>
<td>延迟</td>
<td>未确定</td>
</tr>
<tr>
<td>开发不可行</td>
<td>不可行</td>
<td>次边际条件资源量</td>
</tr>
</tbody>
</table>

References

Petroleum Resources Management System, SPE, Richardson, Texas, USA (March 2007).
CHAPTER 3

Seismic Applications

Jean-Marc Rodriguez ②著，叶禹Ⅱ李二恒 译

② 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.

SEG油气储量委员会主要贡献人② Patrick Connolly, Henk Jaap Kloosterman, James Robertson, Bruce Shang, Raphic van der Weiden and Robert Withers.
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 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 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

3.2.2 Process of Resource Estimation

The processes of resource estimation encompass a wide range of techniques, including those used to interpret seismic data, reservoir simulation, and petrophysical analysis. 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.

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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 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:

(1) A relationship exists at log scale between these attributes and specific reservoir characteristics;

(2) This relationship still exists at seismic scale (which exhibits lower vertical resolution);

(3) The seismic quality is satisfactory;

(4) 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 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 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 as
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 contact in a high quality oil sand. The normalized seismic amplitude map in Figure 3.1 a 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 b. 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.

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).

Figure 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 visualization 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).

利用适当的 AVO 数据体可以提高振幅对构造与烃相关的响应和平点直接烃类指示 DHI 的识别，在任何情况下 DHI 的识别必须提供地震岩性分析来支持 DHI 的识别，以确保反射强度和极性与期望结果是一致的显示的 DHI 也必须与闭合的几何形态一致 图 3.2。
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:

1. The flat-spot and/or seismic amplitude anomaly is clearly...
visible in the 3D seismic, and not related to imaging issues.

(2) 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.

(3) 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:

(1) 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.

(2) 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.

(3) 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 only are 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 with 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

(1) Acquires a baseline seismic data-set

(2) Allows fluid flow to occur through production and/or injection with associated pressure/temperature changes

(3) Acquires additional 3D seismic data-sets sometime after the baseline

(4) Observes differences between the seismic character of the two data-sets in the reservoir interval

- 20 - in a single fault block. In the 3D seismic, and not related to imaging issues.

(2) 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.

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(1) 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.

(2) 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.

(3) 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 only are 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 with 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

(1) Acquires a baseline seismic data-set

(2) Allows fluid flow to occur through production and/or injection with associated pressure/temperature changes

(3) Acquires additional 3D seismic data-sets sometime after the baseline

(4) Observes differences between the seismic character of the two data-sets in the reservoir interval

- 20 - in a single fault block. In the 3D seismic, and not related to imaging issues.

(2) 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.

(3) 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:

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(5) 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.

5) 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.

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CHAPTER 3 Seismic Applications

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 a), different from what was expected. New spectrally boosted 3D seismic (Figure 3.4 b) shows evidence for a normal fault cutting the F block into two separate blocks. The 3D horizon (Figure 3.4 c) shows that the downthrown block corresponds to the same area seen to be unswept on the time-lapse seismic (Figure 3.4 a).

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 d—solid lines) show a much later water breakthrough, as compared to actual production data (Figure 3.5 d—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 d—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.

Figure 3.3 Example of Using Time-Lapse Seismic to Assess OWC Movement.

Diagram showing oil/water contacts (OWCs) and reservoir properties for the F block. The original OWC is shown in red, and the current OWC is shown in blue. The figure illustrates a 3D seismic volume that has been colorized by OWC depth. The red contour represents the original OWC, while the blue contour represents the current OWC. The difference between the two contours indicates the area that has been swept by the oil-water contact.

According to the time-lapse seismic analysis, the oil-water contact (OWC) changes can be mapped laterally and used to update static and dynamic reservoir models that underpin the Resources and Reserves volumes estimate.

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Figure 3.4 Time-lapse Seismic Results Indicate the Presence of A Sealing Fault.

Figure 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

(1) The quality of the seismic data (bandwidth, frequency content, signal-to-noise ratio, acquisition and processing parameters, overburden effects, etc.)

(2) 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

(1) The incorrect positioning of structural elements during the processing of the seismic
(2) Incorrect interpretation
(3) 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 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

展，该转换过程被称作地震反演。通常情况下，声波阻抗和横波阻抗与岩性、孔隙度、孔隙填充物和其他因素之间存在相关关系，因此分析这些相关性、岩性模型，联合反演后的地震数据就可以对这些参数进行评估。

反演后的地震数据主要针对层而不是界面，而且反演后一些地震数据特征可以比常规形式下更明显或更易于解释。因此，将两种形式的地震基础信息都进行分析是很有价值的。

地震反演需要将地震数据与其他的一些数据相结合，因此高品质声波阻抗反演数据体将比常规地震数据体蕴涵更多信息。对于缺少低频的地震数据，需要特别地弥补一些数据。当然，很少有足够的数据完全约束低频分量，所以反演结果可能不是唯一的。由于这种不确定性的存在，可尝试用概率数学方法捕捉可能结果的整个分布范围。不确定性分析应包括反演过程的不唯一性和岩石模型引起的不确定性。不同反演结果的概率随后可以用作储量和资源量评估的输入参数。当然，评价所有不确定性是十分困难的。采用这种技术需要有很好的记录跟踪作为支撑。此外，必须以测井尺度的分辨率构建声波阻抗或弹性波阻抗与岩石物性之间的相关关系，也应考虑该类反演的方法以及基于井网构建的用于生成低频分量背景模型的置信度。

下面是一个地震反演案例。在这个案例中，原地量评估的主要不确定性源于净砂岩厚度分布。储层单元内孔隙度变化很小。尽管总的趋势是随着储层加深，孔隙度略微变小。类似地，含油饱和度的变化也不大。但是，储层厚度和砂体含量变化很大。概率反演被用来更好地评价净砂体的分布。量化不确定性的范围。反演基于层面模型，所有的输入数据整理为网格格式。反演将匹配的地球物理和地质资料与地震数据相结合。在地震振幅的软约束下，通过井和地质数据获得储层参数。如层厚厚度，净毛比，孔隙度和流体饱和度的概率密度函数，使用上述信息和可生
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.

Figure 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.

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CHAPTER 4

Assessment of Petroleum Resources Using Deterministic Procedures

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CHAPTER 4 Assessment of Petroleum Resources Using Deterministic Procedures

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 necessary to determine the in-place, resources, or reserves volumes.
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.

Figure 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. Figure 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.

Figure 4.1 Changes in Uncertainty and Assessment Methods Over the Project’s E&P 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:

1. The type, quantity, and quality of geoscience, engineering, and economics data available and required for both technical and commercial analyses.

2. 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 Figure 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.

Figure 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.

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

油气可采量（储量和资源量）的确定性评估主要有间接和直接两种方法，分别包括基于容积数据的“静态法”以及基于生产数据的“动态法”。储量和资源量评估合理方法的选择及其评估的精确度主要取决于以下因素：

1. 可用于技术和经济分析的地质、工程和经济参数的类型、数量与质量。
2. 具体油气藏地质复杂程度、开采机理、开发阶段、开采程度或成熟度。

更重要的是，储量和资源量评估的可靠性还取决于资深专业评估师的职业道德、专业技能和经验判断。

4.2 技术评估理论与应用

本节提供了一个油气项目案例，对其不同成熟度阶段所采用的资源评估确定性方法进行了技术综述，并在图4.1中追溯了其与勘探开发生命周期中不同时期与阶段的对应关系。另外，本节还增加了一个气藏储量评估案例，以阐述广泛应用并基于动态数据的物质平衡法（视地层压力p/z）和累计产气量的关系。本节重点是风险和不确定性评估，以及如何采用PRMS进行石油资源储量的分类与分级。

4.2.1 定义示例油项目——设定阶段

由于要诠释每一种评估技术的确定性流程，设定好案例油藏所处项目成熟度阶段，并进行适当的状态描述，识别其特征是十分重要的。

图4.1a展示了该案例项目在不同成熟度阶段所采用的油气原始原油量和可采量评估方法与时间轴的对应关系。

该案例油藏是成熟含油气盆地的一个典型油气聚集体，该盆地发育特大型构造，储层区域上连续性好，而且周边有大量可供类比的开发项目，因此，对于其他含油气盆地的资源评估而言，本
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

1. 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 (WSUs'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.

2. 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

![Figure 4.1a Timeline for example oil project maturity stages and assessment methods used](image)
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:

① 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.

② 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, pre-discovery, post-discovery, appraisal, and initial development (or exploitation) stages of the E&P life cycle of any recovery project.

4.2.2.1 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

\[
\text{EUR (STB or scf)} = \text{IIP (STB or scf)} \times \text{RE (fraction of PIIP)}
\] (4.1a)

CHAPTER 4  Assessment of Petroleum Resources Using Deterministic Procedures
In terms of average variables of area (A), net pay (h), porosity (φ), initial water saturation (S\textsubscript{wi}) and hydrocarbon formation volume factor (FVF) (B\textsubscript{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

\[
\text{PIIP (STB or scf)} = A h \phi (1 - S_{\text{wi}})/B_{hi}
\]

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.
CHAPTER 4 Assessment of Petroleum Resources Using Deterministic Procedures

4.2.2.2 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 Figures 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.

4.2.2.2.1 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 Figure 4.2a was developed based on a combination of seismic and geological studies that defined the shape and closure for potential petroleum 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°API.

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Figure 4.2  Volumetric Assessment of Prospective Resources: Pre-discovery stage [Wang (2010)].
The volumetric assessment process starts with the estimate of gross reservoir rock volume depicted by the cross section presented as Figure 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 Figures 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%.

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).

4.2.2.2 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 Figure 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.

容积法评估 可先根据图 4.2a 所示的剖面图来估算油藏岩石总体积。根据区域类比 可乐观估计整个构造全充满 至溢出点海拔深度 -6410ft。保守估计的低估值为海拔深度 -6120ft。最佳估值的垂向界限为高估值和低估值的中部深度 —— 海拔深度 -6265ft。通常 可根据区域和该目标区的地质资料来构建净毛比 (NTG) 分布图 —— 通过邻近类比油藏 可获取净厚度截止值 以剔除不能满足最低生产能力的无效储层 再结合总油藏体积分布 即可得到有效厚度等值线图。在本例中 评估师采用恒定的平均净毛比 0.70。图 4.2b、4.2c 和 4.2d 所示有效厚度等值线图分别代表低估值、最佳估值、高估值情景的油藏有效储层厚度图。这些图展示了每个情景在纵向和平面上的砂体展布。此外 根据对烃源岩、圈闭完整性、油藏充注度以及区域油气运移途径的单独评价 估算发现几率为 40%。基于对经济条件情景的分析和其 他商业或有因素的评价 该目标技术成功之后商业开发的几率 或开发几率 为 60%。因此 该勘探目标的整体商业几率为上述两个风险因子的乘积 即 24%。

表 4.1 列出了一个假定发现的平均油藏参数 估值 包括岩石和流体性质 以及邻近类似油藏成熟应用边缘注水技术开发的采收率范围 以及尚未发现的油气远景资源量估值 由于油藏边部品质变差 在评估每个资源量级别时 油藏平均孔隙度缺值减小 / 和 / 或平均原始含水饱和度变高增加。
Table 4.1 Volumetric Assessment of Prospective Resources (Pre-discovery Stage): Estimates of Project PIIPs and EURs

<table>
<thead>
<tr>
<th>Estimated Parameters</th>
<th>Units</th>
<th>Bases and Categories of Prospective Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Low Estimate</td>
</tr>
<tr>
<td><strong>Bulk Reservoir Pay Volume</strong></td>
<td>M ac·ft</td>
<td>241.4</td>
</tr>
<tr>
<td><strong>Average Porosity</strong></td>
<td>%</td>
<td>17</td>
</tr>
<tr>
<td><strong>Pore Volume PV</strong></td>
<td>M ac·ft</td>
<td>41.0</td>
</tr>
<tr>
<td><strong>Average Initial Water Saturation</strong></td>
<td>%</td>
<td>18</td>
</tr>
<tr>
<td><strong>Hydrocarbon Pore Volume (HCPV)</strong></td>
<td>M ac·ft</td>
<td>33.7</td>
</tr>
<tr>
<td><strong>Average FVF B,</strong></td>
<td>RB/STB</td>
<td>1.4</td>
</tr>
<tr>
<td><strong>Oil Initially-In-Place OIIP</strong></td>
<td>MMSTB</td>
<td>186.5</td>
</tr>
<tr>
<td><strong>Recovery Factor</strong></td>
<td>% (OIIP)</td>
<td>35</td>
</tr>
<tr>
<td><strong>Recoverable Oil EUR</strong></td>
<td>MMSTB</td>
<td>65.3</td>
</tr>
<tr>
<td><strong>Initial Solution Gas-Oil Ratio(Rgs)</strong></td>
<td>scf/STB</td>
<td>500</td>
</tr>
<tr>
<td><strong>Gross-Heating Value of Raw Solution Gas</strong></td>
<td>Btu/scf</td>
<td>1200</td>
</tr>
<tr>
<td><strong>Gas Initially-In-Place GHP</strong></td>
<td>Bscf</td>
<td>93.2</td>
</tr>
<tr>
<td><strong>Recoverable Raw Gas EUR</strong></td>
<td>Bscf</td>
<td>32.6</td>
</tr>
<tr>
<td><strong>Recoverable Raw Gas EUR</strong></td>
<td>MMBOE</td>
<td>6.8</td>
</tr>
</tbody>
</table>

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.

4 Estimated oil and gas Prospective Resources categories of Low, Best and High, respectively.
第 4 章 确定法石油资源评估
CHAPTER 4 Assessment of Petroleum Resources Using Deterministic Procedures

a. Structural Cross Section AA’ (not to scale horizontally) 油藏剖面图AA’（水平方向无比例）
Subsea Depth (ft) 海拔深度 (英尺)

b. Net Pay Isochore Map for Low Estimate (1C) 低估值情景油层等厚图 (1C)

c. Net Pay Isochore Map for Best Estimate (2C) 最佳估值情景油层等厚图 (2C)

d. Net Pay Isochore Map for High Estimate (3C) 高估值情景油层等厚图 (3C)

Figure 4.3 Volumetric Assessment of Contingent Resources: Post-discovery stage [Wang (2010)]

图 4.3 容积法评估条件资源量(发现后)(据 Wang, 2010)
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 (LKH) 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°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.

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.

At this stage, remaining uncertainty in the project’s commercial development was still considerable 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 devised to further evaluate the discovery was deemed necessary.

4.2.2.2.3 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,

尽管开发概念®设计的初步经济评价结果令人振奋®但存在很大不确定性®评估商业开发的几率只有60%因此®该油藏的技术可采量估值只能重新划归为条件资源量®即使在已知烃顶®HKH®以上®也不排除存在气顶的可能性®但由于绝大多数类比油藏是未饱和的®所以简而言之®制图时先忽略气顶®后续获得更多详实的压力/体积/温度®PVT®分析和压力梯度数据之后®再进一步确认®

高估值®3C®情景假设油在整个构造全充满至溢出点®更新后的地质图显示构造闭合面积更大®采收率更高®已知烃底®LKH®是低估值情景®1C®的深度上限®在没有更多限制性条件存在情况下®最佳估值®2C®情景的深度界限基于区域类比认识取®1C®情景和®3C®情景的中值®为海拔深度®6283ft®其采收率也略高于®1C®情景的采收率®根据发现井的构造和测井解释资料®以及取样测得的原油平均重度®32°API®可按照体积加权方式相应地更新平均油藏参数®但该阶段的采收率保持不变®

表4.2给出了平均油藏岩石和流体参数®以及相应的油气条件资源量估算结果®请再次留意®2C®和®3C®情景所用的“平均”孔隙度略低®反映了更大的油藏体积估算量中增加了边部低孔隙度®和高含水饱和度®的储层®

在该阶段®项目商业开发的其他不确定性仍然较大®且没有更多资料®例如®进一步的开发评价®井底®PVT®取样®压力梯度®系统生产测试及相关分析®®业主尚不愿承诺项目开发的资金®为了进一步确认商业化开发潜力®有必要实施评价工作来进一步评估该发现®

4.2.2.2.3 评价®或开发评价®阶段

设计和实施的评价工作方案包括®1®新钻®2®井®开展试验井和®PVT®分析®®采集三维地震数据并解释®实施上述评价工作和完成必要的分析与解释®用了®2®年时间®

井®2®和®3®均钻遇储层®获取了新的已知烃底®(LKH®)®将低估值情景的深度基准线推至海拔®6240ft®井底流体流体®PVT®分析显示油藏未饱和®压力梯度测试也证实了油藏是未饱和状态®从而排除了气顶的存在®另外®还进一步确定了以下
### Table 4.2 Volumetric Assessment of Contingent Resources — Post-Discovery Stage: Estimates of Project PIIPs and EURs

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<td>M ac·ft</td>
<td>448.4</td>
</tr>
<tr>
<td>Average Porosity</td>
<td>%</td>
<td>19.1</td>
</tr>
<tr>
<td>Pore Volume PV</td>
<td>M ac·ft</td>
<td>85.6</td>
</tr>
<tr>
<td>Average Initial Water Saturation</td>
<td>%</td>
<td>14.5</td>
</tr>
<tr>
<td>Hydrocarbon Pore Volume HCPV</td>
<td>M ac·ft</td>
<td>73.2</td>
</tr>
<tr>
<td>Average FVF B Bo</td>
<td>RB/STB</td>
<td>1.4</td>
</tr>
<tr>
<td>Oil Initially-In-Place OIIP</td>
<td>MMSTB</td>
<td>405.8</td>
</tr>
<tr>
<td>Recovery Factor Recovery Factor</td>
<td>% (OIIP)</td>
<td>35</td>
</tr>
<tr>
<td>Recoverable Oil EUR</td>
<td>MMSTB</td>
<td>142.0</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio R_s</td>
<td>scf/STB</td>
<td>500</td>
</tr>
<tr>
<td>Gross-Heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td>1200</td>
</tr>
<tr>
<td>Gas Initially-In-Place GIIP</td>
<td>Bscf</td>
<td>202.9</td>
</tr>
<tr>
<td>Recoverable Raw Gas EUR</td>
<td>Bscf</td>
<td>71.0</td>
</tr>
</tbody>
</table>

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.

4. Estimated oil and gas Prospective Resources categories of 1C, 2C, and 3C, respectively.

Calculated using the conversion factor of 7,758 bbl/acre-ft.  
使用转换系数 7758bbl/acre-ft 进行计算。  
边缘注水开发已在邻近的类比油藏和项目成熟应用。  
使用 5.8MMBtu/BOE 平均转换系数计算。  
原油和天然气条件资源量的低估值、最佳估值和高估值。
1. 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.

2. 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.

3. The reservoir had a bubblepoint pressure ($p_{bp}$) of 1,930 psia, initial solution gas/oil ratio (GOR), or $R_{si}$ of 550 scf/STB, and initial ($B_{o}$) and bubblepoint ($B_{ob}$) FVF's of 1.33 RB/STB and 1.35 RB/STB, respectively.

Figure 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 (Figure 4.4b to 4.4d), illustrating the interpreted areal extent and net reservoir volume for each reserves category.

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.

### 4.4 Revised Map Views

- **Figure 4.4a**: 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.
- **Figure 4.4b**: 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.
- **Figure 4.4c**: 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.
- **Figure 4.4d**: 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.

**Recognize:**

- **1P**: 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.
- **2P**: 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.
- **3P**: 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.

- **GOR**: 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.
- **NTG**: 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.

- **Well 1 (0.75)**: 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.
- **Well 2 (0.70)**: 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.
- **Well 3 (0.55)**: 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.

- **Initial Solution Gas/Oil Ratio (GOR)**: 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.
- **Initial Reserves**: 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.

**Implementation:**

- **Initial Development Program**: 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.
- **Pressure Maintenance**: 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.
- **Peripheral Water Injection**: 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.

**Conclusion:**

- **Updated Reserves**: 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.

- **New Estimates**: 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.

- **Revised Map Views**: 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.
Figure 4.4  Volumetric assessment of Reserves: appraisal stage [Wang (2010)]
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

<table>
<thead>
<tr>
<th>Estimated Parameters</th>
<th>Units</th>
<th>Bases and Reserves Categories</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk Reservoir Pay Volume</td>
<td>M ac·ft</td>
<td></td>
<td>821.0</td>
<td>1370.8</td>
<td>1917.9</td>
</tr>
<tr>
<td>Average Porosity</td>
<td>%</td>
<td></td>
<td>18.9</td>
<td>18.7</td>
<td>18.5</td>
</tr>
<tr>
<td>Pore Volume [ ] PV</td>
<td>M ac·ft</td>
<td></td>
<td>155.2</td>
<td>256.3</td>
<td>354.8</td>
</tr>
<tr>
<td>Average Initial Water Saturation</td>
<td>%</td>
<td></td>
<td>14.8</td>
<td>15.0</td>
<td>15.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon Pore Volume [ ] HCPV</td>
<td>M ac·ft</td>
<td></td>
<td>132.2</td>
<td>217.9</td>
<td>300.5</td>
</tr>
<tr>
<td>Average FVF [ ] B, [ ]</td>
<td>RB/STB</td>
<td></td>
<td>1.330</td>
<td>1.330</td>
<td>1.330</td>
</tr>
<tr>
<td>Oil Initially-In-Place [ ] OIIP</td>
<td>MMSTB</td>
<td></td>
<td>771.2</td>
<td>1271.0</td>
<td>1753.0</td>
</tr>
<tr>
<td>Recovery Factor [ ] (%(OIIP))</td>
<td>%</td>
<td></td>
<td>35</td>
<td>40</td>
<td>45</td>
</tr>
<tr>
<td>Recoverable Oil [ ] EUR</td>
<td>MMSTB</td>
<td></td>
<td>269.9</td>
<td>508.4</td>
<td>788.8</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio (R_o)</td>
<td>scf/STB</td>
<td></td>
<td>550</td>
<td>550</td>
<td>550</td>
</tr>
<tr>
<td>Gross-Heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td></td>
<td>1200</td>
<td>1200</td>
<td>1200</td>
</tr>
<tr>
<td>Gas Initially-In-Place [ ] GIP</td>
<td>Bscf</td>
<td></td>
<td>424.1</td>
<td>699.0</td>
<td>964.1</td>
</tr>
<tr>
<td>Recoverable Raw Gas [ ] EUR</td>
<td>Bscf</td>
<td></td>
<td>148.4</td>
<td>279.6</td>
<td>433.9</td>
</tr>
<tr>
<td></td>
<td>MMBOE</td>
<td></td>
<td>30.7</td>
<td>57.9</td>
<td>89.8</td>
</tr>
</tbody>
</table>

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.
4 Estimated oil and gas Reserves categories of 1P, 2P and 3P, respectively.

使用转换系数 7758bbl/acre-ft 进行计算
采用边缘注水方式开发已成熟应用
使用平均转换系数 5.8 MMBtu/BOE 进行计算
原油和天然气的 1P、2P 和 3P 储量估值

60.
CHAPTER 4 Assessment of Petroleum Resources Using Deterministic Procedures

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 m 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 km² (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.

4.2.2.4 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 of an approved development plan would allow for the installation of necessary equipment.

3口井的注采比约为60个1-km井距有效储层的横向连续性在该范围内是否可以判定很高，储层物性好平均渗透率400mD和连续性佳的特征也在邻近的大量类比油藏中得到印证。因此，满足PRMS关于合理确定性的条件要求，阶段1P储量的状态可考虑为证实未开发PD，而根据研究结果1口井的泄油面积约为1km²，大约250 acres。那么现有3口井的控油面积约占总证实体积60个井距面积或原油原始原地量38.5MMSTB的5%必要的生产设施安装启动之后3口井的储量可划归为证实已开发PD。

4.2.2.4 开发初期阶段

与邻近相同储层的成熟类比油藏类似，推荐以一次采油和二次注水相结合的开发方式实施单一开发项目，项目获得批准后立即实施，项目设计初期产量为75,000 BOPD，2P储量508.4 MMSTB。见表4.3年采油速度为5.4%，日注水量为100,000 BWPD。边缘注水保持油藏压力的开采方式在邻近的几个类比项目中非常有效，部分活跃的边水区域注水驱替原油向上方向流动，从而提高采收率，某些项目的采收率超过了原始原地量的60%。

保守估计平均单井日产量2500～3000 BOPD。初始开发方案共需要34口开发井，包括3口可投产的老井，以保持油田注采平衡。在配产中考虑了油田的生产时效，即考虑由于作业因素造成的无效生产时间，如年度地面设施保养，包括检查、维修和检测，而关井停产的时间项目还需要8口水源井从中床浅水层获取水源，和19口边缘注水井注入油田出水和外部供给的水以保持油藏压力与注采平衡，另外项目还包含相应的地面生产与注入设施以及输油干线。根据已确定的开发方案产量剖面，所需初始投资用于钻井与完井生产管柱，地面生产和注入设施以及管线等。未来投资。未来新钻井及其生产管柱，和项目经济生命期内的操作费可再次确认该开发项目的经济可行性，项目获得批准。
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.

Figure 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 (Figure 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 inplace 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 Figure 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 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.

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准项目纳入公司投资预算计划。该项目的产能建设期为3年。第1年投产，第2年达到峰值，第3年到第5年产量开始下降。为了保持高产，需要在早期阶段开始注水开发，以提高体积波及效率和改善产量下降。更多的注水井（如第16口油井）——加上未标井号的空心圆点——在油藏投产期的第8年期间钻了更多井以全面开发该油藏。
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.

与评价阶段相比，该油藏在开发初期得到了充分地评价。31口井的测井及测试资料显示，该油藏的品质好于类比油藏。因此，各级别储量的采收率比评价期适度提升5% OIIP。高估值情景达到了石油原始原地量的50%。当然，随着生产数据和新井数量的增加，该估值还将在后续评估中进一步修正。

Figure 4.5 Volumetric assessment of Reserves (initial development stage).
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 km² (or about 250 acres) average well spacing. There were approximately 98 1-sq-km WSUs in the area described by the original OWC. Although wells were not necessarily drilled in the center of each WSU (Figure 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 514.7 MMSTB (refer to Table 4.4), 25.7 MMSTB (= 514.7 × 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.

Finally, the example oil project’s EOR potential is supported by the results of a miscible CO₂ 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.

4.2.2.3 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 Figure 4.6.

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.

Table 4.4 lists the updated oil and gas resources with the new approach: the initial oil-in-place (OIP) is shown in Table 4.4.

<table>
<thead>
<tr>
<th>Category</th>
<th>Oil (MMSTB)</th>
<th>Natural Gas (Bscf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PD</td>
<td>25.7</td>
<td>14.7</td>
</tr>
<tr>
<td>2C</td>
<td>13.8</td>
<td>7.1</td>
</tr>
<tr>
<td>2P</td>
<td>12.4</td>
<td>6.7</td>
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<tr>
<td>3P</td>
<td>11.9</td>
<td>6.3</td>
</tr>
</tbody>
</table>

With the revised OIIP (1,429.6 MMSTB), the potential project used conservative incremental recovery of 20% OIIP to calculate the contingent resources. The results of a miscible CO₂ pilot project supported the EOR potential. In the Appraisal Stage, based on the developed OIIP, 25.7 MMSTB of oil and 14.7 Bscf raw gas were assigned.
### Table 4.4 Volumetric Assessment of Reserves (Initial Development Stage): Estimates of Project PIIPs and EURs

<table>
<thead>
<tr>
<th>Estimated Parameters</th>
<th>Units</th>
<th>Bases and Reserves by Category and Status</th>
<th>Proved Reserves Status</th>
<th>Best Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Low Estimate</td>
<td>Proved Developed (PD)</td>
<td>Proved Undeveloped (PUD)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bulk Reservoir Pay Volume</td>
<td>M ac·ft</td>
<td>1523.3</td>
<td>548.4</td>
<td>974.9</td>
<td></td>
</tr>
<tr>
<td>Average Porosity</td>
<td>%</td>
<td>19.0</td>
<td>19.0</td>
<td>19.0</td>
<td></td>
</tr>
<tr>
<td>Pore VolumePV</td>
<td>M ac·ft</td>
<td>289.4</td>
<td>104.2</td>
<td>185.2</td>
<td></td>
</tr>
<tr>
<td>Average Initial Water Saturation</td>
<td>%</td>
<td>15.0</td>
<td>15.0</td>
<td>15.0</td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon Pore VolumeHCPV</td>
<td>M ac·ft</td>
<td>246.0</td>
<td>88.6</td>
<td>157.4</td>
<td></td>
</tr>
<tr>
<td>Average FVF B,</td>
<td>RB/STB</td>
<td>1.335</td>
<td>1.335</td>
<td>1.335</td>
<td></td>
</tr>
<tr>
<td>Oil Initially-In-PlaceOIIP</td>
<td>MMSTB</td>
<td>1429.6</td>
<td>514.7</td>
<td>915.0</td>
<td>1429.6</td>
</tr>
<tr>
<td>Recovery Factor</td>
<td>%(OIIP)</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>45</td>
</tr>
<tr>
<td>Recoverable Oil EUR</td>
<td>MMSTB</td>
<td>571.9</td>
<td>205.9</td>
<td>366.0</td>
<td>643.3</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio (R_s)</td>
<td>scf/STB</td>
<td>570</td>
<td>570</td>
<td>570</td>
<td>570</td>
</tr>
<tr>
<td>Gross Heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td>1350</td>
<td>1350</td>
<td>1350</td>
<td>1350</td>
</tr>
<tr>
<td>Gas Initially-In-PlaceGIIP</td>
<td>Bscf</td>
<td>814.9</td>
<td>293.4</td>
<td>521.5</td>
<td>814.9</td>
</tr>
<tr>
<td>Recoverable Raw Gas EUR</td>
<td>Bscf</td>
<td>326.0</td>
<td>117.3</td>
<td>208.6</td>
<td>366.7</td>
</tr>
<tr>
<td></td>
<td></td>
<td>75.9</td>
<td>27.3</td>
<td>48.6</td>
<td>85.4</td>
</tr>
</tbody>
</table>

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.
4. Estimated oil and gas Reserves categories of 1P, 2P and 3P, respectively.
Table 4.5 Volumetric Assessment of Contingent Resources (Initial Development Stage): Estimates of Project EURs

<table>
<thead>
<tr>
<th>Estimated Parameters</th>
<th>Estimated Parameters</th>
<th>Bases and Categories of Contingent Resources</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Initially-In-Place</td>
<td>Oil Initially-In-Place</td>
<td>MMSTB</td>
<td>1429.6</td>
<td>1429.6</td>
<td>1429.6</td>
</tr>
<tr>
<td>Incremental Recovery Factor</td>
<td>Incremental Recovery Factor</td>
<td>% (OIIP)</td>
<td>5</td>
<td>10</td>
<td>15</td>
</tr>
<tr>
<td>Recoverable Oil EUR</td>
<td>Recoverable Oil EUR</td>
<td>MMSTB</td>
<td>71.5</td>
<td>143.0</td>
<td>214.4</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio</td>
<td>Initial Solution Gas-Oil Ratio</td>
<td>scf/STB</td>
<td>570</td>
<td>570</td>
<td>570</td>
</tr>
<tr>
<td>Gross—Heating Value of Raw Solution Gas</td>
<td>Gross—Heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td>1350</td>
<td>1350</td>
<td>1350</td>
</tr>
<tr>
<td>Gas Initially-In-Place</td>
<td>Gas Initially-In-Place</td>
<td>Bscf</td>
<td>814.9</td>
<td>814.9</td>
<td>814.9</td>
</tr>
<tr>
<td>Recoverable Raw Gas EUR</td>
<td>Recoverable Raw Gas EUR</td>
<td>Bscf</td>
<td>40.7</td>
<td>81.5</td>
<td>122.2</td>
</tr>
</tbody>
</table>

1. Under a CO₂ Miscible Flood based on the results of an already implemented nearby analog CO₂ pilot project.
2. Calculated using an average conversion factor of 5.8 MMBtu per BOE.
3. Estimated Oil and Gas Contingent Resources categories of 1C, 2C and 3C, respectively.

\[ \text{OHIP} = \sum_{j=1}^{n} \frac{A_j h_j \phi(S_{wi,j}) (B_{hi,j})}{(B_{wi,j})} \]

Figure 4.6 3D Multi-cell Geological Model [adapted from PS-CIM (2004)]
4.2.3 Performance-Based Methods

As illustrated in Figure 4.1, the Production Phase can be divided into three producing stages (or periods) of Early Time (Ila), Late Time (Ilb), 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 inplace quantities (by the first two methods only), and thereby provide a useful second check and validation of estimates obtained earlier by volumetric methods.

4.2.3.1 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 \( c_w, c_g, c_o, B_w, B_g, R_w, R_o, \) and \( B_o \) 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 \( (\text{gas} \cap \text{initially-in-place}) \); the results of material balance analysis can be used to directly estimate the recoverable petroleum, but also the petroleum inplace quantities (by the first two methods only), and thereby provide a useful second check and validation of estimates obtained earlier by volumetric methods.

4.2.3.1.1 Application to Example Oil Project in Its Early-Production Stage

(1) 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 ($P_0 = R_o = R_s$), 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

$$ F_p = N[(B_o - B_w) + [(c_e S_{oi} + c_f S_{of})/S_{oi}] \Delta P] + [(W_c + W_{inj} B_w)/B_o c_e \Delta p] $$

(4.2a)

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

$$ F_p = N(B_o c_e \Delta P) = (W_c + W_{inj} B_w) $$

(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

$$ F_p = N \sum_{j=0}^{k} \Delta p_{j+1} W_0 (r_D \Delta t_D) $$

(4.3b)

where $j = 0$ indicates initial reservoir conditions when $P_i = P_o$ and $k = 1, 2, \ldots, n$ 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

$$ c_e = (c_e S_{oi} + c_f S_{of})/S_{oi} $$

(4.3c)

Eq. 4.3 can also be re-arranged as

$$ F_p / (B_o c_e \Delta p) = N \sum_{j=0}^{k} \Delta p_{j+1} W_0 (r_D \Delta t_D) / (B_o c_e \Delta p) $$

(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_o), and (3) Eq. 4.3b can be used to calculate water influx (W_e).

(2) 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% OOIP 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 Figure 4.7.

![Figure 4.7](image-url)
4.2.3.1.2 Application to a Volumetric Gas Reservoir in Its Late Production and Early Decline

(1) 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 (\(W_w = 0\)), no water production (\(W_o = 0\)), and injection of gas (\(G_{inj} = 0\)), the generalized conventional MBE for a volumetric gas reservoir reduces to (Lee and Wattenbarger 1996):

\[ G_p B_g = G (E_g + B_p E_o + B_p E_i) \]  \[ 4.5 \]

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, \(r_p = 5\) (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% OIH (or about 17% of low and 14% of best OIH), (2) a reasonably good match was obtained in Figure 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 CO₂ pilot was also implemented showing similar initial performance to the analogs nearby. 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 CO₂ Miscible Project) were calculated and summarized in Table 4.6.

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.

4.2.3.1.2 Application to a Volumetric Gas Reservoir in Its Late Production and Early Decline

(1) 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 (\(W_w = 0\)), no water production (\(W_o = 0\)), and injection of gas (\(G_{inj} = 0\)), the generalized conventional MBE for a volumetric gas reservoir reduces to (Lee and Wattenbarger 1996):

\[ G_p B_g = G (E_g + B_p E_o + B_p E_i) \]  \[ 4.5 \]

\[ G_p B_g = G (E_g + B_p E_o + B_p E_i) \]  \[ 4.5 \]
### Table 4.6  
Assessment using Material Balance Methods (Early-Production Stage):
Estimates of Project PIIPs, EURs, Reserves and Contingent Resources

<table>
<thead>
<tr>
<th>Measured and Estimated Parameters</th>
<th>Units</th>
<th>Bases and Estimates by Reserves Category</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Low Estimate</td>
</tr>
<tr>
<td><strong>Cumulative Production</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td>MMSTB</td>
<td>220.8</td>
</tr>
<tr>
<td>Raw Gas</td>
<td>% (OIIP)</td>
<td>17.0</td>
</tr>
<tr>
<td></td>
<td>Bscf</td>
<td>125.9</td>
</tr>
<tr>
<td><strong>Oil Initially-In-Place (OIIP)</strong></td>
<td></td>
<td>1300</td>
</tr>
<tr>
<td><strong>Recovery Factor</strong></td>
<td></td>
<td>40</td>
</tr>
<tr>
<td><strong>Recoverable Oil EUR</strong></td>
<td></td>
<td>520.0</td>
</tr>
<tr>
<td><strong>Recoverable Raw Gas EUR</strong></td>
<td></td>
<td>299.2</td>
</tr>
<tr>
<td><strong>Initial Solution Gas-Oil Ratio</strong></td>
<td>scf/STB</td>
<td>570</td>
</tr>
<tr>
<td><strong>Gross-Heating Value of Raw Solution Gas</strong></td>
<td>Btu/scf</td>
<td>1350</td>
</tr>
<tr>
<td><strong>Gas Initially-In-Place (GIIP)</strong></td>
<td></td>
<td>741</td>
</tr>
<tr>
<td><strong>Recoverable Raw Gas EUR</strong></td>
<td>Bscf</td>
<td>296.4</td>
</tr>
<tr>
<td></td>
<td>MMBOE</td>
<td>69.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>170.5</td>
</tr>
<tr>
<td></td>
<td>MMBOE</td>
<td>39.7</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Bases and estimates by Contingent Resources Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Estimate</td>
</tr>
<tr>
<td>Original</td>
</tr>
<tr>
<td>Oil EUR</td>
</tr>
</tbody>
</table>

1. Under peripheral water injection scheme that maintains reservoir pressure above the bubble point.
2. Calculated using an average conversion factor of 5.8 MMBtu per BOE.
3. Under a CO₂ Miscible Flood based on the results of one CO₂ pilot already implemented and a positive response from a second pilot being applied in another nearby analog reservoir.
4. Estimated oil and gas Reserves categories of 1P, 2P and 3P and Contingent Resources of 1C, 2C and 3C.
Except for the special case of abnormally pressured gas reservoirs, relative to significantly high gas compressibility (or \( c_g \approx \) approximately equal to the inverse of reservoir pressure), the formation water (\( E_w \)) and formation or pore-volume compression (\( E_p \)) terms can be neglected because \( E_p > > (B_g E_w + B_g E_g) \), and the Eq. 4.5 will further reduce to:

\[
G_p B_g = G E_g = G (B_g - B_p)
\]

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

\[
B_g = \frac{5.0435 \times 10^{-3}}{T/p, \text{ in RB/scf, or } = 2.8269(10^{-3}) \times T/p, \text{ in Rcf/scf}}
\]

where standard surface pressure \( (p_s) \) and temperature \( (T_s) \) conditions are 14.7 psia and 60°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:

\[
(p/z) = (p/z) - [(p/z) G/G_p]
\]

Where

\( p, p \) = average reservoir pressure (psia) at reservoir datum and “i” stands for initial,

\( T = \) average reservoir temperature at reservoir datum (°F),

\( z_i \) and \( z \) = gas compressibility factors evaluated at \( p \) and \( T \), and any \( p \) and \( T \), respectively,

\( G = \) GIP (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 normal 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 \( (p/z) \) and a slope of \( -(\text{p/z}/G) \) from which the GIP = G and EUR at the economic limit \( (p/z) \) can be estimated.

(2) 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) 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.

Figure 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 Figure 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 Figure 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.

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

<table>
<thead>
<tr>
<th>Reserves Category</th>
<th>Line Type</th>
<th>OGIP (Bscf)</th>
<th>EUR (Bscf)</th>
<th>RE (Low)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1P (Low)</td>
<td>–</td>
<td>1,500</td>
<td>1,130</td>
<td>75</td>
</tr>
<tr>
<td>2P (Best)</td>
<td>–</td>
<td>1,710</td>
<td>1,300</td>
<td>76</td>
</tr>
<tr>
<td>3P (High)</td>
<td>–</td>
<td>1,940</td>
<td>1,475</td>
<td>76</td>
</tr>
</tbody>
</table>

图 4.8 绘制了该湿气藏 p/z 和 G_p 动态关系图。根据压力衰竭过程的监控的数据变化情况，可绘制 3 条不同直线，以体现历史数据在计量和解释过程中的不确定性程度。由图 4.8 可估算天然气原始原始量的最小，最可能和最大估值，分别作为经济极限压力下 1P，2P 和 3P 储量估算的基础。基于上述估算结果，意味着定容开采的采收率约为原始原始量的 75% 到 76%。该评估结果认为是合理的，并得到进一步支持，因为①该气藏已确认为非反凝析定容气藏；②该气藏已全面评价并开发；容积法估算其原始原始量的最佳估值为 1800Bscf；③已累计产气 316.2Bscf，超过容积法原始原始量的 17.6%，或图 4.8 获得的原始原始量低估值的 21.1%；以及④三种不同情景的项目经济评价均可行。其贴现现金流收益率 DCF-RORs 均超过 20%。储量的状态为已开发。
### Table 4.7  
Gas Reserves Assessment by Material Balance Methods (Late-Production Stage): Estimates of Project GIIPs, CIIPs, EURs and Reserves

<table>
<thead>
<tr>
<th>Measured and Estimated Parameters</th>
<th>Units</th>
<th>Bases and Estimates by Reserves Category</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Low Estimate</td>
</tr>
<tr>
<td>Raw Gas (Bscf)</td>
<td></td>
<td>316.2</td>
</tr>
<tr>
<td>% (GIIP)</td>
<td>21.1</td>
<td>18.5</td>
</tr>
<tr>
<td>MMSTB</td>
<td>9.4</td>
<td>9.4</td>
</tr>
<tr>
<td>Bscf</td>
<td>1500</td>
<td>1710</td>
</tr>
<tr>
<td>Btu/scf</td>
<td>1100</td>
<td>1100</td>
</tr>
<tr>
<td>MMBOE</td>
<td>214.3</td>
<td>246.6</td>
</tr>
<tr>
<td>MMBOE</td>
<td>154.3</td>
<td>186.6</td>
</tr>
</tbody>
</table>

1. Estimated directly from Figure 4.8 based on (P/Z) values of 0 and 1500 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 if any.
4. Estimated Gas and Condensate Reserves categories of 1P, 2P and 3P, respectively.

---

Based on the initial condensate gas ratio (CGR) 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 field are shown in Table 4.7. According to the criteria, the total initial pressure is 1100 psi (economic limit), and the recovery factor is 60% OCIP. If there is no condensate dropout, the original in-place and reserves estimates are as follows:

- **Raw Gas**: Bscf 1500
- **Condensate**: MMSTB 214.3
- **Gross-Heating Value of Raw Gas**: Btu/scf 1100
- **Recoverable Raw Gas**: MMBOE 214.3
- **Implied Recovery Factor**: % (GIIP) 75
- **Initial Condensate-Gas Ratio (CGR)**: STB/MMscf 30
- **Condensate Initially-In-Place**: MMSTB 45.0
- **Condensate Recovery Factor**: % (GIIP) 60
- **Recoverable Condensate**: MMSTB 27.0

Please note that Table 4.7 summarizes the in-place and reserves estimates for this gas field. The estimated parameters and units are provided in the table, and the estimation process is described above.
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\textsubscript{2} plus NGLs (8.7%). For more detail, readers should refer to Chapters 9 and 10 on production measurements, reporting, and entitlement issues.

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.

4.2.3.2.1 Reservoir Simulation Methods (RSM)

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 Figure 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 (creal 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
CHAPTER 4 Assessment of Petroleum Resources Using Deterministic Procedures

4.2.3.2.2 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 system. It is notable that due to the presence of a very effective down-dip water injection system, the reservoir underwent stable production and early-decline periods. The example oil reservoir was

...
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 Figure 4.1a), a 0.5 million-cell geocellular model (similar to that depicted in Figure 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 for both in OIIP 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 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 Figure 4.9. As shown in Figure 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.

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.

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
Figure 4.9 Dynamic and Direct Assessment of Reserves Using Reservoir Simulation.

- Project’s production profile and resulting estimates are also presented in Figure 4.9 to illustrate its performance relative to the ongoing peripheral waterflood project without the ESPs. This 7% OOIP 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% OOIP.

- 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% OIH increase in recovery efficiency to the recovery efficiency of each low, best, and high scenario estimated and 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 4.8 Assessment using Reservoir Simulation Studies (Early-Decline Stage): Estimates of Project PIIPs, EURs, and Reserves under Peripheral Waterflood Only

<table>
<thead>
<tr>
<th>Measured and Estimated Parameters</th>
<th>Units</th>
<th>Bases and Estimates by Reserves Category</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Low Estimate</td>
</tr>
<tr>
<td></td>
<td></td>
<td>低估值</td>
</tr>
<tr>
<td>Cumulative Production</td>
<td>Oil 原油</td>
<td>MMSTB</td>
</tr>
<tr>
<td></td>
<td>Raw Gas 原料气</td>
<td>% (OIIP)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Bscf</td>
</tr>
<tr>
<td>Oil Initially-In-Place (OIIP)</td>
<td>MMSTB</td>
<td>1434</td>
</tr>
<tr>
<td>Recovery Factor</td>
<td>% (OIIP)</td>
<td>40</td>
</tr>
<tr>
<td>Recoverable Oil EUR</td>
<td>Original 原始</td>
<td>MMSTB</td>
</tr>
<tr>
<td></td>
<td>Remaining 剩余</td>
<td>MMSTB</td>
</tr>
<tr>
<td>Economic Oil Rate Limit</td>
<td>STB/D</td>
<td>2700</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio</td>
<td>scf/STB</td>
<td>570</td>
</tr>
<tr>
<td>Gross-Heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td>1350</td>
</tr>
<tr>
<td>Gas Initially-In-Place GIIP</td>
<td>Bscf</td>
<td>817.1</td>
</tr>
<tr>
<td>Recoverable Raw Gas EUR</td>
<td>Original 原始</td>
<td>Bscf</td>
</tr>
<tr>
<td></td>
<td>Remaining 剩余</td>
<td>MMBOE³</td>
</tr>
</tbody>
</table>

1 Waterflood RFs calculated or implied for the Best Estimate and assigned for the Low and High Estimates.
2 The Best Estimates obtained from the projected production profiles of a project-specific Reservoir Simulation Study.
3 Calculated using an average conversion factor of 5.8 MMBtu per BOE.
4 Estimated Oil and Raw Gas Reserves categories of 1P, 2P and 3P, respectively.
### Table 4.8a: Assessment Using Reservoir Simulation Studies (Early-Decline Stage): Estimates of Project PIIPs, EURs, and Reserves under Peripheral Waterflood with ESPs

<table>
<thead>
<tr>
<th>Measured and Estimated Parameters</th>
<th>Units</th>
<th>Bases and Estimates by Reserves Category</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Low Estimate</td>
</tr>
<tr>
<td><strong>Cumulative Production</strong></td>
<td></td>
<td>Low Estimate</td>
</tr>
<tr>
<td>Oil</td>
<td>MMSTB</td>
<td>399</td>
</tr>
<tr>
<td>Raw Gas</td>
<td>% (OIP)</td>
<td>27.8</td>
</tr>
<tr>
<td></td>
<td>Bscf</td>
<td>227.4</td>
</tr>
<tr>
<td><strong>Oil Initially-In-Place</strong></td>
<td>MMSTB</td>
<td>1434</td>
</tr>
<tr>
<td><strong>Recovery Factor 1</strong></td>
<td>% (OIP)</td>
<td>47</td>
</tr>
<tr>
<td><strong>Recoverable Oil EUR</strong></td>
<td>MMSTB</td>
<td>673.7</td>
</tr>
<tr>
<td><strong>Economic Oil Rate Limit</strong></td>
<td>STB/D</td>
<td>2700</td>
</tr>
<tr>
<td><strong>Initial Solution Gas-Oil Ratio</strong></td>
<td>scf/STB</td>
<td>570</td>
</tr>
<tr>
<td><strong>Gross-Heating Value of Raw Solution Gas</strong></td>
<td>Btu/scf</td>
<td>1350</td>
</tr>
<tr>
<td><strong>Gas Initially-In-Place</strong></td>
<td>Bscf</td>
<td>817.1</td>
</tr>
<tr>
<td><strong>Recoverable Raw Gas EUR</strong></td>
<td>Bscf</td>
<td>384.0</td>
</tr>
<tr>
<td><strong>Gas Initially-In-Place</strong></td>
<td>MMBOE</td>
<td>89.4</td>
</tr>
<tr>
<td><strong>Remaining</strong></td>
<td>Bscf</td>
<td>156.6</td>
</tr>
<tr>
<td><strong>Remaining</strong></td>
<td>MMBOE</td>
<td>36.5</td>
</tr>
</tbody>
</table>

1. Waterflood RFs calculated or implied for the Best Estimate and assigned for the Low and High Estimates.
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.
4. Estimated Oil and Raw Gas Reserves categories of IP, 2P and 3P respectively.

Furthermore, based on the same geological model representing the best case scenario, and relevant CO₂ and hydrocarbon compositional data (including miscibility test results), an integrated compositional model was developed to study the performance of CO₂ 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 CO₂ injection at the crest. The results for this best-case scenario are also presented in Figure 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 CO₂ EOR project was supported by two CO₂ pilots already implemented in analog oil projects nearby and yielding a reported maximum incremental 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 CO₂ 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 CO₂ 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.”

4.2.3.3 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 not long enough 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:

1. Production conditions, methods, and the overall production strategy are not changed significantly over the projected remaining
### Table 4.8 b Assessment of Contingent Resources Using Reservoir Simulation Studies (Early Decline Stage): EURs under a Planned CO₂ Miscible Project

<table>
<thead>
<tr>
<th>Measured and Estimated Parameters</th>
<th>Units</th>
<th>Bases and Estimates by Contingent Resources Category</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Low Estimate</td>
</tr>
<tr>
<td>Oil Initially-In-place (OIIP)</td>
<td>MMSTB</td>
<td>1434</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio (Rₜₜ)</td>
<td>scf/STB</td>
<td>570</td>
</tr>
<tr>
<td>Gross-Heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td>1350</td>
</tr>
<tr>
<td>Incremental Recovery Factor (%)</td>
<td></td>
<td>15</td>
</tr>
<tr>
<td>Recoverable Oil EUR (MMSTB)</td>
<td></td>
<td>215.0</td>
</tr>
<tr>
<td>Recoverable Raw Gas EUR (MMBOE)</td>
<td></td>
<td>122.6</td>
</tr>
</tbody>
</table>

1. Under a CO₂ Miscible Flood based on the results of two implemented analog CO₂ Pilot Projects.
2. Calculated using an average conversion factor of 5.8 MMBtu per BOE.
3. Estimated Oil and Gas Contingent Resources categories of 1C, 2C and 3C, respectively.

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### 4.2.3.3.1 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

\[
D_t = - \frac{dQ}{dt}/Q = KQ^b \tag{4.8}
\]
Guidelines for Application of the Petroleum Resources Management System

where

\[ D_i = \text{nominal (or continuous) decline rate (slope of the line) at any time (t) and is a fraction of production rate (Q) with a unit of reciprocal time (1/t) in per month, per year, etc, which must be consistent with the units of production rate,} \]

\[ Q = \text{production rate (STB/D, STB/month or STB/yr),} \]

\[ b = \text{decline exponent, and} \]

\[ K = \text{integration constant} \]

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>
<thead>
<tr>
<th>Items</th>
<th>Hyperbolic Model</th>
<th>Exponential Model</th>
<th>Harmonic Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generalized Governing Hyperbolic Decline Equation</td>
<td>( D = -\frac{dQ}{dt} = KQ^b )</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nominal Decline Rate (D)</td>
<td>( D = D_i = \text{constant} )</td>
<td>( D = D_i = Q/Qi )</td>
<td>( D = D_i = Q/Qi )</td>
</tr>
<tr>
<td>Decline Exponent (b)</td>
<td>“b” varies except for 0 &amp; 1</td>
<td>b = 0</td>
<td>b = 1</td>
</tr>
<tr>
<td>Rate-Time Relationships</td>
<td>1ogQ vs. 1og(1+CQi) where C = bDi</td>
<td>1ogQ vs. 1ogQi</td>
<td>1ogQ vs. 1og(1+Dit)</td>
</tr>
<tr>
<td>Type of Linear Plots</td>
<td>1ogQ vs. 1og(1+CQi) where C = bDi</td>
<td>1ogQ vs. 1ogQi</td>
<td>1ogQ vs. 1og(1+Dit)</td>
</tr>
<tr>
<td>Rate-Cumulative Relationships</td>
<td>( N_p = \frac{Q^b}{(1-b)Di(Q_i^{1-b})} )</td>
<td>( N_p = Q/Q_i / D )</td>
<td>( N_p = Q_i \ln Q_i / Q_i - 1 )</td>
</tr>
<tr>
<td>Type of Linear Plots</td>
<td>Not available</td>
<td>Q vs. Np</td>
<td>Q vs. Np</td>
</tr>
</tbody>
</table>

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

\( i = \text{stands for initial time or point at which the decline trend has onset or started.} \)

\( D_i = \text{nominal decline rate (as fraction of Q) with a unit of inverse time (1/t), equals to D, when Q = Q_i} \)

\( Q_i = \text{oil or gas production rate at any time "t" in STB/D or MMscf/D, etc.} \)

\( t = \text{time and the subscript for oil rate & cumulative production variables.} \)

\( N_p = \text{cumulative oil or gas production or recovery at any time "t" in consistent units.} \)

\( * \text{rate}(Q) \text{ & time (t) must be in consistent units in above formulae(i.e. if} \text{ Q is in STB/D, "t" is in days, etc.)} \)

\( \text{上述公式中的产量 (Q) 和时间 (t) 的单位必须一致} \text{, 如果} Q \text{ 为桶 / 天} \text{, 单位则为天} \text{.} \)
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:

<table>
<thead>
<tr>
<th>Value of Decline Exponent (b)</th>
<th>Governing Reservoir Drive Mechanism</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>Single-phase liquid (oil above bubblepoint)</td>
</tr>
<tr>
<td>0</td>
<td>Single-phase gas at high pressure</td>
</tr>
<tr>
<td>0.1 – 0.4</td>
<td>Solution gas drive</td>
</tr>
<tr>
<td>0.4 – 0.5</td>
<td>Single-phase gas</td>
</tr>
<tr>
<td>0.5</td>
<td>Effective edgewater drive</td>
</tr>
<tr>
<td>0.5 – 1.0</td>
<td>Comingled layered reservoirs</td>
</tr>
</tbody>
</table>

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

\[ \frac{D_t}{D_i} = \left( \frac{Q_t}{Q_i} \right)^b \]  

(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

众所周知，广泛应用的递减分析法可形象绘制井、井组或油藏的历史生产动态，并根据其趋势外推至经济极限以估算石油储量。分析检查、推导和理解表4.9所列递减公式及其典型线性特征图版对于正确使用与推广常规递减分析十分重要。需注意，指数模型和调和模型是双曲模型在递减指数b分别为0和1时的特殊情形。

双曲递减模型不仅是油井、气井和油气藏生产动态最常见的递减趋势规律，也通过两个未知参数初始名义年递减率D_i和递减指数b来体现最普通和最具挑战的递减趋势。即b=0和b=1分别代表指数递减和调和递减这两种特殊情形。此外，双曲递减指数b并非固定不变，可以是0和1之外的任意值，已体现不同井和油藏在不同开采方式下所呈现出的生产规律。据广泛报道，b值是随油气藏的驱替机理变化的。尽管在北美非常规油气的开发中，人们发现b值明显大于1，但根据Fekete Associates (2008)的研究报告，常规油气藏普遍采用以下数值：

<table>
<thead>
<tr>
<th>递减指数（b）</th>
<th>油气藏主控驱替机理</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>单相液流 （油相压力超过泡点压力）</td>
</tr>
<tr>
<td>0</td>
<td>高压单相气流</td>
</tr>
<tr>
<td>0.1 – 0.4</td>
<td>溶解气驱</td>
</tr>
<tr>
<td>0.4 – 0.5</td>
<td>单相气流</td>
</tr>
<tr>
<td>0.5</td>
<td>有效边水驱</td>
</tr>
<tr>
<td>0.5 – 1.0</td>
<td>多层合采油气藏（混合驱动）</td>
</tr>
</tbody>
</table>

初始名义递减率D_i是递减开始时初始产量对应的名义值或连续名义递减率任意时间t下的名义递减率D_i与初始递减率D_i的比值和相应产量比的b次方成比例。定义如下：

\[ \frac{D_t}{D_i} = \left( \frac{Q_t}{Q_i} \right)^b \]  

(4.9)

递减率的大小依赖于多方面的因素。如油气藏的采油速度、开发程度或成熟度、平均油气藏压力、岩石与流体性质、规模和分布、和油气藏管理以及实际开采过程。初始名义递减率D_i与
初始有效\( d \) 或递级\( d \) 递减率\( d \) 相关联\( d \) 后者是两个连续产量的阶梯函数而不是连续函数\( d \) 关系式如下\( d \):

\[
d_{i}=1-bD_{i}^{-(1/b)}
\]

(4.10)

例如\( D_{i}=0.25/yr \) 和 \( b=0.5 \), 则

\[
d_{i}=1-(1+0.5\times0.25)^{(1/0.5)}=0.21/yr.
\]

广义双曲递减模型适用于产量 - 时间关系式的表达式如下\( d \) 参见表 4.9\( \)

\[
Q_{i}=Q_{i}(1+bD_{i})^{1/b}
\]

(4.11a)

式\( Q_{i} \) 也可以表达为\( Q_{i}

\[
\log Q_{i} = \log Q_{i} - (1/b) log (1+bD_{i}) log (1+C_{i})
\]

(4.11b)

其中 \( C = bD_{i} \), 这是一个任意定义的未知常数（refer also to Table 4.9）。

对于一个正确的 \( C \), Eq. 4.11b 建议在双对数图版上\( Q \) vs. \((1+C) \) 应该是一条直线，斜率\( m = -1/b \) 和截距为\( Q \) time zero 或当初始递减开始时\( Q \) 然后求解。

若已知递减刚开始的初始产量\( Q \) 和递减期的其他产量数据\( Q \) 可以采用常规和现代递减分析拟合产量曲线并构建特征直线和/或典型曲线\( Q \) 通过非线性回归分析计算两个未知参数 \( D \) 和 \( b \) 的正确取值\( Q \) 我们知道\( Q \) 双曲递减适用于井的生产后期\( Q \) 该阶段的主要驱替机制为重力驱动\( Q \) 当然\( Q \) 当溶解气油比\( Q \) GOR 在后期非常低且稳定时\( Q \) 也可能再次出现指数递减\( Q \) 基于两个未知参数的合理估值\( Q \) 则可应用式 4.12 直接估算该石油资产经济极限所对应的累产量\( N_{pe} \) 即估算最终可采量\( EUR \)

\[
EUR=N_{pe}=N_{pe}+N_{pde}=N_{pe}+\frac{Q_{i}^{b}}{(1-b)D_{i}}[Q_{i}^{(1-b)}-Q_{e}^{(1-b)}]
\]

(4.12)

式中\( Q \) 和 \( Q_{e} \) 分别代表初始时刻\( t=0 \) 或递减刚开始时的产量\( Q \) 以及经济极限\( e \) 对应的产量\( N_{pe} \) \( N_{pe} \) 和 \( N_{pe} \) 分别是初始递减时\( t=0 \) 、整个递减期\( d_{i} \) 以及整个项目至经济极限\( e \) 时对应的累计产量\( Q \) 4.2.3.3.2 主要 PPT 分析法

各种成熟应用的生产动态趋势分析法可归纳为三大类\( Q \) 常规递减分析\( Q \) 现代递减分析\( Q \) MDA 和其他 PPT 分析法\( Q \)
A trial-and-error procedure is used to calculate sets of values for 
(1 + C) for several assumed values of C and generating the resulting 
"log Q vs. log (1 + C)" 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 b and 
D), 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 = 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’s matching the same decline trend that 
avertically extrapolates to different estimates of reserves. Hence, this procedure 
is not recommended.

It would be highly desirable to estimate the nominal decline (D) 
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 7-step procedure described and applied 
to the analyses of this example oil project below.

(2) 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 
j 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’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’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 Figure 4.10a. Note that the EPRCO recommended semi-log plot of “log $Q_t$ vs. time (t)” plot 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.

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 D, and production decline data. The following EPRCO procedure is 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.

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respectively slopes (m) and hence the nominal decline rates (D). Figure 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, (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, 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 Figure 4.10 a) 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. Figure 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 respective slopes (m) and hence the nominal decline rates (D). Figure 4.10a illustrates how this process works and summarizes the resulting hyperbolic decline parameters.

Step 7. Finally, for the best scenario for example project operating under peripheral down-dip water injection scheme, use D, = 9.7% and b = 0.55 and Eq. 4.11a to calculate the oil production rate profile and the cumulative production from Q, 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 (Nstub). Then use Eq. 4.12 to calculate the total EUR (or Nstub) 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 Figure 4.10b. Note that for the best-case scenario, the same results can be obtained by using D, of 5.3% and b of 0.55 to forecast oil rates and cumulative production from Q, 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.

Figure 4.10 b is a resulting characteristic linear plot of “log Q, vs. log (1 + b D, t)” for the best-estimate scenario only. High-quality matches obtained from using the EPRCO procedure is clearly demonstrated by

步骤 3  假设几个合理 b 值。使用任意 D, 值。例如最佳估值情景取年度递减率 5.3% 和方程 4.11a 计算不同时间 t 为负对应的时间量。时间取负 t 是因为产生递减率的最近时间点 t=25.75 年 的产量为 25MBOPD。为了满足方程 4.11a 该产量与前期 Q 直至初始产量 Q, 为 75MBOPD 之间的时间必须为负值 t。

步骤 4 利用第 3 步基于不同 b 值计算的产量 Q 和实际产量数据绘制图版 选取平均偏差最小的最佳拟合线计算最佳 b 值。

如图 4.10a 中空圆点所示 b 值为 0.55 时 计算数据可得到实际数据 实心黑点的最佳拟合线 其最小平均偏差约为 1.6%

步骤 5 重复第 3 步 采用年递减率 5.8% 和 4.8% 分别计算低值和高值情景的最优 b 值 分别为 0.40 和 0.75 最佳拟合线的最小平均偏差分别为 1.8% 和 1.9%。图 4.10a 展示了上述五个步骤的结果。

步骤 6 使用正确递减指数 b=0.55 和产量为 25MBOPD 时的名义年递减率 5.3% 与式 4.9 可计算出最佳情景的初始名义年递减率 D,=9.7% 初始递减产量 Q,=75MBOPD 同理可计算 D, 的低估算和高估值 分别为 9.0% 和 11.1%。

步骤 7 最后 对于本案例实施下倾边缘注水的最佳情景 使用 D,=9.7% b=0.55 以及方程 4.11a 可计算得到原油产量剖面及其产量从 75MBOPD 第 10 年末递减开始时 递减到经济极限产量 3.2MBOPD 期间的累产量 即整个递减期间的累产量。然后 使用方程 4.12 可计算最终可采量 EUR 或 Nstub 为 747.3MMSTB 2P 储量为 228.4MMSTB 最终可采量估值 EUR 减去前 10 年累计产量 518.9MMSTB 如图 4.10b 所示 需注意 由于最佳情景 采用 D,=5.3% 和 b=0.55 预测产量 Q, 从 25MBOPD 第 26 年末 递减至相经济极限产量的累产量再加上前 26 年的累计产量也可得到相同的结果。

图 4.10 b 仅为最佳估值情景的 logQ,—log
Guidelines for Application of the Petroleum Resources Management System

Example Oil Project: Production Performance Trend Analysis By “log (Qt) - log (t)” Characteristic Plot for the Hyperbolic Decline Model

Figure 4.10b Dynamic and Direct Assessment of Reserves by TDA.

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% OIIP over peripheral waterflood, bringing the project recovery to 54% OIIP for the best scenario. Similarly, these

The actual data (represented by black dots) relative to the calculated data (represented by hollow diamonds, circles, and squares) in Figure 4.10a and the resulting similar high-quality decline trend match obtained in the characteristic linear plot of Figure 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×D) and b simultaneously, usually yielding erroneous results because the evaluation of “b” is known to be very insensitive to this procedure [Fekete Associates (2008)].

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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

<table>
<thead>
<tr>
<th>Measured and Estimated Parameters</th>
<th>Units</th>
<th>Bases and Estimates by Reserves Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative Production</td>
<td>Oil</td>
<td>MMSTB</td>
</tr>
<tr>
<td></td>
<td>% OIIP</td>
<td>34.0</td>
</tr>
<tr>
<td></td>
<td>Raw Gas</td>
<td>Bscf</td>
</tr>
<tr>
<td>Oil Initially-In-Place</td>
<td>MMSTB</td>
<td>1525</td>
</tr>
<tr>
<td>Recovery Factors Calculated 1</td>
<td>% OIIP</td>
<td>46.0</td>
</tr>
<tr>
<td>Recoverable Oil EUR</td>
<td>Original</td>
<td>MMSTB</td>
</tr>
<tr>
<td></td>
<td>Remaining 3</td>
<td>MMSTB</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio R</td>
<td>scf/STB</td>
<td>570</td>
</tr>
<tr>
<td>Gross-heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td>1350</td>
</tr>
<tr>
<td>Gas Initially-In-Place</td>
<td>Bscf</td>
<td>869.3</td>
</tr>
<tr>
<td>Recoverable Raw Gas EUR</td>
<td>Original</td>
<td>Bscf</td>
</tr>
<tr>
<td></td>
<td>Remaining 3</td>
<td>MMBOE 2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Bscf</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MMBOE 2</td>
</tr>
</tbody>
</table>

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

Table 4.10 a 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:

a. The best or 2P estimate of 228.4 MMSTB (or remaining reserves) represents only 15% OIIP or about 30% of the 747.3 MMSTB EUR (see Table 4.10).

b. 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% OIIP oil recovery by artificial lift using ESPs (discussed earlier under Reservoir Simulation Methods) was revised downward to 5% OIIP to further ensure reasonable confidence and to bring the overall project recovery to 54% OIIP 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 and Estimates of Project EURs and Reserves under Peripheral Waterflood with ESPs

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Units</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative Production (Oil)</td>
<td>MMSTB</td>
<td>518.9</td>
<td>518.9</td>
<td>518.9</td>
</tr>
<tr>
<td></td>
<td>% OIP</td>
<td>34.0</td>
<td>34.0</td>
<td>34.0</td>
</tr>
<tr>
<td>Raw Gas</td>
<td>Bscf</td>
<td>295.8</td>
<td>295.8</td>
<td>295.8</td>
</tr>
<tr>
<td>Oil Initially-In-Place (OIIP)</td>
<td>MMSTB</td>
<td>1525</td>
<td>1525</td>
<td>1525</td>
</tr>
<tr>
<td>Recovery Factors Calculated</td>
<td>% OIP</td>
<td>51.0</td>
<td>54.0</td>
<td>59.0</td>
</tr>
<tr>
<td>Recoverable Oil (EUR)</td>
<td>MMSTB</td>
<td>777.8</td>
<td>823.6</td>
<td>899.8</td>
</tr>
<tr>
<td></td>
<td>Remaining</td>
<td>258.9</td>
<td>304.7</td>
<td>380.9</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio (Rs)</td>
<td>scf/STB</td>
<td>570</td>
<td>570</td>
<td>570</td>
</tr>
<tr>
<td>Gross-heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td>1350</td>
<td>1350</td>
<td>1350</td>
</tr>
<tr>
<td>Gas Initially-In-Place (GIIP)</td>
<td>Bscf</td>
<td>869.3</td>
<td>869.3</td>
<td>869.3</td>
</tr>
<tr>
<td>Recoverable Raw Gas</td>
<td>Bscf</td>
<td>443.3</td>
<td>469.4</td>
<td>512.9</td>
</tr>
<tr>
<td></td>
<td>MMBOE</td>
<td>103.2</td>
<td>109.3</td>
<td>119.4</td>
</tr>
<tr>
<td></td>
<td>Remaining</td>
<td>147.5</td>
<td>173.7</td>
<td>217.1</td>
</tr>
<tr>
<td></td>
<td>MMBOE</td>
<td>34.3</td>
<td>40.4</td>
<td>50.5</td>
</tr>
</tbody>
</table>

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

Similarly, supported further by the full performance of a second analog CO₂ miscible pilot project nearby with a realized incremental 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 CO₂ 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 CO₂ Miscible Project

<table>
<thead>
<tr>
<th>Measured and Estimated Parameters</th>
<th>Units</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Initially-In-place (OIIP)</td>
<td>MMSTB</td>
<td>1525</td>
<td>1525</td>
<td>1525</td>
</tr>
<tr>
<td>Initial Solution Gas-Oil Ratio (Rₛ)</td>
<td>scf/STB</td>
<td>570</td>
<td>570</td>
<td>570</td>
</tr>
<tr>
<td>Gross-Heating Value of Raw Solution Gas</td>
<td>Btu/scf</td>
<td>1350</td>
<td>1350</td>
<td>1350</td>
</tr>
<tr>
<td>Incremental Recovery Factor¹</td>
<td>% OIIP</td>
<td>13</td>
<td>16</td>
<td>20</td>
</tr>
<tr>
<td>Recoverable Oil EUR³</td>
<td>MMSTB</td>
<td>198.3</td>
<td>244.0</td>
<td>305.0</td>
</tr>
<tr>
<td>Recoverable Raw Gas EUR³</td>
<td>Bscf</td>
<td>113.0</td>
<td>139.1</td>
<td>173.9</td>
</tr>
<tr>
<td></td>
<td>MMBOE²</td>
<td>26.3</td>
<td>32.4</td>
<td>40.5</td>
</tr>
</tbody>
</table>

¹ Under a CO₂ Miscible Flood based on the results of two implemented analog CO₂ Pilot projects.
² Calculated using an average conversion factor of 5.8 MMBtu per BOE.
³ Estimated Oil and Gas Contingent Resources categories of 1C, 2C and 3C, respectively.

(3) Modern Decline Analysis (MDA)

Similar to TDA, the objective of MDA is also to determine the best-fit values of constants n and Dᵢ 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).


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).

(4) Other Production Performance Trend Analyses.

There are other well-established production performance analyses that may be used to predict recoverable volumes based on trends
CHAPTER 4  Assessment of Petroleum Resources Using Deterministic Procedures

1. Cumulative Gas Production vs. Cumulative Oil Production Trends: For oil reservoirs with solution-gas drive, a semi-log plot of log $G_p$ vs. $N_p$ 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 ($\text{GIIP} = R_w \times \text{OIIP}$).

2. 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. A semi-log plot of “$\log f_w$ (or $f_o$) vs. $N_p$” trend may turn down at small values $f_w$ but earlier for light oils and later for viscous oils (Brons 1963).

b. 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. $N_p$” 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.

c. Ershaghi and Omoregie (1978) and Ershaghi and Abdassah (1984) recommended that a plot of $[1/f_o-\ln(1/f_o-1)]$ vs. $N_p$ should be linear. However, they noted that due to the inflection point of the $f_o$ vs. $S_o$ curves, the method will work only at higher water-cuts when $f_o > 50$.

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 ($k_o/ k_w$) vs. $S_o$ 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-

in one 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:

a. In the case of 2P-3P method the reserves corresponding to the reservoir are based on the assumption that the recoverable gas is equal to the original gas in-place ($G_p = R_w \times \text{GIIP}$) and the remaining oil is associated with the gas cap. However, this method is not valid for reservoirs where the recovery factor is less than 1 or where the gas cap is thick.

b. In the case of 2P-3P method the reserves corresponding to the reservoir are based on the assumption that the recoverable gas is equal to the original gas in-place ($G_p = R_w \times \text{GIIP}$) and the remaining oil is associated with the gas cap. However, this method is not valid for reservoirs where the recovery factor is less than 1 or where the gas cap is thick.

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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 Figures 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 Figure 4.11.
### Table 4.11 Reserves Assessment using Performance-Based Methods: Estimates of Project OIIPs, EURs and Reserves during Production Phase

<table>
<thead>
<tr>
<th>Assessment Method</th>
<th>Depletion Stage &amp; Parameters</th>
<th>Units</th>
<th>Estimates under Waterflood Performance only</th>
<th>Estimates under Waterflood and Artificial Lift Performance</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Low Estimate</td>
<td>Best Estimate</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>MMSTB</td>
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<td>220.8</td>
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<tr>
<td></td>
<td></td>
<td>% OIP</td>
<td>17.0</td>
<td>13.8</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MMSTB</td>
<td>1300</td>
<td>1600</td>
</tr>
<tr>
<td></td>
<td></td>
<td>% OIP</td>
<td>40</td>
<td>45</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MMSTB</td>
<td>520</td>
<td>720</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MMSTB</td>
<td>299</td>
<td>499</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MMSTB</td>
<td>399.0</td>
<td>399.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>% OIP</td>
<td>27.8</td>
<td>26.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MMSTB</td>
<td>1434</td>
<td>1525</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MMSTB</td>
<td>573</td>
<td>686</td>
</tr>
</tbody>
</table>

**Assessment Method**: Material Balance (MB) Analyses

**Depletion Stage**: Early Production Stage with 8 years of actual production performance

Cumulative Production

<table>
<thead>
<tr>
<th>Cumulative Production</th>
</tr>
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<tbody>
<tr>
<td>MMSTB</td>
</tr>
<tr>
<td>220.8</td>
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<tr>
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An Indication of Project Maturity

<table>
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<th>An Indication of Project Maturity</th>
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</thead>
<tbody>
<tr>
<td>% OIP</td>
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<tr>
<td>17.0</td>
</tr>
<tr>
<td>13.8</td>
</tr>
<tr>
<td>11.0</td>
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Oil Initially-In-place (OIIP)

<table>
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<th>Oil Initially-In-place (OIIP)</th>
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</thead>
<tbody>
<tr>
<td>MMSTB</td>
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<td>1300</td>
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<tr>
<td>1600</td>
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<td>2000</td>
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Recoverable Oil (EUR)

<table>
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<th>Recoverable Oil (EUR)</th>
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<tbody>
<tr>
<td>MMSTB</td>
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<td>520</td>
</tr>
<tr>
<td>720</td>
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<td>1000</td>
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Oil Reserves

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<td>299</td>
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<tr>
<td>499</td>
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<tr>
<td>779</td>
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**Assessment Method**: Reservoir Simulation Model (RSM) Studies

**Depletion Stage**: Early Decline Stage with 16 years of actual production performance

Cumulative Production

<table>
<thead>
<tr>
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</tr>
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<tbody>
<tr>
<td>MMSTB</td>
</tr>
<tr>
<td>399.0</td>
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An Indication of Project Maturity

<table>
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</thead>
<tbody>
<tr>
<td>% OIP</td>
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<td>27.8</td>
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<td>26.2</td>
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Oil Initially-In-place (OIIP)

<table>
<thead>
<tr>
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<tbody>
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Recoverable Oil (EUR)

<table>
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<td>MMSTB</td>
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Oil Reserves

<table>
<thead>
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<tr>
<td>MMSTB</td>
</tr>
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<td>674</td>
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<tr>
<td>793</td>
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<td>991</td>
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### Assesment Method

#### Depletion Stage & Parameters

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<th></th>
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<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implied Recovery Factor</td>
<td>% OIIP</td>
<td>40</td>
<td>45</td>
<td>50</td>
</tr>
<tr>
<td></td>
<td></td>
<td>47</td>
<td>52</td>
<td>57</td>
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</table>

<table>
<thead>
<tr>
<th></th>
<th>Units</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Reserves</td>
<td>MMSTB</td>
<td>174</td>
<td>287</td>
<td>470</td>
</tr>
<tr>
<td></td>
<td></td>
<td>275</td>
<td>394</td>
<td>592</td>
</tr>
</tbody>
</table>

**Assessment Method**: 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**

| Units | 518.9 | 518.9 | 518.9 | 518.9 | 518.9 |

| An Indication of Project Maturity | % OIIP | 34.0 | 34.0 | 34.0 | 34.0 | 34.0 |

| Oil Initially-In-place OIIP | MMSTB | 1,525 | 1,525 | 1,525 | 1,525 | 1,525 |

| Recoverable Oil EUR | MMSTB | 702 | 747 | 824 | 778 | 824 | 900 |

| Implied Recovery Factor | % OIIP | 46 | 49 | 54 | 51 | 54 | 59 |

| Oil Reserves | MMSTB | 183 | 228 | 305 | 259 | 305 | 381 |

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 CO₂ Miscible Project are summarized in Table 4.12. A close examination of Figure 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.

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### Table 4.12 Assessment of Contingent Resources Estimates of Project OIIPs and EURs during Production Phase

<table>
<thead>
<tr>
<th>Assessment Method</th>
<th>Depletion Stage</th>
<th>Parameters</th>
<th>Units</th>
<th>Bases and Estimates by Contingent Resources Category under a Planned CO₂ Miscible Project</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Material Balance and Analogous Methods</td>
<td>Early Production Stage: 8 years of production performance under Peripheral Waterflood and results of one analog CO₂ Pilot</td>
<td>Cumulative Production</td>
<td>MMSTB</td>
<td>220.8</td>
<td>220.8</td>
<td>220.8</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>An Indication of Project Maturity</td>
<td>% OIIP</td>
<td>17.0</td>
<td>13.8</td>
<td>11.0</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Oil Initially-In-Place OIIP</td>
<td>MMSTB</td>
<td>1300</td>
<td>1600</td>
<td>2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Incremental Recovery Factor</td>
<td>% OIIP</td>
<td>5</td>
<td>10</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Recoverable Oil EUR</td>
<td>MMSTB</td>
<td>65</td>
<td>160</td>
<td>300</td>
<td></td>
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<tr>
<td>Reservoir Simulation Model Studies and Analogous Methods</td>
<td>Early Decline Stage: 16 years of production performance under Peripheral Waterflood and the results of two analog CO₂ Pilots only one fully realized</td>
<td>Cumulative Production</td>
<td>MMSTB</td>
<td>399.0</td>
<td>399.0</td>
<td>399.0</td>
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<tr>
<td></td>
<td></td>
<td>An Indication of Project Maturity</td>
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<td>27.8</td>
<td>26.2</td>
<td>23.0</td>
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<td></td>
<td></td>
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<td>MMSTB</td>
<td>1434</td>
<td>1525</td>
<td>1739</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Incremental Recovery Factor</td>
<td>% OIIP</td>
<td>15</td>
<td>18</td>
<td>22</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Recoverable Oil EUR</td>
<td>MMSTB</td>
<td>215</td>
<td>275</td>
<td>382</td>
<td></td>
</tr>
<tr>
<td>Single OIIP Estimate and Analogous Method</td>
<td>Late Decline Period: 26 years of production performance under Peripheral Waterflood and fully realized results of two analog CO₂ Pilots</td>
<td>Cumulative Production</td>
<td>MMSTB</td>
<td>518.9</td>
<td>518.9</td>
<td>518.9</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>An Indication of Project Maturity</td>
<td>% OIIP</td>
<td>34.0</td>
<td>34.0</td>
<td>34.0</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Oil Initially-In-Place OIIP</td>
<td>MMSTB</td>
<td>1525</td>
<td>1525</td>
<td>1525</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Incremental Recovery Factor</td>
<td>% OIIP</td>
<td>13</td>
<td>16</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Recoverable Oil EUR</td>
<td>MMSTB</td>
<td>198</td>
<td>244</td>
<td>305</td>
<td></td>
</tr>
</tbody>
</table>
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.
CHAPTER 4 Assessment of Petroleum Resources Using Deterministic Procedures

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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

1. Make development plans that can cover the range of possible outcomes
2. Provide a range of production forecasts to evaluate the expected outcome of their ventures
3. Measure exploration, appraisal, and commercial risks
4. Ensure that they can handle an unfavorable outcome (i.e., that they have an economic project, even if the low case materializes)
5. 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 categorized 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 resource categories, using the Petroleum Resources Management System (SPE-PRMS, 2007) guidelines. 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
(1) Both describe the full range of uncertainty and reveal upsides and downsides.
(2) They easily allow calculation of the value of information of various activities.
(3) Both allow calculation of effects of interdependent uncertainties.
(4) They provide a good interface with decision support and financial modeling methods.
(5) 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
(1) The method describes a specific physical case; physically inconsistent combinations of parameter values can be spotted and removed.
(2) The method is direct, easy to explain, and manpower efficient.
(3) The estimate is reproducible.
(4) 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

1. Based on ranked uncertainties. For this purpose we first have to specify and rank the main uncertainties.
2. Internally consistent (i.e., a realization should consist of parameter values or sets of conditions that can physically exist together).
3. Associated with a probability of occurrence (but not necessarily equally probable).
4. 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 Figure 5.1.

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 Figure 5.2, for the example in Figure 5.1. In this curve, the 90, 50, and 10% probability values can be easily identified. In this example, a GIIP estimate of about $40 \times 10^9$ m$^3$ has a probability of 90% to be exceeded.

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

![Figure 5.1](image1.png)

![Figure 5.2](image2.png)
### 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 Figure 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).

<table>
<thead>
<tr>
<th>Fractures</th>
<th>Direction</th>
<th>Intensity</th>
<th>Fracture Perm</th>
<th>Structure (Flanks)</th>
<th>Oil Sat</th>
<th>N/G</th>
<th>Matrix Perm</th>
<th>Wettability</th>
<th>GOR</th>
<th>Cap Rock Integrity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direction</td>
<td>Intensity</td>
<td>Fracture Perm</td>
<td>Structure (Flanks)</td>
<td>Oil Sat</td>
<td>N/G</td>
<td>Matrix Perm</td>
<td>Wettability</td>
<td>GOR</td>
<td>Cap Rock Integrity</td>
<td></td>
</tr>
<tr>
<td>Fractures</td>
<td>Direction</td>
<td>Intensity</td>
<td>Fracture Perm</td>
<td>Structure (Flanks)</td>
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<td>N/G</td>
<td>Matrix Perm</td>
<td>Wettability</td>
<td>GOR</td>
<td>Cap Rock Integrity</td>
</tr>
</tbody>
</table>

**Table 5.3**: Example of scenario method.

![Figure 5.3](image)

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

1. It allows generation of subsurface realizations made up of consistent sets of parameters.
2. It is a useful approach to identify development concepts.

The scenario matrix can be used to generate 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).
5.4 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 Figure 5.4.

Figure 5.4  Monte Carlo approach to volumetric

(3) Development concepts can be tested against all possible reservoir outcomes.

(4) It can be helpful in defining targets for appraisal (through value-of-information analysis).

(5) 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).
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.

5.4.1.1 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

(1) Lack of definition of reservoir limits from seismic data
(2) Time-to-depth conversion in seismic observations
(3) Dips of the top of the formation
(4) Existence and position of faults
(5) 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.

5.4.1.2 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.

5.4.1.3 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.

5.4.1.4 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.

5.4.1.5 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) can help in selecting appropriate distribution functions to represent the uncertainty in individual parameters. Such tools often include sensitivity analysis and Monte Carlo simulation to assess the impacts of parameter uncertainty on the overall resource estimate.
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:

(1) 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.

(2) 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.

(3) 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.

(4) 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.

(5) Do not confuse the three measures of centrality (expectation or mean, mode, and median) when defining the distribution.

(6) 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.).

(7) 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.

(8) 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.

(9) 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

可供选择各种概率密度函数（正态分布、对数正态分布、三角分布、泊松分布等）。

下面对参数分布的选择提供一些实用性指引

(1) 基于油气藏和地质的直接数据或适合的类比油气藏信息，有意识选择容积法输入参数的分布范围与概型。

(2) 该分布须仅用于有效反映不确定性范围，避免无限扩展。对于用小数或比率表示的参数，例如孔隙度、净油比、饱和度或采收率等，要确保其数值的分布范围不为负或大于1。

(3) 描述均值不确定性的最通用概率密度函数（PDF）是呈正态分布和对数正态分布，其缺陷是尾部无限长可能导致不切实际的情形组合，解决方案是在有意义数值处作截断处理。当然，如果截断值明显影响PDF的整体形态，那更恰当的做法是另行选择PDF。

(4) 重申，所需的参数分布是针对评估师对均值的不确定表征，而非数据分布本身。

(5) 选择概率分布函数时，不要混淆三个中值（期望值或均值、众数和中值）的度量。

(6) 要清楚认识低值和高值的涵义，以及极值如最小值和最大值（P100/P0）或其他一些概率值如 P95/P05, P90/P10 等。

(7) 一组对数正态分布之和的PDF趋于呈正态分布；因此对数级数相同的独立分布的乘积，其结果趋向于呈对数正态分布。企业的案例显示，受此影响大的分布是油气聚集体的储量和多孔介质渗透率。

(8) 众多级数相同独立分布之和的PDF趋于呈正态分布。例如一个资产组合中大量规模相当油田的储量以及岩石的孔隙度。

(9) 若独立分布的级数不同，其求和函数及其PDF形态将取决于数值大的分布。

许多实践者采用三角分布作为近似PDF，特别是在资料有限且分布范围窄的情形。当概率分布不易确定时，有时可采用均值一值分布。这种分布可视为是对现实情形的粗略近似。当然，评估
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. Figure 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).

The known distribution of available data should be considered only as the starting point to define the PDF for reservoir parameters. 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. Figure 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).

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

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Range</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRV</td>
<td>+/- 30%</td>
<td>3D Seismic, 2D Seismic</td>
</tr>
<tr>
<td>Net-to-Gross</td>
<td>+/- 20%</td>
<td>Well Logs</td>
</tr>
<tr>
<td>Porosity from Logs</td>
<td>+/- 15%</td>
<td>Logs</td>
</tr>
<tr>
<td>Porosity from Cores</td>
<td>+/- 10%</td>
<td>Cores</td>
</tr>
<tr>
<td>Hydrocarbon Saturation</td>
<td>+/- 20%</td>
<td>Well Logs</td>
</tr>
<tr>
<td>Dip</td>
<td>+/- 10%</td>
<td>Dipmeter</td>
</tr>
<tr>
<td></td>
<td>+/- 30%</td>
<td>Seismic</td>
</tr>
<tr>
<td>Formation Volume Factor (B_o or B_g)</td>
<td>+/- 5%</td>
<td>PVT Test</td>
</tr>
</tbody>
</table>

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.

警告：该表中数值为典型范围值，仅作为实际参数范围值的对比与参照，不要用作不确定性的默认范围。
5.4.2 Performance Methods

5.4.2.1 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:

\[ q = \frac{q_i}{(1 + bd_i)^b} \]  \hspace{1cm} (5.1)\]

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).

5.4.2.2 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. Figure 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:

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

Strengths of the probabilistic method include:

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

Weaknesses, on the other hand, are:

1. Can lead to extensive, complicated, and sometimes ineffective calculation work
2. 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.
3. The PDF of basic parameters is not always known and technical judgment has to be applied
4. Dependencies between parameters are even more difficult to assess.

5.4.3 概率法的优势包括：

1. 评估结果不确定性范围可根据基础参数的不确定性范围来获取。
2. 易于开展数值处理工作。
3. 可应用于勘探到生产的全业务过程。
4. 可与信息价值分析工作自然衔接。
5. 可在详细资料不足时拾取可能结果的分布。

另一方面，其缺陷在于：

1. 可能导致大量复杂而且有时无效的计算工作量。
2. 在应用简单蒙特卡洛法时[储量级别]，如P90，P50，P10可能并不对应具体的实际面积或体积，当应用地质和数值模拟模型进行概率法分析时，才可能识别P90，P50和P10情景所对应的模型与参数。
3. 基本参数的PDF并非总是已知，必须进行技术判断。
4. 参数间的相关性甚至更加难以评估。
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:

1. 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].

2. 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].

3. 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 performance data, such as material balance or reservoir performance data, such as material balance or reservoir.
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 Figure 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.

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).

有关应用案例的描述可参见 Al Salhi 等人 (2005) 文献。

5.5.3 信息价值

评价的目的是降低不确定性。因而有必要探讨获取更多信息的价值与成本。图5.7所示勘探评价案例, 其STOIIP结果分布曲线的斜度在评价之前比较平缓, 表明可能结果的分布范围比较宽。评价工作完成后，曲线斜度变陡，表明可能结果的分布范围减小。即便结果不利，也就是说，评价后曲线低于最小经济界限，评价工作仍给出了避免不必要投资的有价值结论。若评价后的曲线在经济范围内，则可开展更有针对性的开发活动。

若评价后的STOIIP范围超过经济门槛，那么可能结果分布范围的减小将有利于开展更具成本效益的开发设计。开发增加的效益便是评价工作所获取的信息价值VoI。只要评价工作的成本低于该VoI，就有必要进一步推进。
### 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. 

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 (CDF); Survival Function (SF)**

To each possible value of a variable, a CDF (SF) assigns a probability that the variable does not exceed (or 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. 

\[
\text{Mean}= \sum_{i=1}^{n} x_i P(x_i) \text{or } \int x P(x) d(x)
\]

Where, \( x \) = reserve value and \( P(x) \) = probability of \( x \).

**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. 

**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.

---

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.

实际采出量将等于或超过该估算量的概率为 90% 的数量。储量评估中，P90 是证实储量估值。

The quantity for which there is a 50% probability that the quantities actually recovered will equal or exceed the estimate.

实际采出量将等于或超过估算量的概率为 50% 的数量

The quantity for which there is a 10% probability that the quantities actually recovered will equal or exceed the estimate.

实际采出量将等于或超过估算量的概率为 10% 的数量

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:

\[ s^2 = \frac{\sum_{i=0}^{n} (x_i - \mu)^2}{n} = \int_{a}^{b} (x - \mu)^2 f(x) \, dx \]

Where \( x = \) reserve, \( \mu = \) mean, and \( f(x) = \) PDF.

其中, \( x \) 为储量, \( \mu \) = 平均值, 和 \( f(x) \) 为其概率密度函数。它方便地对差值进行平方处理，这可以避免正负值的影响。取差值的绝对值进行计算也可得到同样的效果，但不如方差的数学特性好。

Describes the spread of a variable around its mean value. It is defined as the square root of the variance.

描述变量偏离其均值的情况。定义为方差的平方根。
CHAPTER 6 Aggregation of Reserves

Wim J.A.M. Swinkels 著 衣艳静 译
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 analysis.

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.

...
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. Statistically add Proved estimates from well level to reservoir level.

6.2.1.1 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:

1. The performance will include the effects of ongoing drilling, development, and maintenance activities.
2. The aggregate may include wells at different stages of decline, with different GORs, etc.
3. 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.

6.2.1.2 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:

1. 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.
2. 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 Figure 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.

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 Figure 6.2 illustrates.

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 Figure 6.3, which shows the cumulative probability curves of Blocks A and B. The figure also shows the arithmetic sum of the two blocks (curve Block A + Block B) compared with the actual distribution of the
<table>
<thead>
<tr>
<th>Type of Dependence</th>
<th>Example of Situation/Parameter</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
<td>Local, independent pressure systems</td>
</tr>
<tr>
<td>No shared risk identified (fully independent)</td>
<td>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).</td>
</tr>
<tr>
<td>Weak</td>
<td>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. A shared risk is not considered to important when compared to other, known, independent risks.</td>
</tr>
<tr>
<td>Medium</td>
<td>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. The shared risks could be real and significant.</td>
</tr>
<tr>
<td>Strong</td>
<td>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. The shared risks are absolute and inverse.</td>
</tr>
<tr>
<td>Total</td>
<td>An oil field is developed in a core area only. Additional upside in stock-oil initially-in-place (STOIP) in flank areas will result in a reduction in the average recovery factor.</td>
</tr>
<tr>
<td>Negative</td>
<td>Uncertainty in fault location works in the opposite direction for gross rock volume (GRV) in two adjacent blocks.</td>
</tr>
</tbody>
</table>
CHAPTER 6 Aggregation of Reserves

Figure 6.1 West Star field area vs. depth

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

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 to recognize the added complexity and value of such a probabilistic approach.

Figure 6.3 Probability Distribution—Reservoir Blocks A and B

---

GIP (10^9 m^3), 天然气原始原始地量（十亿方）

Reservoir 气藏层级

Block A+Block B 断块A+断块B

Block A 断块A

Block B 断块B

Cumulative Probability (%) 累积概率（%）

GIIP (10^9 m^3), 天然气原始原始地量（十亿方）

满油藏. 概率对应的证实储量估值之和约为 7×10^9 m^3 (0.245×10^12 ft^3) 相比气藏层级 90% 概率对应的证实储量估值小 11%。

另一种常见负相关的情形是气顶油藏单独估算其气油界面 GOC 以下的溶解气量. 若油气界面的深度存在不确定性 总油气界面下两部分的天然气储量则呈负相关关系. 显然 原油储量与气顶气储量也为负相关. 除非有可靠资料 (如详实的流体性质分析) 来确定 GOC 的位置 一般合理的做法是假定最浅已知油顶以上为低价值流体 通常指天然气.

加合最佳估值  或 2P 估值 则可以试算天然气总原始原始地量 GIIP —— 自由气与溶解气之和 显然 该方法不适用于证实储量. 因为自由气低估值情景是与溶解气高估值情景相关联. 反之亦然. 为应对这种情况 可采用一种随机模拟程序 电子表格应用程序 如水晶球™ 或 @Risk™ 软件 来求取油田层级天然气原始地量 GIIP 与储量的分布.
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 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

为了特定目的，采用概率法加合至油气田层级。

PRMS (SPE 2007) 建议 开展储量汇并工作时，统计法的应用不宜超出油气田资产或项目层级。行业其他机构 (SEC 2008) 随后采纳了该做法。

当一个油气田包含不同断块 (油气层、油气藏、油气聚集体)，则可作为一个财务单元进行开发。那么该资产的财务产储法折旧也在该层级进行。超出该层级的汇并，统计法加合可能会带来财政问题。鉴于此，行业界很少采纳统计法在高于油气田的层级 (公司和地区层级) 进行储量汇并。只有大公司涉及资产组合管理的小部分专业人士可能有兴趣采用概率法加合进行这些高层级的储量汇并。

应注意，若仅有确定法评估结果，则储量汇并方法的唯一选择仍为算术求和。有关统计法汇并的讨论只适用于已有概率法分析的情形 (或将情景法结果转换为定量化的概率法结果)。

6.3.1 Pitfalls of Arithmetic (Dependent) Addition of Proved Reserves

当我们提及证实储量时，通常是指油气田开发过程中“可合理确定”商业开采“的油气数量。当采用概率法时，PRMS 解释称合理确定性是指有90%的概率达到或超过所指定数量 (SPE 2007)。证实储量体现了资源可采量估值的高置信度，即相对保守，因此被投资者和银行家广泛使用。对于一个单一资产而言，这是有意义的，可让人体会开发风险可能导致结果——油气开采量远低于预期数量。

无论何时，当石油投资方或油气公司算术加合多个油气藏的证实储量时，他们会低估整个资产的价值。这是因为资产组合中，大部分储量估值上调的潜力将大于10%概率因表现不佳而储量下调所必需的补偿。这种情况会在在储量评估结果相互独立的情形发生。因此，大多数油公司在编制业务规划时，更多采用的是最佳估值 2P 数据，而不是高置信度的 1P 估值。

日常经营中，我们意识到应分担风险，避免...
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.

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

Note that for the sum of the Proved Reserves in Table 6.2, we have...
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• 证实储量 (均有 90% 概率达到或超出) 的算术求和，即将两者直接加合，即假定其完全相关；也就是说，当一个断块出现低估值情景时，另一个将同时出现低估值。由此，所得到的证实 GIIP 期望值，即为两个断块 GIIP 的算术和。将两者直接加合，意味着假设这两个断块的估值完全相关，即如果一个断块出现低估值，另一个断块也将同时出现低估值。

Table 6.2 Example Case: Gas Reservoirs A and B

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Block A</th>
<th>Block B</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total GRV (10^9 m^3)</td>
<td>1.74</td>
<td>1.16</td>
<td>2.9</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.22</td>
<td>0.22</td>
<td>0.22</td>
</tr>
<tr>
<td>Net to Gross</td>
<td>0.85</td>
<td>0.85</td>
<td>0.85</td>
</tr>
<tr>
<td>Saturation</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
</tr>
<tr>
<td>Gas Expansion</td>
<td>205</td>
<td>205</td>
<td>205</td>
</tr>
<tr>
<td>Expectation of GIIP (10^9 m^3)</td>
<td>53.4</td>
<td>35.6</td>
<td>89.0</td>
</tr>
<tr>
<td>Proved GIIP (10^9 m^3)</td>
<td>43.3</td>
<td>28.5</td>
<td>71.8</td>
</tr>
</tbody>
</table>

Figure 6.4 Probability Distribution—Reservoir Blocks A and B

取两个证实储量的算术和，其概率分布如图 6.4 所示。
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 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 Figure 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.

![Cumulative Probability](image)

**Figure 6.5** Arithmetic and Probabilistic Addition, A and B

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.
Applying this approach and making the assumption of complete independence, we can state with 90% certainty that there is at least $77 \times 10^9$ m$^3$ of gas in both reservoir blocks, as opposed to $72 \times 10^9$ m$^3$ of gas using arithmetic summation. In situations where gas contracts are based on Proved Reserves, this may have considerable business implications.

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

1. Scenario trees, representing the possible outcomes as branches of a tree and calculating the overall outcome. This method is treated in Sec. 6.5.
2. Monte Carlo methods, using a spreadsheet add-in (such as @Risk or Crystal Ball).
3. Treating the volume estimates as a physical measurement with an associated error and then using error propagation methods.

In the last mentioned method, we approach the uncertainty of the estimate for a reservoir volume by $\Delta V = \text{Mean} - \text{Proved}$. We can then calculate the uncertainty for the sum of Reservoirs A and B using the relation $\Delta V_{ab} = \Delta V_A + \Delta V_B$.

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.

证实储量的定义为有 90% 概率达到或超过的体积数量。算术求和各气田证实储量得到项目的证实储量。比随机概率求和的 P90 值低 15%。由于不假设完全关联或完全独立，非关联非关联，所以作者采用以下步骤来分析单一估算值之间的潜在关联性：

1. 列出各气田相关领域，识别气田间的共有因素。这些领域包括各气田的 GIIP 估值之间存在的技术手段、方法原理以及天然储层与流体的共性等。将共性划分为弱、中、强。

2. 根据相关系统评估，给弱、中、强相关性分别赋予相关系数 0.1、0.3 和 0.5，构成适用于蒙特卡洛法的数组。

3. 各气田的储量分布由 P90、P50 和 P10 定义，用双三角概率密度函数描述分布范围。

4. 各气田之间的共享风险用一个关联系数矩阵描述，每一对气田的相关系数在 0（完全不相关）至 ±1（完全相关）之间变化。

5. 然后，应用 Excel™ 中 @Risk™ 插件事先定义的关联矩阵。在项目层级概率求和各气田的储量分布。

该案例应用上述方法的结果表明，90% 置信度的天然气储量比算术求和的结果高 9%。若不考虑各气田之间的相关性，则相应结果比直接算术求和高 15%。

下面介绍一些通用做法，更有利于实际操作。首先，将相关性最高的气田作算术相加，构建气田组。这样确保近似处理的偏差不至于太大。由此相关系数矩阵减少为 15 个气田组。高相关性出现在压力连通的相邻气田或共享构造风险的新开发气田。

另一个重要措施，是在相关性半量化过程中进行专家审查。审查重点是确定引起完全相关或几乎非相关的因素。如容积法的不确定性。若不考虑各气田之间的相关性，则相应结果比直接算术求和高 15%。

简化程序的第 3 个做法，是在分析中忽略负相关系数。两个气田的相关系数出现负值是有可能的。尽管在原则上正相关和负相关都能处理。
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:

1. 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.

2. 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 Resources 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 untapped 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

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(7) PRMS Sec. 4.2.1.1
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 ($P_{oS}$). $P_{oS}$ 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 ($P_{oS}\times MSV$) 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.

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 (Figure 6.6).

As can be seen in Figure 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.
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It is important to note 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.

Table 6.3 STOIIP Uncertainty Range of Three Oil-bearing Sands

<table>
<thead>
<tr>
<th>Sands</th>
<th>Low</th>
<th>Median</th>
<th>High</th>
<th>Mean = Expection</th>
</tr>
</thead>
<tbody>
<tr>
<td>M – Sand</td>
<td>17</td>
<td>23</td>
<td>30</td>
<td>23.3</td>
</tr>
<tr>
<td>N – Sand</td>
<td>29</td>
<td>41</td>
<td>54</td>
<td>41.3</td>
</tr>
<tr>
<td>S – Sand</td>
<td>10</td>
<td>15</td>
<td>25</td>
<td>16.7</td>
</tr>
</tbody>
</table>

Figure 6.6 Scenario Tree (Low Degree of Dependency)

It is important to note 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, play a secondary role and disregard them to keep the number of branches limited. Figure 6.7 shows the scenario tree for this case.

In the scenario tree in Figure 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.

图6.7为该情形的情景图。图6.7的情景图中3套砂岩之间的关联关系显示砂岩体积高值与高值组合的几率较高。一套砂岩出现低值另一套砂岩也趋向于出现低值。第6.5.3节提供了以上数据的交会图。
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 pseudoprobabality curves for each of the three cases by sorting and calculating cumulative probabilities. Figure 6.8 shows the results. This analysis now results in the summations of the three sands shown in Table 6.4.

Table 6.4 Probabilistic Addition with Varying Degrees of Dependency, STOIIP

<table>
<thead>
<tr>
<th>Items</th>
<th>P85=Low</th>
<th>P50=Median</th>
<th>P15=High</th>
<th>Expectation=Mean</th>
</tr>
</thead>
<tbody>
<tr>
<td>M – Sand</td>
<td>17</td>
<td>23</td>
<td>30</td>
<td>23.3</td>
</tr>
<tr>
<td>N – Sand</td>
<td>29</td>
<td>41</td>
<td>54</td>
<td>41.3</td>
</tr>
<tr>
<td>S – Sand</td>
<td>10</td>
<td>15</td>
<td>25</td>
<td>16.7</td>
</tr>
</tbody>
</table>

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.

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

Table 6.5 Comparison between Scenario Tree and Correlation Matrix Methods

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

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, 1 atm (14.7 psia).
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:

   - \(9,500 \text{ kcal/Nm}^3 = 39.748 \text{ MJ/Nm}^3\)
   - \(1,000 \text{ Btu/scf (60°F, 30 in. Hg)} = 39.277 \text{ MJ/Nm}^3\)

   The volume equivalent in total combustion heat is

   \(1 \text{ Nm}^3 \text{ (GHV = 9,500 kcal/Nm}^3) = 37.674 \text{ scf (GHV = 1,000 Btu/scf).}\)

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 Nm³ (e.g., m³ 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/Nm³].

### 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.

销售气采用其他单位计量和报告时可能存在单位转换造成的局部偏差。另外，对于天然气可采用以下两个标准化步骤：

1. 转换为标准压力与温度条件。目前压力和温度的矿场单位和国际标准单位经常混用。某种程度上，天然气压力与温度转换系数取决于天然气组分，采用的系数可能略有不同。
2. 转换为热值当量体积。热值转换系数为：

   - 9500 kcal/Nm³ = 39.748 MJ/Nm³
   - 1000 Btu/scf (60°F, 30 in. Hg) = 39.277 MJ/Nm³

总燃烧热值当量体积 (GHV) 下标准化的总热值当量体积 (GHV = 9500 kcal/Nm³) = 37.674 scf (GHV = 1000 Btu/scf)。

在矿区，天然气通常在井口按标准条件计量的组分和热值进行报告，不适用转换为热值当量体积。销售气的计量与报告通常以标准立方米 (Nm³) 表示。有时转换为能量当量 [例如，9500kcal/Nm³ 系数条件下] 标准化总热值当量体积 (GHV)。
(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).

References,


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:

1. 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.

2. A reasonable expectation that there is a market for all or at least some sales quantities of production required to justify development.
CHAPTER 7 Evaluation of Petroleum Reserves and Resources

(3) Evidence that the necessary production and transportation facilities are available or can be made available.

(4) Evidence that legal, contractual, environmental, and other social and economic concerns will allow for the actual implementation of the recovery project evaluated.

(5) 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:

(1) The production profiles (expected quantities of petroleum production projected over the identified time periods).

(2) 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.

(3) 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.

(4) Future projected petroleum production and revenue-related taxes and royalties expected to be paid by the entity.

(5) A project life that is limited to the period of entitlement or reasonable expectation thereof (see Chapter 10) or to the project economic limit.

(6) 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:

$$\text{Nominal}_t = (\text{Current-year}_t) \times \text{EF}_t = (\text{Current-Year2010}_t) \times (1 + E_t)^t$$

(7.1)

Where

$$\text{EF}_t = (1 + E_t)^t$$

(7.1a)

$E_t$ 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.

$E_k$ is 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 $\$$.)

7.3.2 Economic Evaluation

Calculating and analyzing any petroleum resource projects’ economic performance requires understanding basic definitions and well-established industry practices. These include the current and the expected economic conditions, economic limit, and use of appropriate discount rate for the corporation.

7.3.2.1 Economic Conditions

Agricultural production involves many factors, including land, labor, and capital. 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.

$$\text{Nominal}_t = (\text{Current-year}_t) \times \text{EF}_t = (\text{Current-Year2010}_t) \times (1 + E_t)^t$$

(7.1)

Where

$$\text{EF}_t = (1 + E_t)^t$$

(7.1a)

$E_t$ 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.

$E_k$ is 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 $\$$.)
7.3.1.2 恒定方案或替代方案

采用当年美元进行 DCF 分析，恒定方案是一个替代的经济评估方案。PRMS 将当前经济条件定义为过去 12 个月的平均值。除项目合同或资产有关协议中对价格有明确的规定，PRMS 推荐的恒定方案储量评估要求项目现金流的价格与成本构成以当年美元为单位。采用预测方案评估时，项目现金流使用名义美元为单位表述。表 7.1 阐述了如何通过关系式 7.1 将以 2010 当年美元表示的平均原油价格每桶 50 美元转换为 2011 年和 2012 年的名义美元价格。

有关价格与成本流动的内容可参见 SPEE 推荐的评估实践 (2002)。当然，公司可改变对价格与成本的假设，计算更多经济方案，以评估项目的经济性对预测条件不确定性的敏感程度。

### Table 7.1 Oil Price in Different Dollar Units

<table>
<thead>
<tr>
<th>Year</th>
<th>Current-Year 2010 $</th>
<th>Nominal $</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>50.00</td>
<td>50.00</td>
</tr>
<tr>
<td>2011</td>
<td>52.00</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>54.08</td>
<td></td>
</tr>
</tbody>
</table>

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

7.3.2 经济极限

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

7.3.2.1 经济极限

根据预测经济条件计算的经济极限对石油储量的估算具有显著影响。SPE 建议采用行业标准规范，来计算经济极限以及维持运营所需的操作成本。这里所使用术语定义如收入、成本和现金流，请读者参见第 7.4.1 节。

经济极限是指一个产量极限值，低于该极限值意味着项目单井、租赁区或整个油田的净现金流为负值，其对应的时间点即项目的经济年限。或者说，达到该产量时项目的净收入与运营项目的现金支出成本相等。
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:

(1) 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

文所述。例如，对于海上作业，评估师应保持谨慎，确保任何单个储量实体（如一口井或油藏所控）的估算经济年限不超过支撑该区域经济开发的平台的经济年限。因此，对于拥有卫星周边回接设施的平台而言，应考虑其整体经济极限。可通过情景法或概率模拟分析来检测所做假设最可能的置信度。

操作成本。第7.4.1节有详细定义和说明，在PRMS中也有描述。应该与价格的测算方案或时间运行表一致。操作成本应只包括那些项目中用于计算经济极限的增量成本。换而言之，在进行经济极限计算时，仅考虑那些若项目停产就会消除的现金成本。

操作成本应包含资产的特定管理费（如果是项目的实际成本增量）、生产税和资产税，但在计算经济极限时不含折旧、弃置、恢复资本和所得税以及任何超出资产评估对象或项目/自身运营所需的管理费用。根据PRMS，可通过对各种降低成本和增加收入的办法，如共享生产设施、联营维修合约或销售伴生的非烃产品等，延长项目生命期。

在短期低油价或暂遇重大经营问题期间，但从长远预期看，仍然可以实现正现金流时，则容许项目出现暂时的负净现金流。

7.3.3

开采项目的储量价值可定义为其经济年限内的累计贴现现金流。即项目的净现值（NPV），项目的净现金流按照公司贴现率也称投资项目期望的MARR进行贴现，主要体现企业加权平均资本成本（WACC）。各种用于确定公司适宜贴现率的原则性方法可参见Campbell等2001和Higgins2001的研究。

最后，重申PRMS石油资源评估程序的下列有关指南可能会有所帮助。

· 实施评估的商业实体在其内部进行评估结果的汇报与报告不能代替后续按外部监管、政府机构和任何当前或未来的会计准则进行公共披露的指引。因此，由于公司内部业务规划假
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.”

(2) 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.

(3) 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
设和政府监管机构规定的对外披露要求之间的差异。公司内部使用的石油储量评估结果可能与对外报告和披露的数据有所不同。所以公司内部评估结果可以根据监管机构对外披露的规则要求进行调整。例如，可能会有这样的特定要求：若可采量限定为证实可采储量，则其恒定方案在外部规定的贴现率下仍应当产生正现金流。对外披露也可能对“当前经济条件”有其它的特定要求。

2) 可能会出现这种情况：按照预测方案，项目能够满足储量划分标准。但尚不满足对外披露的证实储量标准。在这种具体情况下，实体可以登记 2P 和 3P 储量而不单独登记证实储量。随着成本实际发生和开发的进行，低估值情景最终会完全满足对外披露规定的标准。这时再登记证实储量。

3) PRMS 指南虽不要求项目在登记储量前确认融资，但融资可能是另一外部要求。在许多情况下，贷款是有条件的。要求项目仅基于证实储量。即具有经济性。总的来说，如果不能对贷款或其他形式的融资，例如招标出售，有合理预期，以便在合理期限内启动项目，那么项目要划归为条件资源量。如果融资可合理预期，但尚未确定，而当地管辖区要求将融资情况对外披露，那么该项目可在公司内部划归为储量类别。已论证可开发，但不能报告证实储量。

7.4 Development and Analysis of Project Cash Flows

本节叙述了如何生成项目现金流。在对不同现金流术语进行定义之后，概述了现金流的主要构成部分。产量剖面、产品价格、投资成本与操作成本、以及所有权益、矿费、国际财税协议及其随时间变化的不确定性。或精确度。下一节将为项目进行现金流分析获得价值评估结果提供技术依据，并简要说明。

7.4.1 Definitions and Development of Project Cash Flows

现金流价值评估模型将估算获得的资金收入，然后扣减所有矿费、成本、操作成本和资
CAPEX), and income taxes, yielding the resulting project NCFs. Detailed definitions, basis, and description of the key project cashflow 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:

\[
NCF(t)=REV(t)-ROY(t)-PTAX(t)-OPEX(t)-OH(t)-CAPEX(t)-ITAX(t)+TCR(t)
\]  

(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:

1. Calculation of annual net revenue (NREV):
\[
NREV(t)=REV(t)-ROY(t)-PTAX(t)
\]  

(7.2a)

2. Calculation of annual taxable income (TINC):
\[
TINC(t)=NREV(t)-OPEX(t)-OH(t)-EXSI(t)-DD&A(t)-OTAX(t)
\]  

(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,
- \(OTAX(t)\) = capital recovery or allowance in terms of depreciation.

本成本和所得税得到项目的净现金流 NCF

有关项目现金流主要构成的详细定义 NCF 项目净现金流


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- \(EXSI(t)\) = expensed investment capital,
- \(DD&A(t)\) = capital recovery or allowance in terms of depreciation,
- \(OTAX(t)\) = capital recovery or allowance in terms of depreciation.
depletion and amortization (of allowed nonexpensed investment capital), and

\[ \text{OTAX}(t) = \text{other tax payments} \]

(3) Calculation of annual ITAX:

\[ \text{ITAX}(t) = \text{TINC}(t) \times \text{ITR}(t) \] (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, TINC(t) = \text{式 } 7.2b\] 定义的年度应纳税收入

EXSI(t) = 费用化资本投资

DD&A(t) = 以折旧、折耗与摊销计入的未费用化资本回收或备抵额

OTAX(t)= 其他税负

\[ 3 \] 所得税 ITAX 的计算

\[ \text{ITAX}(t) = \text{TINC}(t) \times \text{ITR}(t) \] (7.2c)

其中 ITR(t) 为公司的年度企业实际所得税率

计算项目净现金流时，必须考虑到上述术语

包括所有其他相关经济和商业术语，涉及的收入与成本构成

即便不同的实体（例如公司或政府）

对这些术语的定义不同

根据作业公司与主

管油气具体业务开发与作业权的政府所达成的财税协议

不同国家对这些术语的定义也可能有所不同

国际上常见的财税合约包括租让制/含矿费和/或税和合同制，这些内容将在第 10 章和其他文献（Campbell 等，2011; Seba 1998）中介绍。这些协议定义了如何回收成本和分配资源国与作业者之间的利润，充分了解相关管理规则/矿费/税负和其他优惠政策的细节对合理可靠地开展项目储量评估和评价十分重要。

尽管项目年度现金流的各构成要素可以直接计算，但其结果的精确度/数量与质量取决于所采用的特定合同区油气资产输入数据/预测方法/确定法或概率法/以及多学科评估小组的专业知识和成员间的有效合作。

项目净现金流关系式/7.2 中的各术语/如产量/产品价格/资本成本/操作成本/通货膨胀率/税和利率等/具有随时间变化的不确定性/对项目净现金流具有重要影响的术语概述如下/7.4.1.1 储量与产量预测

储量与相关产量预测的不确定性通常至少用低估值/最佳估值/高估值/3 种情景来量化。对于多数项目而言，也就是 1P/2P 和 3P 储量，可采用确定法或概率法进行估算。很多公司即使选用概率法量化储量的不确定性，也采用具体的储量情景，而不是蒙特卡洛法进行现金流计算。这样可在储量和相应的开发情景与成本间形成清
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 corresponding relationship. For those projects with勘探前景的项目Ⅰ公司经常会将其预测结果与储量累加，但除非确实正确考虑了适当的发现与开发风险，否则会导致评估过于乐观。  

7.4.1.2 产品价格

考虑原油品质或天然气热值确定合理产品价格至关重要。无论未来原油价格采用何种预测方法，远期剥离价格或公司内部估算价格，均应考虑与公认基准原油价格（如西得克萨斯中质油或布伦特原油）的差异。理想情况下，最佳的方式是采用实际的历史油价差异。对于新的混合油产品，市场分析师应对样品进行检测。若该油品通过管线与其他原油混输，则应考虑混合后的平均价格，并且评估师应当了解是否存在银行账务处理细则，允许单种油品按其品质伟大复兴为API重度和含硫量等考虑不同的价格差异。

对于天然气而言，重要的是依据其脱液处理后销售气的最终组分确定合理价差。每种副产品（如丙烷、丁烷等）都应当按适当价格进行评估。原料气由于脱液处理和非烃气体（如CO\(_2\)等）造成的损耗应当予以体现。燃料气量应从销售气储量中扣除。

如果井口不是销售点，油气的运输成本应当视为操作成本的一部分，或者在销售价格中扣除。

7.4.1.3 项目资本成本

对于典型油气开发项目而言，其资本成本的主要构成包括土地租用、勘探、钻井与完井、地面设施、油气集输基础设施、处理厂与管线以及弃置等。

钻井与完井的成本可分为有形成本，可形成折旧备抵额和无形成本，费用化部分与可摊销部分。

地面设施的成本可产生设施折旧抵扣，用于计算税负和各种优惠。

处理设施或有多台装置的处理厂的资本投资大体上分为四类（Clark and Lorenzoni, 1978 and Humphreys and Katell, 1981）直接成本。指与采购的处理厂或设施实体及其安装启动相关的所有物料和人工成本，包括直接构建处理厂的所有物料和人工成本，以及完成安装所需散装物料。如地基、管线、基础设施等的成本间接受
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 Figure 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 decision thresholds).
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.

![Figure 7.1 Typical project phases [adapted from Clark and Lorenzoni (1978)].](image)

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 Figure 7.1), which are approximately defined as follows:

1. 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.

2. Preliminary estimate is considered accurate within -15 to +30%. Based on flow sheets, layouts, and equipment details, the semi-detailed cost estimate is made during the conceptual-design stage of a project, and is used for budget proposal and expenditure approval purposes.

3. 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

<table>
<thead>
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<th>Time (Project Development Stages)</th>
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<tr>
<td>Evaluation &amp; Planning</td>
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<tr>
<td>Conceptual Engineering</td>
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<tr>
<td>Construction</td>
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<tr>
<td>3 months to 3 years</td>
</tr>
<tr>
<td>3 to 12 months</td>
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<tr>
<td>1 to 3 years</td>
</tr>
</tbody>
</table>

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尽管我们所知或定义的术语名称可能有所不同，但美国成本核算工程师协会 (Humphreys 和 Katell 1981) 根据不同用途，如图7.1项目各阶段所示的具体细节与精度要求，建议将项目的成本估算大致分为：

- 数量级估值 精度介于 -30% ~ +50% 之间
- 初步概算值 精度介于 -15% ~ +30% 之间
- 最终预算值 精度介于 -5% ~ +15% 之间

7.4.1.4 项目操作成本

与资本成本类似，各种操作成本的评估与处理对税负和项目利润的计算也是非常重要的。操作成本按基准年美元或当年美元的估算通常以工程项目的类比为基础。再根据产能、人工
CHAPTER 7 Evaluation of Petroleum Reserves and Resources

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 (lessee) 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.,

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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 Figure 7.2.

![Figure 7.2](image)

Figure 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:

\[
Npv(t,MARR) = \sum_{t=0}^{n} \frac{NCF_t}{(1+MARR)^t} = \sum_{t=0}^{n} NCF_t \cdot DF_t \tag{7.3}
\]

and can also be rewritten in the following open form:

\[
Npv(t,MARR) = \sum_{t=0}^{n} NCF_t \cdot DF_t - \sum_{t=0}^{n} IC \cdot DF_t \tag{7.3}
\]
CHAPTER 7 Evaluation of Petroleum Reserves and Resources

NPV\( (t,MARR) = NCF_t + NCF_{t+1} \cdot DF_{t+1} + NCF_{t+2} \cdot DF_{t+2} + \ldots + NCF_n \cdot DF_n \) \hspace{1cm} (7.3a)

where

\[ NCF_t = \text{annual year-end NCF (revenue minus cost) at any year (t) ranging from 0 to n} \]
\[ NCF_0 = \text{the initial investment capital (IC) made as a single lump sum in the first or “0” year-end for the most projects. However, for large projects, the initial CAPEX profile does span more than one year and thus, the NCFt’s for (t) ranging from initial (0) to say (m) years would be negative during these early years. They are actually spent as nominal dollars during these earlier m years and are also equivalent to their future value (FVI) assumed to be spent only in zero-year (or current-year) as a lump-sum initial investment capital (IC or NCF0) and can now be defined as follows:} \]

\[ IC = NCF_0 = FVI(t,MARR) = \sum_{t=0}^{m} IC_t (1 + MARR)^t \]
\[ = \sum_{t=0}^{m} IC_t / DF_t \] \hspace{1cm} (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:

\[ MARR = \text{Minimum acceptable rate of return desired or the company’s annual discount rate,} \]
\[ t = \text{time starting from zero (0) or current-year to (n) years in the future,} \]
\[ n = \text{project economic (or contractual) life in years,} \]
\[ m = \text{number of years (usually 2 to 5 for megaprojects) during which initial project capital is actually spent,} \]
\[ DF_t = \text{discount factor at any year (t) defined as follows:} \]
\[ DF_t = 1 / [1 + MARR]^t \text{ for the year-end cash receipts} \]
\[ DF_t = 1 / [1 + MARR]^{0.5} \text{ for the mid-year cash receipts} \]

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 (DFt) 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

\[ NPV(t,MARR) = NCF_0 + NCF_1 \cdot DF_1 + NCF_2 \cdot DF_2 + \ldots + NCF_n \cdot DF_n \]

其中\( NCF_t = 0 \) to n 之间任一年度的年净现金流\( \) 收入减去成本\( \) 的年净现金流\( \)

\[ NCF_0 = \text{初始资本投资} \]
\[ IC = \text{即大多数项目} \]
\[ 各项目将有收入的} \]
\[ dp = 0 \] \至式\( 7.3c \) 假定项目仅在年底获得年度净现金流\( \) 若项目净现金流为年初获得\( \)

根据 PRMS 指南\( \) 一个已发现石油开发项目经过评价能获得正净现值\( \) NPV\( \) 且不存在影
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 invested), payout
time, or payback period) that are routinely used in project economic
evaluations (Campbell et al. 2001, Higgins 2001, Newendorp and

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. Figure 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).
CHAPTER 7 Evaluation of Petroleum Reserves and Resources

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

<table>
<thead>
<tr>
<th>Key Economic Parameters</th>
<th>Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Economic Conditions</td>
<td></td>
</tr>
<tr>
<td>Current-year 2010 Oil Price ($/bbl)</td>
<td>60</td>
</tr>
<tr>
<td>Current-year 2010 Gas Price ($/MMBtu)</td>
<td>5</td>
</tr>
<tr>
<td>Average Annual Product Price &amp; Cost Escalation Rates (%)</td>
<td>3</td>
</tr>
<tr>
<td>Operating Expenditures (OPEX)</td>
<td>3.5</td>
</tr>
<tr>
<td>Capital Expenditures (CAPEX)</td>
<td>4</td>
</tr>
<tr>
<td>Average Annual Inflation Rate (f)</td>
<td>3</td>
</tr>
<tr>
<td>Average Nominal Discount Rate (ANDR)</td>
<td>10</td>
</tr>
</tbody>
</table>

Figure 7.3 Example Evaluation: Production rate profiles and reserves.
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.

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:

(1) 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.

<table>
<thead>
<tr>
<th>Type of Basic Data Required</th>
<th>Low Estimate (1P)</th>
<th>Best Estimate (2P)</th>
<th>High Estimate (3P)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Reserves (MMSTB)</td>
<td>32.4</td>
<td>48.5</td>
<td>71.6</td>
</tr>
<tr>
<td>Solution GOR (scf/MMSTB)</td>
<td>600</td>
<td>600</td>
<td>600</td>
</tr>
<tr>
<td>Solution Gas Reserves (Bscf)</td>
<td>19.4</td>
<td>29.1</td>
<td>42.9</td>
</tr>
<tr>
<td>Gross Heating Value of Gas (Btu/scf)</td>
<td>1330</td>
<td>1330</td>
<td>1330</td>
</tr>
<tr>
<td>Initial Oil Rate (MSTB/D)</td>
<td>10</td>
<td>15</td>
<td>20</td>
</tr>
<tr>
<td>Initial Investment Capital, IC (MMS)</td>
<td>140</td>
<td>180</td>
<td>230</td>
</tr>
<tr>
<td>Annual Future Expenses and Capital (2010 MMS)</td>
<td>8</td>
<td>10</td>
<td>12</td>
</tr>
<tr>
<td>Effective Royalty Rate</td>
<td>20</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>Effective Production Tax Rate</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Annual Declining Balance Depreciation Rate</td>
<td>25</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>Effective Income Tax Rate</td>
<td>35</td>
<td>35</td>
<td>35</td>
</tr>
</tbody>
</table>
7.2. (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. Figure 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.

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 Figure 7.3, discounted annual price and cost escalation and inflation rates are assumed to be zero during the entire project life of 25 years.

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 Figure 7.3, discounted annual discount rates for the initial investment spent in terms of 2010 dollars during 2 years for these three reserves scenarios evaluated.

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. Figure 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.

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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 Figure 7.3, discounted annual
and cumulative NCF profiles under PRMS Forecast Case and Constant Case assumptions can be generated for each reserves scenario. Figure 7.5 illustrates these profiles only for the 2P reserves scenario.

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.

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

<table>
<thead>
<tr>
<th>Parameters (in 2010$’s)</th>
<th>Low Estimate (1P)</th>
<th>Best Estimate (2P)</th>
<th>High Estimate (3P)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Key Parameters</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Reserves (MMSTB)</td>
<td>32.4</td>
<td>48.5</td>
<td>71.6</td>
</tr>
<tr>
<td>Associated Gas Reserves (Bscf)</td>
<td>19.4</td>
<td>29.1</td>
<td>42.9</td>
</tr>
<tr>
<td>Initial Oil Rate (MSTB/D)</td>
<td>10</td>
<td>15</td>
<td>20</td>
</tr>
<tr>
<td>Initial Investment Capital, IC (MMS)</td>
<td>140</td>
<td>180</td>
<td>230</td>
</tr>
<tr>
<td>Value of Petroleum Reserves or Net Present Value, NPV@10%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Forecast Case</td>
<td>467</td>
<td>740</td>
<td>1139</td>
</tr>
<tr>
<td>Constant Case</td>
<td>392</td>
<td>623</td>
<td>958</td>
</tr>
<tr>
<td>DCF Rate of Return, DCF-ROR (%)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Forecast Case</td>
<td>81</td>
<td>96</td>
<td>107</td>
</tr>
<tr>
<td>Constant Case</td>
<td>76</td>
<td>90</td>
<td>101</td>
</tr>
<tr>
<td>Profitability Index ($, Returned per $ Initially Invested)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Forecast Case</td>
<td>4.3</td>
<td>5.1</td>
<td>6.0</td>
</tr>
<tr>
<td>Constant Case</td>
<td>3.8</td>
<td>4.5</td>
<td>5.2</td>
</tr>
</tbody>
</table>

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

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:

1. Oil price (and production rate) would change it by ±37%, with a direct relationship.
2. Other parameters impact the NPV inversely, as expected (e.g., (+) changes resulting in (−) changes in NPV and vice versa). It follows that
   ① Discount rate would change it by -17% and +22%, respectively,
   ② CAPEX would change it by -5% and +5%, respectively, and
   ③ 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

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

Figure 7.6 Results of sensitivity analysis.

可见主要参数恒定变化±30%对其他储量或资源量级别的效果大致类似。例如，参数数值的增加会导致净现值的降低，反之亦然。贴现率将使项目净现值分别降低17%和增加22%。资本成本将使项目净现值分别减少5%和增加5%。操作成本将使项目净现值分别减少2%和增加2%。当然，尽管资本支出对项目的经济性影响较小，但仍需要进行一致性和准确的估算。因为它们经常会被用来估计项目和公司的年度开发和运营单位成本（美元/桶）。

决策分析是Campbell等2001年、Newendorp和Schuyler 2000年、Schuyler 2004年提出的一种基于明确目标与条件要求的结构化分析流程。它可用于许多可界定性问题的评价，对比以及理性决策，包括项目投资。

投资决策一般是通过评价和对比竞争对手的资金投资组合的项目净现值来进行的。在该案例项
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

\[
EV = \sum X_i p(x_i) \quad (7.4) 
\]

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:

\[
EMV@MARR = \sum EMV_i p(x_i) 
\]

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 \( \geq 50% \) 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 volume (ERV) and the EMV for the example petroleum project can be calculated as follows:

\[
ERV = (0.97) \times 32.2 + (0.7) \times (48.5-32.2) + (0.3) \times (71.6-48.5) = 50.1 \text{ MMSTB}
\]

\[
EMV \text{ at } 10\% = (0.97) \times 467 + (0.7) \times (740-467) + (0.3) \times (1,139-740) = \text{USD 763 million}
\]

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.

7.5.3.2 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 Figure 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

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

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 Figure 7.7.

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 Figure 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 Figure 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 Figure 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

\[
\begin{align*}
\text{P90} & \approx 5.0 \text{ billion} \\
\text{P50} & \approx 7.05 \text{ billion} \\
\text{P10} & \approx 9.95 \text{ billion}
\end{align*}
\]
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 Figure 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 Figure 7.8.

### Key Probabilistic Variables
- **Inputs**
  - **Cash Flow Model**
  - **NPV@10%** = \( \sum_{t=0}^{n} \frac{NCF_t}{(1+MARR)^t} \)
  - MARR = 8% (Discount Rate)
  - A = Projections of Prices, Net Cash Flow, etc.
  - B = EMV Profile (Expectation Curve)
  - C = Expectation Profiles for DCF-ROR, Profitability Index, etc.

### References


Guidelines for Application of the Petroleum Resources Management System

Engineers 1.


第 8 章
CHAPTER 8

非常规资源的估算
Unconventional Resources Estimation

Phil Chan, John Etherington, Roberto Aguilera, C.R. Clarkson, G.J. Barker, Creties Jenkins 著
Phillip Chan、郑舰、郭明黎、邵新军 译
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.

The relationship of conventional to unconventional resources is illustrated by a resource triangle (Figure 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.

Figure 8.1 Resource triangle (Modified from Holditch, 2002)

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) resource 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

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.

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 Canada 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 flotation 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 and efficiency (estimated to be 1,700,000 bbl) and expanded to 3,000,000 bbl by 2012. 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.

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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). 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. Production decline and material balance calculations do not apply.

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.

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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.

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
8.4.4 Assessment Methods

The integration of geoscience and engineering aspects are of

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 features (Byrnes et al. 2002) are some examples of this methodology.

Amenas and In Salah fields in Algeria and in the Khazzan and Makarem 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 Kuuskra 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-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

专业技术人员 Arevalo-Villagran 等 2006 Palacio 和 Blasingame 1993 分析天然气产量递减的这一特征 即在有利环境下可使用气体流动物质平衡法 Rahman 等 2006 评估渗透率和天然气原地量某些情况下可根据致密气产量递减的历史数据绘制用于特定用途的曲线 假设致密气藏的井距小于常规气藏的井距 单井模拟器可以得出合理的结果

如果气井已经生产几年 那么用归一化气产量进行递减分析就可以对动态进行合理预测 如果缺少压力数据而无法进行归一化 那么可采用双曲线递减通常也可得到合理结果 在这种情况下 需要的一点是限制预测时间 避免最终采收率的预测因生产期过长而受影响 指南建议最长考虑 30 年

有时致密气储层可作为天然气储气库 而有些情况下例如砾岩 可成为连通井筒的商业输送介质 在加拿大的西部盆地 有时就会出现这种情况 随着 Cadomin 地层压力的下降 Nikanassin 致密砂岩中的天然气开始运移到渗透率更高的砾岩中 Zaitlin 和 Moslow 2006 并通过 Cadomin 砾岩流入井筒

8.4.5 钻井、完井与增产措施

截取天然裂缝需要知道裂缝的走向和倾角 一个已经被业界认可的致密气开发概念是 钻井须垂直开启裂缝 如果开启裂缝超过一组 那么采用精心设计的斜井 水平井或分支井在经济可行条件下与尽可能多地穿插裂缝组 可使天然气产量和可采量最大化

在常规钻井中 防止发生潜在的井喷 选择的泥浆比重需超过储层压力 但在致密气层中 因为这些地层非常容易受到伤害 泥浆入侵可导致较大的表皮系数值 这一问题由于致密气层复杂的地质条件而更加严重 这些复杂情况包含天然裂缝 造成钻井液漏失和潜在的脱砂 福敏和断层 导致高应力 使水力压裂启动困难或无法实现 河道砂以及煤和页岩夹层 导致向夹层的漏失或预料之外的裂缝延伸路径

因此 欠平衡钻井成为钻探致密气的一种合理方法 在欠平衡钻进中 常用的泥浆被特殊钻井
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:

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.

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.

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).

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.

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 gas field.
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.

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 coal seam 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

...
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 infilling 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

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).

Generally use Darcy’s law to simulate flow in fractures. The permeability is highly dependent upon the existence, frequency, orientation (relative to current in-situ stresses), height, and degree of mineral infilling 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.

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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 (Figure 8.2).

随着储层的开采，CO$_2$含量增加至20%以上。这是因为煤对CO$_2$的吸附性比甲烷强，所以随着气藏开发，会释放更多CO$_2$。

煤基质可为裂缝系统提供气源。如果裂缝密度足够大，且/或扩散系数足够大，那么可以假定基质与裂缝实现平衡，解吸作用按瞬间向裂缝释放气体来模拟。另外，假定裂缝系统的压力决定基质吸附的气体量，可利用平衡吸附等温方程（例如 Langmuir 方程）模拟基质解吸。

如果裂缝间距大，并且/或扩散系数小，那么从基质向裂缝的解吸就不是瞬时的，需要利用拟稳态流公式，使用煤基质中的平均气体浓度，其与裂缝表面浓度不同，或非稳态状态公式建模模拟基质内气体的浓度梯度。不论哪种情况，浓度驱动流动扩散的菲克定律的某些形式可用于模拟气体在基质中的渗流。

由于CBM气藏特殊的赋存和渗流机制，CBM井的生产剖面非常特别。San Juan盆地CBM井两相流的生产特征参见图8.2。
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 adopted 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 (truck 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.

排水中心井要获得高的商业产量，必须形成有效的气体渗透率才可能登记储量。在先导试验的设计里需要减少气藏主要参数的不确定性，测试各种完井钻井技术以确定哪些是最符合成本效益的。

CBM的独特属性也影响其后期的开发方案。大多数CBM开采中的两相流性质表明设计必须考虑井距、井身结构和方向以加速排水。反过来，这又会增加气相的有效渗透率。最初天然气产量减少达到天然气峰值产量的时间。但必须注意不要过度打井或过度开发，避免导致单纯增加加密井。由于CBM区块的水平和垂直非均质性，勘探阶段即需要开始收集关键数据，例如天然气含量等温线数据、压力、流动和关井压力以及有效/绝对渗透率数据。在开发初期甚至成熟阶段还应继续收集这些数据对于开发和商业决策来说很有必要。

地面作业也必须谨慎规划，需要考虑开采动态。必须对作业设施进行合理设计，以便进行煤层气井排水人工举升收集输送，卡车或集水系统和处理大量产出水。尤其是在气田开发初期为促进初期排水、井优化的性能，必须考虑压缩机配置。此外，由于开采过程中气体组分可能变化，可能还需要分离非烃气体，例如二氧化碳的设施以满足市场要求。

8.5.5 商业性

商业性的主要考量是资源规模，其与煤层厚度和气体含量有关。煤层的深度是一项既可以影响气体含量，通过压力和温度又可以影响绝对渗透率的重要因素。由于煤层裂缝开度的应力敏感性，绝对渗透率一般随深度的增加而降低。因此，CBM的商业生产一般只限于深度不超过4000ft的煤层。影响天然气实现大量生产、产量高于可支付操作成本的经济极限时间的因素，例如欠饱和度也影响商业性。其商业性还受影响总产量达到峰值和天然气产量达到峰值时间的因素影响，例如气相有效渗透率。这些因素随饱和度和气藏压力而变化。
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:

1. Volumetric
2. Material balance
3. Production data analysis (PDA)
4. 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.

Volumetric. 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)

$$G_i = Ah \left( \frac{43560 \phi_f (1-S_{wi}) B_{gi}}{B_{gi}} + 1.3597 \bar{\rho}_c G_c \right)$$

(8.1)

where

- $G_i$ = GIIP, Mscf
- $A$ = reservoir area, acres
- $h$ = reservoir thickness, ft
- $\phi_f$ = 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
- $\bar{\rho}_c$ = average in-situ coal-bulk density corresponding to the

对 CBM 项目而言，以下几个方面很重要：

1. 基础设施足以收集和处理大量初期产水
2. 安装了充足的压缩设备以提高 CBM 采收率并协助煤层气井排水
3. 设计了人工举升并包括在操作成本中
4. 设计了煤层气的非烃气体分离设施
5. 考虑了监管问题

8.5.6 特殊的评估方法

CBM 资源 / 储量的评估方法主要来源于常规气藏评价技术。常用的四种方法是

1. 容积法
2. 物质平衡法
3. 生产数据分析 (PDA) 法
4. 气藏模拟法

需基于 CBM 气藏的开发阶段合理应用这些方法。虽然容积法和气藏模拟法在开发的所有阶段均可应用，但准确性随着可用数据的增加而提高。物质平衡法、递减曲线和 PDA 法只能在获得大量产量、流动压力数据和关井压力数据后才能使用。
average in-situ coal composition, g/cm³

\( G_c = \) 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 \( G_c \), 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 \( (G_c) \). 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/cm³ 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

\[ G_c \] g/cm³

•

Gc = 煤层原地平均组分对应的原地平均煤层气含量, scf/ton.


在式 (8.1) 的推导中, 假定只有煤基质吸附的气体和天然裂缝体系中保存的游离气构成煤层气的原始原地量. 通常, 煤基质中吸附的气体量是煤层气原始原地量的主要组成部分. 基质和裂缝中存储的游离气一般可以忽略.


煤的无机和有机组分都会影响煤的密度 \( (G_c) \). 煤的总密度与各组分的体积比相关联. 根据煤的定义, 煤有机体的体积分数超过 70% 质量分数超过 50% 的煤可以很容易通过裸眼密度测井探测. 煤层的密度测试和识别煤层的上限值为 1.75g/cm³ 相信此数值的选取与煤的定义有关. 但是, Mavor 和 Nelson (1997) 指出, 使用这一定义可能使其他富含有机质的煤层 (例如煤质页岩) 的地层被排除在总厚度的计算之外. 将其他含有机质地层计算在内的一种方法是在零吸附气含量下设置煤总密度上限值. 使用这种方法的 Fruitland 煤层得出的密度上限与 Mavor 和 Nelson
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/cm³).

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 (ϕf), which is difficult to determine quantitatively from core analysis as discussed by Mavor (1996). Initial water saturation in the fracture system (Swi) 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 RF as follows (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引用的一致(2.1 ~ 2.5 g/cm³)。储层厚度(h)是指考虑密度截止值的煤层厚度。对各煤层而言，使用与零吸附气含量对应的密度截止值可能是厚度预测的最佳方法。如果缺少高质量的密度测井数据，那么可使用其他电缆测井结果预测煤层厚度。因为煤的中子孔隙度一般大于40%，所以可使用中子孔隙度测井。可在已下入套管井中进行。伽马射线测井必须跟其他测井结合使用，因为虽然伽马射线在煤层中的响应一般较低，但也与煤层中铀的含量有关。

储层面积(A)与井眼、气田、区块或盆地规模的人工/天然边界对应。人工边界包括所有权边界、勘测边界或井间干扰边界(Mavor, 1996)。天然边界包括煤层尖灭边界、断层边界、渗透率变化边界、横向相变边界以及其他地质变化边界。由于单个煤层非常薄，通常很难用3D地震确定和识别煤层边界。单井的生产数据分析、物质平衡计算和数值模拟的历史拟合可用于推算泄气量，之后可利用泄气量和体积测定信息预测泄气面积。

在方程式8.1中，孔隙度一词指天然裂缝孔隙度(ϕf)。正如Mavor (1996)所述，很难根据岩心分析定量确定。裂缝系统中原始含水饱和度(Sw)情况类似，也很难根据岩心分析技术确定。通常被假定为100%。大部分具有商业价值的CBM储层的裂缝孔隙度通常<1%。对天然气总量的贡献很小。因此，其预测的某些错误对GIIP预测不会产生实质性影响。但是，如果这类孔隙最初充满了水，那么因为实际裂缝孔隙有2%而不是1%的裂缝孔隙度，所以储层排水需去除两倍的水量。

预测RF的方法包括如下几种(Zuber, 1996)。

1. 原始解吸压力和废弃条件下，使用吸附等温线计算吸附天然气含量
2. 类比
3. 气藏模拟

8.5.6.2 物质平衡法

已研发了多种包含吸附气储集的物质平衡方程式(King, 1993; Jenson和Smith, 1997)。
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

Seidle, 1999; Clarkson and McGovern, 2001; Ahmed et al. 2006. But whenever the 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.

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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:

8.5.7.1 Conditions

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/
8.5.7.4 证实未开发储量
井距规则——与证实已开发井位的距离通常为1个井距。若渗透率高且有区域经验证明煤层横向连续性好，则可增加到2个井距。

8.5.7.5 概算储量
井距规则——与概算井位的距离通常为2个井距。但如果煤层地质、煤层质量和地方性经验允许，在证实区域之间的距离可扩展到更大。

8.5.7.6 可能储量
井距规则——与概算井位的距离通常为2个井距。如果煤层地质、煤层质量和地方性经验允许，距离可扩展到更大。

图8.3展示了目前的惯例做法。图上所示的200m和1000m等深线是本例的预期商业生产的垂向深度界限。这些经验法则可以根据经验或更多的数据，如观察井的压力数据，反映更远距离和更大泄气面积的连通性，来改进。

Figure 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 may 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. 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.

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:

(1) It is typically based on a "best estimate" outcome for wells 8.5.7.7 生产实践评价

目前的生产实践有几点要注意。在评价或开发初期阶段，因为整个气藏资源潜力可能还没有完全发掘和/或披露，2P储量经常大幅增长。这也说明了在很小距离内煤层的性质就可能有很大的差别。需要获取足够的数据来增加对可采量评估的信心。面积是影响可采量不确定性的主要变量。1P储量的转化速率意味着2P和3P必须具有比常规储量估算更高的置信度。有些开发者会将不相邻或在不同区域的区域作为3P储量，将一些区域串连起来，加速这一转化过程。

在没有进一步调整信息的情况下，使用常规的并距规则下，每个证实已开发井位可以进一步证实8个证实未开发井位和40个概算储量井位。如果1/49约2%的计划井可以成功完钻并以商业产量投产，整个区域可划分为2P储量。这一结果实现的前提是该井组位于煤层厚度充足、含气量和渗透率在横向连续性上均发育的有利区。

完钻1/9即11%的计划开发井位，假设双倍并距。后整个区域可以划分为1P储量。这时原来所有的概算和可能储量都转化为了证实储量。这意味着可采量评估的不确定性将很小。根据煤层气的性质，这对任何合理规模的煤层气项目都是不可能的。因此，随着时间的推移，完钻的进展，储量趋近于3P评估值。同样，在条件资源量和远景资源量转化为储量时也通常接近3P估值。

基于传统并距增量法的煤层气储量核算的优点是可预见，有规则。但在应用中应注意以下几个问题。

(1) 通常所有的储量级别都是基于井的最
in all reserves category and relies primarily on area to provide a range of uncertainty in the outcome.

(2) 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.

(3) 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.

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
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.

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.
### Table 8.1 Data Needed to Fully Characterize Shale Gas Reservoirs

<table>
<thead>
<tr>
<th>Data</th>
<th>Usage</th>
</tr>
</thead>
<tbody>
<tr>
<td>TOC</td>
<td>Provides an indication of source-rock richness and sorption capacity.</td>
</tr>
<tr>
<td>Gas content</td>
<td>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.</td>
</tr>
<tr>
<td>Sorption isotherm</td>
<td>A relationship, at constant temperature, describing the volume of gas that can be sorbed to a shale as a function of pressure.</td>
</tr>
<tr>
<td>Gas composition</td>
<td>Used to quantify the percentage of methane, carbon dioxide, nitrogen, ethane, etc. in the desorbed gas. Used to build composite sorption isotherms.</td>
</tr>
<tr>
<td>Rock-eval pyrolysis</td>
<td>Assesses the petroleum-generative potential and thermal maturity of organic matter in a shale sample.</td>
</tr>
<tr>
<td>Mineralogical analyses</td>
<td>Determines bulk and clay mineralogy using petrography, X-ray diffraction, scanning electron microscopy, and similar techniques.</td>
</tr>
<tr>
<td>Vitrinite reflectance</td>
<td>A value indicating the amount of incident light reflected by the vitrinite maceral. It is a fast and inexpensive means of determining thermal maturity.</td>
</tr>
<tr>
<td>Core description</td>
<td>Visually captures lithology, bedding, fracturing, grain size variations, etc.</td>
</tr>
<tr>
<td>3D Seismic</td>
<td>Used to determine interwell shale properties including lateral extent, thickness, faulting, and those areas with higher gas saturation and brittleness.</td>
</tr>
<tr>
<td>Kerogen types</td>
<td>Used to assess whether rocks are Type I oil-prone, II mixed, or III coal.</td>
</tr>
<tr>
<td>Routine core analysis</td>
<td>Includes total porosity, fluid saturations, bulk density, and matrix permeability via pressure pulse testing on crushed samples.</td>
</tr>
</tbody>
</table>

- **Data**
  - TOC: Total Organic Carbon
  - Gas content: Gas content
  - Sorption isotherm: Sorption isotherm
  - Gas composition: Gas composition
  - Rock-eval pyrolysis: Rock-eval pyrolysis
  - Mineralogical analyses: Mineralogical analyses
  - Vitrinite reflectance: Vitrinite reflectance
  - Core description: Core description
  - 3D Seismic: 3D Seismic
  - Kerogen types: Kerogen types
  - Routine core analysis: Routine core analysis
  - Conventional logs: Conventional logs
<table>
<thead>
<tr>
<th>Data</th>
<th>Usage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Special logs</td>
<td>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.</td>
</tr>
<tr>
<td>Pressure-transient tests</td>
<td>Pressure buildup or injection fall-off tests to determine static reservoir pressure, permeability, skin factor, and to detect fractured-reservoir behavior.</td>
</tr>
<tr>
<td>Geomechanical properties</td>
<td>Young's modulus and Poisson's ratio for determining shale brittleness, stress orientations and magnitudes to predict fracture growth.</td>
</tr>
<tr>
<td>Microseismic</td>
<td>Used to assess hydraulic fracture geometries and stimulated reservoir volumes.</td>
</tr>
<tr>
<td>Fracture diagnostics</td>
<td>Treating pressures, closure stress, pumped volumes, flowback volumes, etc. to determine the quality of a fracture stimulation.</td>
</tr>
<tr>
<td>Gas, water rates</td>
<td>Captured daily[ preferably] to assess individual well behavior.</td>
</tr>
<tr>
<td>Bottomhole pressures</td>
<td>Preferably recorded in closely-spaced increments[ every 10 min] early in well life; can also use surface pressures with wellbore-fluid gradients.</td>
</tr>
<tr>
<td>Tracer surveys</td>
<td>Chemical or radioactive tracers to assess which fracture stages are contributing.</td>
</tr>
<tr>
<td>Facilities</td>
<td>Variations in line pressure, etc., that affect producing well rates.</td>
</tr>
<tr>
<td>Rate-transient analysis</td>
<td>Decline analysis tool that analyzes production rates and pressures using various methods to assess EUR, GIP, drainage area, etc.</td>
</tr>
<tr>
<td>Numerical modeling</td>
<td>Helpful in understanding reservoir mechanisms, predicting early well behavior, and estimating EURs and recovery factors.</td>
</tr>
<tr>
<td>Decline-curve analysis</td>
<td>Traditionally used to forecast well performance. More reliable later in well life[ after a few years] due to uncertainties regarding b-factor values.</td>
</tr>
<tr>
<td>Analogs</td>
<td>May be useful to estimate EURs and recovery factors if a strong correlation exists between key reservoir parameters of subject and analog reservoir.</td>
</tr>
</tbody>
</table>

*Notes:*
- Data used in petroleum resource management include various types of logs and tests, such as special logs (e.g., image, NMR, and dipole sonic logs), pressure-transient tests (e.g., pressure buildup or injection fall-off tests), and geomechanical properties (e.g., Young's modulus and Poisson's ratio).
- Facilities can affect producing well rates, and rate-transient analysis can help understand reservoir mechanisms.
- Numerical modeling and decline-curve analysis are crucial for estimating EURs and recovery factors.
- Analogs can be useful if there is a strong correlation between key reservoir parameters of the subject and analog reservoirs.
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. Microseismic is used to monitor the stimulations to understand fracture geometries and estimate the stimulated reservoir volume.

L 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 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 ($P_d$) and a chance of commerciality ($P_c$). 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 greater than 5 to less 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.

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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 fracturing 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.

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.

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.
References, 参考文献

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**Bitumen:**


**Tight Gas Formation:**


Canadian Society for Unconventional Gas.


Coalbed Methane:


CHAPTER 8  Unconventional Resources Estimation


Shale Gas:


Oil shale:


Gas Hydrates:


第 9 章
CHAPTER 9

产量的计量与处理
Production Measurement and Operational Issues

Satinder Purewal 著，衣艳静，杨涛 译
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.

Figure 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](image)

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 Figure 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 Figure 9.1).

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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:

(1) 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).

(2) 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.

(3) 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 Figure 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 (H₂S, CO₂) 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.
CHAPTER 9 Production Measurement and Operational Issues

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 by 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 CO₂, the pipeline may accept sales gas with a limited CO₂ content. For example, if produced gas has 4% CO₂ and the pipeline will accept up to 2% CO₂, then it is acceptable to design facilities to deliver sales gas to that specification. Thus, the sales gas volume would include 2% CO₂ and reserves dedicated to that pipeline would be estimated including 2% CO₂. In the case where CO₂ must be extracted before sale, and the sales gas contains only hydrocarbon gases, then all categories of reserves should reflect only the hydrocarbon gas that will be sold.

The treatment of gas and crude oil containing H₂S is generally handled in a similar fashion. For gas containing small quantities of H₂S, 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 H₂S must always be totally removed and therefore should be excluded from reserves.

For high concentrations of H₂S (concentrations as high as 90% have been known), the H₂S gas may be separated and converted to sulfur, which can then be sold. In such cases, the natural gas reserves exclude the H₂S 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 should 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.

气量若要计人储量，须满足定义标准。尤其需证明其开采经济性。邻近有天然气集输和外输条件，以及其生产与销售是油田开发方案的一部分等。对于混相注入或其他提高采收率措施，需考虑到相关过程存在必然损耗，以致回注气最终不能采出。通常，这部分天然气量不纳入 PRMS 储量的任何级别。有时，将天然气注入储层的目的是为了有效处理废气。这种情况下，不应计入天然气回贮量。

第三方也可能从异地购买天然气。用于储层循环注气，保持压力。混相注入或其他提高采收率措施。在这种情形下，天然气气源拥有者正常上报天然气储量。产量与销售量。但气源接受者。即使最终天然气将被售出。这些天然气通常划归为购入天然气。假定为长期购买协议。而此类购入不视作储量。应视为库存量。一旦开采。不应算作油气田的产量。如果购入不计为产量。正常。这种情况。储气库中储藏了原来油气藏的部分气量，以及作为库存的注入气量。当气田投入生产。推荐采用后进先出原则。因此。库存气应最先产出。一旦库存气再次产出。应从天然气产量中扣除。不计入储量和产量。上述方法确保了气田的不确定性与天然气储量相关而非库存气。有一种可能出现的例外情形，如果天然气是以产量支付方式购入，则这部分购入天然气量可视作储量。

9.7 地下储气库

天然气从气田采出后，可经管线输送到一个地下储气库。 UGS。以备将来开采。地下储气库可用于应对季节周期影响的天然气需求波动。地下储气库也可通过存储天然气而备后期使用。避免直接燃烧生产中采出的天然气。从而减少火炬放量。产量销售收入应标明产量的组份分子量。并可根据不同业主之间签署的协议而存储于另一个储气库内。
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:

(1) In gas swaps, early production from one field may be traded with later production from another field.

(2) 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.

失衡状况以及账户平衡的处理方式的
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$^3$ or Nm$^3$, the conversion factor is generally 35.3xxx, and for Nm$^3$, the conversion factor is normally 37.3xxx (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:

1 Btu = 1,055.06 J

1,000 Btu/scf = 1.055 MJ/scf

= 1.055 MJ/scf $\times$ 35.3147 ft$^3$/m$^3$

= 37.257 MJ/m$^3$ at STP (15°C and 1 atm).

From Figure 9.2, an approximate 35°API oil has a heat content of some 5.8 million Btu/bbl. Thus,

1 BOE = 5.8 MBtu = 5.8 $\times$ 10$^8$ $\times$ 1,055.06 J

= 6,119 MJ

= 164,238 m$^3$ (at 37.257 MJ/m$^3$)

= 5,800 ft$^3$ (at STP, viz. 15°C and 1 atm).

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 m³ of gas per 1 std m³ 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

\[ 1 \text{ MJ/m}^3 = 1 \text{ Btu/scf} \times 35.3 \text{ scf/m}^3 \times \frac{1 \text{ kJ}}{0.948 \text{ Btu}} \times \frac{1 \text{ MJ}}{1000 \text{ kJ}}. \]

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:

\[ \Sigma(\text{Component CV}) = \text{Gross Stage CV}(*) \]

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 × GOR₁ + Stage 2 CV × GOR₂
+ ... + Stage n CV × GORₙ) (*)(*).

GOR₁ + GOR₂ + ... + GORₙ

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.

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<th>Table 9.1 Abbreviations</th>
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<td><strong>Abbreviations</strong></td>
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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 Figure 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).

Figure 9.2—Btu content of crudes, condensates, fuel oils, and paraffins. (Graph provided through personal communication with Chapman Cronquist.)

有关单位与转换系数的详细内容请参见
SI公制单位系统与 SPE公制标准 SPE Richardson 1984 以及第6章的第6.6节

9.10.2 液烃的油当量转换

监管披露规则通常规定，液烃与天然气储量应分别报告。液烃是指原油、凝析油、天然气液的合称。对于公司内部报告和常规公司之间的分析，若将原油、凝析油、天然气液和天然气体积数汇为油当量，就可方便地进行对比。

通常，原油、凝析油和天然气液储量可进行简单的算术加合，得到油当量的数量。当其中一种产品占绝大多数而其余两种数量相对较少时，该方法通常是可行的。另一种更准确，但尚不完善的核算方法是考虑不同流体的密度。

进一步完善原油、凝析油和天然气液的汇并还可以考虑三种液体热值当量的相应加合。

图9.2为原油、凝析油、燃料油和烷烃热值含量的对比图。是基于多种来源的组合数据，包括Katz表A-1化合物基础数据，EIA/国际能源年报1995年，以及资源报告。阿拉斯加分报告1997年4月。
References, 参考文献


Petroleum Resources Management System 2007. SPE, Richardson, Texas, USA.
CHAPTER 10 Resources Entitlement and Recognition

Elliott Young 著，原瑞娥 译
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. Figure 10.1 summarizes the PRMS reserves and resources categories with the reserves categories that many government regulatory agencies allow in required disclosures. Figure 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:

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 nonoperating 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). Properties do not include other supply agreements or contracts that represent the right to purchase, rather than extract, oil and gas.

- **Regulatory Reporting** 监管机构披露规则
  - US Securities and Exchange Commission 美国证券交易委员会
  - US Financial Accounting Standards Board 美国财务会计准则委员会
  - International Accounting Standards Board 国际会计准则委员会
  - UK Accounting Standards Board 英国会计准则委员会
  - Australian Securities Exchange 澳大利亚证券交易所
  - Canadian Securities Administrators 加拿大证券管理委员会
  - China Petroleum Reserves Office 中国石油储量办公室
  - Norwegian Petroleum Directorate 挪威石油理事会

- **Technical 技术体系**
  - SPE/WPC/AAPG/SPEE PRMS 石油资源管理系统(SPE/WPC/AAPG/SPEE)
  - United Nations Classification Framework 联合国资源分类框架
  - Host Country Technical Definitions 资源国技术定义

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![Figure 10.1 PRMS Classification Categories](image1)

**Figure 10.1** PRMS Classification Categories

![Figure 10.2 Regulations, Standards, and Definitions](image2)

**Figure 10.2** Regulations, Standards, and Definitions

PRMS 认可经济权益（Economic Interest）的概念并将其作为油气储量 / 资源量认定与披露的依据。为了确定是否拥有油气经济权益，许多油公司均参照 SEC 第 S-X 节第 4-10b 条款“成果法”（美国 SEC 1993）[或财务会计标准第 19 节（FASB 1977）]。第 4-10b 条款在 2008 年 SEC 油气披露最新规定中进行了修订。其矿产权益定义中包含的基本原则为界定资产权益和指导 PRMS 和政府规则下油气储量 / 资源量认定提供了非常有用的框架和条件标准。

SEC 第 S-X 节第 4-10b 条款“成果法”中包括以下合同区油气资产的矿产权益包括：

1. 拥有获得油气收益的所有权或租赁权，租让权或其他按照权益转让条款规定的体现油气开采权利的权利；
2. 矿费权益，油气产量支付以及在其他方作业的资产中拥有的非作业者权益；
3. 根据与外国政府和权威机构签署的协议，披露实体参与相关油气资产的经营或承担地下储量的开发，不同于作为独立购买者/经纪人/经销商或进口商的情形，其他体现购买权而不是油气开采权的供应协议或合同不能包含在披露资产中。
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:

1. The right to extract oil or gas
2. The right to take produced volumes in kind or share in the proceeds from their sale
3. Exposure to market risk and technical risk
4. 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:

1. Participation that is limited only to the right to purchase volumes
2. Supply or brokerage arrangements
3. 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 储量与资源量的认定

根据 SEC 第 S-X 节第 4-10b 条款，可以把判断能否获得经济权益和认定储量/资源量资格的要素归纳为下列几点：

1. 拥有开采油气的权利
2. 能够获得实物产量或油气销售收益分成的权利
3. 承担市场风险和技术风险
4. 通过参与生产活动有机会获得回报

此外第 4-10b 条款还指出下列情况不支持获得经济权益和认定储量和资源量：

1. 参与权仅限于购买产量
2. 供应或佣金协议
3. 服务或融资协议，不涉及风险及回报或矿产权益转让。

请注意，美国财务会计准则委员会（议题 932）允许愿披露储量的企业在参与经营或担任作业者的情形下，披露与政府所签长期供应协议所获得的证实储量。根据 PRMS，此类协议可根据项目成熟度和技术确定性将可采量划分为储量和/或资源量。

拥有油气开采的权利、承担风险以及有机会获得回报是储量/资源量认定的三个关键要素。许多公司利用这些要素来区分哪些协议允许储量/资源量的认定，并上报监管机构。哪些是纯服务性的协议，没有储量和资源量披露和认定的权利。与油气生产活动相关的风险和回报主要源于技术和经济风险导致的收益变化。技术风险通常取决于一系列技术参数，影响公司开采油气的实际技术能力。经济风险是项目成功率的函数，并主要取决于经济开采地下油气的能力。经济风险在很大程度上依赖于项目生命周期内的经济环境，并随市场价格和成本构成的变化而波动。应当指出的是，仅与操作成本变化相关的风险通常不能满足风险与回报要求。因而也不允许披露储量。应注意，有权利或义务向监管机构披露储量并不意味着拥有地下资源。
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.

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 Figure 10.3. This template has also been expanded to include three additional types of agreements: purchase agreements, loan agreements, and production payments. These agreements are further expanded in this section to provide useful guidelines on when reserves and resources may be recognized.

Further extension is also provided to 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.

The section introduces the classification system template proposed by Johnston (Johnston 1994; Johnston 1995; McMichael and Young 1997) as shown in Figure 10.3. This template has been expanded to include three additional types of agreements: purchase agreements, loan agreements, and production payments. These agreements are further expanded in this section to provide useful guidelines on when reserves and resources may be recognized.

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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 Figure 10.4 (McMichael and Young 1997). Key aspects of each type of agreement are summarized in Table 10.1 (McMichael and Young 1997).
## 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

<table>
<thead>
<tr>
<th>Contract Type</th>
<th>Ownership</th>
<th>Payment</th>
<th>Reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concession</td>
<td>Contractor</td>
<td>In-Kind</td>
<td>Yes</td>
</tr>
<tr>
<td>Production Share</td>
<td>Contractor (When Produced)</td>
<td>In-Kind</td>
<td>Yes</td>
</tr>
<tr>
<td>Revenue Share</td>
<td>Government</td>
<td>Share of Revenue</td>
<td>Yes</td>
</tr>
<tr>
<td>Risked Service</td>
<td>Government</td>
<td>Fee-Based</td>
<td>Likely</td>
</tr>
<tr>
<td>Pure Service</td>
<td>Government</td>
<td>Fee-Based</td>
<td>No</td>
</tr>
<tr>
<td>Purchase</td>
<td>Government</td>
<td>Product Cost</td>
<td>No</td>
</tr>
<tr>
<td>Loan</td>
<td>Government</td>
<td>Interest</td>
<td>No</td>
</tr>
<tr>
<td>Conveyance</td>
<td>Government</td>
<td>Production Payment</td>
<td>Likely</td>
</tr>
</tbody>
</table>
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). Figure 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.

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

结束之后可采量正常情况下应划归为资源量。取决于合同延期谈判是否成功。若合同含有延期条款，而延期的可能性是合理的，那么在项目承诺和资金到位的情况下，合同延期后可采量有可能认定为储量。

10.5.2 生产分成合同

在合同者和资源国政府间签订的产品分成合同中，通常由合同者承担油气勘探、开发和生产中所有的风险和成本。作为回报，如果勘探成功，合同者将有机会根据具体的限制条款从产量中回收投资。成本油。在成本回收之后，合同者还可对扣减成本油后剩余的产量利润油按规定进行分成。资源国政府总是拥有油气资源所有权。但合同者通常有权获得合同期内规定的产量分成。根据勘探开发技术的不确定性，合同者通常可以认定 PRMS 标准的各级份额储量。份额量大小是按照合同条款计算的成本油加上利润油得到的。当项目成熟度不够或者合同延期并非理所当然的情况下，未来开发阶段估算的可采量可认定为资源量。

在产品分成合同下，合同者的份额产量一般会随着价格的上涨而降低。因为需要更多的份额产量即可回收投资和成本。随着产量、各阶段产量的增加和 / 或累计产量 R 因子的增加，协议中往往有降低合同者份额的条款。参见合合同者与资源国政府项目年度产量分配流程示意图。图 10.5。 与租让制合同一致，合同期之后的可采量通常被归为资源量。除非合同包括延期条款，且项目承诺继续投资开发。

10.5.3 收入分成合同 / 风险服务合同

除了合同者报酬费用外，在风险服务合同中，合同者通常得到的是规定的油气收入分成而
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.

Figure 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.

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 Figure 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

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Figure 10.6  Example Revenue-Sharing Contract

Figure 10.7  Example Risked-Service Contract
CHAPTER 10 Resources Entitlement and Recognition

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

定总包费率或者其他商定方式计费，酬金的支付可以在指定时间或服务业务完成时，有时酬金可绑定油气田生产情况，操作成本减少量与预期相比或其他一些重要指标，许多情况下，支付给服务商的酬劳往往来自政府的总收入，以避免与油田的经营直接关联。

服务公司在这种类型的合同中承担的风险通常仅限于不可回收的超支成本，由客户违约造成的损失，违约金或者合同纠纷方面。此类协议一般不受产量或市场价格的影响，因此在这种合同类型下，合作者通常不能认定储量/资源量。尽管如此，服务公司可能仍然有义务向资源国监管机构上报项目总储量/资源量。图10.8是项目年度收入在合作者和政府之间的分配示意图。

**Figure 10.8 Example Pure-Service Contract**

10.5.5 贷款协议

贷款协议一般指为油气项目筹措全部或部分资金而同银行、其他金融投资者或合作伙伴签订的协议。贷款资金的偿还通常只限于规定利率，贷方不参与利息之外的项目利润分成。正常情况下，贷款的偿还还是按固定时间表，权益投资者通常在获得回报之前履行偿还义务，风险仅限于借
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 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

贷方的违约或者项目的失败\(\) 产量\(\) 市场价格和销售的变化一般不影响贷款的偿还\(\) 在这类协议中\(\) 贷方不能认定 PRMS 任何级别的储量与资源量\(\)

10.5.6 生产贷款、远期销售及类似协议

现实中存在各种交易形式\(\) 可通过向油气合同区资产权益所有者预付资金\(\) 获取其未来运营产量的现金收益或实物产量的权利\(\) 此类交易中\(\) 油气权益所有者总是对未来负债有经营义务\(\) 但经营成效具有一定的不确定性\(\) 该交易是出售还是融资取决于交易的具体情况\(\)

如果矿权所有者承担与未来生产有关的风险\(\) 特别是与最终可采量及价格有关的风险\(\) 这类交易应作融资\(\) 或有融资\(\) 在这种情况下\(\) 还款义务通常以货币的形式体现\(\) 不能认定 PRMS 储量和资源量\(\) 如果受让方承担与未来生产有关的风险\(\) 特别是与最终可采量及价格有关的风险\(\) 则此类交易为或有销售或者固定资产的处置\(\) 受让方则可认定 PRMS 储量和资源量\(\) 允许向有关政府机构上报储量\(\) 但应咨询相关的具体会计准则\(\)

10.5.7 干股权益

干股权益是一种协议\(\) 按照该协议\(\) 在双方均拥有工作权益的矿权区\(\) 合同一方\(\) 义务承担方\(\) 同意由另一方\(\) 义务转出方\(\) 支付一部分或全部的投产前成本费用\(\) 此类协议通常发生在义务转出方不愿承担勘探风险\(\) 或者无法直接支付勘探与开发费用的情况\(\) 矿权主可在勘探阶段\(\) 开发阶段或勘探开发两个阶段与现有或者即将合作的伙伴方签署干股协议\(\)

如果油气资产商业性投产\(\) 义务承担方可通过以下两种方式得到补偿\(\) 从义务转出方的油气份额产量收益中获得现金补偿\(\) 义务承担方获取不成比例的高份额产量 \(\)

- \(\)

- 240
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. Figure 10.9 gives an example of a typical conveyance.

Figure 10.9 Example Conveyance—Production Payment

![Diagram of production payment conveyance](image-url)
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>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field Size</td>
<td>500 million bbl</td>
</tr>
<tr>
<td>Production During PSC</td>
<td>400 million bbl</td>
</tr>
<tr>
<td>Exploration Cost</td>
<td>$450 million</td>
</tr>
<tr>
<td>Drilling Cost</td>
<td>$600 million</td>
</tr>
<tr>
<td>Development Cost</td>
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<td>Fixed Operating Cost</td>
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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 is 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.

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.

Figure 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 based on a simple split: 20% to the contractor and 80% to the host government.
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<td>600</td>
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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

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<tr>
<th>Year</th>
<th>Total Revenue ($Million)</th>
<th>Net Revenue After Royalty ($Million)</th>
<th>Recoverable Costs ($Million)</th>
<th>Costs Carried Forward ($Million)</th>
<th>Contractor Recovered Costs ($Million)</th>
<th>Available For Profit Sharing ($Million)</th>
<th>Contractor Profit Share ($Million)</th>
<th>Contractor Cost + Profit Share ($Million)</th>
<th>Contractor Share%</th>
<th>Contractor Entitlement (Mbbls)</th>
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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 Proven at the time of classification, as noted in Sec. 10.6.1. In this situation, the non-Proven 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.

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</table>

Table 10.5  Base Case, Oil Price, and Tax Sensitivity

许多协议加入了 R 因子和 / 或其他分步核算条款，减少合同者在整个合同期的利润分成。这样的条款形式很多，但通常与累计产量、累计回报或较高的开采速度存在关联。
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

Satinder Purewal 著，杨 桦、王庆如、郑舰、胡允栋 译
### 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.

说明：本指南一列所给出的数字表示使用该术语的章号和本章中使用的次数。例如“4.12”则表示该术语在第4章出现了12次。

| Term | Reference* | Used in These Guidelines | Definition
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<thead>
<tr>
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<tbody>
<tr>
<td>1C</td>
<td>2007-2.2.2</td>
<td>1.1, 2.8, 4.12, 5.3, 6.1, 8.1, 10.3</td>
<td>Denotes low estimate scenario of Contingent Resources. 表示条件资源量的低估值情景。</td>
</tr>
<tr>
<td>2C</td>
<td>2007-2.2.2</td>
<td>1.1, 2.6, 4.12, 5.3, 6.1, 8.1, 10.3</td>
<td>Denotes best estimate scenario of Contingent Resources. 表示条件资源量的最佳估值情景。</td>
</tr>
<tr>
<td>3C</td>
<td>2007-2.2.2</td>
<td>1.1, 2.4, 4.12, 5.3, 6.1, 8.1, 10.2</td>
<td>Denotes high estimate scenario of Contingent Resources. 表示条件资源量的高估值情景。</td>
</tr>
<tr>
<td>1P</td>
<td>2007-2.2.2</td>
<td>1.1, 2.13, 4.18, 5.6, 6.4, 7.9, 8.8, 10.2</td>
<td>Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves. 相当于证实储量，表示储量的低估值情景。</td>
</tr>
<tr>
<td>2P</td>
<td>2007-2.2.2</td>
<td>1.1, 2.15, 4.25, 5.6, 6.7, 7.18, 8.10, 10.2</td>
<td>Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves. 相当于证实储量与概算储量之和，表示储量的最佳估值情景。</td>
</tr>
<tr>
<td>3P</td>
<td>2007-2.2.2</td>
<td>1.1, 2.12, 4.20, 5.5, 6.2, 7.11, 8.11, 10.1</td>
<td>Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves. 相当于证实储量与可能储量之和，表示储量的高估值情景。</td>
</tr>
<tr>
<td>Accumulation 油气聚集体</td>
<td>2001-2.3</td>
<td>2.22, 3.6, 4.9, 5.3, 6.3, 8.37</td>
<td>An individual body of naturally occurring petroleum in a reservoir. 在储层中自然形成的油气单体。</td>
</tr>
<tr>
<td>Aggregation 汇并</td>
<td>2007-3.5.1 2001-6</td>
<td>1.1, 2.1, 4.1, 5.1, 6.26, 8.1</td>
<td>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. 指对油气藏或项目层级的资源估值进行汇总，得到油田/公司等更高层级的资源总量的过程。不同增量级别的资源数量算术求和，可能与概率分布汇总的结果不同。</td>
</tr>
<tr>
<td>Term</td>
<td>Reference*</td>
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<td>Definition</td>
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</tbody>
</table>
| Approved for Development | 2007 - Table 1  
2007 - 表 1 | 2.4 | All necessary approvals have been obtained; capital funds have been committed, and implementation of the development project is underway. 
指已获得所有必要的批准，投资资金已承诺，开发项目正在实施中。 |
| 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. 
资源评价中类比油气藏指与被评估的目标油气藏具有相似岩石与流体性质，油藏条件，温度与压力，和驱动机理，但通常处在开发的更高阶段，因此有助于为数据有限情形下解释和采出量估算等提供依据。 |
| Assessment | 2007 - 1.2 | 1.2, 2.11, 3.6, 4.60, 5.2, 6.3, 7.5, 8.23, 10.1 | See Evaluation. 
参见术语“评估(Evaluation)” |
| Associated Gas | 2007 - 2.4 | 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. 
伴生气是在储层中与原油接触或溶解在原油中的一种天然气，可进一步划分为气顶气和溶解气。 |
| Barrels of Oil Equivalent BOE | 2001 - 3.7 | 4.12, 9.13 | See Crude Oil Equivalent. 
参见术语“原油当量(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. 
指区域性广泛分布，低渗，异常高压，饱和气藏中无下倾水体的非常规天然气聚集体。 |
| Behind-pipe Reserves | 2007 -2.1.3.1 | none—no occurrences未出现 | 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. 
管外储量是指需要追加完井作业或来未重新完井之后才能从已钻生产井层段中采出的油气数量，无论何种情形，追加或重新完井投产或复产的费用均比一口新井的费用低。 |
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<tr>
<th>Term</th>
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<tbody>
<tr>
<td><strong>Best Estimate</strong></td>
<td>2007 - 2.2.2, 2001 - 2.5</td>
<td>2.5, 4.36, 5.2, 6.5, 7.9, 8.1</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Bitumen</strong></td>
<td>2007 - 2.4</td>
<td>1.1, 8.29, 9.2</td>
<td>See Natural Bitumen.参见术语“天然沥青Natural Bitumen”</td>
</tr>
<tr>
<td><strong>Buy Back Agreement</strong></td>
<td>none—no occurrences 未出现</td>
<td></td>
<td>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.指资源国政府和合同者之间达成的一种协议根据该协议对合同者所生产的所有油气数量政府将按照协议价格支付费用通常定价机制可以让合同者有机会在约定利润范围内回收投资</td>
</tr>
<tr>
<td><strong>Carried Interest</strong></td>
<td>2001 - 9.6.7</td>
<td>7.1, 10.3</td>
<td>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.干股权益是一种协议按照该协议在双方均拥有工作权益的矿权中合同一方义务承担方同意支付一部分或全部的投产前成本费用</td>
</tr>
<tr>
<td><strong>Chance</strong></td>
<td>2007 - 1.1</td>
<td>2.36, 4.6, 5.1, 6.4, 8.4</td>
<td>Chance is 1- Risk (See Risk).几率=1-风险参见术语“风险Risk”</td>
</tr>
<tr>
<td><strong>Coalbed Methane (CBM)</strong></td>
<td>2007 - 2.4</td>
<td>8.49</td>
<td>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).指煤层中所含的天然气不管是否以气态形式存在尽管煤层气的主要成分是甲烷但也可能在生产过程中伴生数种不等的惰性气体甚至非惰性气体也称煤层气CSG或煤层天然气NGC</td>
</tr>
</tbody>
</table>

**Coalbed Methane (CBM)**

煤层气

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).指煤层中所含的天然气不管是否以气态形式存在尽管煤层气的主要成分是甲烷但也可能在生产过程中伴生数种不等的惰性气体甚至非惰性气体也称煤层气CSG或煤层天然气NGC。
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<th>Term</th>
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<th>Definition</th>
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</thead>
<tbody>
<tr>
<td>Commercial</td>
<td>2007 - 2.1.2 and Table 1</td>
<td>1.1, 2.66, 3.1, 4.5, 5.2, 6.2, 7.10, 8.40</td>
<td>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.</td>
</tr>
<tr>
<td>Committed Project</td>
<td>2007 - 2.1.2 and Table 1</td>
<td>none</td>
<td>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.</td>
</tr>
<tr>
<td>Completion</td>
<td></td>
<td></td>
<td>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.</td>
</tr>
</tbody>
</table>

当一个项目是商业的，意味着其运行所需的社会、环境和经济条件得到满足，包括政治、法律、管理规定及合同条件，并承诺在合理期限内进行开发与生产。建议以5年作为期限基准，但某些情形下也可延长期限。例如项目的经济开发可根据生产商的选择而推迟，原因包括市场因素、合同或战略目标等。在所有情况下，项目分类为储量的理由应清楚记录。
<table>
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</thead>
<tbody>
<tr>
<td>Completion Interval</td>
<td>none</td>
<td>—no occurrences</td>
<td>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. 井下打开的与地面设施相连通的能够进行生产和注入的油气藏层段或者是为了注入目的而在井下打开的互相连通的油气藏层段</td>
</tr>
<tr>
<td>Concession</td>
<td>2001-9.6.1</td>
<td>7.3, 10.7</td>
<td>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. 指特定区域和时期的准入资源国把生产油气的某些权益转让给企业企业通常负责油气勘探开发开采和采出量的销售资源国依据立法规定的财税制度收取相关的税费有时还要针对企业所获利润收取矿费</td>
</tr>
<tr>
<td>Condensate</td>
<td>2001-3.2</td>
<td>4.16, 7.1, 8.2, 9.10</td>
<td>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). 凝析油是在原始地层温度和压力条件下以气态存在于储层中的烃混合物主要是戊烷及以上重组分但是在采出时在地面压力和温度条件下以液态存在凝析油不同于天然气液主要表现在两个方面天然气液主要在天然气处理厂提取回收而不是在合同区分离器或者其他合同区设施中提取回收天然气液既包含轻烃组分(乙烷丙烷丁烷)也包含作为凝析油主要组分的戊烷及以上重组分对照术语“天然气液(NGL)”</td>
</tr>
<tr>
<td>Conditions</td>
<td>2007-3.1</td>
<td>2.1, 3.9, 4.6, 5.3, 6.4, 7.17, 8.6, 9.6, 10.1</td>
<td>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). 预计在评价期内存在并对项目产生影响的经济市场法律环境社会以及政府等因素也称为或有因素</td>
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<tr>
<td>Term</td>
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<tr>
<td>Constant Case</td>
<td>2007 - 3.1.1</td>
<td>7.11</td>
<td>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. 对项目资源估算量及相关的现金流的评估是基于评估条件，包括成本和产品价格，在某时间点为固定值或阶段平均值，并在整个项目生命周期内保持不变，合同允许变化除外。换言之，在整个评估期的资本和收入不进行通货膨胀或通货紧缩的相应调整。</td>
</tr>
<tr>
<td>Contingency</td>
<td>2007 - 3.1 and Table 1</td>
<td>2.4, 7.1</td>
<td>See Conditions. 参见术语“条件”</td>
</tr>
<tr>
<td>Contingent Project</td>
<td>2007 - 2.1.2</td>
<td>none</td>
<td>Development and production of recoverable quantities has not been committed due to conditions that may or may not be fulfilled. 由于能否满足各种条件尚不确定，可能满足也可能不满足，可采量的开发和生产尚未承诺的项目。</td>
</tr>
<tr>
<td>Contingent Resources</td>
<td>2007- 1.1 and Table 1</td>
<td>2.27, 3.2, 4.29, 5.3, 6.2, 7.4, 8.18, 10.1</td>
<td>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. 截至给定日期估计的，可能由已知聚集采用开发项目而实现商业可采的石油量。由于一个或多个或有条件，目前不被视为商业可采的条件资源量是已发现可采资源量类别之一。</td>
</tr>
<tr>
<td>Continuous-Type Deposit</td>
<td>2007- 2.4 2001- 2.3</td>
<td>8.1</td>
<td>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. 一种大面积广泛分布的油气聚集体，不受水动力效应的明显影响。这些聚集体属于非常规资源。例如盆地中心气，页岩气，天然气水合物，天然沥青和油页岩聚集体。</td>
</tr>
<tr>
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</tr>
<tr>
<td>Conventional Crude Oil</td>
<td>2007- 2.4</td>
<td>none</td>
<td>Crude Oil flowing naturally or capable of being pumped without further processing or dilution [see Crude Oil and compare to Synthetic Crude Oil (SCO)].</td>
</tr>
<tr>
<td>Conventional Gas</td>
<td>2007- 2.4</td>
<td>8.3</td>
<td>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.</td>
</tr>
<tr>
<td>Conventional Resources</td>
<td>2007- 2.4</td>
<td>1.1, 8.3</td>
<td>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.</td>
</tr>
<tr>
<td>Conveyance</td>
<td>2001- 9.6.9</td>
<td>10.11</td>
<td>Certain transactions that are in substance borrowings repayable in cash or its equivalent and shall be accounted for as borrowings and may not qualify for the recognition and reporting of oil and gas reserves.</td>
</tr>
<tr>
<td>Cost Recovery</td>
<td>2001- 9.6.2, 9.7.2</td>
<td>10.21</td>
<td>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. In typical product分成协议中，合作者负责油田开发并承担所有的勘探开发费用。作为回报，合作者从总产量中回收成本，包括投资和操作费。合作者一般通过原油产量的照得分配支付。但要承担技术和市场双重风险。</td>
</tr>
<tr>
<td>Term</td>
<td>Reference*</td>
<td>Used in These Guidelines</td>
<td>Definition</td>
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<tr>
<td>Crude Oil</td>
<td>2001-3.1</td>
<td>4.2, 7.1, 8.3, 9.9</td>
<td>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.</td>
</tr>
<tr>
<td>Crude Oil Equivalent</td>
<td>2001-3.7</td>
<td>none—no occurrences</td>
<td>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.)</td>
</tr>
<tr>
<td>Cumulative Production</td>
<td>2007-1.1</td>
<td>4.27, 7.1, 10.2</td>
<td>The sum of production of oil and gas to date (see also Production).</td>
</tr>
<tr>
<td>Current Economic Conditions</td>
<td>2007-3.1.1</td>
<td>7.3</td>
<td>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. The current economic conditions should also 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.</td>
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*Reference*
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<th>Used in These Guidelines</th>
<th>Definition</th>
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<tbody>
<tr>
<td>Cushion Gas Volume 垫底气量</td>
<td>none — no occurrences未出现</td>
<td>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. 在天然气地下储气库中，垫底气量是出于气藏管理的需要，为了维持足够的最低储存压力以满足工作气量交付所要求的采出剖面所需气量。在溶洞中，为了保持稳定也需要垫底气量。垫底气量可以包括地下可采气量和不可采气量及注入气量。</td>
<td></td>
</tr>
<tr>
<td>Deposit 沉积体</td>
<td>2007–2.4</td>
<td>Material that has accumulated due to a natural process. In resource evaluations it identifies an accumulation of hydrocarbons in a reservoir (see Accumulation). 自然聚集形成的物质，在资源评价中指油气藏中的一个油气聚集体；参见术语“油气聚集体（Accumulation）”</td>
<td></td>
</tr>
<tr>
<td>Deterministic Estimate 确定法评估</td>
<td>2007–3.5</td>
<td>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. 根据已知的地球科学、工程和经济数据获得储量或资源量的离散估算结果的评估方法。</td>
<td></td>
</tr>
<tr>
<td>Developed Reserves 已开发储量</td>
<td>2007–2.1.3.2 and Table 2</td>
<td>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. 已开发储量指预计可以从现有井中采出的石油数量，包括管外储量；提高采收率获得的储量只有在所需设施安装后或当其费用低于一口新钻井费用时，才可视为已开发储量。已开发储量可进一步细分为已开发正生产储量和已开发未生产储量。</td>
<td></td>
</tr>
<tr>
<td>Developed Producing Reserves 已开发正生产储量</td>
<td>2007-2.1.3.2 and Table 2</td>
<td>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. 已开发正生产储量是指预计从评估时已打开并正在生产的完井层段中采出的储量，提高采收率获得的储量只有进入实施阶段才能划分为已开发正生产储量。</td>
<td></td>
</tr>
<tr>
<td>Term 术语</td>
<td>Reference* 参考文献*</td>
<td>Used in These Guidelines 本指南引述情况</td>
<td>Definition 定义</td>
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<tr>
<td>Developed Non-Producing Reserves 已开发未生产储量</td>
<td>2007-2.1.3.2 and Table 2 2007-2.1.3.2 和表 2</td>
<td>2.1</td>
<td>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. 已开发未生产储量包括关井和管外储量。关井储量是指预计从以下情况采出的量：(1) 评估时已打开但尚未投产的完井层段；(2) 由于市场条件和管线连接原因而关井的井；(3) 由于机械原因不能生产的井。管外储量也包括预计从现有井层段中采出的储量。这些储量需要追加完井或者未来重新完井才能生产。无论何种情况下，投产或恢复生产的费用都比新钻一口井的成本低。</td>
</tr>
<tr>
<td>Development not Viable 开发不可行</td>
<td>2007-2.1.3.1 and Table 1 2007-2.1.3.1 和表 1</td>
<td>2.6, 8.3</td>
<td>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. 一个已发现的油气聚集体由于生产潜力小，目前没有开发或采集更多数据的计划。它是一个项目成熟度的亚类，反映了项目要实现商业化生产尚需采取的行动。</td>
</tr>
<tr>
<td>Development Pending 待开发</td>
<td>2007-2.1.3.1 and Table 1 2007-2.1.3.1 和表 1</td>
<td>2.4</td>
<td>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. 一个已发现的油气聚集体，其项目活动正在论证其近期的商业开发合理性。它是一个项目成熟度的亚类，反映了项目要实现商业化生产尚需采取的行动。</td>
</tr>
<tr>
<td>Development Plan 开发方案</td>
<td>2007-1.2</td>
<td>1.1, 2.12, 3.2, 4.5, 5.2, 6.1, 8.4, 9.1</td>
<td>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.) 项目进行开发的设计说明，时间安排和成本评估，包括但不限于井位、完井技术、钻井方法、处理设施、运输和市场情况等。参见“项目（Project）”</td>
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</tbody>
</table>

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| Term                        | Reference* | Used in These Guidelines本指南引述情况 | Definition
|-----------------------------|------------|----------------------------------------|--------------------------------------------------|
| Development Unclarified or on Hold | 2007-2.1.3.1 and Table 1 | 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.

一个已发现的油气聚集体其项目活动暂停和/或商业开发合理性的论证可能长期推迟它是一个项目成熟度的亚类反映了项目要实现商业化生产所需采取的行动。 |
| Discovered 已发现              | 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.)

指通过已钻的一口或者几口探井经测试取样或测井确认存在相当数量的潜在可动油气的一个油气藏或者几个油气藏的集合“相当数量”意味着通过钻井资料确认地下存在充足的可经济开采的油气数量参见术语“已知油气聚集体”Known Accumulations“ |
| Discovered Petroleum Initially-In-Place 已发现石油原始原地量 | 2007-1.1 | none — no occurrences未出现 | 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.

在规定日期所估算的已知油气聚集体在投产前所含的油气数量已发现石油原始原地量可划分为商业的次商业的和不可采量其中商业的可采估算量归类为储量次商业的可采估算量归类为条件资源量 |
| Dry Gas 干气                    | 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)

干气是指在到达参照点之前脱去液烃的天然气干气和脱去的液烃在资源评价中应分别记账应注意到这是资源评估的定义而不是相态定义干气也称贫气 |
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<tbody>
<tr>
<td>Dry Hole</td>
<td>2001- 2.5</td>
<td>4.2, 8.1</td>
<td>A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. 被证实不能生产足够的油气数量而不能作为油井或气井完井的井。</td>
</tr>
<tr>
<td>Economic</td>
<td>2007- 3.1.2, 2001- 4.3</td>
<td>2.14, 4.22, 5.6, 6.2, 7.46, 8.25, 9.2, 10.8</td>
<td>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. 在油气储量和资源量评估中经济的是指作业的收入超过其相关支出的情况。</td>
</tr>
<tr>
<td>Economic</td>
<td>2001- 9.4.1</td>
<td>7.2, 10.12</td>
<td>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. 投资者已获得矿产原地量的权益并以任何形式的合法关系得到采矿收入以寻求资本回报时即持有经济权益。</td>
</tr>
<tr>
<td>Economic Limit</td>
<td>2007- 3.1.2, 2001- 4.3</td>
<td>4.27, 7.10, 8.3, 9.1</td>
<td>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. 经济极限是指极限产量值低于该产量项目可以是单井租赁区块或整个油田的作业净现金流扣除矿费及其他各方的产量分成后为负值。</td>
</tr>
<tr>
<td>Entitlement</td>
<td>2007- 3.3</td>
<td>1.1, 7.1, 9.4, 10.30</td>
<td>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. 依据与出租人签订的开发和生产合同合法归属于承租人或合同者的那部分未来产量即资源量。</td>
</tr>
<tr>
<td>Entity</td>
<td>2007- 3.0</td>
<td>5.1, 7.10, 9.1, 10.1</td>
<td>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. 实体机构指有能力承担法律权利和义务的合法机构在资源评价中主要是指承租人或合同者即某种形式的合法公司或公司联盟在更广意义上实体机构可以是任何形式的组织可以包括政府或其代表机构。</td>
</tr>
<tr>
<td>Term</td>
<td>Reference*</td>
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<tr>
<td>Estimated Ultimate Recovery (EUR) 估算最终可采量</td>
<td>2007-1.1</td>
<td>4.85, 5.1, 6.2, 7.1, 8.12</td>
<td>Those quantities of petroleum that are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. 在给定日期估算的□从一个油气聚集体中将来可能采出的石油数量□加上已经采出的数量□</td>
</tr>
<tr>
<td>Evaluation 评估</td>
<td>2007-3.0</td>
<td>1.4, 2.15, 3.2, 4.4, 5.2, 6.1, 7.42, 8.5, 10.1</td>
<td>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.) 指对石油勘探□开发或生产项目进行的地球科学□工程和相关研究□包括经济分析等□可得到规定的未来条件下油气可采和销售的估算量以及相关的现金流□可根据适用的指南对项目进行分类□对得到的估算量进行分级□也称为“评估”“Assessment”□</td>
</tr>
<tr>
<td>Evaluator 评估师</td>
<td>2007-1.2, 2.1.2</td>
<td>2.2, 4.5, 5.1, 6.1, 7.5, 8.2</td>
<td>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. 负责执行项目评价的个人或小组□他们可以是拥有项目经济权益的实体的员工□也可以是受合同聘请□进行审查和审计的独立咨询顾问□不管何种情形□接受评估的实体要对包括储量□资源量及其价值等的评估结果负责□</td>
</tr>
<tr>
<td>Exploration 勘探</td>
<td>2.8, 3.4, 4.8, 5.6, 6.4, 7.3, 8.7, 10.16</td>
<td>Prospecting for undiscovered petroleum. 对未发现油气资源的勘探□</td>
<td></td>
</tr>
<tr>
<td>Field 油气田</td>
<td>2001-2.3</td>
<td>1.1, 2.7, 3.18, 4.8, 5.4, 6.52, 7.6, 8.15, 9.19, 10.14</td>
<td>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. 由单个油气藏或多个地质构造特征和地层条件相同的油气藏组成的区域□一个油气田可能包含两个或多个油气藏□纵向□由不渗透岩石隔开□横向□由局部地质隔层隔开□或二者兼有□各监管机构可能对该术语有不同定义□</td>
</tr>
<tr>
<td>Term 术语</td>
<td>Reference*参考文献</td>
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<td>Definition定义</td>
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</tr>
<tr>
<td>Flare Gas火炬气</td>
<td>2007-3.2.2</td>
<td>9.1</td>
<td>Total volume of gas vented or burned as part of production and processing operations.生产和处理作业过程中被排放或烧掉的天然气总量。</td>
</tr>
<tr>
<td>Flow Test产能测试</td>
<td>2007-2.1.1</td>
<td>none未出现</td>
<td>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).指通过将石油开采到地面和/或得到该油气藏潜在产能指标为论证油气藏中存在可流动油气而设计的井中作业例如电缆地层测试。</td>
</tr>
<tr>
<td>Fluid Contacts流体界面</td>
<td>2007-2.2.2</td>
<td>3.2, 4.1</td>
<td>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.油气藏内将流体饱和度具明显差异的两个区域分隔开的表面或界面由于毛细管和其他现象的影响流体饱和度变化不一定是突变的或完全的界面也不一定是水平的。</td>
</tr>
<tr>
<td>Forecast Case预测方案</td>
<td>2007-3.1.1</td>
<td>7.15</td>
<td>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.对项目资源估算量及相关现金流的评估是基于评估师对项目整个生命周期评估条件包括成本和产品价格剖面的合理预测评价期的成本和收入可进行通货膨胀或通货紧缩的调整。</td>
</tr>
<tr>
<td>Forward Sales远期销售</td>
<td>2001-9.6.6</td>
<td>10.1</td>
<td>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.指先向油气资产权益人预付资金从而有权从未来资产运营中获得产量的现金收入或者实物油气的多种交易形式这些交易中油气权益人几乎总是负有未来开发效果的义务但其结果有某种程度的不确定性决定交易是出售还是进行融资取决于各案例具体情况。</td>
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<tr>
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<tr>
<td>Fuel Gas</td>
<td>2007- 3.2.2</td>
<td>4.1, 7.1, 9.1</td>
<td>See Lease Fuel. See术语“ 合同区自用燃料 - Lease Fuel”</td>
</tr>
<tr>
<td>Gas Balance</td>
<td>2007- 3.2.7</td>
<td>none</td>
<td>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. 在多业主联合作业的天然气生产中,可能出现天然气产量交付不平衡的情形。因此,必须实时监测这些不平衡,并根据认可的会计程序实现最终的平衡。</td>
</tr>
<tr>
<td>Gas Cap Gas</td>
<td>2001- 6.2.2</td>
<td>none</td>
<td>Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of Associated Gas. 位于油气藏顶部与原油接触的游离天然气。气顶气是伴生气的一种。</td>
</tr>
<tr>
<td>Gas Hydrates</td>
<td>2007- 2.4</td>
<td>1.1, 8.9</td>
<td>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. 天然气水合物是水与天然气组成的天然结晶物。其中固态的水分子晶格与气体分子结合形成笼状或格状结构，在标准温度和压力条件下的甲烷水合物可含多达 164 体积的甲烷气。由于储气容量大,天然气水合物被认为是未来天然气的重要来源。天然气水合物为非常规资源的一种,其商业生产技术尚未开发。</td>
</tr>
<tr>
<td>Gas Inventory</td>
<td>none</td>
<td>4.1, 6.1, 7.1, 8.1, 9.7</td>
<td>The sum of Working Gas Volume and Cushion Gas Volume in underground gas storage. 对于地下储气库,天然气库存量是工作气量与垫底气量之和。</td>
</tr>
<tr>
<td>Gas/Oil Ratio (GOR)</td>
<td>2007- 3.4.4</td>
<td></td>
<td>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 ratio (Rs); produced gas/oil ratio (Rp); or another suitably defined ratio of gas production to oil production. 油田的气油比是指在规定条件下测量的天然气和原油体积之比。气油比可能是溶解气油比,符号为 Rs; 或生产气油比,符号为 Rp; 或其他适当定义的天然气产量与石油产量之比。</td>
</tr>
<tr>
<td>Term</td>
<td>Reference*</td>
<td>Used in These Guidelines</td>
<td>Definition</td>
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</tr>
<tr>
<td>Gas Plant Products</td>
<td>None</td>
<td>None</td>
<td>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.天然气处理厂产品是通过天然气处理厂或油气田设施从天然气中回收的天然气液(或组分)。天然气处理厂产品包括乙烷、丙烷、丁烷、丁烷/丙烷混合物、天然汽油以及处理厂回收的凝析油、硫、二氧化碳、氮和氦。</td>
</tr>
<tr>
<td>Gas-to-Liquids (GTL) Projects</td>
<td>None</td>
<td>None</td>
<td>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.气制油项目指应用专门的处理工艺(例如Fischer-Tropsch合成法)将天然气转换为液态石油产品的项目。这类项目一般适用于由于缺乏基础设施和当地市场，使常规天然气不能经济开发的大型天然气聚集体。</td>
</tr>
<tr>
<td>Geostatistical Methods</td>
<td>2001- 7.1</td>
<td>None</td>
<td>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.多种数学方法，用于收集、分析和表现大量的地学和工程资料。从数学方面描述任意油气藏单元的变异性与不确定性的多种数学方法。这里特指与资源评估有关的地质统计方法，包括所有井和油气藏参数在一维、二维和三维的定义以及相应的地质模型和对各种动态的可能预测结果。</td>
</tr>
<tr>
<td>High Estimate</td>
<td>2007- 2.2, 2001- 2.5</td>
<td>2.10, 4.27, 5.3, 7.4, 8.2</td>
<td>With respect to resources 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.在资源分级中，高估值是指项目能够从油气藏中实际采出的油气数量的乐观估计。如果应用概率法，则实际采出量至少有10%的概率(P10)等于或超过高估值。</td>
</tr>
<tr>
<td>Term 术语</td>
<td>Reference* 参考文献*</td>
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<td>Definition 定义</td>
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</tr>
<tr>
<td>Highest Known Hydrocarbons 已知烃顶</td>
<td>2007-2.2.2.</td>
<td>4.1</td>
<td>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”). 根据测井、产能测试、压力测量和岩心数据等资料综合解释的具有产能的油气聚集体中的最浅部位，该深度的上覆地层可能有油气，也可能没有，通常添加修饰语说明烃的具体类型，如“最浅已知气顶”。</td>
</tr>
<tr>
<td>Hydrocarbons 烃</td>
<td>2007-1.1</td>
<td>2.1, 3.2, 6.1, 8.7, 9.2, 10.14</td>
<td>Chemical compounds consisting wholly of hydrogen and carbon. 由碳和氢组成的化合物。</td>
</tr>
<tr>
<td>Improved Recovery (IR) 提高采收率</td>
<td>2007-2.3.4</td>
<td>2.1, 8.2, 10.1</td>
<td>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.) 提高采收率是指一次采油之后，通过对天然油气藏补充能量采出更多油气的开采方法，提高采收率方法包括水驱和注气等保持压力的二次采油、三次采油方法和其他增加天然油气藏可采量的方法，提高采收率方法还包括用来改善各种稠油地下原油流度的热采和化学采油方法，也称强化开采。</td>
</tr>
<tr>
<td>Injection 注入</td>
<td>2001-3.5 2007-3.2.5</td>
<td>3.6, 4.36, 5.1, 7.2, 8.4, 9.4</td>
<td>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. 通过加压泵送或空吸自流方式使物质进入地下的多孔渗透性岩层，注入的物质可包括气体或液体。</td>
</tr>
<tr>
<td>Justified for Development 已论证可开发</td>
<td>2007-2.1.3.1 and Table 1</td>
<td>2.5, 7.1</td>
<td>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. 储量报告或披露时，开发项目的实施在合理预测商业条件的基础上经过了论证，且可合理预期会获得所有必要的审批/合同，它是项目成熟度亚类，反映项目进入商业生产所需的活动。</td>
</tr>
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<tr>
<td>Kerogen</td>
<td>8.3</td>
<td>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.)</td>
<td></td>
</tr>
<tr>
<td>Known Accumulation</td>
<td>2007-2.1.1 2001-2.2 2.1, 3.2, 8.1</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>Lead</td>
<td>2007-2.1.3.1 and Table 1 2007-2.1.3.1 and Table 1</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>Lease Condensate</td>
<td>none -no occurrences</td>
<td>Lease Condensate is condensate recovered from produced natural gas in gas/liquid separators or field facilities.</td>
<td></td>
</tr>
</tbody>
</table>
Reference Terms

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<tr>
<td>Lease Fuel</td>
<td>2007- 3.2.2</td>
<td>9.1</td>
<td>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.</td>
</tr>
<tr>
<td>Lease Plant</td>
<td>none</td>
<td>-no occurrences</td>
<td>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”).</td>
</tr>
<tr>
<td>Liquefied Natural Gas (LNG) Project</td>
<td>9.2</td>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Loan Agreement</td>
<td>2001- 9.6.5</td>
<td>10.5</td>
<td>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.</td>
</tr>
</tbody>
</table>

Note: The definitions provided are translations of the original text into English.
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<tr>
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<tbody>
<tr>
<td>Low/Best/High Estimates 低 / 最佳 / 高估 值</td>
<td>2007-2.2.1, 2.2.2</td>
<td>1.1, 2.5, 3.1, 4.9, 5.1, 7.2, 8.2</td>
<td>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. 不确定性范围反映一个单一油气聚集体或项目的潜在可采量估值合理范围的不同不确定性程度。使用累积情景法。</td>
</tr>
<tr>
<td>Low Estimate 低估值</td>
<td>2007-2.2.2, 2001-2.5</td>
<td>2.4, 4.18, 5.2, 7.5</td>
<td>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. 资源分级中，低估值指项目能够从油气聚集体中开采出的油气数量的保守估计。如果应用概率法，则实际采出量等于或超过低估值的概率应至少有90% (P90)。</td>
</tr>
<tr>
<td>Lowest Known Hydrocarbons 已知烃底</td>
<td>2007-2.2.2.</td>
<td>3.1, 5.1</td>
<td>The deepest occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, or core data. 按照测井、产能测试、压力测量或岩心数据解释的具有产能的油气聚集体最深部位。</td>
</tr>
<tr>
<td>Marginal Contingent Resources 边际条件资源量</td>
<td>2007-2.1.3.3</td>
<td>2.1</td>
<td>Known (discovered) accumulations for which a development project(s) has been evaluated as economic or reasonably expected to become economic but commitment is with held because of one or more contingencies (e.g., lack of market and/or infrastructure). 已知油气聚集体，其开发项目经评价是经济可行的，或者可合理预期经济可行，但是由于一种或多种或有因素，例如缺少市场和/或基础设施，没有承诺启动开发项目。</td>
</tr>
<tr>
<td>Measurement 计量</td>
<td>2007-3.0</td>
<td>4.4, 5.4, 6.3, 8.1, 9.14</td>
<td>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. 按照交付合同或监管机构规定条件确定交付到参照点的石油产品数量、体积或质量和品质的过程。</td>
</tr>
<tr>
<td>Term</td>
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</tr>
<tr>
<td>Mineral Interest</td>
<td>2001- 9.3</td>
<td>7.4, 10.6</td>
<td>Mineral Interests in properties including (1) afe 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).</td>
</tr>
<tr>
<td>Monte Carlo Simulation</td>
<td>2001-5 2007- 3.5</td>
<td>2.3, 6.2, 7.1</td>
<td>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).</td>
</tr>
<tr>
<td>Natural Bitumen</td>
<td>2007- 2.4</td>
<td>2.1, 8.3</td>
<td>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.).</td>
</tr>
<tr>
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</tr>
<tr>
<td>Natural Gas</td>
<td>2007-3.2.3</td>
<td>1.1, 4.3, 8.4, 9.8</td>
<td>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.石油在地下的天然气气藏中以气态存在或溶解于原油的部分在正常温压条件下为气态天然气中可能含有一些非烃组分。</td>
</tr>
<tr>
<td>Natural Gas Inventory</td>
<td>none</td>
<td>-no occurrences</td>
<td>With respect to underground natural gas storage operations “inventory” is the total of working and cushion gas volumes.对于地下储气库作业天然气库存量是工作气量和垫底气量的总和。</td>
</tr>
<tr>
<td>Natural Gas Liquids (NGL)</td>
<td>2007-A13</td>
<td>4.2, 6.1, 7.1, 9.3</td>
<td>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).天然气液(NGL)是指在油气藏条件下以气态存在但在天然气处理厂作为液体回收的轻烃组分混合物NGL与凝析油有两个方面的不同(1) NGL是在天然气处理厂提取和回收而不是在合同区分离器或其他合同区设施提取和回收(2) NGL既包含轻烃乙烷丙烷丁烷等也包含作为凝析油主要组分的戊烷及以上重组分。</td>
</tr>
<tr>
<td>Natural Gas Liquids to Gas Ratio</td>
<td>none</td>
<td>-no occurrences</td>
<td>Natural gas liquids to gas ratio in an oil or gas field, calculated using measured natural gas liquids and gas volumes at stated conditions.油气田中的天然气液与天然气之比是指在规定条件下计量的天然气液体量和天然汽量的体积之比。</td>
</tr>
<tr>
<td>Net-back</td>
<td>2007-3.2.1</td>
<td>none</td>
<td>Linkage of input resource to the market price of the refined products.指参照点输入端资源价格与成品油市场价格之间的关联关系。</td>
</tr>
<tr>
<td>Net Profits Interest</td>
<td>2001-9.4.4</td>
<td>none</td>
<td>An interest that receives a portion of the net proceeds from a well, typically after all costs have been paid.从井生产石油所获净利润一般指已支付全部成本后的分得一部分的权益。</td>
</tr>
<tr>
<td>Net Working Interest</td>
<td>2001-9.6.1</td>
<td>10.2</td>
<td>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.)根据适用的租赁和财税条款将公司的工作权益扣除矿费或其他各方份额产量也称为净收入权益后拥有的权益也称为净收入权益。</td>
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<tr>
<td>Non-Hydrocarbon Gas</td>
<td>2007-3.2.4</td>
<td>4.1, 9.12</td>
<td>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.</td>
</tr>
<tr>
<td>Non-Associated Gas</td>
<td>None</td>
<td>None</td>
<td>Non-Associated Gas is a natural gas found in a natural reservoir that does not contain crude oil.</td>
</tr>
<tr>
<td>Normal Production Practices</td>
<td>None</td>
<td>none</td>
<td>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.</td>
</tr>
<tr>
<td>Offset Well Location</td>
<td>8.4</td>
<td></td>
<td>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.</td>
</tr>
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<tr>
<td>Oil Sands</td>
<td></td>
<td>8.7</td>
<td>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.</td>
</tr>
<tr>
<td>Oil Shales</td>
<td>2007- 2.4</td>
<td>8.13</td>
<td>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).</td>
</tr>
<tr>
<td>On Production</td>
<td>2007- 2.1.3.1 和 Table 1</td>
<td>2.4, 3.2, 4.2, 7.3, 8.2</td>
<td>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.</td>
</tr>
<tr>
<td>Operator</td>
<td>2.1, 4.2, 7.1, 8.2, 10.1</td>
<td>The company or individual responsible for managing an exploration, development, or production operation.</td>
<td></td>
</tr>
<tr>
<td>Overlift / Underlift</td>
<td>2007 - 3.2.7 2001- 3.9</td>
<td>9.5</td>
<td>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.</td>
</tr>
<tr>
<td>Penetration</td>
<td>2007- 1.2</td>
<td>2.1</td>
<td>The intersection of a wellbore with a reservoir.</td>
</tr>
<tr>
<td>Term</td>
<td>Reference*</td>
<td>Used in These Guidelines</td>
<td>Definition</td>
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</tr>
<tr>
<td>Petroleum</td>
<td>2007- 1.0</td>
<td>1.12, 2.11, 3.1, 4.31, 5.3, 7.28, 8.18, 9.1, 10.4</td>
<td>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%.石油是自然形成的由气态、液态或固态烃组成的混合物；石油也可能包含非烃化合物，其中常见的如二氧化碳、氮气、硫化氢和硫，在极少数情况下，非烃组分的含量可能大于50%。</td>
</tr>
<tr>
<td>Petroleum Initially-In-Place</td>
<td>2007- 1.1</td>
<td>2.2</td>
<td>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.)石油原始原地量是指天然油气藏中原始存在的石油估算总量；原油原地量、天然气原地量和天然沥青原地量定义的方式相同；参见术语“资源”(Resources)”也称为总资源基础或油气禀赋。</td>
</tr>
<tr>
<td>Pilot Project</td>
<td>2007-2.3.4, 2.4</td>
<td>2.5, 4.6, 8.3</td>
<td>A small-scale test or trial operation that is used to assess the suitability of a method for commercial application.用于评价某种方法商业适用性的小规模试验或试运行。</td>
</tr>
<tr>
<td>Play</td>
<td>2007- 2.1.3.1 and Table 1</td>
<td>2.1, 8.15</td>
<td>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.指有潜力成为潜力目标区的项目，但需要更多的数据采集和/或评价才能确定为具体的潜在有利区或目标区；它是项目成熟度亚类，反映项目向商业生产转化所需的活动。</td>
</tr>
<tr>
<td>Pool</td>
<td>3.5, 6.1</td>
<td></td>
<td>An individual and separate accumulation of petroleum in a reservoir.油气藏中单个离散的油气聚集体。</td>
</tr>
<tr>
<td>Term 术语</td>
<td>Reference* 参考文献</td>
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<tr>
<td>Possible Reserves 可能储量</td>
<td>2007 - 2.2.2 and Table 3</td>
<td>1.1, 2.5, 4.1, 5.1, 10.4</td>
<td>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. 这相当于高估值的概率情景。当采用概率法时，实际采出量等于或超过 3P 估值的概率应至少为 10%</td>
</tr>
<tr>
<td>Primary Recovery 一次开采</td>
<td></td>
<td>2.1, 4.1</td>
<td>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. 一次开采是指仅利用油气藏天然能量将流体从储层送入井底、采出地面的石油开采方式</td>
</tr>
<tr>
<td>Probability 概率</td>
<td>2007 - 2.2.1</td>
<td>2.19, 3.1, 5.44, 6.23, 7.16, 8.1</td>
<td>The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of 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.) 一个事件发生的可能性，用出现的有利案例数与所有可能案例数之比表示。SPE 的惯用做法是引用超过或等于某一数量的累积概率。其中 P90 为低估值，P10 为高估值。参见术语“不确定性”</td>
</tr>
<tr>
<td>Probabilistic Estimate 概率法估计</td>
<td>2007 - 3.5</td>
<td>5.3, 7.1</td>
<td>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. 用已知的地球科学、工程和经济数据产生一个连续的估值范围及其相应概率的资源评估方法</td>
</tr>
<tr>
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</tr>
<tr>
<td>Probable Reserves 概算储量</td>
<td>2007 - 2.2.2 and Table 3</td>
<td>1.1, 2.4, 6.2, 8.3, 10.3</td>
<td>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.</td>
</tr>
<tr>
<td>Production 产量</td>
<td>2007- 1.1</td>
<td>1.1, 2.13, 3.12, 4.151, 5.12, 6.10, 7.44, 8.89, 9.42, 10.78</td>
<td>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.</td>
</tr>
<tr>
<td>Production-Sharing Contract 产品分成合同</td>
<td>2007 - 3.3.2 2001- 9.6.2</td>
<td>10.33</td>
<td>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.</td>
</tr>
</tbody>
</table>

一种与规定的不确性程度相关的可采估算量的增量级别；概算储量是通过地球科学和工程数据分析表明其采出的可能性低于证实储量，但确定性高于可能储量的储量增量；实际剩余采出量大于或小于证实储量加概算储量2P的可能性相同；就是说，当采用概率法时，实际采出量等于或超过2P估值的概率应至少为50%。
<table>
<thead>
<tr>
<th>Term 术语</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Profit Split 利润劈分</td>
<td>2001- 9.6.2</td>
<td>10.7</td>
<td>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. 典型产品分成合同中，合同者负责油气田的开发，并承担所有勘探和开发费用，作为回报，合同者有权分享剩余的利润油或气。合同者获得油或气产量支付，并承担技术和市场双重风险。</td>
</tr>
<tr>
<td>Project 项目</td>
<td>2007-1.2, 2001-2.3</td>
<td>1.2, 2.184, 3.2, 4.172, 5.5, 6.12, 7.158, 8.59, 9.10, 10.47</td>
<td>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.) 项目体现了油气聚集体与决策过程之间的联系，包括财务预算拨款。一个项目可能是单个油气藏或油气田的开发，或者是一个正在生产油气田的增量开发，亦或是所有权相同的多个油气田及其地面设施的综合开发。一般而言，一个独立项目将代表一个具体的成熟度水平，以此作为支持是否继续推进项目决策依据，例如投资。应有一个项目可采估算量的相应范围。参见“开发方案”</td>
</tr>
<tr>
<td>Property 资产</td>
<td>2007-1.2, 2001-9.4</td>
<td>2.1, 3.6, 6.3, 7.9, 8.3, 9.1, 10.11</td>
<td>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. 地壳内的一个区域，这里指公司实体或个人已取得合同权利来开采，处理和出售指定地下矿产（包括石油）的一定部分。在一般情况下，被规定为一个面积区域，但可以有深度和层位方面的限制，也可以称为租赁区，租让区，许可证区等。</td>
</tr>
<tr>
<td>Prorationing 配额</td>
<td>none -no occurrences 未出现</td>
<td></td>
<td>The allocation of production among reservoirs and wells or allocation of pipeline capacity among shippers, etc. 指油气藏和井之间的产量分配或交运货物者之间的管输量分配等。</td>
</tr>
<tr>
<td>Term 术语</td>
<td>Reference* 参考文献 *</td>
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<tr>
<td>Prospect 目标区</td>
<td>2007-2.1.3.1 and Table 1</td>
<td>2.4, 4.3, 5.9, 8.1, 10.1</td>
<td>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. 一个与潜在油气聚集体相关的项目，经充分落实，为一个可行的钻井目标，它是项目的成熟度亚类，反映项目向商业化生产转化所需的活动。</td>
</tr>
<tr>
<td>Prospective Resources 远景资源量</td>
<td>2007- 1.1 and Table 1</td>
<td>1.1, 2.16, 3.2, 4.8, 6.2, 7.1, 8.5</td>
<td>Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. 在给定日期估算的，可能从未发现的油气聚集体中采出的石油数量。</td>
</tr>
<tr>
<td>Proved Economic 证实经济的</td>
<td>2007- 3.1.1</td>
<td>none -no occurrences 未出现</td>
<td>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.” 多数情况下，外部监管报告规定和/或融资要求，即使项目只实际采出证实储量估算量，项目仍能满足经济极限条件，则该项目称为“证实经济的”。</td>
</tr>
<tr>
<td>Proved Reserves 证实储量</td>
<td>2007- 2.2.2 and Table 3</td>
<td>1.1, 2.4, 4.2, 5.3, 6.24, 7.5, 8.4, 9.1, 10.7</td>
<td>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 under defined 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.” 与指定不确定性程度相关联的可采量增量级别，证实储量，指通过地球科学和工程数据分析，在给定日期起，在确定的经济条件、作业方式及政府规定下，能合理确定地从已知油藏中商业开采的石油估算数量。如果采用确定法，则“合理确定性”这一术语旨在表明采出这些数量的置信度高，若采用概率法，则实际产出量等于或超过估算量的概率应至少是90%，常称1P，也称“证实的”。</td>
</tr>
<tr>
<td>Term</td>
<td>Reference*</td>
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<td>Definition</td>
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</tr>
<tr>
<td>Purchase Contract</td>
<td>2001-9.6.8</td>
<td>10.4</td>
<td>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.指购买油气的合同，它为买方提供在规定期限内按商定价购买一定产量的权利。</td>
</tr>
<tr>
<td>Pure-Service Contract</td>
<td>2001-9.7.5</td>
<td>10.5</td>
<td>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. 服务公司的投资一般仅限于设备、工具以及执行服务的人员费用。多数情况下，服务承包商的报酬按合同条款是固定的，基本与项目执行效果或市场因素无关。</td>
</tr>
<tr>
<td>Range of Uncertainty</td>
<td>2007-2.2, 2001-2.5</td>
<td>2.28, 3.1, 4.3, 5.4, 6.2, 8.2</td>
<td>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.) 可采量和潜在可采量的不确定性范围可由确定性情景法或概率分布法来表述，参见术语“资源不确定性级别”。</td>
</tr>
<tr>
<td>Raw Natural Gas</td>
<td>2007-3.2.1</td>
<td>4.2</td>
<td>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. 但其所含的烃组分是值得开发利用的。原料天然气往往不适合大多数类型消费者直接利用。</td>
</tr>
<tr>
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<tr>
<td>Reasonable Certainty</td>
<td>2007-2.2.2</td>
<td>4.3, 6.2, 8.1</td>
<td>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. 使用确定法评估可采资源量时合理确定性是指估算的量能被采出有高置信度。</td>
</tr>
<tr>
<td>Reasonable Expectation</td>
<td>2007-2.1.2</td>
<td>7.3</td>
<td>Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. 表明该项目进行商业开发或引用事件的发生有高置信度, 失败风险低。</td>
</tr>
<tr>
<td>Reasonable Forecast</td>
<td>2007-3.1.2</td>
<td>7.1</td>
<td>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. 表明对未来事件和商业条件的预测置信度高, 合理预测的基础包括但不限于对历史记录和已公布的全球经济模型的分析。</td>
</tr>
<tr>
<td>Recoverable Resources</td>
<td>2007-1.2</td>
<td>2.1, 5.1, 6.1, 8.1</td>
<td>Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations. 可从已发现或未发现油气聚集体中采出的油气估算量。</td>
</tr>
<tr>
<td>Recovery Efficiency</td>
<td>2007-2.2</td>
<td>2.4, 4.19, 5.1, 8.7, 10.1</td>
<td>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. 采收率是估算的石油原地量中通过特定过程或项目可采出部分的数值表达, 其常常用表述方式为百分比。</td>
</tr>
<tr>
<td>Reference Point</td>
<td>2007-3.2.1</td>
<td>7.1, 9.13</td>
<td>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. 石油开采与加工处理作业链中的一个指定位置, 石油产品在此处进行交付或消费之前按规定条件进行计量, 也称销售点或交付点。</td>
</tr>
<tr>
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</table>
| **Reserves 储量** | 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. 储量是指在规定条件下自指定日期起可通过开发项目从已知油气聚集体商业开采的石油数量，根据实施的开发项目储量应满足四个条件：已发现的、可采的、商业的和剩余的（截至指定日期）。

| **Reservoir 油气藏** | 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. 含有单个独立可流动油气聚集体的岩性地层，由非渗透性岩石/地层分隔，并具有单一压力系统。

| **Resources 资源** | 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 “unconventional” (see Total Petroleum Initially-In-Place). (In basin potential studies, it may be referred to as Total Resource Base or Hydrocarbon Endowment.) 这里所用术语“资源”是指地壳中自然形成的所有石油数量（可采的和不可采的），包括已发现和未发现的石油数量以及已经产出的数量。此外，资源包括所有类型的石油资源，无论是目前的“常规”还是“非常规”，参见石油总原始原地量。在盆地潜力研究中，它也指总资源基础或油气禀赋。

| **Resources Categories 资源级别** | 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). 项目可采资源估算量的相关不确定性程度的资源量细分，不同级别反映了油气聚集体内总剩余石油量的不确定性，通过实施规定的某一开发项目可采出石油原地量的一部分数量的不确定性以及各种可能影响商业开发的条件，如市场可获得性合同的变化等的不确定性。
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<tr>
<td>Resources Classes 资源类别</td>
<td>2007- 1.1, 2.1 and Table 1</td>
<td>6.1</td>
<td>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. 所实施的开发项目采出可采估算量的相对成熟度的资源量细分；项目成熟度可以定性地用类别和亚类来表示它；或/或定量地用其达到生产状态的几率来表示。</td>
</tr>
<tr>
<td>Revenue-Sharing Contract 收入分成合同</td>
<td>2001- 9.6.3</td>
<td>10.3</td>
<td>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. 收入分成合同和前文介绍的产品分成合同非常相似，只是合同者的支付方式不同。通常合同者从这种合同得到的是规定的油气收入的分成而不是产量分成。</td>
</tr>
<tr>
<td>Reversionary Interest 可复归权益</td>
<td>7.1</td>
<td></td>
<td>The right of future possession of an interest in a property when a specified condition has been met. 指将来在满足指定条件时拥有资产权益的权利。</td>
</tr>
<tr>
<td>Risk 风险</td>
<td>2001- 2.5</td>
<td>2.24, 3.3, 4.3, 5.6, 6.23, 7.1, 8.7, 10.23</td>
<td>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. 指损失或失败的概率。由于“风险”Risk”通常与负面结果有关，术语“几率(Chance)”一般更常用于表述离散事件发生的概率。</td>
</tr>
<tr>
<td>Risk and Reward 风险与回报</td>
<td>2001- 9.4</td>
<td>10.2</td>
<td>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. 与油气生产活动有关的风险和回报主要源于技术和经济风险引起的收入变化。技术风险影响公司实际开采油气的能力，且常常取决于一些技术参数。经济风险是项目成功的函数，主要取决于成本、价格和政治或其他经济因素。</td>
</tr>
<tr>
<td>Risked-Service Contract 风险服务合同</td>
<td>2007- 3.3.2</td>
<td>10.4</td>
<td>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. 风险服务合同与产品分成合同很相似，只是合同者的支付方式不同。但合同者要承担风险。在风险服务合同中，合同者通常是获得规定的收入分成而不是产量分成。</td>
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<tr>
<td>Royalty</td>
<td>2007- 3.3.1</td>
<td>7.16, 9.1, 10.16</td>
<td>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. 矿费指资源国政府或矿产所有者从生产者承租人合同者开采油气藏获得石油资源的收益中得到的回报。有些协议允许生产者提取矿费对应的产量代表矿费所有者将其出售然后向矿产所有者支付收益。有些协议规定矿费只能以实物形式支付给矿产所有者。</td>
</tr>
<tr>
<td>Sales</td>
<td>2007- 3.2</td>
<td>2.6, 4.3, 6.3, 7.9, 9.38, 10.3</td>
<td>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. 按照销售合同和或监管当局规定的规格和计量条件在交付点交付的石油产品的数量。所有可采资源量都按计量的产品销售量评估。</td>
</tr>
<tr>
<td>Shut-in Reserves</td>
<td>2007- 2.1.3.2 and Table 2</td>
<td>none — no occurrences</td>
<td>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. 关井储量是期望从以下情况采出的储量：(1) 评估时已经打开、尚未投产的完井层段；(2) 由于市场或管线原因而关闭的井；(3) 因机械原因而不能生产的井。</td>
</tr>
<tr>
<td>Solution Gas</td>
<td>4.28, 6.3, 7.1, 8.2</td>
<td>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. 溶解气是指在地层压力和温度条件下溶解于储层原油中的天然气，它是一种伴生气。</td>
<td></td>
</tr>
<tr>
<td>Sour Natural Gas</td>
<td>2001- 3.4</td>
<td>none — no occurrences</td>
<td>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. 酸性天然气是指含硫化物和二氧化碳的天然气，需要去除后才能销售或有效利用。</td>
</tr>
<tr>
<td>Stochastic Estimate</td>
<td>2001- 5</td>
<td>2.1, 6.6</td>
<td>Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation. 指涉及或包含一个或一组随机变量或涉及几率或概率，如随机模拟的过程。</td>
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<tr>
<td>Subcommercial 次商业的</td>
<td>2007- 2.1.2</td>
<td>2.2</td>
<td>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. 如果对一个项目未承诺油气聚集体在合理时间框架内预期开发投产，则该项目属于次商业的。一般建议以五年期限为基准，但有些情形下也可以适用较长的期限，例如生产者出于市场原因或为实现合同或战略目标选择推迟经济项目的开发。已发现的次商业的项目划分为条件资源量。</td>
</tr>
<tr>
<td>Submarginal Contingent Resources 次边际条件资源量</td>
<td>2007- 2.1.3.3</td>
<td>2.1</td>
<td>Known (discovered) accumulations for which evaluation of development project(s) indicated they would not meet economic criteria, even considering reasonably expected improvements in conditions. 指开发项目评估表明，即使合理预期评估条件改善后项目仍不能满足经济条件的已知（已发现）油气聚集体的资源量。</td>
</tr>
<tr>
<td>Sweet Natural Gas 无硫天然气 甜气</td>
<td>2001- 3.3</td>
<td>none 未出现</td>
<td>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. 无硫天然气指不含或者含极少量硫和硫化物，在销售前不需要去硫处理的天然气。</td>
</tr>
<tr>
<td>Synthetic Crude Oil (SCO) 合成原油</td>
<td>2001- A12, A13</td>
<td>8.2</td>
<td>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. 通过天然沥青（来源于油砂）和干酪根（来源于油页岩）改质（即化学改变）或者通过处理天然气或煤炭等其他物质得到的烃混合物。合成原油可能含硫或其他非烃化合物，与原油有很多的相似之处。</td>
</tr>
<tr>
<td>Taxes 税负</td>
<td>2001- 9.4.2</td>
<td>7.15, 8.1, 10.14</td>
<td>Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority. 指政府部门对个人财产或收入强制征收用于公共资金的义务费用。</td>
</tr>
<tr>
<td>Technical Uncertainty 技术不确定性</td>
<td>2007- 2.2</td>
<td>2.1, 4.1</td>
<td>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. 表明油气藏内受潜在油气原地资源量范围和项目采收率范围影响的可采估算量的不确定性程度。</td>
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<tr>
<td>Total Petroleum Initially-In-Place</td>
<td>2007-1.1</td>
<td>2.2</td>
<td>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.”</td>
</tr>
<tr>
<td>Uncertainty</td>
<td>2007-2.2 2001-2.5</td>
<td>2.50, 3.17, 4.28, 5.30, 6.20, 7.8, 8.18, 9.1</td>
<td>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.)</td>
</tr>
<tr>
<td>Unconventional Resources</td>
<td>2007-2.4</td>
<td>1.1, 8.6</td>
<td>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 shalegas, 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).</td>
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<tr>
<td><strong>Undeveloped Reserves 未开发储量</strong></td>
<td>2001-2.1.3.1 and Table 2</td>
<td>2.4, 6.1, 8.2</td>
<td>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. 未开发储量是指预期可通过未来投资采出的石油数量：(1) 从已知油气聚集体未钻井区域所钻新井; (2) 从加深现有井到另一不同的已知油气藏; (3) 从填空井中采出更多石油; (4) 在于钻一口新井的成本相比较下，需要较大成本用于①一口现有井的重新完井或②为一次采油或提高采收率项目安装生产或运输设施。</td>
</tr>
<tr>
<td><strong>Unitization 联合作业</strong></td>
<td>None - no occurrences 未出现</td>
<td></td>
<td>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). 指所有者们联合开发毗邻的合同区资产并根据各自在共享油气藏中石油可采量的份额来分割储量、产量、成本和其他要素的过程。</td>
</tr>
<tr>
<td><strong>Unproved Reserves 未证实储量</strong></td>
<td>2001-5.1.1</td>
<td>none -no occurrences 未出现</td>
<td>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. 未证实储量是根据类似于证实储量估算中所用的地球科学和工程数据得到的。但由于技术或其他方面存在的不确定性使其不能划分为证实储量。未证实储量可进一步分级为概算储量和可能储量。</td>
</tr>
<tr>
<td><strong>Unrecoverable Resources 不可采资源量</strong></td>
<td>2007-1.1</td>
<td>8.1</td>
<td>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. 指在给定日期估算的已发现或未发现石油原始原地量中不能被开采的那部分数量。将来由于商业环境变化和技术发展或者获得更多资料而不可采量中的一部分可能转化成为可采量。</td>
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**Reference Terms**

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<td>Upgrader</td>
<td>2007-2.4</td>
<td>9.2</td>
<td>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.  一种应用于超重原油和天然沥青转化为轻质原油和低黏度合成原油的处理加工厂的通用术语。尽管具体处理过程不尽相同，但基本原理都是通过焦化除碳或者通过催化剂加氢过程增加氢的含量。</td>
</tr>
<tr>
<td>Well Abandonment</td>
<td>4.3, 7.3</td>
<td></td>
<td>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.  指对干井、注入井、探井、不再生产石油的井或不再盈利生产的井进行永久性封堵的井的废弃要经过下列几个步骤：从政府机构获得废弃许可及程序要求；若可能，要移除和打捞套管；要在井筒中注入一段或多段水泥塞和/或钻井液，防止井筒钻开的不同层位间发生窜流；某些情况下，在长时间停止作业时，井可以临时报废，以备将来转成监测和提高采收率等其它用途。</td>
</tr>
<tr>
<td>Wet Gas</td>
<td>2001-3.2</td>
<td>4.2, 8.1, 9.3</td>
<td>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.  湿气是在参照点之前没有去除任何液体的天然气，在资源评估中，湿气量要记账，但不单独登记湿气中所含的液量，应注意这是资源评估的定义，而不是相态定义。</td>
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<tr>
<td>Working Gas Volume 工作气量</td>
<td></td>
<td>none 未出现</td>
<td>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. 对于地下天然气储气库，工作气量是储气库内超过所设计垫底气量的气体数量。工作气量可以在法律和技术限制（压力、速度等）范围内通过地下和地面设施（井、放喷管线等）进行采出/注入。根据当地现场条件，工作气量可实现每年一次以上的循环。</td>
</tr>
<tr>
<td>Working Interest 工作权益</td>
<td>2001-9</td>
<td>7.1, 9.3, 10.4</td>
<td>A company’s equity interest in a project before reduction for royalties or productionshare owed to others under the applicable fiscal terms. 指根据适用的财税条款，公司在扣除矿费或其他各方的份额产量之前所拥有的项目权益。</td>
</tr>
</tbody>
</table>
Acknowledgements

SPE Oil and Gas Reserves Committee
1. PRMS Application Guidelines in English Version

These guidelines represent the collaboration of an international group of more than 40 experienced reserves estimation professionals who were involved in the writing, editing, review, and preparation of this document. The SPE Oil and Gas Reserves Committee (OGRC) gratefully acknowledges the time and effort of the following:

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<td>Yasin Senturk</td>
</tr>
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<td>Chapter 5</td>
<td>Wim J.A.M. Swinkels</td>
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<td>Chapter 6</td>
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<td>Chapter 7</td>
<td>Yasin Senturk</td>
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<td>Chapter 8</td>
<td>Phil Chan, John Etherington, Geoff Barker, Creties Jenkins, Roberto Aquilera, and Chris Clarkson</td>
</tr>
<tr>
<td>Chapter 9</td>
<td>Satinder Purewal</td>
</tr>
<tr>
<td>Chapter 10</td>
<td>Elliott Young</td>
</tr>
</tbody>
</table>

*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.

The authors of the individual chapters have relied on their expertise regarding appropriate guidance and application examples in relation to PRMS. The views expressed in this document do not necessarily represent the views of the employers of any of the authors, nor of any organizations with which they may be associated. All chapters have been peer reviewed and the complete document has been endorsed by the sponsoring organizations of PRMS.

Applications Document Committees

Delores Hinkle and Jeff Tenzer, Chairpersons of the OGRC during development and review of these guidelines, provided required support throughout the process. The following Applications Document Subcommittee members laid the foundations during the first two years: Satinder Purewal (Chair), Delores Hinkle, Bernard Seiller, Stuart Filler, Stefan Choquette, Yasin Senturk, Phil Chan, James Pearson. The contributions of the following committees are also gratefully acknowledged.

致谢
Acknowledgements

*SEG 石油天然气储量委员会的主要贡献人员包括 Patrick Connolly, Henk-Jaap Kloosterman, James Robertson, Bruce Shang, Raphic van der Weiden 和 Robert Withers。

各章节作者是指导 PRMS 应用及提供应用示例的专家，其在本文件中表达的观点不代表其雇主的观点，也不代表任何相关组织的观点。所有章节都经过同行审阅，最终文稿得到了 PRMS 发起组织的背书。

在编制和审阅本指南期间，OGRC 主席 Delores Hinkle 和 Jeff Tenzer 在整个过程中提供了必要的支持。应用指南委员会的以下成员在头两年为工作奠定了基础：Satinder Purewal 主席，Delores Hinkle, Bernard Seiller, Stuart Filler, Stefan Choquette, Yasin Senturk, Phil Chan 和 James Pearson，也感谢以下委员会成员的贡献。
In addition, Holly Hargadine and other SPE staff contributions are acknowledged for providing continuous support throughout the process of developing this document. Without SPE staff support, this project would not have been possible to bring to fruition.


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.

2. PRMS Application Guidelines in English-Chinese Version

Recognizing the wide acceptance and applications of PRMS in global petroleum industry, the SPE Oil and Gas Reserves Committee (OGRC) decided to translate the PRMS Application Guidelines (2011) into other main languages, including Chinese and Russian, to maintain the quality and integrity of the document as well as for the convenience of users who are more comfortable with their native languages.

This is a significant, multidisciplinary, complicated and creative task with a huge workload. Like any other work in the society, it must rely on many qualified professionals serving as volunteers to accomplish. China National Petroleum Corporation (CNPC) and her subsidiaries have provided great support. In a short time, more than 20 volunteers were invited from CNPC, China National Offshore Oil Corporation (CNOOC), China Petrochemical Corporation (Sinopec), and other IOCs respectively and formed the Chinese Translation Subcommittee. The whole task has experienced three rounds of translation, review and integration, which lasted for 5 years. In the later stage of standardization work, the Department of Mineral Resources Protection and Supervision,
the Ministry of Natural Resources of China played an important guiding role on this task.

All translated chapters have been reviewed by international professionals assigned by the SPE OGRC, and the complete document has been endorsed by the sponsoring organizations of PRMS.

**Chinese Translation Subcommittee**

This English-Chinese translation document represents the collaboration achievement of an international joint taskforce of more than 20 experienced reserves evaluation professionals who were involved in the translating, editing, review, and standardization work of this document. Major contributors to the translation are:

<table>
<thead>
<tr>
<th>Chapter, 章</th>
<th>Translator(s), 编译者</th>
</tr>
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<tbody>
<tr>
<td>Chapter 1</td>
<td>Hua YANG (CNPC), Tony WONG (SPE)</td>
</tr>
<tr>
<td>Chapter 2</td>
<td>Henian LIU (CNPC), Lei WU (CNPC)</td>
</tr>
<tr>
<td>Chapter 3</td>
<td>Yu YE (CNPC), Erheng LI (MNR)</td>
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<tr>
<td>Chapter 4</td>
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<td>Yanjing YI (CNPC), Haibo ZHANG (MNR)</td>
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<tr>
<td>Chapter 7</td>
<td>Ruie YUAN (CNPC), Zhiyu LI (CNPC)</td>
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<tr>
<td>Chapter 8</td>
<td>Phillip CHAN (SPE), Jian ZHENG (Sinopec), Mingli GUO (Sinopec), Xinjun SHAO (CNPC)</td>
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<tr>
<td>Chapter 9</td>
<td>Tao YANG (PetroChina Southwest Oil and Gas Field Company), Yanjing YI (CNPC)</td>
</tr>
<tr>
<td>Chapter 10</td>
<td>Yanjing YI (CNPC), Ruie YUAN (CNPC)</td>
</tr>
</tbody>
</table>

**Reference Terms**

Hua YANG (CNPC), Ruie YUAN (CNPC), Quingru WANG (CNOOC), Jian ZHENG(Sinopec), Lei WU (CNPC), Yundong HU (GCA) |

**Translation Steering Committee**

The Translation Steering Committee have played important leading role on the translation. Members are: Jianhua JU, Feng WANG, Xiandeng YE, Henian LIU, Quingru Wang, Yongle HU, Chunlei QIAO, Lei WU, Jian Zheng, Haizhen MA, Yuwen CHANG and Hua
YANG. Their valuable guidance and contribution are also sincerely acknowledged.

Other Major Contributors

Chairpersons of the SPE OGRC, Rawdon Seager, Dan Diluzio, Bernard Seiller, and Steven McCants provided necessary guidance and monitoring during the development and review of this document.

The Department of Mineral Resources Protection and Supervision, the Ministry of Natural Resources of the People's Republic of China (MNR) have provided vigorous support and important guidance on the translation work, in particular on the standardization of PRMS terminology in Chinese.

Melissa Schultea, Holly Hargadine and other SPE staff have provided continuous efforts and supports throughout the process of developing this document. Their devotion and contribution are also gratefully acknowledged.

Assigned by the SPE OGRC, the following experts have been involved in the reviewing work as well:

Busheng LI, BBVA Compass, nominated by Stephen Gardner;
Phillip CHAN, Author of Chapter 8, nominated by John Lee;
Yundong HU, GCA, nominated by Doug Peacock; and
Yangyang LIU, BP, nominated by Mark Neiberding.

In addition, Zheng HAN, Hong CHEN, Wuhe WANG, Jun TIAN, Yingtao SUN, Yong HU, Junzhang ZHENG and Shishen LI have also provided valuable comments during the review process.

CNPC and her subsidiaries, in particular China National Oil and Gas Exploration and Development Company Ltd. (CNOOC), Research Institute of Petroleum Exploration and Development (RIPED), and Petroleum Industry Press (PIP), have provided great supports for the translation work, including sponsoring translation, review, travelling, meeting, and preparation of the document.

The translation of PRMS Application Guidelines is important to disseminate PRMS knowledge and methodology in China, and further promote globally communication and transparency on petroleum resources evaluation and management. The SPE Oil and Gas Reserves Committee (OGRC) gratefully acknowledges again all sponsors and contributors' time, efforts and wisdom.

SPE 油气储量委员会的历届主席 Rawdon Seager, Dan Diluzio, Bernard Seiller 和 Steven McCants 为本文的编译和审阅工作提供了必要的指导与监管。

中国自然资源部矿产资源保护监督司对本指南编译工作给予了大力支持并提供了重要指导意见，尤其是 PRMS 中文术语体系的标准化工作。

Melissa Schultea, Holly Hargadine 和其他 SPE 工作人员在本文的整个编制过程中提供了持续不懈的努力和支持，衷心感谢他们所作出的贡献与奉献。

经 SPE 油气储量委员会选派，还有以下专家参与了本指南的审阅工作：

Busheng LI 康百士银行，Stephen Gardner 提名;
Phillip CHAN 第 8 章作者，John Lee 提名 ;
Yundong HU, GCA 公司，Doug Peacock 提名 ;
Yangyang LIU, BP 公司，Mark Neiberding 提名。

此外，韩征，陈红，王武和，孙英涛，胡勇，郑俊章和李士申等专家也在审阅期间提供了宝贵意见。

中国石油天然气集团公司及其下属机构特别是中国石油国际勘探开发有限公司，CNOOC，中国石油集团科学技术研究院 RIPED，中国石油工业出版社 PIP 对编译工作给予了大力支持，包括翻译，审阅，差旅，会议和文本编辑等。

PRMS 应用指南的翻译工作对于在中国宣传 PRMS 理念和方法，进一步促进全球石油资源评估与管理领域的交流力度与透明度十分重要，SPE 油气储量委员会 OGRC 再次衷心感谢所有赞助机构和参译专家们为翻译工作所付出的宝贵时间，精力与智慧。
Addendum-Corrections & Modifications

SPE Oil and Gas Reserves Committee
### Addendum-Corrections & Modifications

The following corrections and modifications have been made since the original publication of the PRMS Application Guidelines in November 2011:

<table>
<thead>
<tr>
<th>Page</th>
<th>Original Text</th>
<th>Corrected Text</th>
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<tbody>
<tr>
<td>5, Line 6</td>
<td>Chap. 7 covers commercial evaluations, including a discussion on public disclosure and regulatory reporting under existing regulations.</td>
<td>Chap. 7 covers commercial evaluations.</td>
<td>July 2012</td>
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<tr>
<td>66, Line 1</td>
<td>…parameters Di and n.</td>
<td>…parameters Di and b.</td>
<td>July 2012</td>
</tr>
<tr>
<td>84, Line 18</td>
<td>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.</td>
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<td>July 2012</td>
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<td>119, Eq. 7.3d</td>
<td>DF&lt;sub&gt;i&lt;/sub&gt; = 1/([MARR]&lt;sup&gt;0.5&lt;/sup&gt;)</td>
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<td>134, Line 15</td>
<td>basic-centered gas accumulations (BCGA)</td>
<td>basin-centered gas accumulation (BCGA)</td>
<td>July 2012</td>
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With the SPE OGRC’s guidance, more minor modifications have been made in the English-Chinese version of the PRMS Application Guidelines as well.