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Chapter 7

Evaluation of Petroleum Reserves and Resources

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7.1 Introduction

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

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

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

7.2 Cash-Flow-Based Commercial Evaluations

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

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

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

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

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

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

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

7.3 Definitions of Essential Terms

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

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

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

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

where

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

and EF_{kt} is the escalation factor (or the cumulative overall multiplier) at any time t, which ranges from $t = 0$ (zero or current-year) to $t = n$ (project's economic life in years) for any price or cost component ($k = 1, 2, 3\ldots$) of project cash flows.

E_k = average and constant annual escalation rate or goods/products and services specific inflation rate (in fraction) for any price and cost component (k) over the entire project life ($t = 0$ to n). Although generally expressed and used as annual rates, these rates can be expressed over any time period provided that other data are also expressed in the same time unit.

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

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

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

Table 7.1—Oil Price in Different Dollar Units

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

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

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

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

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

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

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

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

- Presentation and reporting of evaluation results within the business entity conducting the evaluation should not be construed as replacing guidelines for subsequent public disclosure under guidelines established by external regulatory and government agencies and any current or future associated accounting standards. Consequently, oil and gas reserves evaluations conducted for internal use may vary from that used for external reporting and disclosures due to variance between internal business planning assumptions and regulated external reporting requirements of governing agencies. Therefore, these internal evaluations may be modified to accommodate criteria imposed by regulatory agencies regarding external disclosures. For example, criteria may include a specific requirement that, if the recovery were confined to the technically Proved Reserves estimate, the constant case should still generate a positive cash flow at the externally stipulated discount rate. External reporting requirements may also specify alternative guidance on "current economic conditions."

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

7.4 Development and Analysis of Project Cash Flows

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

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

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

All affected annual terms above are expressed in applicable working interest (WI) portions are defined as follows:
NCF(t) = NCF,
REV(t) = revenue = annual production rate (t) times price (t),
ROY(t) = royalty payments = REV(t) times effective royalty rate (t),

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

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

- Calculation of annual net revenue (NREV):

$$NREV(t) = REV(t) - ROY(t) - PTAX(t) \quad (7.2a)$$

- Calculation of annual taxable income (TINC):

$$TINC(t) = NREV(t) - OPEX(t) - OH(t) - EXSI(t) - DD\&A(t) - OTAX(t) \quad (7.2b)$$

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

- Calculation of annual ITAX:

$$ITAX(t) = TINC(t) \cdot ITR(t) \quad (7.2c)$$

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

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

Although the generation of these annual project cash-flow components is straightforward, the accuracy of the estimates (magnitude and quality) is dependent on the property-specific input data and forecasting methods used (deterministic or probabilistic) and the expertise of and effective collaboration among the multidisciplinary valuation team members.

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

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

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

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

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

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

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

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

Total capital investment cost required for any process equipment (or plant with several units of equipment) is generally recognized under four categories (Clark and Lorenzoni 1978 and Humphreys and Katell 1981). *Direct costs include* all material and labor costs associated with a purchased physical plant or equipment and its installation. They include the costs of all material items that are directly incorporated in the plant itself as well as those bulk materials (such as foundation, piping, instrumentation, etc.) needed to complete the installation. *Indirect costs* represent the quantities and costs of items that do not become part of, but are necessary costs involved in, the design and construction of process equipment. Indirect costs are generally estimated as "percentage of direct costs." Indirect costs are further subcategorized as engineering, constructor's fee (covering administrative overhead and profit), field labor overhead (FLOH), miscellaneous others and owner's costs (such as land, organization, and startup costs). Engineering indirects include the costs for design and drafting, engineering and project management, procurement, process control, estimating and construction planning. FLOH includes costs of temporary construction consumables, construction equipment and tools, field supervision and payroll burden, etc. *Miscellaneous others* include freight costs, import duties, taxes, permit costs, royalty costs, insurance and sale of surplus materials. *Contingency* is included to allow for possible redesign and modification of equipment, escalated increases in equipment costs, increases in field labor costs, and delays encountered in startup. Finally, *working capital* is needed to meet the daily or weekly cost of labor, maintenance, and purchase, storage and inventory of field materials.

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

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

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

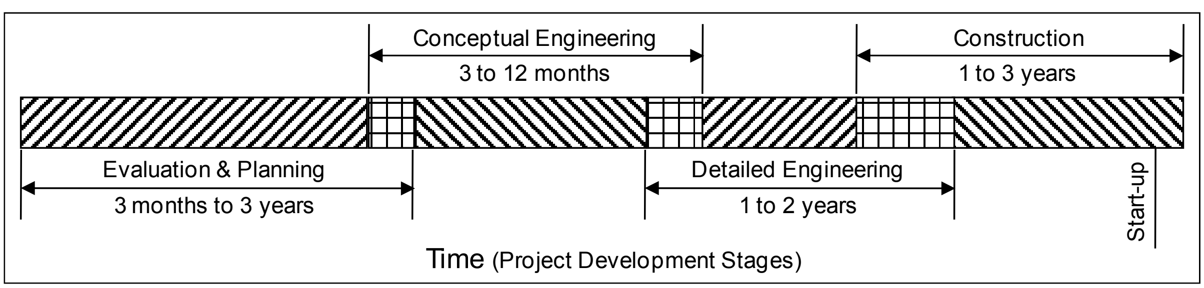

Fig. 7.1—Typical project phases [adapted from Clark and Lorenzoni (1978)].

Although they may be known or defined by different names, the American Association of Cost Engineers (Humphreys and Katell 1981) recommends three basic categories of project cost estimates according to detail and accuracy required by their intended use (during project phases illustrated in Fig. 7.1), which are approximately defined as follows:

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

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

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

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

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

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

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

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

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

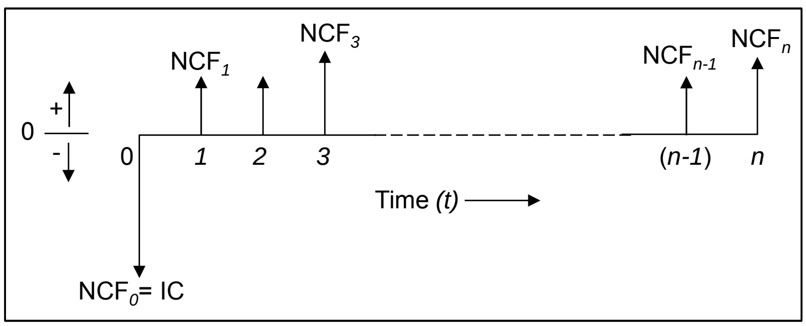

Fig. 7.2—A typical project net cash flow diagram.

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

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

and can also be rewritten in the following open form:

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

where

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

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

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

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

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

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

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

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

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

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

7.5 Application Example

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

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

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

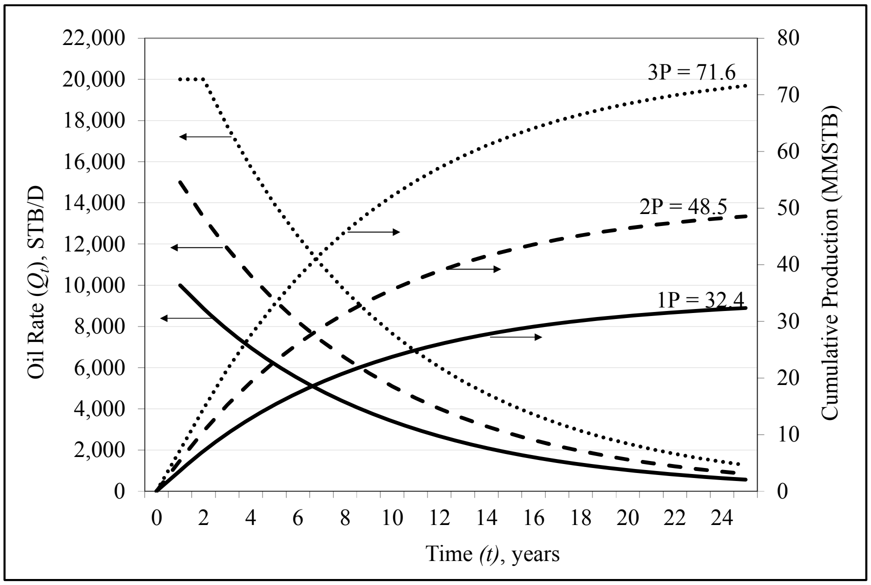

Fig. 7.3—Example Evaluation: Production rate profiles and reserves.

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

Table 7.2—Example Evaluation: Key Economic Parameters

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

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

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

Table 7.3—Example Evaluation: Basic Reserves and Cost Data

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

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

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

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

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

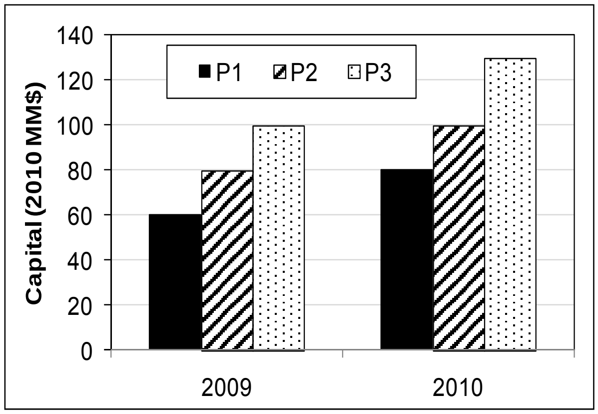

Fig. 7.4—Evaluation Example: Expenditure profiles of initial capital investment.

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

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

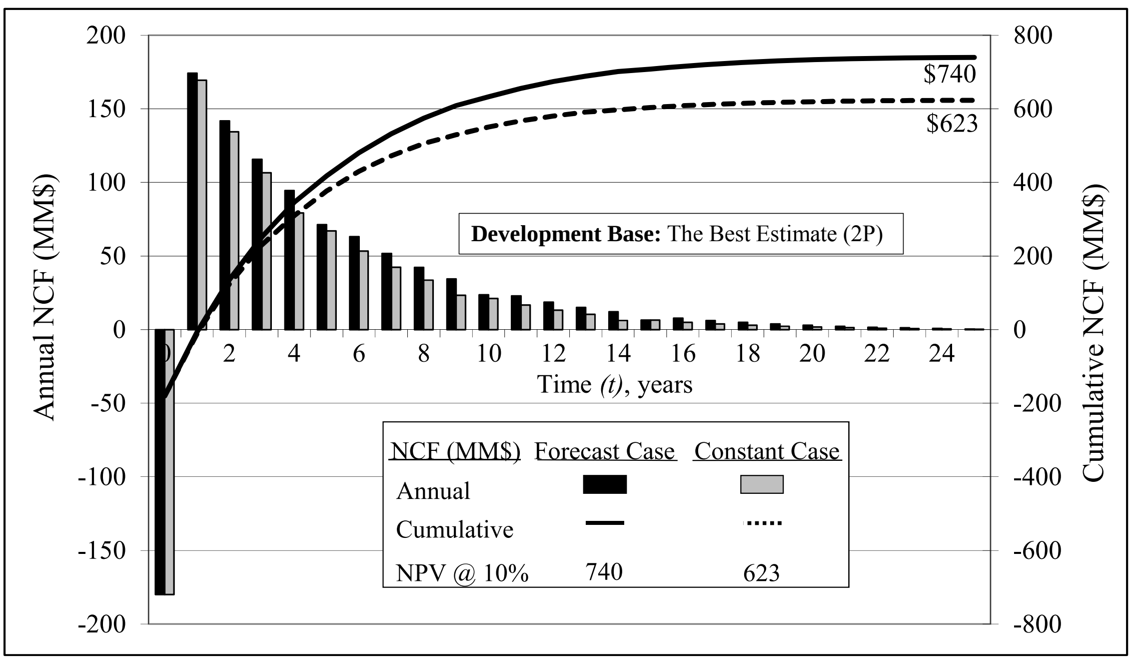

Fig. 7.5—Evaluation example using the best reserves estimate (2P): Discounted Net Cash Flow (NCF) projections (million $) at 10%.

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

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

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

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

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

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

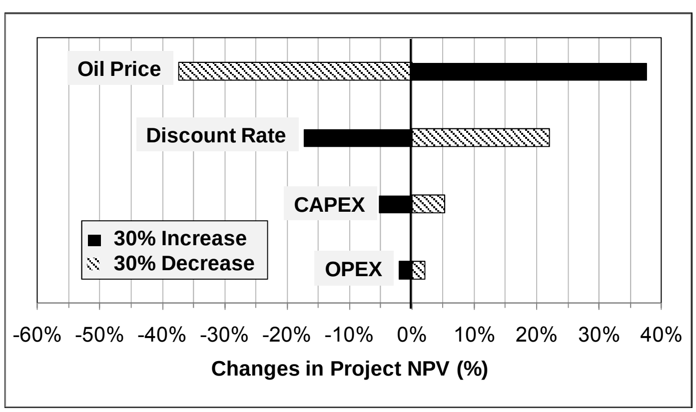

Fig. 7.6—Results of sensitivity analysis.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

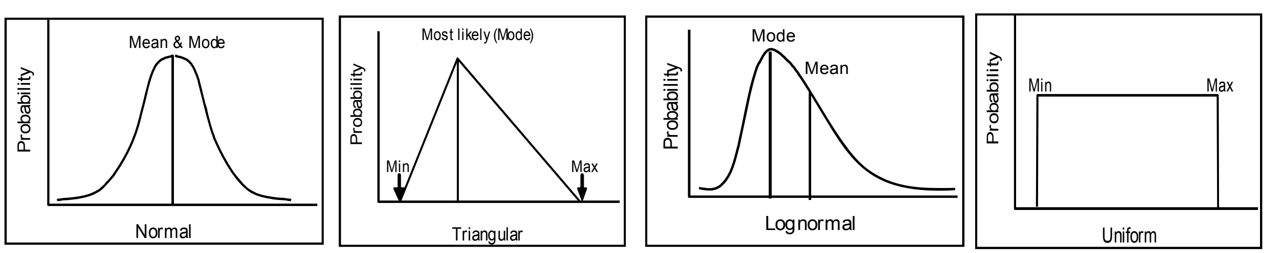

Fig. 7.7—Common probability distribution curves.

Selecting and using the probability distribution curve [or probability-density function (PDF)] appropriate for each random variable and accounting for other fixed input parameters in the cash-flow model (see Eqs. 7.3 and 7.6), MCS sampling technique randomly generates the estimates of project annual NCFs over the study period and the resulting single EMV at each trial. After hundreds or thousands of trials, it can generate the project NCF profiles representing different confidence bands, associated EMVs, and hence the resulting EMV profile (or profiles for other profitability measures as well). Results are usually presented in terms of both PDFs (approximately bell-shaped distribution curves) and ECs, as illustrated for the EMV profiles of the example evaluation project on the right side of **Fig. 7.8.**

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

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

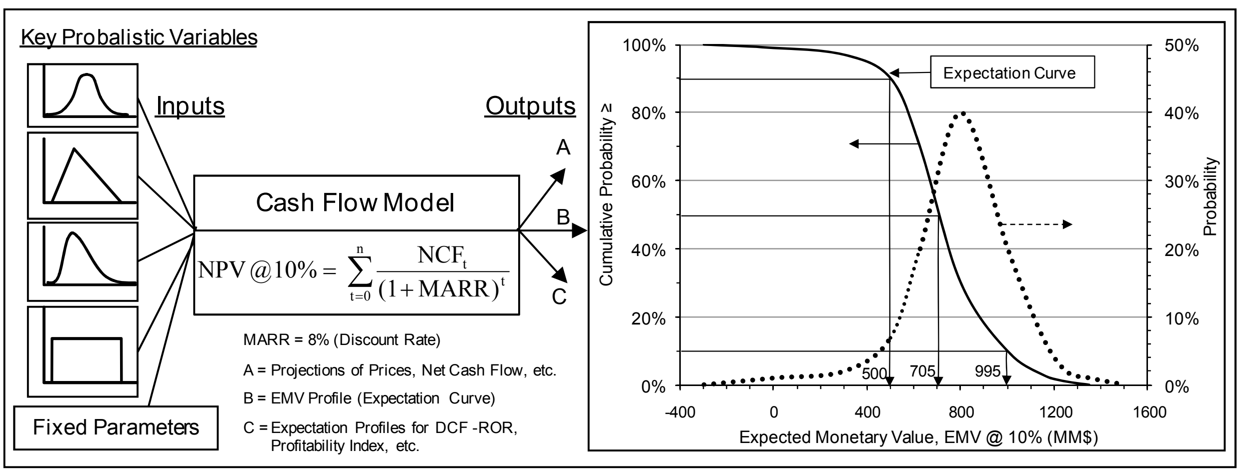

Fig. 7.8—Example evaluation: Project's EMV profiles generated by the MSC technique.

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