Chapter 4

Assessment of Petroleum Resources using Deterministic Procedures

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4.1 Introduction

This chapter provides additional guidance to the Petroleum Resources Management System (PRMS) § 4.1 and § 4.2 regarding the application of the three broad categories of deterministic analytical procedures for estimating the range of recoverable quantities of oil and gas. These categories are: analogy, volumetric analysis, and production performance analysis methods, which include material balance, reservoir simulation, decline curve analysis, and other techniques.

In the early days of a project's life when the project may not have advanced much beyond the development plan, modeling generally will be simple (such as through the use of analogs or volumetric analysis) and then gradually increase in complexity as the project matures. Depending on the scale of the investment, it is not uncommon to have advanced models available (even full-scale reservoir simulations) and ready at sanction. However, it is more common to see a progression of these models throughout the life of the project as the evaluating entity gathers more data and information about the reservoirs being produced. Once the project is fully mature, and only little further investment (financial and/or data acquisition) is anticipated, evaluators may use simpler models such as decline analysis, which rely mainly on the production performance of existing wells.

If the project is incremental (PRMS § 2.3.0.1) to an already existing project (with an existing resource recovery estimate already attached, often referred to as the base profile), it is important to evaluate the resources for the addition and the existing project together (to take into account effects such as interference amongst wells or back-pressure effect in the production facility) and to compare the resulting profile with the base profile. Sometimes an incremental project will accelerate the production of resources from the base profile, but the acceleration may be accompanied by a deceleration (relative to the base profile) at later time. This is generally a positive situation because it improves the economics, but only the added resources (difference between the total profile and the base profile) of the new project should be counted in the PRMS matrix when booking reserves and resources. Care must also be taken if incremental projects are booked as additive to a base profile/project because these projects may not be independent.

Simpler models used for estimation of resources during the early phases of a project (such as exploration, appraisal, and sometimes initial development periods) can be derived by estimating initially in-place volumes using static-data-based volumetric methods and the associated recovery efficiency derived from analog development projects, or by using analytical methods. As these models generally are not very detailed, their execution may require less computer power and will therefore be a relatively quick exercise. It is common to incorporate these early efforts into multiple models or scenarios, whether deterministic or probabilistic (please see Chapter 7—*Probabilistic Resources Estimation* for further details).

Once on production, resources (now likely to be classified as reserves) may be estimated using dynamic-data-based performance analysis (such as reservoir simulation or advanced material balance models).

The PRMS accepts two deterministic approaches to resource/reserves estimation: the "incremental" and the "scenario" (or "cumulative") methods (PRMS § 4.2.1.1). When both are applied to the same project, they should arrive at comparable results (PRMS § 2.2.2.11), especially when aggregated to the field level; they are simply different ways of thinking about the same problem.

In the incremental approach, more emphasis is placed on the experience and professional judgment of the evaluator in the estimation of discrete quantities to be assigned to each category (e.g., P1, P2, and P3 for incremental reserves). 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. This method works best when there is insignificant interference among the low, best, and high estimates.

In the scenario/cumulative approach, three separate analyses are prepared to bracket the uncertainty through sensitivity analysis (i.e., values estimated by three plausible sets of key input geoscience and engineering data parameters). These scenarios are designed to represent the low, best, and high realizations of original in-place volumes and associated recoverable petroleum quantities (PRMS § 2.2.1.4). Depending on the stage of commercial maturity, these scenarios underpin the PRMS categorization of Reserves (low, best, high or 1P, 2P, 3P) and Contingent Resources (low, best, high or 1C, 2C, 3C) of the projects applied to discovered petroleum accumulations or Prospective Resources (low, best, and high or 1U, 2U, 3U) of the undiscovered accumulations with petroleum potential.

The advantages of a deterministic approach are the following: It describes a specific case where physically inconsistent combinations of parameter values can be identified and removed (i.e., the specific combination of static and dynamic parameters must physically exist); it is easier to prepare; it is easier to audit; and the approach has a history of use with estimates that generally can be reliable and reproducible.

The guidance in this chapter is focused on the deterministic methods where the range of uncertainty is captured primarily using a scenario approach. The reader is referred to Chapter 7—*Probabilistic Resources Estimation*, herein, for guidance on applying probabilistic methods.

4.2 Project Life Cycle

Fig. 4.1 illustrates the range of uncertainty of estimated ultimate recovery (EUR) for any petroleum project, which is expected to decrease over time as the accumulation is discovered, appraised (or delineated), developed, and produced, with the degree of uncertainty normally decreasing at each stage. Once discovered, the length of each period depends on many factors, such as the size of the accumulation (which affects the duration of the appraisal and construction periods) and the development design capacity in terms of annual reservoir depletion rate. For example, projects with lower depletion rates will support a relatively longer plateau period followed by a longer decline period, and the opposite is also true. While the "best estimate" is conceptually illustrated as remaining constant, there may be significant volatility in this estimate in actual projects over the course of the field appraisal and development life cycle.

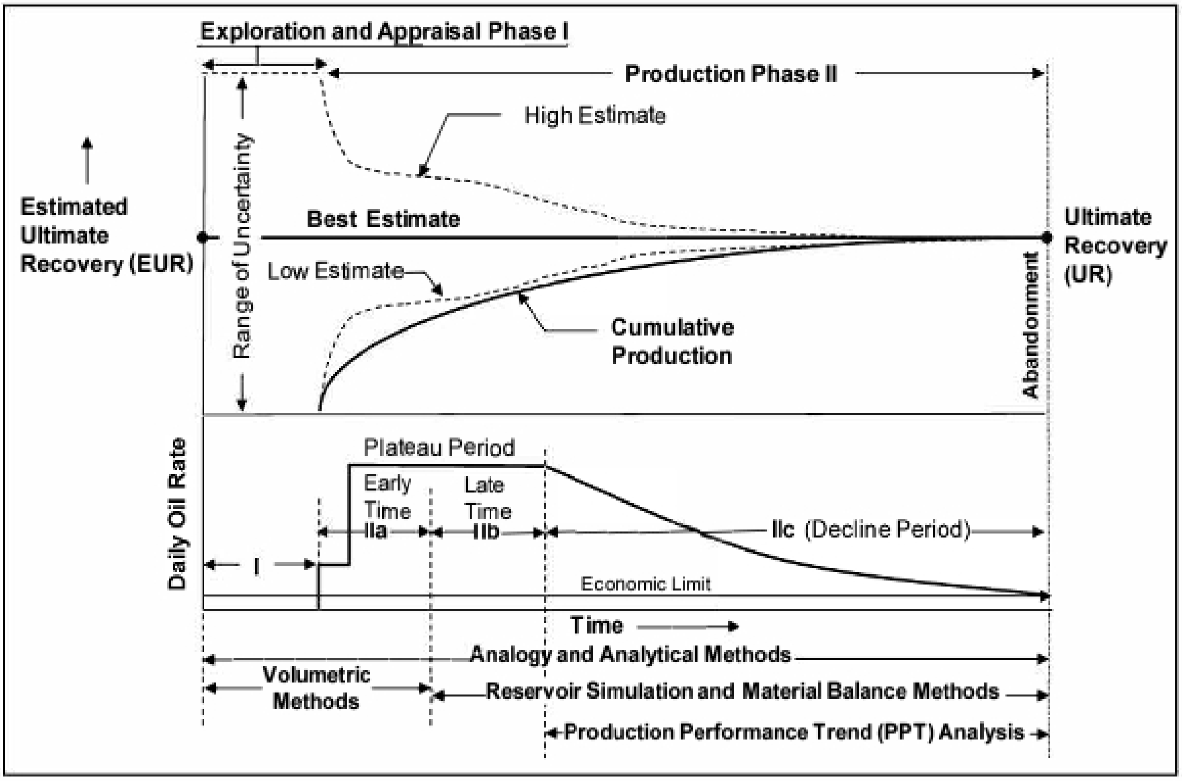

Fig. 4.1—Change in uncertainty and examples of assessment methods over the project's exploration and production life cycle.

The selection of the appropriate method with which to estimate reserves and resources changes for any petroleum recovery project over its life cycle, and the accuracy of estimates depend largely on the following factors:

- The type, quantity, and quality of geoscience, engineering, and economics data available and required for both technical and commercial analyses.
- Reservoir-specific geologic complexity, hydrocarbon type, recovery mechanism, stage of development, and maturity or degree of depletion. (For unconventional reservoirs, the reader is referred to Chapter 10—*Unconventional Resources Estimation* herein.)
- Partnership agreements—Many petroleum accumulations are developed by joint ventures, with one company conducting operations. While generally the operator will have a preferred modeling type/approach, and the other partners either may adapt to the operator or supplement provided estimates with their own independent work, it is good practice to have multiple model types to increase the reliability of the estimate. Other types of agreements may only address a shared cost with the operator, and in those cases, all evaluations are done independently of the other interest holders in the project.
- The anticipated size of investment (higher investment normally requires more initial work to reduce uncertainty, e.g., by applying more complex models).

Although certain estimation techniques are better suited to a particular stage in the project as per the application ranges indicated by the arrows at the bottom of Fig. 4.1, the reader should not consider the indicated limits as strict. The darker areas of the bars in **Fig. 4.2** generally conform to the stages at which each technique is most applicable.

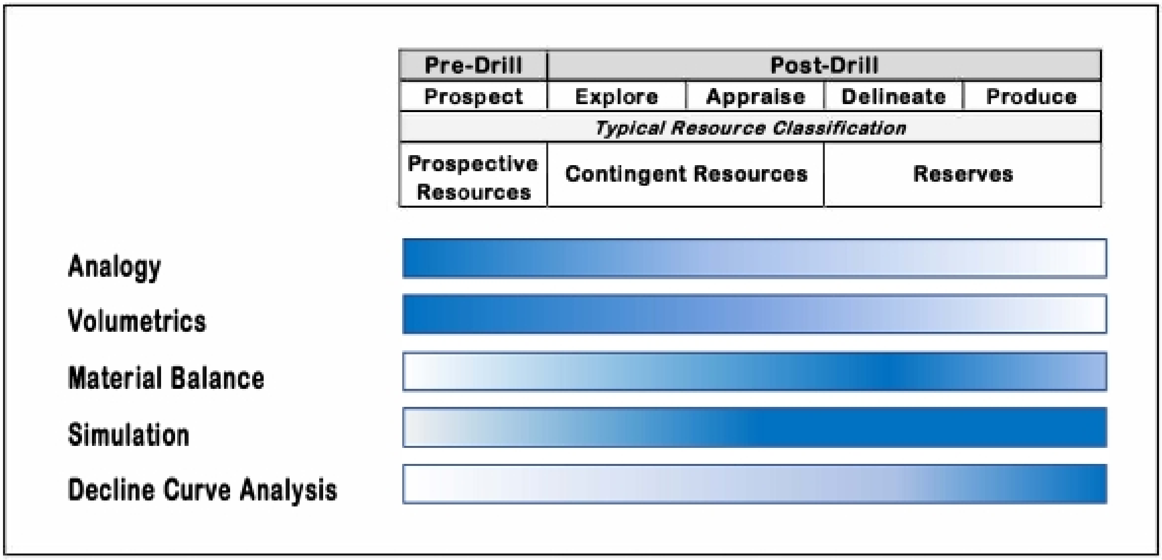

Fig. 4.2—Change in assessment methods over the project's exploration and production life cycle.

For example, simulation is most applicable in a project where sufficient data have been acquired to enable a history match of performance. However, a near-field prospect might already be covered by an existing geocellular model and have sufficient offset wells to provide meaningful input to the subject model. Likewise, a material balance approach is helpful in the initial stages to test scenarios, and it is also useful with postproduction data.

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) analyses (such as decline curve analysis) can be used not only to estimate directly the recoverable petroleum, but also to estimate the petroleum in-place quantities (by the first two methods only) and thereby provide a useful second check and validation of estimates obtained earlier by volumetric methods.

4.3 Analogy-Based Assessment

According to Hodgin and Harrell (2006, p. 2), an analog reservoir is one that is "at a more advanced stage of development than the reservoir of interest and thus may provide concepts or patterns to assist in the interpretation of more limited data." The PRMS added further emphasis when evaluating analogs to incorporate the development plan elements, which are often a material consideration in the resultant applicability of the proposed analogous reservoir(s).

Although there are several suggestions in the literature as to how an analog should compare with the reservoir in question, the suitability of the analog fundamentally depends on the purpose of comparison. The PRMS allows some flexibility in the choice of the analog, but certain fundamentals must be considered.

The evaluator should start by considering four aspects: the depositional environment, the fluid type, the reservoir drive mechanism, and the development type. Should any of these factors be materially different between the subject reservoir and the proposed analog, it is highly likely that the analogy will be poor. Once these four aspects have been considered, the remainder of the aspects (PRMS § 4.1.1.2) can be reviewed in detail.

Subsequently, the petrophysical properties (termed as the "familiar six" by Sidle and Lee 2010) should be considered explicitly: porosity, permeability, permeability distribution, net thickness, continuity, and hydrocarbon saturation.

In certain resource classifications, additional mandatory requirements for the analog are stipulated, as described below.

Note that, apart from certain exceptions pointed out below, the analog reservoir does not need to be in the same geographic area as the subject reservoir, nor should geographic proximity be the foremost consideration in assigning analogy (PRMS § 4.1.1.5).

4.3.1 Purpose of Analogs. Fundamentally, there are two reasons why analogs are used in resource management: classification of resources and estimation of resources. The former typically has more stringent expectations of the analog than the latter.

4.3.1.1 Classification of Resources. The PRMS system explicitly references four situations where analogs may be used to justify classification in a given resource class:

- Economic producibility without a flow test (PRMS Table 1: Reserves): In this situation, the analogous reservoir should be in the same area.
- Applicability of workover, treatment, and changes of equipment (PRMS § 2.3.1.1): Incremental recovery from such treatments may be classified dependent on analogous reservoirs.
- Improved recovery (PRMS § 2.3.4.3): Commerciality may be justified based on a reservoir with analogous rock and fluid properties where a similar improved recovery project has been successfully applied.
- Unconventional Contingent Resources without a flow test (PRMS § 2.4.0.4): In this situation, log and core data and nearby producing analogs provide evidence of potential economic viability.

4.3.1.2 Estimation of Resources. The extent to which analogs are used in the estimation of resources will depend largely on the maturity of the project in question. For Prospective Resources or predevelopment Contingent Resources, there will be limited information on the reservoir in question, so some fundamental questions will need to be answered with the help of analogs, perhaps in combination with other analytical methods, including:

- Recovery efficiencies (primary/secondary/tertiary)
- Production rates and profiles
- EUR/well
- Reserves life index (defined as reserves divided by average or current production rate)

As the project becomes more mature, it is likely that alternative analytical techniques will be used, but analogs still may be necessary to fill in the blanks, at least prior to establishing meaningful production trends.

Note that the estimation of a resource quantity may well impact the resource classification (e.g., a review of the profile or EUR/well might indicate questionable commerciality).

4.3.2 Methodology for the Application of Analogy. The procedure for using analogy should be applied in a consistent, rigorous manner [the following is modified from Hodgin and Harrell (2006)]:

1. Determine the purpose of the analog and explicitly define the parameters that will impact the validity of the analog. For resource classification, there may be some mandatory parameter requirements.
2. Identify multiple analogs and compare the results with reference to the input parameters. As described by Sidle and Lee (2010), should there be any outliers in terms of performance, they need to be fully understood before progressing.

3. Evaluate the subject reservoir in light of the analog. In general, the subject reservoir should be better than the analog reservoir, at least "in the aggregate" for recognizing Proved Reserves. For example, for economic producibility, the porosity of the analog reservoir may be better than the subject reservoir, but a more germane test would be the reservoir transmissivity (Kh/μ, where Kh is horizontal conductivity, and μ is viscosity), which should be better in the subject reservoir than in the analog reservoir.
4. Establish the proof of analogy under the relevant Reserves definitions to a mature reservoir and recovery process.

The analog normally will help to generate the best estimate, or 2P, but it will inform the 1P and 3P estimates too. If there are any weaknesses in the analog, this should give the evaluator thought to widen the resource range. Such examples could be:

- Few applicable analogs
- Analogs with one or more parameters better than the subject reservoir
- Large range of "output values" (e.g., EUR/well) among the analogs
- A difference in scale between the analogs and the subject reservoir (e.g., small subject reservoir, large analog reservoirs)

The *Canadian Oil and Gas Evaluation Handbook* [Society of Petroleum Evaluation Engineers (Calgary Chapter) 2019] gives some useful advice on certain specific reserves parameters (*Canadian Oil and Gas Evaluation Handbook* § 6.4.4.2). On areal assignments, when the analog is being used to estimate the areal extent, it should be noted if progressively smaller pools are encountered in a mature area, so the subject area should be reviewed on a regional basis. On recovery factors, key elements such as abandonment pressures and fluid displacement efficiencies must be considered, but the *Canadian Oil and Gas Evaluation Handbook* suggests that geographic proximity, while desirable, is not essential. On performance characteristics, analogs can help greatly, not only on the explicit decline, but also to understand the reservoir engineering aspects such as water loading of gas wells in the future.

4.3.3 Application of Analogy to an Oil Example. Consider the case of a small offshore oil discovery in a mature province with two appraisal wells in the reservoir. No core has been taken, and no flow test has been conducted. The evaluator would like to estimate the recovery efficiency (RE). It is assumed the development will be a subsea tieback to a host platform operated by a third party. Gas lift will be supplied by the host platform.

The first question to be answered is whether there is an active aquifer or not. Absent a well test, it will be necessary to use analogs. Using the methodology outlined above, the following steps should be taken:

1. The purpose of the analog is to determine whether a natural aquifer will provide adequate pressure support and thereby a reasonable RE, without recourse to the use of injection wells. The analog will only be valid if it is in the same geological setting in the same reservoir and it has similar petrophysical parameters, the same development scheme, and similar fluid types. Given that a natural aquifer waterflood is the primary recovery method, there are no additional requirements in the use of analogs for resource classification.
2. Next, it will be necessary to gather multiple analogs by relying on internal, commercial, regulatory, or other public data. Assuming there have been multiple developments in the geological setting, how many developments have relied on natural aquifer support, and how many have required injection wells? Have any of the analogs run into difficulty from

a recovery point of view? If there are any fields that are outliers (either they chose water injection wells or relied on natural aquifer waterflood and ran into problems), then these need to be understood in detail before progressing.

3. Assuming for this example that the natural aquifer is the norm in the geological setting, that any outliers can be explained as being not relevant, and that the regional fields are true analogs, then it will be necessary to compare petrophysical parameters between the analog(s) and subject reservoir. This may be problematic if the regional analog data are not public. In this instance, it may be necessary to cast the net wider using analog data away from the regional area.
4. Following this process, other key questions must be answered using analogs, including economic producibility, production rates, production trends, etc. A test against the Reserves definitions must be made at this point.

Starting with the first two points, several analogs are gathered, concentrating on aspects that would impact the aquifer support. **Table 4.1** outlines the relevant parameters from analogs with aquifers. Note that "overpressure" can indicate limited geological extent. Analog reservoirs are also chosen based on magnitude/ranges of measurable reservoir factors such as permeability, porosity, transmissivity, etc., as indicated earlier in this section.

	Reservoir				
	Deposition	Type	Quality	Extent	Overpressure
Subject	Deepwater marine	Turbidite	Excellent	Continuous	None
Analog A	Deepwater marine	Turbidite	Excellent	Continuous	None
Analog B	Shallow marine	Sheet deposits	Excellent	Limited	None
Analog C	Deepwater marine	Turbidite channels	Excellent - fair	Channelized	None
Analog D	Shallow marine	Tidal channels	Good - fair	Channelized	None
Analog E	Shallow marine / deltaic	Elongate / lobate	Excellent - fair	Continuous	None
Analog F	Shelf marine	Shelf deposits	Good	Limited	Significant

	Faulting			Aquifer		
	Density	Throw	Seal	Strength	Size	Support
Subject	Limited	Sub-seismic	Unknown	Unknown	Unknown	Unknown
Analog A	Limited	Sub-seismic	None	Excellent	Large	Excellent
Analog B	Limited	Sub-seismic	None	Fair	Fair	Fair
Analog C	Significant	10 m max	None	Good	Large	Good
Analog D	Limited	Sub-seismic	None	Good	Large	Good
Analog E	Some	20 m max	Sealing	Poor	Large	Poor
Analog F	Limited	Sub-seismic	Baffle	Good	Fair	Fair

Table 4.1—Example analog parameters for aquifer support.

The next step is to interrogate the data, identify any outliers, and determine whether they are relevant to the subject reservoir. In the example above, the only reservoir with poor aquifer support (Analog E) is one with seismically identifiable fault throws, which we know is not the case in our reservoir. However, there are two reservoirs (Analogs B and F) with fair support, but with limited sand extent (identifiable through regional correlations).

In this instance, there is no strong evidence against good aquifer support, but the analogs are few, and there are significant differences between the analog reservoir and the subject reservoir. It is suggested that the evaluator assume a low case scenario, which has "fair" aquifer support, while the best estimate is based on "good" aquifer support.

The analyst must employ their judgement to consider two options, either: to plan for injection wells to be included in the low case, with a similar RE to the best case but with significantly more capital expenditure, or to assume a reduced RE for the low case and add a new, separate project for incremental resources attributable to water injection in the event of finding poor aquifer support.

In this example, Analog B could be a good candidate for the low case scenario (based on the fair aquifer support and fair aquifer size rationale; Analog E has poor support but a large aquifer size, plus some seismically identifiable faults); Analog C could be a good analog for the best case scenario (choice based also on the aquifer support rationale, as well as on the reservoir characteristics); and Analog A could be used for the high case scenario (based on analogy of reservoir characteristics associated with excellent aquifer support).

4.4 Volumetric Analysis

Volumetric analysis, as described in the PRMS § 4.1.2.1, "uses reservoir rock and fluid properties to calculate PIIP [petroleum initially in place] and then estimate that portion that will be recovered by a specific development project." Volumetric analysis is the most widely used technique for early stage developments, but there can be many pitfalls associated with its use.

It is essential to consider the range of uncertainty throughout the estimation process, whether via deterministic or probabilistic methods. Within deterministic procedures, it is normal practice to consider low, best, and high estimates, but it is also advisable to consider alternative scenarios, particularly for the fundamental assumptions, including horizon interpretation, velocity modelling, structural interpretation, depositional environment, and geological unit correlation.

Consider the well and reservoir schematics in **Fig. 4.3** below. Without additional data, such as a detailed sequence stratigraphic model, there are numerous possibilities for correlation of the flow units.

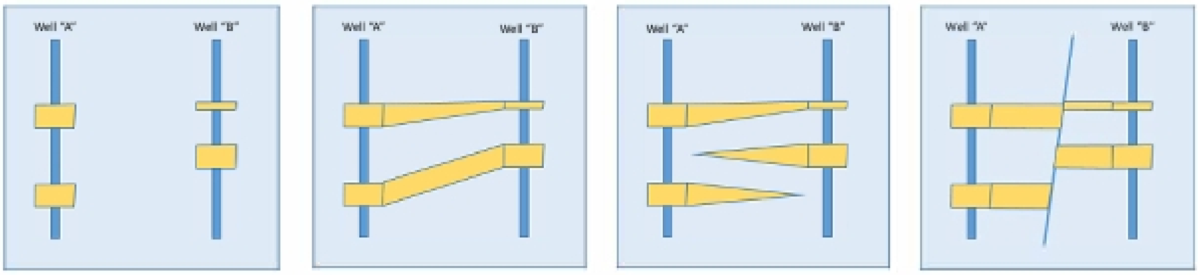

Fig. 4.3—Example of interwell correlation uncertainty.

The issue of reservoir continuity is a major concern in the volumetric estimation of petroleum initially in place (PIIP). Geologic understanding of the depositional environment(s) and the use of pressure and fluid data are key factors in the establishment of reservoir continuity or compartmentalization. A field example of how correlations can change as more data are acquired was discussed in Ray et al. (2010). In this field, a change in correlation following initial development drilling moved a significant portion of the PIIP from a lower-quality unit to a higher-quality unit, thereby dramatically increasing reserves and resources.

The general volumetric equation may be expressed in terms of EUR by:

EUR (STB or scf) = PIIP (STB or scf) × RE (fraction of PIIP), ... (4.1a) dependent upon average values for area (A), net pay (h), porosity (ϕ), initial water saturation (S_{wi}), and initial hydrocarbon formation volume factor (B_{hi}) for oil (RB/STB) or gas (Rcf/scf), where R indicates reservoir conditions. The generalized classic volumetric equation for the PIIP [oil initially in place (OIIP) or gas initially in place (GIIP)] is given by:

PIIP (STB or scf) = $Ah\phi(1 - S_{wi})/B_{hi}$,..(4.1b)

where oil or gas volumes are in barrels or cubic feet, abbreviated as STB and RB or scf and Rcf, respectively, representing the measurements at standard surface and reservoir conditions, based on prevailing pressure and temperature standards.

4.4.1 Estimating Volumetric Parameters. Volumetric analysis should be generated by an integrated technical team, including geoscience, reservoir and production engineering, and facilities/process engineering. The first step is to quantify the static parameters, followed by an assessment of the RE based on dynamic parameters. The RE is also a function of the anticipated depletion strategy, and it can be either calculated or supported through the use of analogs.

4.4.1.1 Static Parameters. The gross rock volume is often the parameter with the greatest uncertainty, and it must be explicitly defined. An area-depth map, whether generated traditionally or as an output from geocellular models, is an excellent tool for estimating gross rock volume ranges. The interpreter should consider alternative horizon and fault picks from seismic data as well as alternative velocity modelling if there is any doubt in these areas. For regions of dense well control, this will be less of an issue.

Other static parameters (porosity, net-to-gross ratio, hydrocarbon saturation) can then be estimated from available data and/or supplemented by analogs. It is advisable, however, that thought be given to the depositional setting, since a mathematical average of the wells may not be appropriate in channelized systems, for example. Similarly, parameters may degrade further from the sedimentological source, or they may degrade with greater depth due to diagenesis.

Geological conceptual models capturing the deposition of the sand bodies, particularly when there are multiple/stacked sands, should be created. The way in which each sand body connects to another (laterally and possibly vertically) will be critical in understanding PIIP and RE. Unless the region is very well understood and shows strong correlation throughout, or if there are unambiguous geological or geochemical markers, then it is expected that the sand correlation will be nonunique and should be explicitly considered as an uncertainty. In addition to depositional reservoir architecture, faulting within the field must also be considered because it will similarly have an impact on RE as well as resource category.

Care must be exercised with the estimation of hydrocarbon phase contacts. Pressure gradient measurements yield invaluable information, but all possibilities must be considered outside of well control. For example, the existence of a thin oil rim may not be encountered with initial drilling, yet it might make a significant impact on the development scheme, investment scope, and ultimate recovery. A gas cap above the highest known oil is also possible, although the degree of undersaturation should provide an indication of the potential for a gas cap. It should also be recognized that the quality (i.e., representativeness) of the pressure-volume-temperature data is paramount in establishing appropriate hypotheses. Representative pressure-volume-temperature data are required for dynamic simulation and material balance calculations as well as for volumetric estimates, which are dependent upon accurate formation volume factors for PIIP assessment, considering the surface separation conditions.

Attention should also be paid to petrophysical cutoffs. Not all the microscopic hydrocarbon pore space will contribute, and it is important for PIIP and RE to be calculated on the same basis. There are arguments for and against using cutoffs, but this question should be explicitly considered. Further discussion on petrophysical cutoffs may be found in Chapter 5—*Petrophysics* herein.

4.4.1.2 Dynamic Parameters. It is useful to break down RE into its component parts as discussed in the subsections below and suggested by Smalley et al. (2009). The aim of their paper was to maximize efficiency for a producing field, but it is also useful in early estimates.

- Pore-Scale Displacement Efficiency: This refers to the microscopic (displacement) efficiency of the reservoir, and it also serves as the maximum theoretical RE obtainable under waterflood. For example, microscopic RE for a waterdrive oil reservoir may be given by:

$$RE_{\mu} = \frac{1 - S_{wi} - S_{or}}{1 - S_{wi}}, \quad (4.2)$$

where:

RE_{μ} = microscopic RE of oil, fraction
S_{wi} = initial water saturation, fraction
S_{or} = residual oil saturation, fraction.

Rough estimates for the fluid saturations can be made through initial core and log measurements or through judiciously chosen analogs. This displacement is a function of rock-fluid and fluid-fluid interaction properties, such as wettability, fluid mobility, relative permeability, and capillary pressure. In some textbooks, RE_{μ} is referred to as "displacement efficiency" with the symbol E_D.

- Areal Sweep Efficiency: This refers to the areal connectedness of the producing well; i.e., the producing well may not be connected to other parts of the reservoir as a result of faulting or the fact that the various sands are not stratigraphically connected. Smalley et al. (2009) referred to this as "drainage efficiency." Thought should be given to the depositional environment (sand continuity, sand consistency, net-to-gross ratio), the mobilities of the fluids, and the degree of faulting seen at seismic and core scale.

For early stage estimates, analog EUR/well gives a very good sense that drainage efficiency has been appropriately considered. Some textbooks give areal sweep efficiency the symbol E_A.

- Vertical Sweep Efficiency: Vertical sweep efficiency concerns the fraction of the vertical section of the reservoir actually contacted by displacing fluid(s). This parameter is also affected by fluid mobilities, in addition to vertical heterogeneity, any gravity segregation forces, the quantity of injected fluid(s) if any, and so on. In some textbooks, vertical sweep efficiency is denoted by the symbol E_V.
- Volumetric Sweep Efficiency: In the literature, volumetric sweep efficiency is the product of vertical and horizontal sweep efficiencies, and it represents the percentage of the oil that is moved to the producing wells within the drained area. This would be a low number for depletion-drive reservoirs and a higher number for waterdrive reservoirs.

4.4.1.3 Recovery Efficiency. The total RE, often referred to by the symbol E_R, is the multiplicative product of the microscopic displacement and volumetric sweep efficiencies or:

$$E_R = E_D \times E_A \times E_V. \quad (4.3)$$

As mentioned previously, RE may be calculated, although it is acknowledged that this estimate is inferior to RE determined from actual, lengthy, and reliable performance data. It must be stressed that RE is a function of many parameters, such as the reservoir drive mechanism, any improved oil recovery applications, the rock and fluid properties (e.g., wettability, relative permeability, etc.), "complex situations" (discussed later), development characteristics, and even the project economics.

For example, within the industry, there are empirical RE formulae generated "in-house" by larger producing companies based on the reservoirs developed and producing by the company. These REs are typically predicated on the study of RE performed by the American Petroleum Institute in 1967 (American Petroleum Institute Subcommittee on Recovery Efficiency 1967; Arps 1968) and are expressed in the following form:

$$RE = A \times \left\{\frac{\phi(1-S_w)}{B_{oi}}\right\}^B \times \left(\frac{k\mu_{wi}}{\mu_{oi}}\right)^C \times (S_w)^D \times \left(\frac{p_i}{p_a}\right)^E, \quad (4.4)$$

where:

RE = RE of oil, fraction
A, B, C, D, E = displacement-dependent coefficients **(see Table 4.2)**
ϕ = effective porosity, fraction
S_w = initial water saturation, fraction
B_{oi} = initial oil formation volume factor, reservoir barrels per stock tank barrel (= bubblepoint formation volume factor for solution gas drive reservoirs without primary gas cap)
k = arithmetic average of absolute permeability, Darcies
μ_{wi} = initial water viscosity, centipoise (= 1 for solution gas drive)
μ_{oi} = initial oil viscosity, centipoise (= μ_{ob} for solution gas drive at bubblepoint pressure)
p_i = initial reservoir pressure, psig (= bubblepoint pressure for solution gas drive)
p_a = abandonment reservoir pressure, psig.

Drive Mechanism	A	B	C	D	E
Solution gas	0.41815	0.1611	0.0979	0.3722	0.1741
Waterdrive	0.54898	0.0422	0.077	- 0.1903	- 0.2159

Table 4.2—Recovery efficiency displacement-dependent coefficients.

"Complex situations" may include reservoirs that are nonvolumetric, stratified, fractured, or overpressured, those characterized by thin oil rims with large gas caps and/or underlying aquifers, dual-porosity/dual-permeability reservoirs, and so on. The fundamental equation above was not formulated using examples of such reservoirs.

The reader should also be aware that the API (API 1984, p. 6) followed up the 1967 study with a statistical review cautioning "against continued use of the (1967) correlations…to predict recovery or recovery efficiency for any one reservoir." Nevertheless, the 1967 equations are widely used still, with local or company-specific variation as noted.

There are a number of other RE correlations available in practice, such as that developed by Guthrie and Greenberger (1955), formulated as

$$RE = 0.272\log(k) + 0.256(S_w) - 0.136\log(\mu_o) - 1.538(\phi) - 0.00035(h) + 0.114, \quad (4.5)$$

where k is in millidarcies (md), but all other parameters are in the same units as in Eq. 4.4. This correlation was developed for waterdrive sandstone reservoirs specifically. The use of recovery factor correlations is cautioned, because they were developed for specific conditions with limited databases using values for the key parameters that are subject to uncertainty.

Finally, several published empirical correlations that can be used to estimate RE can be found in Cronquist (2001), Walsh and Lake (2003), and Craig (1971). However, it should be emphasized that even a rough estimate of RE from a near-analog or a value determined by using a physically based analytical method is preferable to using empirical correlations.

4.4.2 Application of Volumetrics to Oil Example. Let us consider the same example as presented previously (Section 4.3.3), consisting of an offshore oil discovery with two appraisal wells. The most usual method for determination of resources at this stage of development would be through a combination of volumetrics and analogs, although a simple material balance model might also be appropriate.

For the volumetric analysis, the first step is to establish the parameters that should be included to define the range of PIIP and technically recoverable resources. A common mistake is to make the assumption that the uncertainty range is limited to traditional parameters such as gross rock volume, porosity, and the like, whereas more fundamental questions such as depositional environment, reservoir correlation, top structure pick, and velocity model should be explicitly considered.

Some example parameters are shown below in **Table 4.3** for our offshore oil example. Note that there is a mix of static and dynamic parameters. The evaluator assumes that, while the horizon interpretation is unambiguous (hence a single interpretation), the velocity model is highly uncertain, and there are three possible scenarios or characteristics. These scenarios will be used in defining the low, best, and high estimate cases.

		Scenarios		
Parameter	Uncertainty Aspect	Low	Mid	High
Depositional environment	Regionally understood	Shallow marine / deltaic	Shallow marine	Shallow marine
Correlation	Two geological models	Correlation style "A"	Correlation style "A"	Correlation style "B"
Horizon interpretation	Unambiguous	Interpretation 1	Interpretation 1	Interpretation 1
Velocity model	Significant uncertainty	Methodology 1	Methodology 2	Methodology 3
Compartmentalization	Low uncertainty	Central fault sealing	Central fault baffle	Central fault open
Phase contacts	Significant uncertainty	Oil-water contact = Oil-Down-To	Oil-water contact between Oil-Down-To position and spill	Oil-water contact at spill point

Table 4.3—Fundamental uncertainty parameter table.

Next, a standard volumetric calculation is performed. The two key elements in **Table 4.4** below that will have the most impact in the static calculation are the velocity model, which generates differing top structure maps, and the treatment of the contact or lowest known hydrocarbon (LKH). The column "low/best" highlights the relative difference between input parameters. (Since this is an oil reservoir, the term OIIP has been used in place of PIIP. GRV is gross rock volume, NTG is net to gross, S_o is oil saturation, and B_o is oil formation volume factor.)

Parameter	Units	Source	Scenarios Low	Best	High	Low/Best
GRV (spill)	MMRB	Velocity model 1	550	887	1,842	62%
GRV (intermediate)	MMRB	Velocity model 2	413	665	1,107	62%
GRV (LKH)	MMRB	Velocity model 3	275	444	739	62%
NTG	fraction	Analogs	0.80	0.89	0.97	90%
Porosity	fraction	Analogs	0.27	0.29	0.31	93%
S_o	fraction	Analogs	0.81	0.85	0.91	95%
B_o	rb/STB	Analogs	1.07	1.10	1.16	97%
OIIP	MMSTB		45.0	132.7	434.6	34%

Table 4.4—Example volumetric calculation: static parameters, where MM indicates million.

The dynamic aspects are considered next. Again, the two key uncertainties in **Table 4.5** below are correlation style (the degree of compartmentalization), which will affect the connectedness, and the treatment of the faulting.

Recovery Efficiency			Scenarios			
Parameter	**Units**	**Source**	**Low**	**Best**	**High**	**Low/Best**
Pore/micro	%	Inputs from analogs	75%	76%	78%	98%
Drainage (open)	%	Correlation	80%	85%	93%	94%
Drainage (baffle)	%	Correlation	78%	83%	91%	94%
Drainage (sealing)	%	Correlation	70%	75%	83%	93%
Sweep	%	Range from analogs	53%	62%	71%	85%
Overall	%	Range from analogs	28%	39%	52%	71%
Tech resource	MMSTB		12.6	52.2	223.8	24%

Table 4.5—Example volumetric calculation: dynamic parameters, where MM indicates million.

Note that the parameters that have the biggest influence are the fundamentals in the table (such as the velocity model and the correlation) rather than the individual petrophysical parameters.

For the example above, the overall low case is a simple product of all the low input variables, for clarity of the procedure only. In reality, the analyst should consider the combinations of parameters that would represent a reasonable low case.

4.5 Performance-Based Methods

Performance-based methods include material balance, reservoir simulation, and PPT analysis. PPT analyses are commonly used methods to directly estimate the technically recoverable resources for oil and gas wells, reservoirs, and specific development (or recovery) projects. PPT analyses are traditionally known as decline curve analyses (DCAs) but may also be considered to include techniques that have found acceptance in unconventional resources assessment, such as rate transient analysis and production decline analysis. (The reader is referred to Chapter 10—*Unconventional Resources Estimation*, herein.) The theory behind traditional DCA was crystallized in 1945 by Arps (1945), and it still remains one of the most prevalent and dependable methods for production forecasting today, under specified flow conditions.

Historical production performance trends observed in mature wells, reservoirs, or projects may generally be extrapolated to the cumulative production at the economic limit, and this will provide a reasonable assessment of the technically recoverable resources when lift type and well design are also considered.

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 resulting reserves estimates for the asset under study:

- Production conditions, methods, and the overall production strategy are not changed significantly over the projected remaining producing life.
- The reservoir has been fully developed, and the well count is relatively stable. There is no new project that may change the behavior of the reservoir.
- Wellbore interventions and other remedial work can be classified solely as maintenance.

This also implies that the evaluator will have sufficient reliable production data for the analysis, and that the production for all phases, including oil, gas, condensate, and water, is well established, with an emphasis on understanding water breakthrough maturity when an active waterdrive is present.

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

4.5.1 Material Balance. Material balance data include production and injection history, volume-weighted average reservoir pressures, and reservoir-specific relevant fluid and rock properties, all as a function of reservoir pressure and temperature. Independent of the volumetric methods, the material balance methods can be used to directly and simultaneously estimate in-place volumes, the relative size of a gas cap, and/or the water entering the reservoir through influx or injection.

The results of material balance analysis are considered more reliable when longer performance histories, high-quality production data, and high-quality stabilized reservoir pressures are used. A well-established and reasonable assumption is that use of the material balance analysis to estimate in-place volumes is often considered valid if the cumulative production exceeds 10% of the original in-place volume {Cronquist 2001, 30; or *Canadian Oil and Gas Evaluation Handbook* § 2.9 [Society of Petroleum Evaluation Engineers (Calgary Chapter) 2019]}, provided the development of the accumulation is such that the pressures used in the analysis represent an average over the entire reservoir. Uncertainty in the estimate is expected to decrease over time as historical production performance data cover at least the early production period (shown in Fig. 4.1 as IIa) and beyond. A material balance analysis using all available data and information typically should result in a best estimate of the in-place volume.

Technical principles and definition of the terms involved in developing the conventional material balance equation (MBE) applicable to any oil or 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 main difference between a flowing material balance and a classic static material balance lies in the source of the pressure data. The flowing material balance uses flowing pressures to estimate in-place volumes instead of buildup or other static pressure measurements. One significant benefit to the flowing material balance is that, so long as the data are of sufficient quality and frequency, it is not necessary to shut in well or field production in order to obtain a good estimate of gas initially in-place (GIIP). While the flowing material balance technique is more computationally intensive, the methodology is generally intuitive to someone accustomed to classical material balance analysis.

A general discussion of the use of material balance methods follows, but more detail on special topics is provided in Appendix A to this chapter.

4.5.1.1 Technical Principles of Oil Material Balance. *The* general MBE is commonly expressed as:

$$N = \frac{N_p\left[B_o+(R_p-R_s)B_g\right]-(W_e-W_pB_w)-G_{\text{inj}}B_{g\text{inj}}-W_{\text{inj}}B_{wi}}{(B_o-B_{oi})+(R_{si}-R_s)B_g+mB_{oi}\left[\frac{B_g}{B_{gi}}-1\right]+B_{oi}(1+m)\left[\frac{S_{wi}c_w+c_f}{1-S_{wi}}\right]\Delta p}, \quad (4.6)$$

where

N = initial oil in-place, STB
N_p = cumulative oil produced, STB
B_o = oil formation volume factor at current reservoir pressure, RB/STB
R_p = cumulative produced gas-oil ratio, scf/STB
R_s = current solution gas-oil ratio, scf/STB
B_g = current gas formation volume factor, RB/scf
W_e = cumulative water influx, RB
W_p = cumulative water produced, STB
B_w = water formation volume factor, RB/STB
G_{inj} = cumulative gas injected, scf
$B_{g\text{inj}}$ = gas formation volume factor of the injected gas, RB/scf
W_{inj} = cumulative water injected, STB
B_{wi} = injected water formation volume factor, RB/STB
B_{oi} = oil formation volume factor at initial reservoir pressure p_i, RB/STB
R_{si} = gas solubility at initial pressure p_i, scf/STB
m = ratio of gas-cap gas volume to oil volume, RB/RB
B_{gi} = gas formation volume factor at p_i, RB/scf
S_{wi} = initial water saturation, fraction
c_w = water compressibility coefficient, psi^{-1}
c_f = formation compressibility coefficient, psi^{-1}
Δp = change in average reservoir pressure, $(p_i - p)$.

There are several practical aspects to consider when using oil material balance techniques that will affect the quality of analysis results, a few of which are outlined in the sections below. For additional detail on applying the methodologies presented, it is suggested to consult a textbook such as Dake (1986, 2001) or Ahmed (2001).

4.5.1.2 Technical Principles of Gas Material Balance. In volumetric gas reservoirs, there is by definition no (or insignificant) aquifer water influx, and the volume of initial hydrocarbon pore volume will not significantly decrease from its initial value, but it will remain constant during reservoir pressure depletion. Therefore, with no adjoining aquifer or water influx ($W_e = 0$), no water production ($W_p = 0$), and no injection of gas ($G_{inj} = 0$), the generalized conventional MBE for a volumetric, normally pressured gas reservoir reduces to (Lee and Wattenbarger 1996):

$$GB_{gi} = (G - G_p)B_g, \qquad (4.7)$$

where

G = GIIP, scf

B_{gi} = gas formation volume factor at p_i, RB/scf

G_p = cumulative gas produced, scf

B_g = current gas formation volume factor, RB/scf.

Assessment of abnormally pressured gas reservoirs will necessitate the introduction of water and formation expansion terms (i.e., $\Delta V_w + \Delta V_f$) that must be added in Eq. 4.7; the reader is referred to Lee and Wattenbarger for further detail. Otherwise, Eq. 4.7 may be rewritten to:

$$G_p = G\left(1 - \frac{B_{gi}}{B_g}\right). \qquad (4.8)$$

The gas formation factor (B_g) can be calculated using $B_g = \frac{zTp_{sc}}{T_{sc}p}$, where standard surface pressure (p_{sc}) and temperature (T_{sc}) conditions are 14.65 psia and 519.67°R (60°F), subject to local, contractual, or regulatory variations.

It is common practice to express this relationship in terms of average reservoir conditions by combining and rearranging the different elements to yield this well-known equation applicable only to volumetric gas reservoirs:

$$\frac{p}{z} = \frac{p_i}{z_i} - \frac{\frac{p_i}{z_i}}{G}\,G_p, \qquad (4.9)$$

where

p_i, p = average reservoir pressure (psia) at reservoir datum, and "i" stands for initial

T = average reservoir temperature at reservoir datum (°R)

z_i and z = gas compressibility factors evaluated at p_i and T and any p and T, respectively

G = GIIP (scf)

G_p = cumulative gas production (scf) at reservoir pressure (p).

Eq. 4.9 simply asserts that in volumetric gas reservoirs, the gas production, and therefore the ultimate recovery under natural pressure depletion, is a direct function of the expansion of the free gas initially in place. Furthermore, Eq. 4.9 suggests that a plot of (p/z) vs. G_p should yield a straight line with an intercept (p_i/z_i) and a slope of $[-(p_i/z_i)/G]$, from which the GIIP = G relationship can be estimated. When an abandonment pressure is assumed (p_{ab}), the z factor at that pressure (z_{ab}) and a corresponding EUR may be estimated.

An example of a (p/z) plot for a conventional, normally pressured volumetric gas reservoir, with the variables mentioned above, is shown in **Fig. 4.4.**

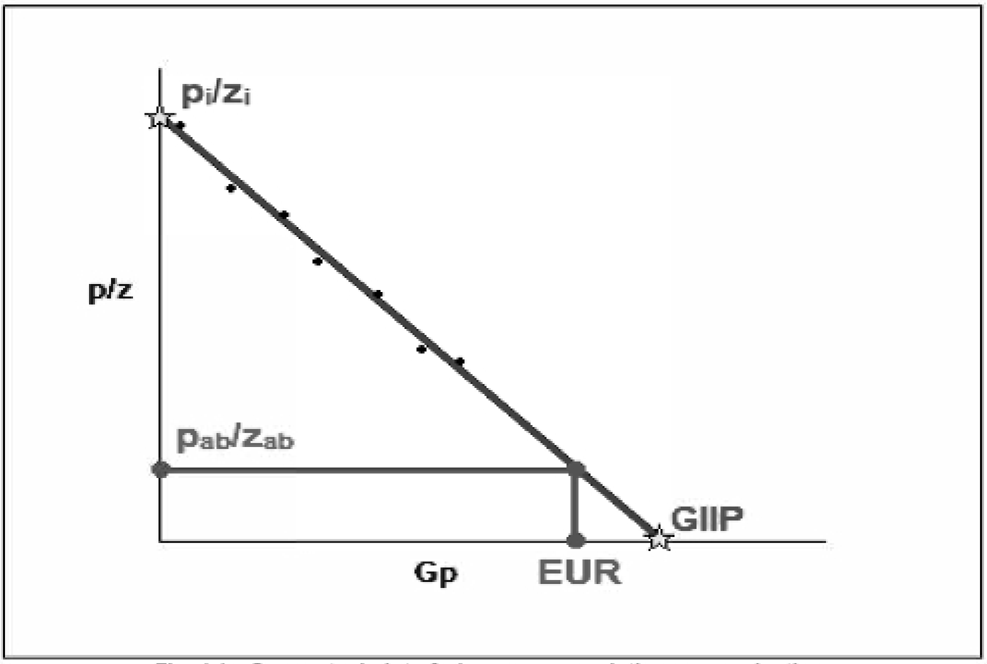

Fig. 4.4—Conceptual plot of *p/z* versus cumulative gas production.

4.5.1.3 Considerations When Applying Material Balance to Gas Reservoirs. There are several practical aspects to consider when using gas material balance techniques that may improve the quality of analysis results, some of which are outlined in Appendix A. For additional detail on applying the methodologies presented, the reader may consult a textbook such as Lee and Wattenbarger (1996) or another source as presented in the references.

4.5.1.4 Material Balance: Comparison with Results from Other Methods. Once a material balance analysis has been completed, it should be compared against other methods used to estimate in-place volume, especially volumetrics. If there are conflicts between the material balance result and other estimation methods, an attempt at reconciliation should be made to avoid over- or underestimation of in-place volumes and technically recoverable resources.

Here are a few examples of situations that may arise:

- If the volumetrics-estimated in-place volumes are higher than the material balance–estimated in-place volumes, and enough oil and/or gas has been produced from the reservoir to provide confidence in the material balance results (generally at least 10% of the in-place volume), perhaps there is compartmentalization in the field resulting in the current wells only accessing a portion of the total volume in the area. In other words, the MBE is indicative of the contacted area only.
- For a gas reservoir, if the volumetrically estimated GIIP volumes are lower than the material balance estimated GIIP, and the initial reservoir pressure is high, it may suggest that this is a case of an overpressured reservoir, and the p/z analysis is overestimating the GIIP.
- If the technically recoverable resources estimated by production decline analysis are significantly less or greater than the value estimated by material balance, perhaps an incorrect value was applied as an abandonment pressure in performing the material balance.

- If the recovery factor estimated by material balance differs greatly from the values obtained from analogs, perhaps a closer look at the analogs' parameters is required to explain the differences. In many cases, the reservoir properties may be a good match, but there are differences in the recovery process that may not have been considered.

4.5.1.5 Application of Material Balance to Oil Example. The example oil project is a black-oil reservoir, initially undersaturated (i.e., no gas cap) with partially active water influx, which was developed by peripheral downdip water injection to supplement reservoir energy and to help maintain a constant reservoir pressure 100 to 200 psia above the bubblepoint pressure. The project produced 220.8 million STB of oil (15.4% OIIP of 1,429.6 million STB estimated), 126 billion scf of solution gas, and 80 million STB of water and injected 385 million STB of produced and supply water into the aquifer below the original oil-water contact. Furthermore, above the bubblepoint, solution gas-oil ratios are equal ($R_s = R_{si} = R_p$), as all gas produced at the surface would be dissolved in the oil. The straight-line MBE (Havlena and Odeh 1963, 1964) is suitable for this particular case, and its details may be found in the references cited.

$$\frac{F_p}{(B_{oi}\ c_e \Delta P)} = N + \frac{(W_e + W_{\text{inj}} B_w)}{(B_{oi}\ c_e \Delta P)}, \qquad (4.10)$$

where

F_p = cumulative net reservoir withdrawal, RB
N = oil initially in-place, STB
B_{oi} = oil formation volume factor evaluated at p_i and T
ΔP = change in pressure from p_i to p, psia
W_e and W_{inj} = water influx (in RB) and water injection (in STB), respectively
B_w = water formation volume factor, RB/STB
c_e = effective saturation-weighted compressibility of the reservoir system, $(S_o c_o + S_w c_w + c_f)/(1 - S_w)$, psi^{-1}
S_o = oil saturation, fraction
c_o = oil compressibility coefficient, psi^{-1}.

This MBE represents reservoir depletion under a combined waterdrive (i.e., water influx and/or downdip water injection into the aquifer) that is effective and strong enough to maintain average reservoir pressure above the bubblepoint pressure. Since 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 to displace oil or how much of it enters the aquifer.

Eq. 4.10 suggests that a same-scale Cartesian plot of the left-hand side vs. the second term of the right-hand side should yield a unit slope intercepting the ordinate at N (i.e., PIIP), as in **Fig. 4.5.**

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 and c_e data can be calculated using the relevant relationships and measured production and injection data, (2) the unsteady-state water influx theory of Van Everdingen and Hurst (1949) may be used to estimate dimensionless influx rates (W_D), and (3) then the water influx (W_e) can be calculated.

Based on the average reservoir pressure observed and 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. 4.10 were calculated and plotted **(Fig 4.6)** in the same fashion as in Fig. 4.5.

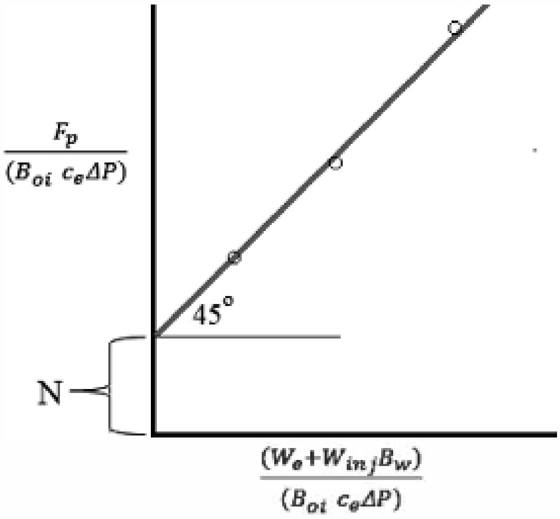

Fig. 4.5—Material balance plot for oil reservoir with waterdrive.

With the variations shown in the plotted data, three parallel straight lines were drawn with a unit slope supporting the value of the dimensionless radius, $r_D = 5$ (defined as a ratio of the aquifer radius to reservoir radius), and bracketing the degree of uncertainty in the measured and interpreted data. These minimum, most likely, and maximum interpretations of PIIP (in this situation, oil, hence OIIP or N) values of 1,300, 1,600, and 2,000 million STB were assumed to represent the low, best, and high estimates, respectively.

Over the past 8 years, the ongoing peripheral waterflood project confirmed similar performance to the analogs nearby, one of which had been since converted to a CO_2 pilot, while another was recently initiated, with encouraging performance similar to the initial response seen in the first CO_2 pilot. Recovery potential due to the implementation of a CO_2 pilot in this project would be incremental and subject to development contingencies.

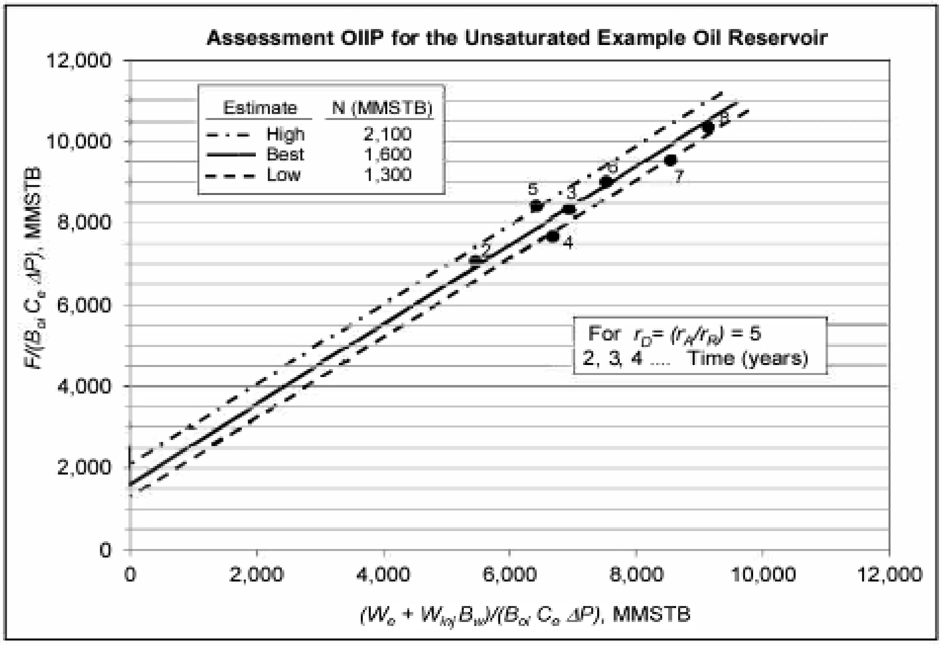

Fig. 4.6—Assessment of OIIP by material balance methods (early production stage), where MM indicates million.

Based on these low, best, and high estimate OIIPs, the respective Technically Recoverable Resources (under the ongoing peripheral waterflood project) and Contingent Resources (under a proposed CO_2 miscible project) were calculated as presented in **Table 4.6.**

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves and Resources Category		
			Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Oil	MMSTB	**220.8**	**220.8**	**220.8**
		% OIIP	17.0%	13.8%	11.0%
	- Raw Gas	Bscf	**125.9**	**125.9**	**125.9**
Original Oil In-Place (OIIP)		MMSTB	**1,300**	**1,600**	**2,000**
Recovery Factor[1]		% OIIP	40%	45%	50%
Recoverable Oil (EUR)[4]	- Original	MMSTB	**520.0**	**720.0**	**1,000.0**
	- Remaining[4]	MMSTB	**299.2**	**499.2**	**779.2**
Initial Solution Gas-Oil Ratio (R_{si})		scf/STB	570	570	570
Gross-Heating Value of Raw Solution Gas		Btu/scf	1,350	1,350	1,350
Original Gas In-Place (GIIP)		Bscf	**741.0**	**912.0**	**1,140.0**
Recoverable Raw Gas (EUR)	- Original	Bscf	**296.4**	**410.4**	**570.0**
		MMBOE[2]	69.0	95.5	132.7
	- Remaining[4]	Bscf	**170.5**	**284.5**	**444.1**
		MMBOE[2]	39.7	66.2	103.4
			Basis and Categories of **Contingent Resources**		
		Units	Low Estimate	Best Estimate	High Estimate
Recovery Factor[3]		% OIIP	5%	10%	15%
Recoverable Oil[4]		MMSTB	**65.0**	**160.0**	**300.0**
Recoverable Raw Gas[4]		Bscf	**37.1**	**91.2**	**171.0**
		MMBOE[2]	8.6	21.2	39.8

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

Table 4.6—Assessment using oil material balance methods (early production stage), where MM indicates million, B indicates billion, and BOE is barrels-oil-equivalent.

4.5.1.6 Application of Material Balance to Gas Example. **Fig. 4.7** depicts the p/z vs. G_p performance plots for this example volumetric 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 low, best, and high estimate interpretations of PIIP (in this case, gas, therefore GIIP) estimates from Fig. 4.7 may be used 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 reservoir RE is calculated to be about 75% to 76% of GIIP. Estimates are further supported by the following factors 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 billion scf using volumetric methods; (3) it has already produced 316.2 billion scf, which is more than 17.6% of this volumetric GIIP or 21.1% of the low GIIP estimate from Fig. 4.7; and (4) the project economics based on these three different scenarios are all determined to be viable with discounted cash flow rates of return exceeding 20%.

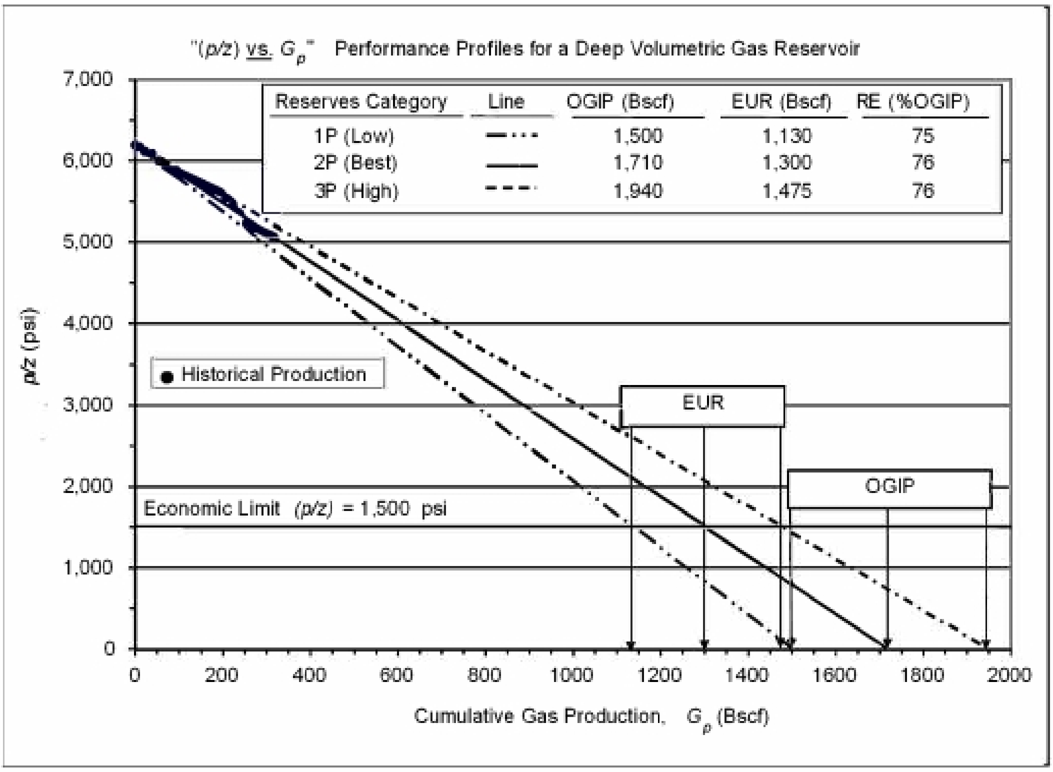

Fig. 4.7—Gas reserves assessment by material balance methods (late production stage), where OGIP is original gas in-place, and B indicates billion.

Based on the initial condensate gas ratio of 30 STB/million scf raw gas (with a gross heating value of 1,100 Btu/scf) and a recovery factor of 60% original condensate in-place from the nearby analog reservoirs, the in-place and reserves estimates for this gas reservoir are summarized in **Table 4.7.** Note that the recoverable raw gas volumes (in terms of both scf and therefore 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 non-hydrocarbons (8.1%) and recovery of C_2 plus natural gas liquids (8.7%). For more detail, readers should refer to Chapters 11—*Production Measurement & Operational Issues* and 12—*Resources Entitlement and Recognition*, herein, on production measurement, 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 in the tubing string in the wellbore. A gas well will stop flowing when the average reservoir pressure drops to 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 optimal compression ratio) at the point of sales (or plant feed) to significantly reduce the sales gas pipeline-imposed backpressure.

Measured and Estimated Parameters		Units	Bases and Estimates by Reserves Category		
			Low Estimate	Best Estimate	High Estimate
Cumulative Production	- Raw Gas	Bscf	**316.2**	**316.2**	**316.2**
		% GIIP	21.1%	18.5%	16.3%
	- Condensate	MMSTB	**9.4**	**9.4**	**9.4**
Gas Initially In-Place (GIIP)[1]		Bscf	**1,500**	**1,710**	**1,940**
Gross-Heating Value of Raw Gas		Btu/scf	1,100	1,100	1,100
Recoverable Raw Gas (EUR)[1]	- Original	Bscf	**1,130**	**1,300**	**1,475**
		MMBOE[2]	214.3	246.6	279.7
	- Remaining[4]	Bscf	**813.8**	**983.8**	**1,158.8**
		MMBOE[2]	154.3	186.6	219.8
Implied Recovery Factor		% GIIP	75%	76%	76%
Initial Condensate-Gas Ratio (CGR_i)		STB/MMscf	30	30	30
Condensate Initially In-Place (CIIP)		MMSTB	**45.0**	**51.3**	**58.2**
Condensate Recovery Factor[3]		% CIIP	60%	60%	60%
Recoverable Condensate (EUR)	- Original	MMSTB	**27.0**	**30.8**	**34.9**
	- Remaining[4]	MMSTB	**17.6**	**21.4**	**25.5**

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

Table 4.7—Gas reserves assessment by material balance methods (late-production stage).

The economic limit (p/z) of 1,500 psia for this example 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 project volumes associated with compression are considered as Contingent Resources pending future updates for cost reduction and/or higher gas prices.

4.5.2 Reservoir Simulation. Traditional material balance analysis using analytical procedures is routinely being performed during reservoir simulation studies. A history-matched numerical simulation is a powerful tool, capable of modelling the complex interactions of production and injection from multiple wells, changing pressure-volume-temperature properties, and changing pressure gradients within a field to provide a rigorous material balance–based solution and, of course, to compare alternative development scenarios. Reservoir simulation is further discussed in Chapter 6—*Reservoir Simulation* herein.

4.5.3 Decline Curve Analysis. Decline curve analysis is well known and widely used because it provides a visual illustration of the historical production performance of a well, a group of wells, or a reservoir. The established trend can be extrapolated beyond the economic limit to estimate petroleum reserves as well as subeconomic remaining resources. Review, derivation, and understanding of these governing equations (summarized in **Table 4.8**), representing each decline model, are very important for correct use and application of traditional DCA.

	Exponential $b=0$	Hyperbolic	Harmonic $b=1$
$q(t)$	$q(t)=q_i e^{-D_i t}$	$q(t)=\frac{q_i}{(1+bD_i t)^{1/b}}$	$q(t)=\frac{q_i}{1+D_i t}$
$N_p(t)$	$N_p(t)=\frac{q_i-q(t)}{D_i}$	$N_p(t)=\frac{q_i^{\,b}}{D_i(1-b)}\left(q_i^{1-b}-q^{1-b}\right)$	$N_p(t)=\frac{q_i}{D_i}\ln\frac{q_i}{q}$
r	$r=\frac{q_i}{q_a}$	$r=\frac{q_i}{q_a}$	$r=\frac{q_i}{q_a}$
t_a	$t_a=\frac{\ln r}{D_i}$	$t_a=\frac{r^b-1}{bD_i}$	$t_a=\frac{r-1}{D_i}$
N_{pa}	$N_{pa}=\frac{q_i-q_a}{D_i}$	$N_{pa}=\frac{q_i^{\,b}}{D_i(1-b)}\left(q_i^{1-b}-q_a^{1-b}\right)$	$N_{pa}=\frac{q_i}{D_i}\ln\frac{q_i}{q_a}$
$D(t)$	$D(t)=D_i$	$D(t)=\frac{D_i}{1+bD_i t}$	$D(t)=\frac{D_i}{1+D_i t}$
D_{ei}	$D_{ei}=1-e^{-D_i}$	$D_{ei}=1-\frac{1}{(1+bD_i)^{1/b}}$	$D_{ei}=\frac{D_i}{1+D_i}$
D_i	$D=-\ln(1-D_e)$	$D_i=\frac{1}{b}\left[\frac{1}{(1-D_{ei})^b}-1\right]$	$D_i=\frac{D_{ei}}{1-D_{ei}}$

i = initial time or point at which the decline trend has started

b = decline exponent

D_i = nominal decline rate as fraction of $q(t)$ with a unit of inverse time ($1/t$), equal to D_i when $q(t)=q_i$

$q(t)$ = oil or gas production rate at any time t

t = time

$N_p(t)$ or $G_p(t)$ = cumulative oil or gas production at any time t

D_e = effective decline rate

D_{ei} = effective decline rate at initial conditions (time = 0)

q_a = production rate at abandonment

Table 4.8—Governing equations for decline curve analysis.

DCA is based on the solution of the following generalized differential hyperbolic equation defining the nominal decline rate (D) as the fraction of "change in production rate with time (t)" as:

$$D=-\frac{1}{q}\left(\frac{dq}{dt}\right)=Kq^b, \qquad (4.11a)$$

where

D = nominal decline rate (related but not equal to the slope of the tangent to the line) at time (t); a fraction of production rate (Q_t) with a unit of reciprocal time ($1/t$) per month, year, etc., consistent with the units of production, frequently expressed as percent per year

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

b = hyperbolic decline exponent

K = integration constant.

The reciprocal of the nominal decline rate is called the “loss ratio”:

$$\frac{1}{D} = -\frac{q}{dq/dt} \quad \text{(4.11b)}$$

The hyperbolic decline exponent, b, is defined as the derivative of the loss ratio:

$$b = \frac{d}{dt}\left[-\frac{q}{dq/dt}\right] \quad \text{(4.11c)}$$

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 it 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 decline exponent (b) may have any value except $b = 0$ and $b = 1$, which represent the special cases defined by exponential and harmonic models, respectively.

Note that the exponential and harmonic models are just specific cases of the hyperbolic model. When originally conceived, the Arps-style approach assumed boundary-dominated flow, with an upper limit of 1 for the harmonic decline case. Investigations since this original formulation have demonstrated the presence of “hyperharmonic” exponents associated with transient flow regimes in unconventional reservoirs. For example, the exponent observed for transient linear flow is 2, while that for transient bilinear flow is 4. This is described further in Chapter 10—*Unconventional Resources Estimation*, herein.

Initial nominal decline rate (D_i) is the *nominal* (or continuous) decline rate corresponding to the initial production rate at which decline begins **(Fig. 4.8).** It is a tangent to the initial production rate at a given time. The ratio of nominal decline rate at any time t (i.e., 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:

$$\frac{D_t}{D_i} = \left(\frac{q_t}{q_i}\right)^b \quad \text{(4.12)}$$

D_i is related to the initial *effective* (or stepwise) decline rate (d_i), which is a step function rather than a continuous function between two consecutive rates, represented as the secant of a rate-versus-time arc connecting the two rates by the following relationships:

$$D_i = -\ln(1-d_i) \text{ or } d_i = 1 - e^{-D_i} \text{ [exponential decline],} \quad \text{(4.13a)}$$

and

$$D_i = \frac{1}{b}\left[\frac{1}{(1-d_i)^b} - 1\right] \text{ or } d_i = 1 - \frac{1}{(1+bD_i)^{1/b}} \text{ [hyperbolic decline]} \quad \text{(4.13b)}$$

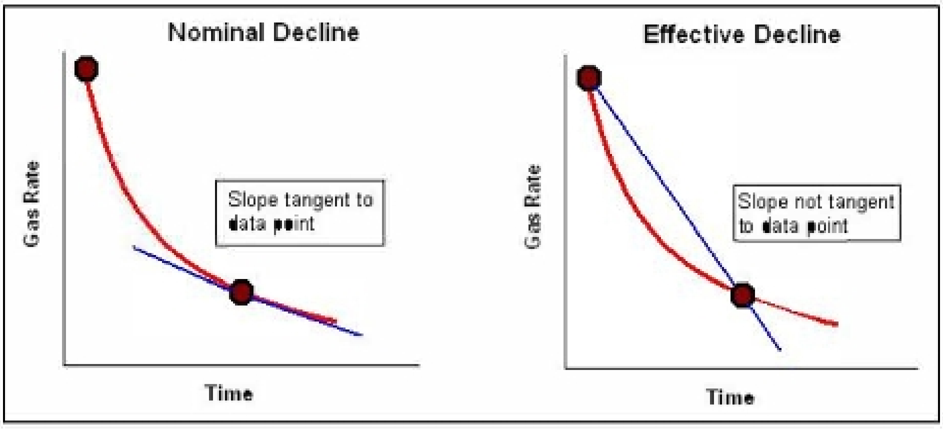

Fig. 4.8—Nominal compared to effective decline rate (IHS Markit 2022).

For example, if D_i = 0.25/yr and b = 0.5, then $d_i = 1 - \frac{1}{(1+0.5\times0.25)^{1/0.5}}$ = 0.21/yr.

The effective decline rate, d_i, is the one petroleum engineers are most familiar with, as it is typically read directly from a rate-vs.-time plot. Many commercially available DCA packages rely on the effective decline rate (secant) in their analysis; usually, there is not much difference between the nominal and effective decline rates except in the case of unconventional reservoirs, where initial steep declines have a significant impact—the larger is the D_i, the greater is the difference with d_i.

Rate of decline depends on several factors, such as the reservoir depletion rate, the reservoir maturity, the average reservoir pressure, the reservoir rock and fluid properties (magnitude and distribution), and the reservoir management and production practices.

The decline trend analysis of production rate vs. time advanced by Arps (1945) employs hyperbolic equations similar to Eq. 4.11a, which are summarized in Table 4.8.

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 (e.g., b = 2 for linear flow and b = 4 for bilinear flow; see Chapter 10—*Unconventional Resources Estimation* herein), the following generally applicable values may be expected **(Table 4.9):**

Value of Decline Exponent (b)	Governing Reservoir Drive Mechanism
0	Single-phase liquid (oil above bubblepoint)
0	Single-phase gas at high pressure
0.1–0.4	Solution gas drive
0.4–0.5	Single-phase gas
0.5	Effective edge waterdrive
0.5–1.0	Commingled layered reservoirs
$b > 1$	Observed in unconventional reservoirs

Table 4.9—General hyperbolic exponents related to reservoir drive mechanisms (after IHS Markit 2018).

The governing rate-time relationship of a general hyperbolic decline model (Table 4.8) is:

$$q_t = \frac{q_i}{(1+bD_i t)^{1/b}} \quad (4.14a)$$

Eq. 4.14a may also be rewritten as:

$$log\ q_t = log\ q_i - \frac{1}{b}\log(1 + bD_i t) = log\ q_i - \frac{1}{b}\log(1 + Ct), \quad (4.14b)$$

where $C = bD_i$, which is an unknown constant (refer also to Table 4.8). For a correct value of C, Eq. 4.14b suggests that a log-log plot of q vs. $(1 + Ct)$ should yield a straight line with a slope of m $(= -1/b)$ and intercept of q_i at time zero.

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

With estimated correct values of these two unknowns, the cumulative production at any given time can now be directly calculated using the following relationship:

$$N_{pt} = N_{pi} + \frac{q_i^b}{(1-b)D_i} \times \left[q_i^{(1-b)} - q_t^{(1-b)}\right], \quad (4.15)$$

where q_i and q represent the production rate at initial time i and any time t, respectively, and N_{pi} and N_{pt} represent the cumulative oil production at the initial (i) production rate (q_i) or from time zero ($t = 0$) up to the time t.

It is difficult to determine the correct value of the decline exponent (b) while attempting to estimate two unknowns (C and b) simultaneously. It is quite possible to have the same b but different D_i values matching the same decline trend that extrapolates to different estimates of reserves, and this must be taken into account to quantify the uncertainty associated with the analysis.

Ideally, one would estimate the nominal decline (D_i) first and then perform a simple trial-and-error procedure iterating on this single insensitive decline exponent b to evaluate and establish the best-matched decline trend that corresponds to the best value of b. Also, b can be calculated as follows: from Eq. 4.14b, when $Ct >> 1$ (which happens soon enough), we can determine b from the slope of a log-log plot of q vs. t. This is almost always possible for wells in transient flow (when D is large), whereas it might be more difficult for wells in boundary-dominated flow (when D_i is much smaller, and so time to reach $D_i bt >> 1$ is longer).

In most cases, the well count in a producing asset (reservoir, field, etc.) changes with time. The conditions may not be stable enough to perform the DCA on a reservoir basis. Also, as the reservoir produces, wells will die, and the slope of the declining asset will change to reflect only the remaining wells, a situation known as "survivor bias." To remedy this situation, DCA should be performed on a well-by-well basis (or completion-by-completion basis). The engineer will need to use their judgment to extrapolate production trends despite inherent errors that will be caused by noise in the data, inaccuracies in the b and D parameters, or even potential changes in dynamic conditions that may not be obvious by looking at the data.

Well-by-well DCA, originally performed manually, is most often carried out using relevant software. However, the results provided by commercially available software should always be scrutinized in light of the characteristics of the reservoir as well as the depletion drive mechanisms, which must be understood by the evaluating engineer. Production down-time, curtailment, stimulation, platform maintenance activity, and other factors impacting production at capacity must be understood. Furthermore, particularly in the case of hydraulically fractured wells, early time cleanup must be excluded from the decline analysis. Determination of the end of the cleanup period is often assisted by analyzing secondary phase ratios such as the gas-oil or water-oil ratios. The analysis is typically completed based on plots such as the following (example shown is a hydraulically fractured, low-permeability oil well):

Fig. 4.9 shows a log-log rate vs. cumulative production plot (left) and the same plot when the production rate is adjusted by normalizing for pressure drop [i.e., $q/(p_i - p_{bhf})$] on the right. No trend can be identified without pressure-normalizing the rate. However, this technique requires the availability of bottomhole flowing pressure data at intervals similar to the production data.

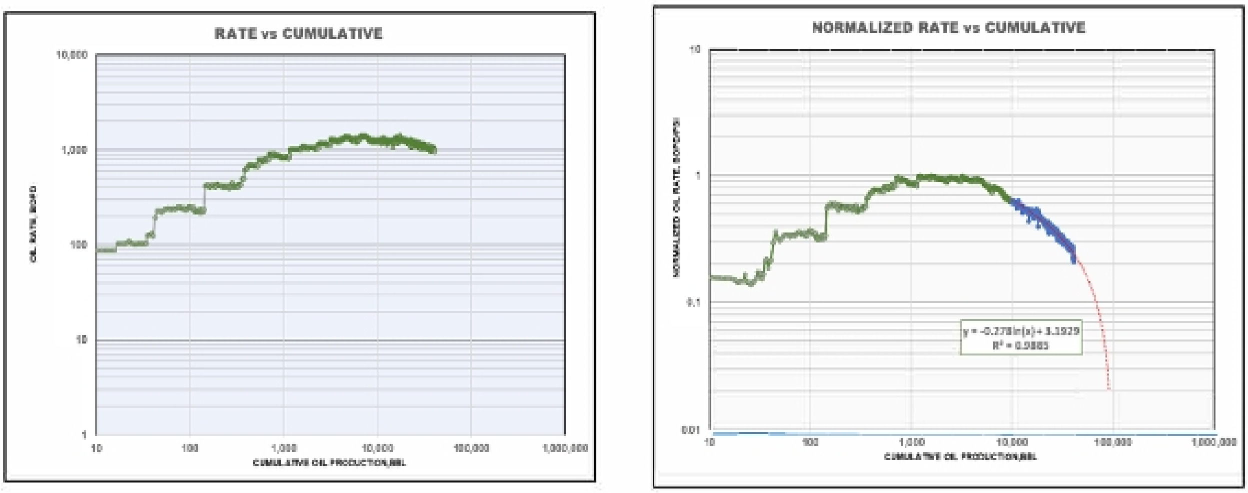

Fig. 4.9—Rate vs. cumulative oil (left); pressure-normalized rate vs. cumulative oil (right), where BOPD indicates barrels of oil per day.

Fig. 4.10 illustrates the use of secondary ratios in identifying the portion of the production history that extends beyond the cleanup period and thus may be used for DCA. In this example, the evaluator defined the first 7 days as the cleanup period, based on the stabilization of the oil production rate and the gas-oil ratio. However, the water-oil ratio (WOR) has not yet stabilized, although it is declining favorably. The figure also includes the choke setting to ensure that production fluctuations are not due to the changing of choke settings.

Fig. 4.11 is a typical semi-log plot of primary phase production rate vs. time. Again, this is an example of a low-permeability oil reservoir, and the production history is quite short; nevertheless, the figure demonstrates the way in which such a routinely used plot can be employed to determine the decline rate under an exponential depletion mode. Semi-log plots have been used as the main DCA tool for decades and are quite easy to generate and analyze in commercial software as well as spreadsheet programs.

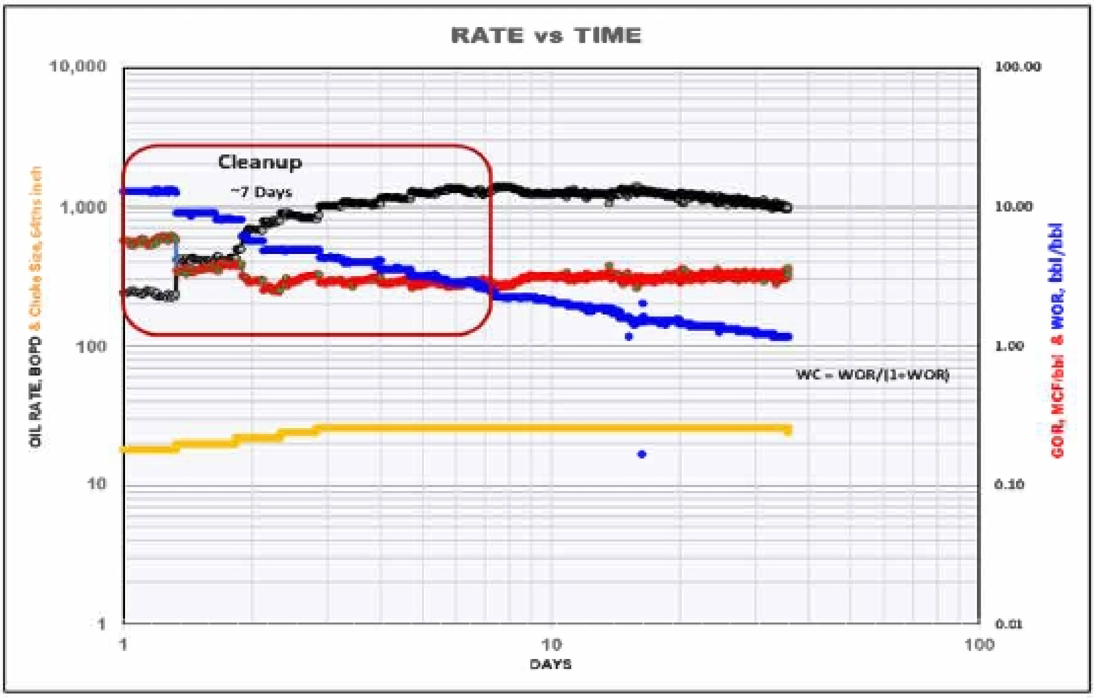

Fig. 4.10—Rate vs. time showing cleanup time, choke size, and secondary ratios, where GOR is gas-oil ratio, WOR is water-oil ratio (both dimensionless), and WC is water cut (as a fraction).

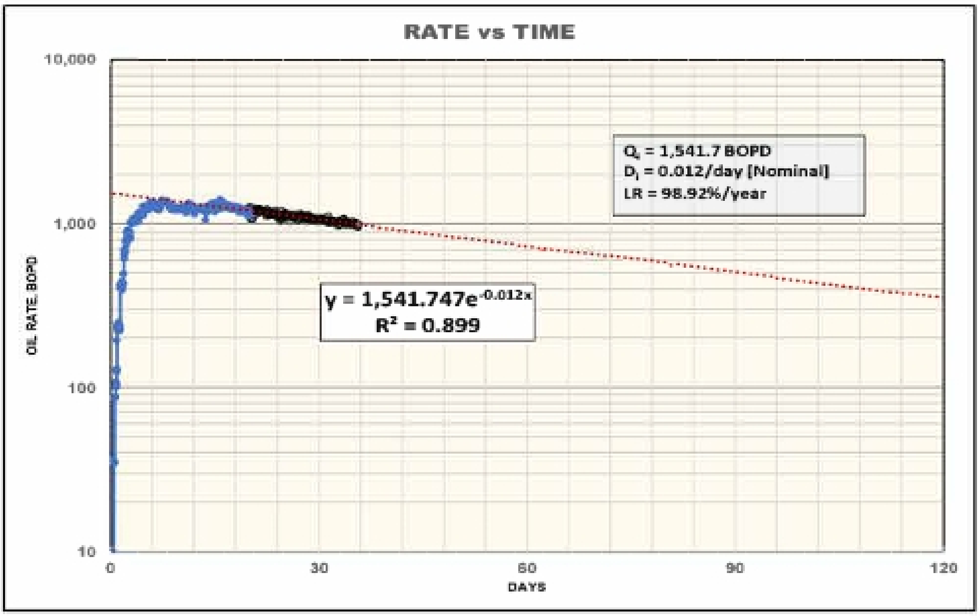

Fig. 4.11—Rate vs. time, semi-log, primary phase, exponential fit. LR = loss ratio.

While the foregoing discussion has been on per-well DCA, DCA may be conducted for a group of wells (such as for a unitized project); however, in doing so, the details of the underlying individual well performances will be lost, and the aggregate production history likely will provide misleading forecasts. This will be mentioned in Section 4.5.3.3. In addition, a curve fit of past performance to extrapolate future production does not necessarily yield the Proved (1P) Reserves forecast, as mentioned in Section 4.5.3.5. The evaluator needs to be aware that, for each DCA-generated fit of past performance, there is a range of uncertainty for the predicted performance that may be expressed in terms of 1P, 2P, and 3P quantities, as shown in the example of Section 4.5.3.4.

4.5.3.1 Supplementary Decline Curve Analysis Techniques. There are other well-established production performance analyses that may be used to predict recoverable volumes based on trends exhibited for a well and/or a reservoir even before the production rate begins to decline. These reservoir drive-specific analyses were briefly discussed by Cronquist (2001). Salient points of these methods may be summarized as follows:

- Cumulative Gas Production vs. Oil Production Trends: For oil reservoirs with solution gas drive, a semi-log plot of log G_p vs. N_{pt} may develop a trend that could be extrapolated to estimate oil recovery, with the maximum G_p being equal to the original solution gas in-place (GIIP = R_{si} × OIIP).
- Water Cut, Oil Cut, or WOR vs. Cumulative Production Trends: These performance trends have been found to be particularly useful in analyzing an oil reservoir producing with waterdrive or producing with downdip water injection or a pattern waterflood. The established trend is extrapolated to the economic water cut (f_w) or WOR to obtain EUR under the prevailing production method with which the trend has been established. It may be useful to note the following reported observations:
    - A plot of "log f_w (or f_o) vs. N_{pt}" (i.e., semi-log plot) trend may turn down at small values of f_o, but this will occur earlier for light oils and later for viscous oils (Brons 1963).
    - A semi-log plot of (WOR + 1) and total fluids withdrawal (F_p) vs. time (t) may help to define oil rate trend (Purvis 1985). Additionally, a semi-log plot of "(WOR + 1) vs. N_{pt}" tends to be linear at WOR values less than 1 and therefore may help to define performance trends at low values of WOR or water cuts.
    - Ershaghi and Omoregie (1978) and Ershaghi and Abdassah (1984) recommended that a plot of $\{\ln[(1/f_w) - 1] - (1/f_w)\}$ vs. N_{pt} should be linear. However, they noted that due to the inflection point of the f_w vs. S_w curves, the method will work only at higher water cuts when $f_w > 50\%$.
    - For reservoirs with an active waterdrive or that are under waterflooding operations, a semi-log plot of cumulative oil production (x-axis) versus oil cut can yield an excellent extrapolation (at high water cuts) to the EUR. Generally, this method works best for $f_w > 50\%$.

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 unreliable reserves estimates.

4.5.3.2 Type Curve Analysis. Fetkovich (1980) introduced a robust means with which to match performance data to empirical type curves for the purpose of estimating not only decline parameters but also certain productivity properties, such as skin or flow capacity. This approach relies on the assumption that there are basically two flow regimes during the producing life of a well, namely, a transient period (when the drainage radius is expanding, usually in early time) and semi-steady-state or depletion stage (when the boundaries have been reached, and pressure in the drainage area declines in an approximately uniform fashion). The approach is further predicated on single-phase, slightly compressible, radial flow from a homogeneous reservoir.

Other forms of type curve analysis exist, such as Carter's (1985) gas type curves and the gas-to-liquid equivalent type curves of Palacio and Blasingame (1993), but discussion of the selection and use of type curves is beyond the scope of this work. The reader is referred to the sources at the end of this chapter.

4.5.3.3 Pitfalls and Potential Issues Associated with DCA/TCA. During any DCA exercise, the evaluator also will need to consider carefully all the elements that will affect the behavior of the wells. Such parameters will include, for example:

- Physical cutoff rates and maximum water cuts: Production trends can be extrapolated to very low production rates [or very high basic sediment and water, (BSW)]; however, the expected vertical flow performance of the wells must be taken into account (through lift curves, for example) to ensure that the technical forecast is truncated according to physical constraints. Likewise, water handling can constrain production rates due to facility limitations.
- Test data vs. actual production data: The evaluator should review the data and filter carefully any element that will affect the production trend. This includes potential downtimes, allocation issues, validity/thoroughness of field measurements, noise, etc.
- Well aggregation: While DCA may be performed best on a well-by-well basis (or even completion-by-completion basis), this may be an issue for the well aggregation in large assets. The deterministic sum of P90s will be very pessimistic, and the sum of P10s will be very optimistic. (The reader is referred to Chapter 8—*Aggregation of Reserves*, herein.) What may appear to be a reasonable low case on a well-by-well basis may lead to an unrealistic forecast when many low cases are aggregated.
- Individual vs. group level inputs: DCA likely will be misleading if performed for a group of wells where production is reported, or at least supplied to the evaluator, at the group level. This may be the case for a waterflood unit, in which the aggregate production trend does not identify well workovers or rapidly rising individual well water cuts, for example, or an asset that is operated by another entity that does not provide individual well performance data.
- General decline trends and external parameters: The evaluator should understand the general decline trend and avoid the influence of external parameters such as choke changes. For example, a well may have a very low decline rate because the choke is opened slightly on a regular basis until it reaches the maximum choke setting. Similarly, some companies may set an annual depletion rate for their reservoirs or fields, and the wells are choked back to adhere to this practice.
- All produced phases and constraints: The evaluator should consider all produced phases in the DCA and any facilities or regulatory constraints. The evaluator should not merely focus on the major phase production forecast, and a restriction may be caused by secondary phase production.
- Outliers: Some reservoirs cannot easily be evaluated with DCA. Fractured carbonate reservoirs may produce dry oil at a plateau rate for a long time, but the well will die very quickly when water breakthrough starts. Low-permeability reservoirs cannot easily be evaluated because the *b* factor will vary with depletion stage, and it can be greater than 1 in unconventional assets.
- Production metrics: Producing days vs. calendar days trends will be very different. Calendar day production will introduce external parameters, shutdowns, etc. PPTs are not only reservoir specific, but they also depend on the specific reservoir management and production practices. Any significant change in these practices could easily shift and change the previously established decline trends and invalidate their extrapolations.

Therefore, proper application of these procedures, to a large extent, depends on the experience and skill levels of the professional evaluators and their ability to judge the reasonableness of results obtained by comparing them to known analogs and/or other performance-based methods.

4.5.3.4 DCA Application Example. A well of interest is located in the New Mexico side of the US Permian Basin. The laminated sand-shale turbidite reservoir produces black oil under solution gas depletion drive. Crude quality is 39 °API with a solution gas-oil ratio of 350 scf/STB and initial formation volume factor of 1.25 RB/STB. Water production exists from the start, but data from more mature wells indicate that the wells do not water out regardless of structural position (this is a stratigraphic trap). Thirty-six months of capacity production has yielded the semi-log rate-time relationship plotted in **Fig. 4.12.**

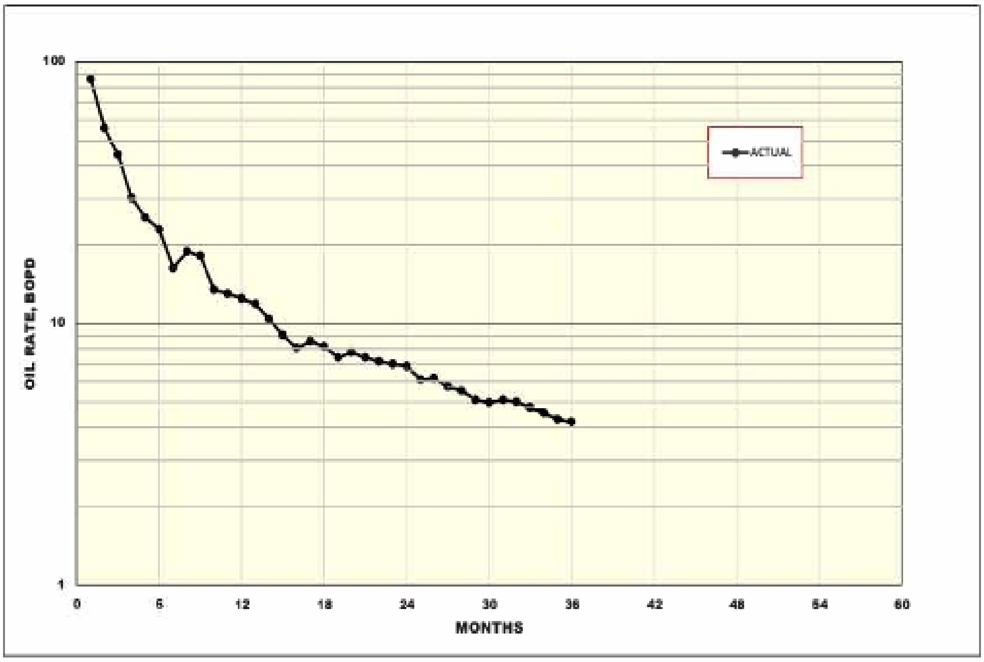

Fig. 4.12—Semi-log rate-time graph.

A curve fit of the data should represent the most likely, or 2P, forecast **(Fig. 4.13).** Honoring the most recent data (approximately the last 18 months) results in a hyperbolic fit with a *b* exponent of 0.75 and an initial nominal decline rate of 0.015/D (loss ratio of 88.6%/yr). The evaluator checks the exponent against empirical values and finds that multilayered reservoirs usually may be matched with values between 0.5 to 1.0. As a further check, the evaluator notes that core data analysis characterizes the reservoir as extremely heterogeneous, with a Dykstra-Parsons coefficient of 0.87.

However, the first half of the data is not matched as well. This may be explained as a revision in decline as the more permeable layers have depleted to the point that the lower-permeability layers contribute a greater percentage of the total flow rate at the later time. If the evaluator believes that the late-time data actually represent all layering, a high-side projection results in **Fig. 4.14.** In this case, the *b* exponent has been increased to 0.9, and the initial nominal decline rate has been increased to 0.022/D (loss ratio of 90.4%/yr).

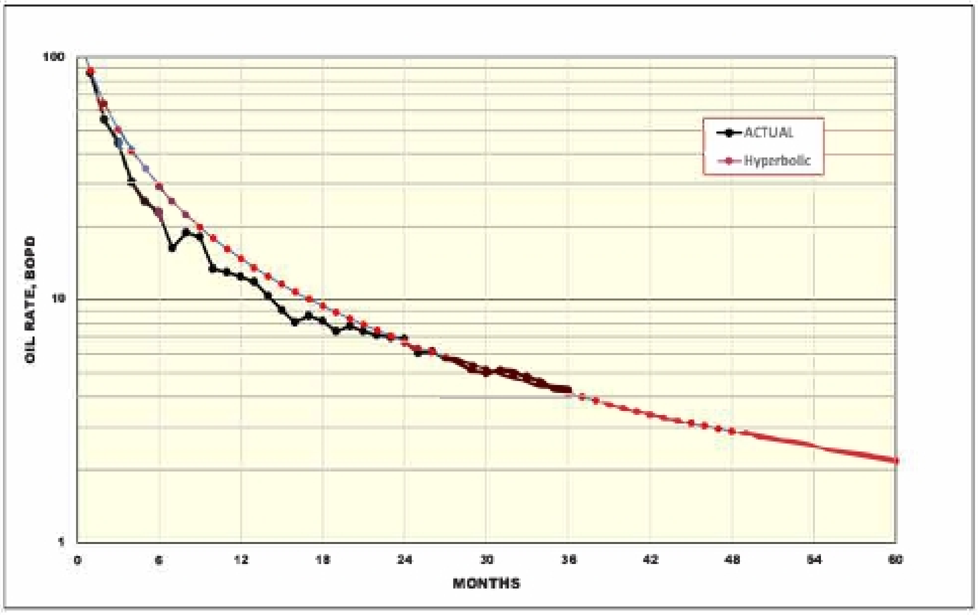

Fig. 4.13—Hyperbolic curve fit.

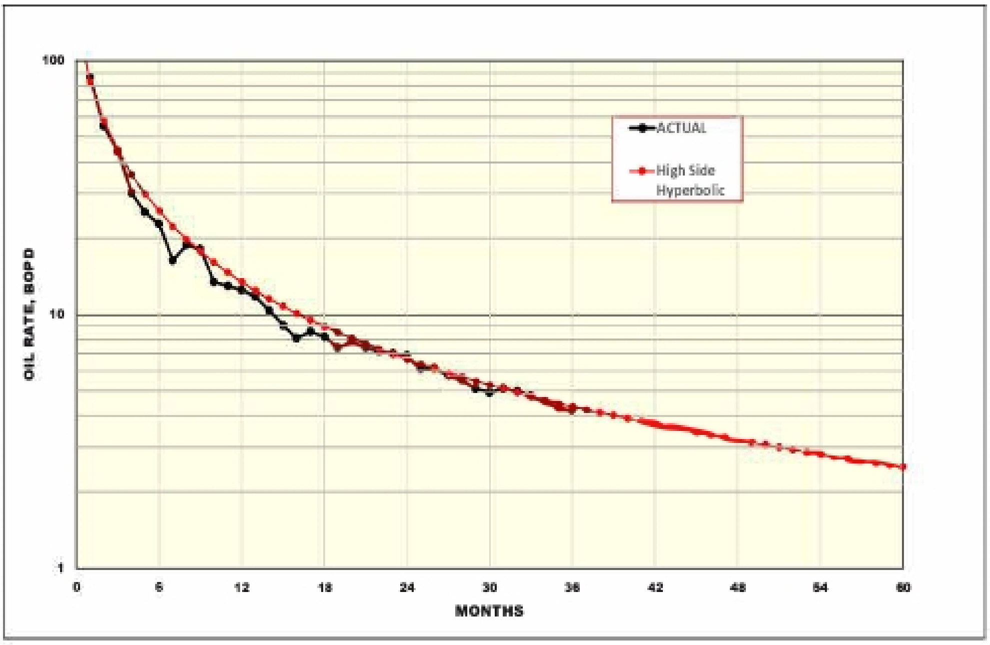

Fig. 4.14—High-side hyperbolic fit.

Finally, again looking only at the late-time trend, an exponential trend may also be fit, with the resulting trendline (correlation coefficient of 0.977) shown in **Fig. 4.15.** This exponential decline is 36.7%/yr and can serve as the 1P projection.

A comparison of the three profiles, now designated as 1P, 2P, and 3P, is depicted in **Fig. 4.16.** A slight adjustment was made to the initial rates at the beginning of the projections.

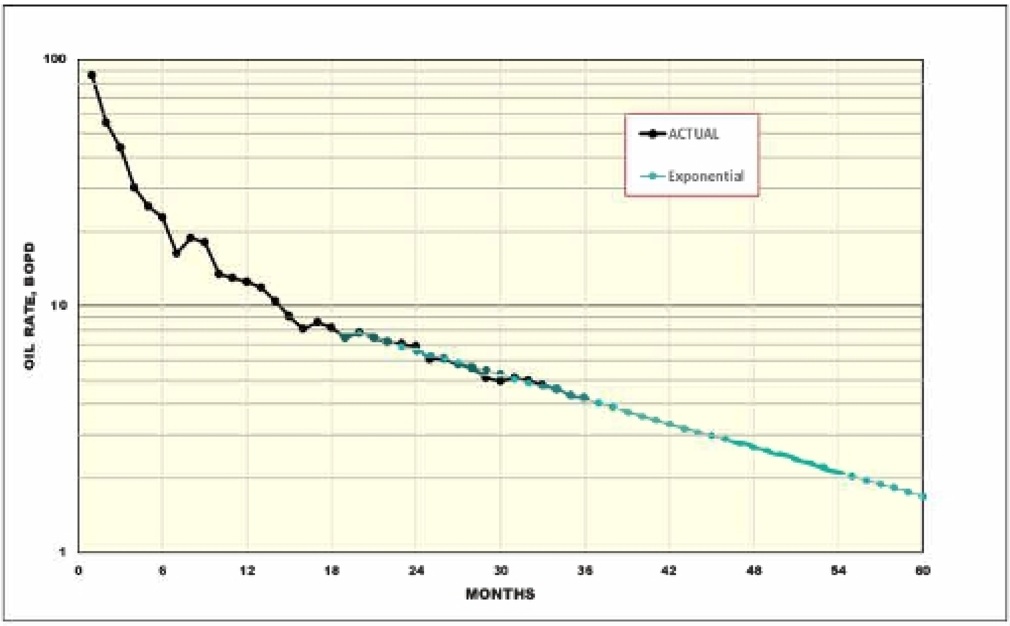

Fig. 4.15—Exponential late-time fit.

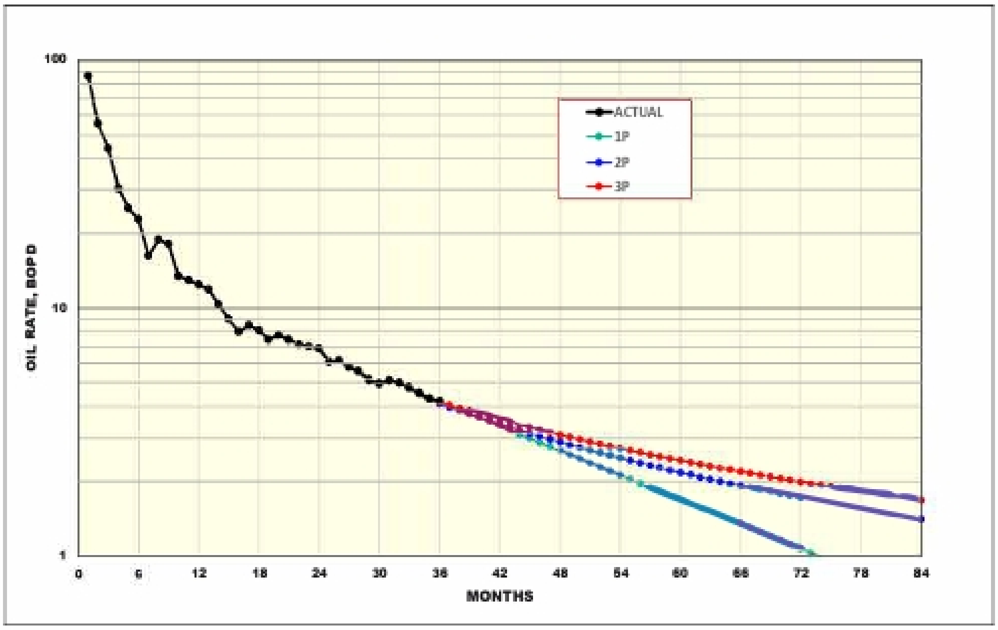

Fig. 4.16—1P, 2P, and 3P projections.

The evaluator has independently verified that the economic limit, on a per-well basis, is 1 barrel of oil produced per day (BOPD), under the defined operating conditions of primary (solution gas drive) recovery only. A terminal decline rate switching from hyperbolic to an 8%/yr exponential decline has been observed in other wells producing from the reservoir, but the switch point occurs beyond the remaining economic life of the well in question. Consequently, the reserves (and EUR, including the prior production) for the three cases may be summarized as in **Table 4.10.**

Case	Reserves*	EUR
1P	83	15,820
2P	4,371	20,108
3P	4,423	20,160
* Reserves to 1 BOPD Economic Limit		
Actual Cum. Production =		15,737 STB

Table 4.10—Summary of 1P, 2P, and 3P projections.

The reserves evaluator will note the difference between the 1P and both the 2P and 3P reserves. The 2P and 3P projections have economic lives of 6.2 and 8.3 years, respectively, compared with 3.1 years for the 1P; however, the real effect is the initial instantaneous decline rate of about 29%/yr for the 2P and 3P estimates relative to 37%/yr for the 1P estimate. The variance increases steadily as the hyperbolic decline rate progressively becomes more shallow, nearing 9% at the economic limit.

4.5.3.5 Uncertainty. As explained above, until the wells or the field have reached the end of field life, there will always be some uncertainty inherent to this analysis. Even with good-quality data, the *b* and *D* parameters may not be quantified satisfactorily for a number of reasons. In the example above, the evaluator may get different outcomes despite a very steady trend compared to most actual data observed.

It is important to note that, even an No Further Activity (NFA) case computed with DCA may not correspond to a "Proved Developed Producing" case. The DCA should always be representative of the full range of uncertainty, and the evaluator should be able to quantify a 1P NFA (PDP), 2P NFA, and 3P NFA case. This also means that all flowing wells should contribute to the 1P, 2P, and 3P cases, or, incrementally, that all flowing wells should have a Proved, Probable, and Possible component.

However, uncertainty may be much lower for flowing wells than for new development projects **(Fig. 4.17).** Using a single trend for the DCA instead of a full low-best-high range would suggest that the uncertainty is so small such that the approximation 1P = 2P = 3P can be used. While this may be practical in a very mature asset, it may not be realistic.

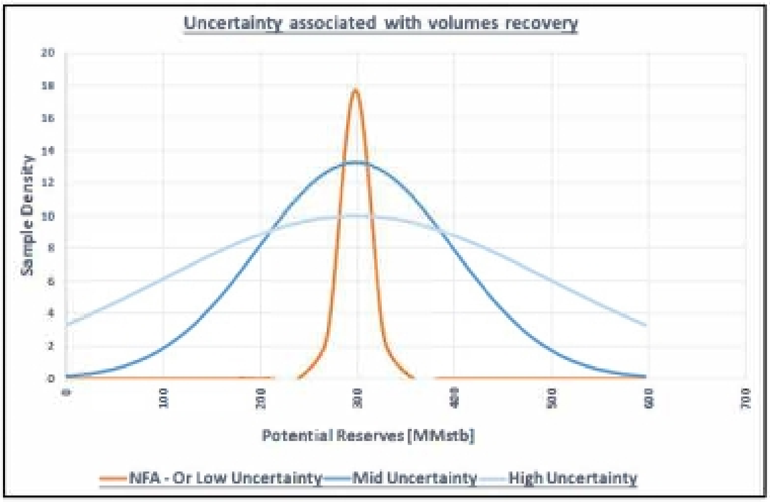

Fig. 4.17—Range of potential reserves narrows as uncertainty decreases.

Finally, DCA will provide very little information in the early stage of a field's life when few production data are available, and uncertainty is driven by the geology (gross rock volume, net-to-gross ratio, porosity, etc.). In late life, performance curves may be used to assess the reservoir production as geology is better understood and uncertainty is driven by fluid dynamics, connected zones, pressure communication, etc.

4.6 Summary and Conclusions

Consistent with the PRMS guidelines on petroleum resources and reserves definitions, classification, and categorization, different deterministic assessment methods and procedures have been illustrated to estimate oil and raw gas resources and reserves.
Key takeaways from this chapter are as follow:

- Petroleum resources assessment is and must be a continuous ongoing technical process supported by good practices and collaborative efforts across many disciplines.
- Petroleum resources assessment should use the methods most suitable for analyzing the data available, including static geoscientific and engineering approaches as well as dynamic actual production performance (both subsurface and facilities considered), and these methods should be carried out by a collaborative multidisciplinary team of expert evaluators.
- 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.
- Material balance methods rely upon pressure data gathered from wells. Ideally, collected data should have sufficiently long testing times to reach stabilized buildup pressures. For shorter shut-in durations, pressure points used for analysis should be the result of extrapolation from pressure transient analysis of the acquired data or a comparable correction method that can be used to estimate an appropriate stabilized pressure.
- A good practice when employing material balance is to first review reservoir pressure data as a function of time through use of a plot (see Appendix A to this chapter). This is especially helpful in low-permeability reservoirs, where pressures may not equilibrate throughout the whole reservoir, causing multiple trends to appear. In cases where significant pressure differentials exist, some means of averaging is needed to estimate a uniform trend for the reservoir as a whole.
- In gas material balance analysis, initial p/z trends may suggest a linear relationship, but care must be taken to understand the reservoir drive mechanism. Several drive mechanisms may cause significant deviation from a straight p/z relationship over the life of the reservoir and can lead to materially incorrect GIIP estimates.
- Irrespective of project maturity and the amount and quality of performance data available, the reliability of the 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 known analog reservoirs.

- 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.

4.7 Acknowledgments

We wish to acknowledge the contributions and inputs of Charles Vanorsdale, Monica Clapauch Motta, Rich DuCharme, Dan DiLuzio, and Dr. John Lee. A special acknowledgment also goes to Yasin Senturk, author of this chapter in the previous version of the *Guidelines for Application of the PRMS*.

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Appendix A—Special Considerations for Material Balance Analyses

4A.1 Diagnostic Plots

A good practice when employing material balance methods is to first review reservoir pressure data as a function of time in a plot. Major events that have occurred during the life of the reservoir should be noticed as changes in the trend of the data, and they should be annotated on the plot or included in the documentation supporting the estimate, as appropriate. For example, if the reservoir pressure drops below the bubblepoint in a solution gas reservoir, then this will be evident as a decrease in the rate of pressure decline, as shown in **Fig. A-1.**

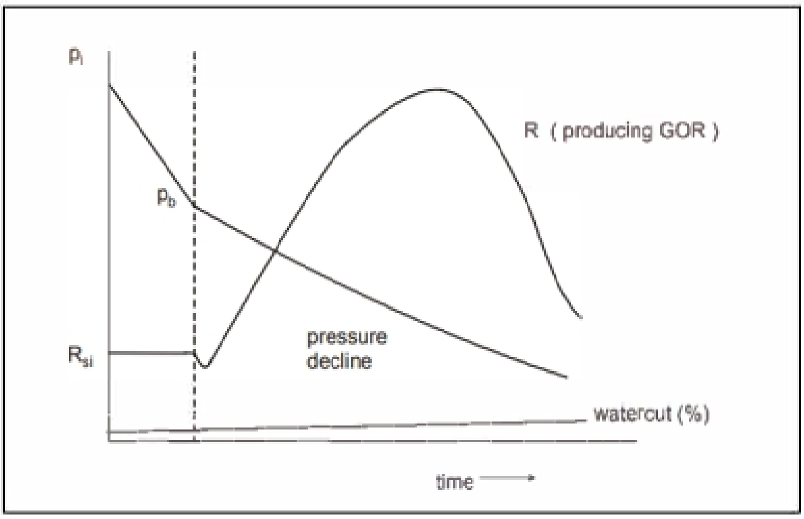

Fig. A-1—General pressure-time plot for a solution gas drive reservoir (Dake 1986), where GOR is gas-oil ratio.

Other noteworthy items include the following, some of which are presented in **Fig. A-2:**

- There may be measurement errors, which may be evident in pressures that are too high or too low when compared with the main pressure-depletion trend. This includes cases where pressures have inadequately built up prior to measurement.
- There may be measurements that are taken from a separate reservoir or fault block that exhibit a different, nonparallel depletion trend.
- There may be evidence of pressure support, causing a flattening or bending upwards of the pressure data, especially in later times.
- There may be significant historical operational changes, including field shut-ins for maintenance or abrupt production changes.

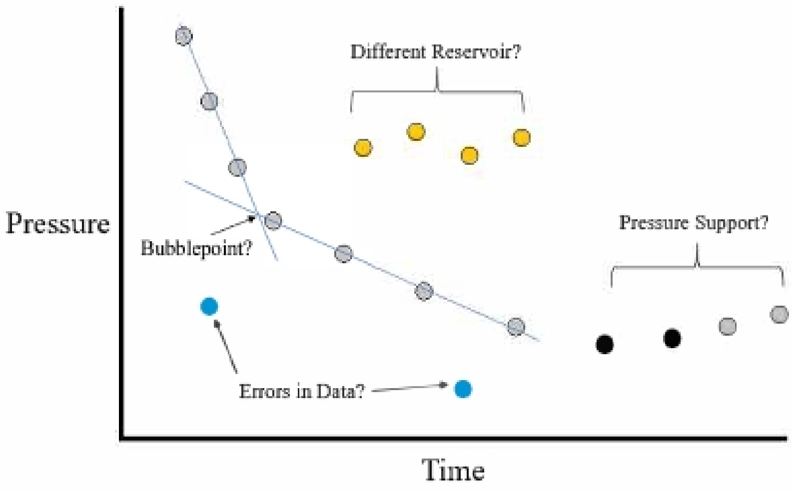

Fig. A-2—Example of effects in a pressure-time plot.

Diagnostic plots can greatly enhance the material balance analyses. Care must be taken to use the correct plot to represent the active drive mechanism because interpretation of an incorrectly selected plot will give misleading results. For example, **Fig. A-3a** represents a gas cap drive material balance analysis plot using the Havlena-Odeh approach, in which the in-place oil volume is represented by the slope of the line, whereas in Fig. A-3b, which is used for waterdrive reservoirs, the in-place oil volume (*N*) is represented by the *y*-axis intercept. In addition, an appropriate straight-line analysis must be created, as indicated by the various possible incorrect analyses indicated in Fig. A-3a and A-3b.

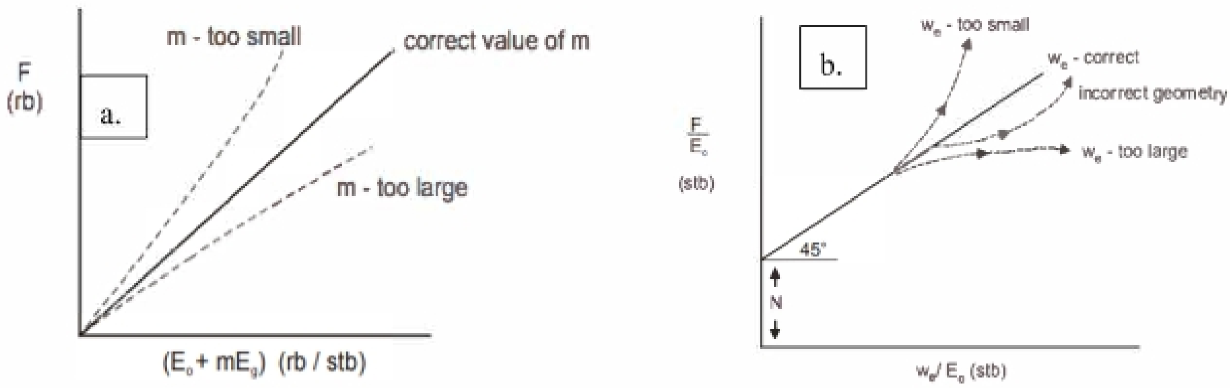

Fig. A-3—Oil material balance analysis plots: (a) estimating gas cap size; (b) estimating aquifer size (Dake 1986).

The terms in the figure above are defined as follows:

$$F = N_p\big(B_o + \big(R_p - R_s\big)B_g\big) + W_pB_w,$$

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s)B_g,$$

$$E_g = B_{oi}\left(\frac{B_g}{B_{gi}} - 1\right),$$

where:

F = production term in the material balance equation, bbl
E_g = expansion of gascap gas term in material balance equation, rb/STB
E_o = expansion of oil and its originally dissolved gas term in the material balance equation, rb/STB
m = ratio of gas-cap gas volume to oil volume, bbl/bbl
W_e = cumulative water influx, bbl
N_p = cumulative oil produced, STB
B_o = oil formation volume factor at reservoir pressure, rb/STB
R_p = cumulative produced gas-oil ratio, scf/STB
R_s = current gas-oil ratio, scf/STB
B_g = current gas formation volume factor, bbl/scf
W_p = cumulative water produced, STB
B_w = water formation volume factor, bbl/STB
B_{oi} = oil formation volume factor at initial reservoir pressure pi, rb/STB
R_{si} = gas solubility at initial pressure pi, scf/STB
B_{gi} = gas formation volume factor at pi, bbl/scf.

4A.2 Low-Permeability Reservoirs

While permeability is not a direct input into material balance equations, it is important to consider the effect of reservoir permeability on pressure. In a low-permeability reservoir (and also, in certain conditions, in a reservoir developed with large well spacing), pressures may not equilibrate throughout the whole reservoir. **Fig. A-4a** presents an example of a high-permeability reservoir where all the pressures have equilibrated for each measurement, while Fig. A-4b presents a low-permeability case where each well has a different pressure trend.

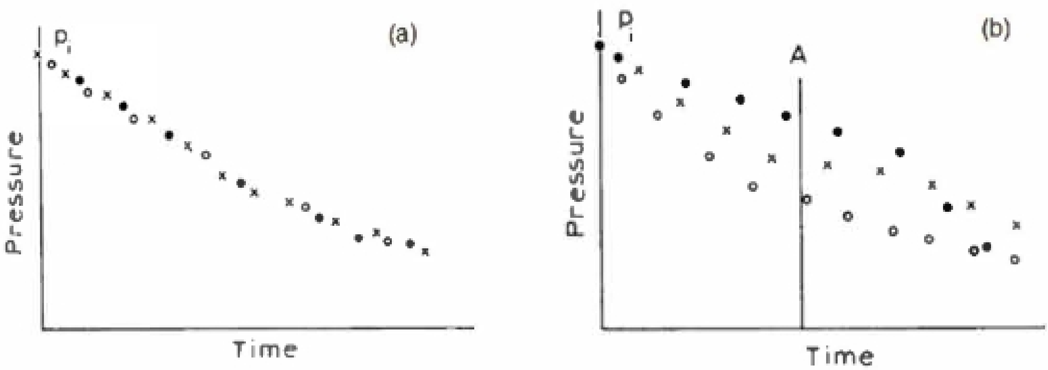

Fig. A-4—Comparison of high- and low-permeability reservoir pressure-time plots (Dake 2001).

In cases where significant pressure differentials exist, some method of averaging individual well pressure declines is needed to estimate a uniform trend for the reservoir as a whole. One simple approach recommended for oil material balances by Dake (2001) is to assign drainage areas to each well and then estimate the average pressure decline by volume weighting of the pressures for each drainage area.

4A.3 Volatile Oils

It is assumed that there is pressure equilibrium in a reservoir for each measured pressure data point, and that fluid samples are representative of in-situ conditions. For a volatile oil system, more caution is required around those assumptions due to the dynamic nature of compositions and increased liquid dropout from produced gases. Conventional material balances with standard laboratory pressure-volume-temperature (black-oil) data tend to underestimate oil recovery for volatile oils (Ahmed 2001).

A volatile oil analysis requires use of a modified form of the oil material balance, such as that presented by Walsh and Raghavan (1994). As reservoir pressure drops below the bubblepoint, and there is a release of gas, there will also be an amount of volatilized oil present in the gas. The MBE is modified by including the ratio of the volume of stock-tank oil to surface gas existing in a vapor phase at reservoir conditions (Rv), representing the volatile gas-oil ratio.

4A.4 Material Balance Pressure Data Quality

Estimates of average reservoir pressure rely upon data gathered from wells. In an ideal situation, all pressure measurements taken and appropriately corrected would represent the true average reservoir pressure. This is generally a reasonable assumption for gas reservoirs where sufficiently long testing times have allowed for a stabilized buildup pressure to be measured. As a guideline, a pressure can be considered to be stable if evidenced by an increase in pressure of no more than 2 kPa/hr (0.3 psi/hr) over a 6-hour period (Alberta Energy Regulator 2013).

For shorter shut-in durations, where pressures may not be stabilized, pressure points used for analysis should be the result of extrapolation from pressure transient analysis of the acquired data or a comparable method, to estimate an equivalent stabilized pressure. If there is no evidence provided of the length of shut-in of pressure data, a wider range of uncertainty should be considered to encompass the possibility of insufficiently built up pressures.

All pressure data should be appropriately corrected to a common datum depth, such as the reservoir midpoint in a well or the field-wide average depth of a reservoir. If wellhead pressure measurements are used, then they must be properly corrected to estimate reservoir pressures at the datum depth, considering fluid property variations that may occur throughout the length of the wellbore. A common method of wellhead-bottomhole pressure drop estimation is to divide the wellbore into segments and estimate the pressure drop for each segment, assuming each segment has uniform fluid properties due to its relatively short length.

4A.5 Abandonment Pressure and Compression

The bottomhole flowing pressure of a well is the sum of a delivery point pressure (typically a plant inlet pressure or sales pipeline pressure) and the pressure drops that occur in the gas gathering system on the surface and in the tubing string in the wellbore. A gas well will stop flowing when the average reservoir pressure approaches the minimum bottomhole flowing pressure at which the system is able to operate. This minimum pressure is also known as the abandonment pressure.

Gas well abandonment pressure (p_{ab}) depends on surface and/or subsurface constraints as well as economics. At the surface, the constraint is typically the pipeline gathering pressure; in the subsurface, the reservoir permeability has a significant influence on the abandonment pressure (low permeability usually results in higher p_{ab}, while higher permeability may result in lower p_{ab}). In the absence of a predetermined p_{ab}, there are rules-of-thumb as a function of the completion depth that may be applied for initial conventional gas reserves estimates. One such rule-of-thumb for Canadian reservoirs (Petroleum Society of the Canadian Institute of Mining Institute 2004) is to use 1500 kPa per 1000 m of depth (approximately 66 psi/1,000 ft). Similarly, a value of 100 psi/1,000 ft of depth has long been used for US fields in Texas and Oklahoma. These figures do not reflect the benefits of compression.

The abandonment pressure and its corresponding (p_{ab}/z_{ab}) value do not necessarily represent the economic limit because the minimum achievable flowing pressure can be reduced by subsequent design and installation of a compression system in the gas delivery system (typically installed at the plant or at the well). It is a common practice to determine whether gas compression is economically viable and can be used to lower well flowing pressures to help gas wells achieve lower abandonment pressures (and associated p_{ab}/z_{ab} values) and thus increase EUR. An example showing an increase in EUR after installation of surface compression can be observed in **Fig. A-5.**

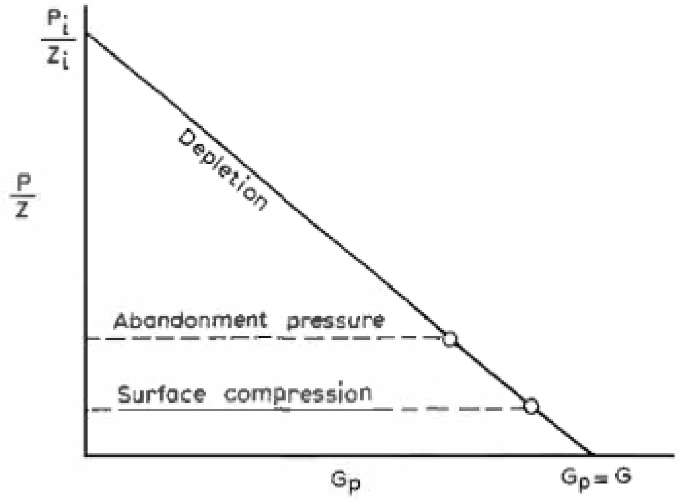

Fig. A-5—Conceptual plot showing the effect of compression on EUR (Dake 2001).

Due to a reduction in flowing pressure, compression may significantly increase the gas production rate of a well, which needs to be considered when modelling gas forecasts and estimating economic viability.

4A.6 Nonlinear *p/z* Relationships

The key assumption of straight-line *p/z* analysis of a volumetric reservoir is that the system behaves like a single tank; i.e., there are minimal pressure variations within the reservoir and no other sources of addition pressure support. Although initial data points may show a linear trend, depending on the drive mechanism present in the reservoir, there may be a deviation from a linear *p/z* analysis trend, such as that shown in **Fig. A-6.**

Note that for most of the mechanisms shown in Fig. A-6, it can be observed that the curves initially appear to exhibit a linear relationship. If only the early data are used for *p/z* analysis estimates, then this would lead to erroneous GIIP estimates.

If the reservoir drive mechanism can be correctly identified, then appropriate correction factors may be applied to either adjust or relinearize the *p/z* plot. In many cases, a more complicated solution, such as the solving of multiple simultaneous material balances, may be required—a task often undertaken using reservoir simulation.

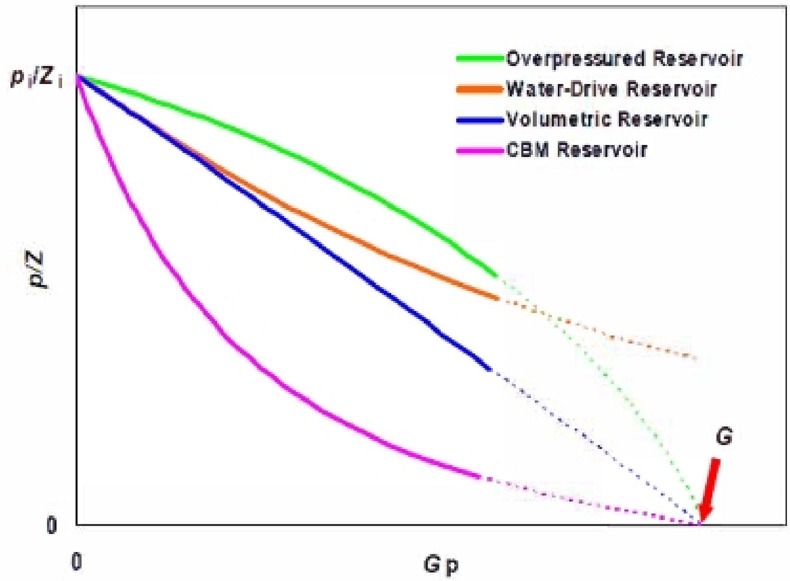

Fig. A-6—Conceptual *p/z* plot showing nonlinear curves due to various reservoir drive mechanism types. CBM stands for coalbed methane (Moghadam et al. 2011).

4A.7 Overpressured Reservoirs

An overpressured reservoir, which includes abnormally pressured and geopressured reservoirs, is defined as a reservoir with a high pressure gradient, generally above 0.5 psi/ft (Ahmed and McKinney 2005). In an overpressured reservoir, the initial formation compressibility may be the same order of magnitude as the gas compressibility. Initially, the formation contributes a significant amount of energy to the reservoir. As the pressure in the reservoir is depleted, the compressibility of the gas increases much faster than the formation compressibility, until the effect of the formation compressibility is negligible.

Material balance analysis of an overpressured reservoir yields two distinct slopes: a shallow trend in the pressure range where the formation expansion plays a significant role and a steeper trend when gas expansion is the single dominant production mechanism. A *p/z* analysis of initial data would significantly overestimate GIIP for an overpressured reservoir, as shown in **Fig. A-7.**

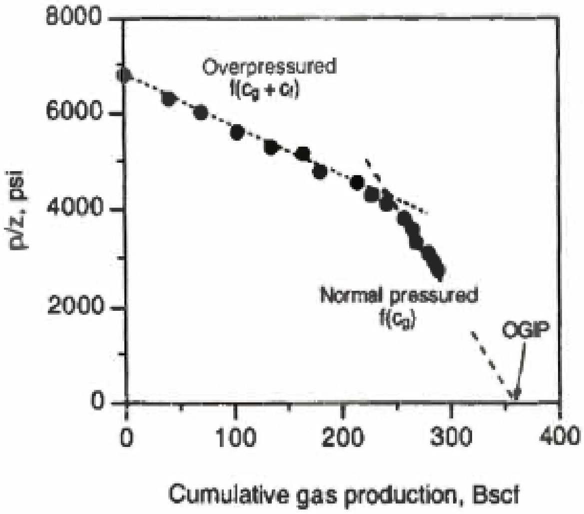

Fig. A-7—Typical overpressured gas reservoir dual-slope *p/z* plot (Poston and Berg 1997), where c_g indicates compressibility of gas.

4A.8 Waterdrive Reservoirs

As pressure declines in a reservoir, there may be influx of water from an aquifer, which acts to provide pressure support. This is generally shown as initial volumetric behavior followed by an upwards bend in the *p/z* analysis line. The strength of the pressure support system can be inferred by the time at which the bend in the analysis line is evident after initial production and the magnitude of the deviation from volumetric behavior.

While the *p/z* analysis line may indicate the presence of a significant waterdrive mechanism, it generally does not allow for identification of the magnitude of the drive. Cole (1969) suggested a simple plot of $G_pB_g/(B_g - B_{gi})$ vs. G_p that would provide an indication of the strength of a waterdrive depending on the shape of the resulting curve, as shown in **Fig. A-8.**

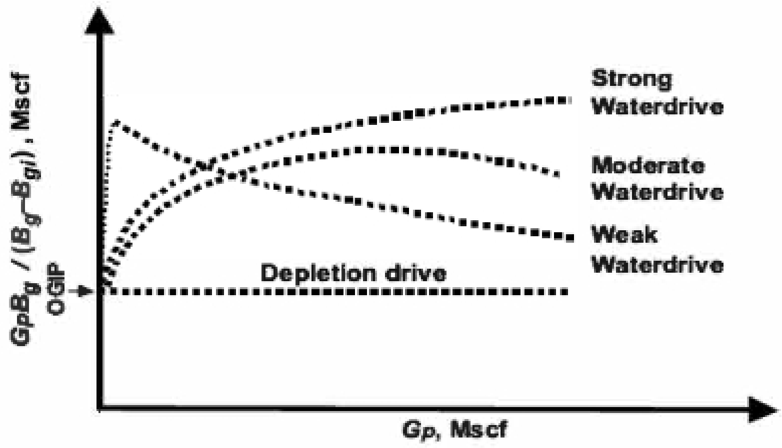

Fig. A-8—Cole plot comparing different waterdrive efficiencies (Pletcher 2002).

Due to gas being trapped by encroaching water, recovery factors for gas reservoirs with a significant waterdrive component tend to be 30% to 50% lower than their dry gas expansion counterparts; this effect may be partially mitigated in high-pressure and high-temperature (HPHT) reservoirs. Identification of the correct pressure support mechanism may be helpful in avoiding overestimation of recoverable volumes.

4A.9 Retrograde Condensate Reservoirs

When performing a material balance on a gas condensate reservoir, it is good practice to use a two-phase gas deviation (z) factor when estimating volumes of gas below the dew point and at higher condensate yields.

The two-phase z factor is used to account for liquid dropout in the reservoir as pressure declines and changes occur in fluid composition in the reservoir. Generally, if only single-phase compressibility factors are used, then there will be an underestimation of gas and condensate recoverable volumes. **Fig. A-9** shows a conceptual example of how the two values may differ, although the shape of the curves will vary based on composition and in-situ conditions.

In Fig. A-9, the two curves would provide similar results when the pressure is close to initial conditions. As the pressure in the reservoir is depleted, condensate dropout commences, which leads to a divergence in the behavior of the z factor curves.

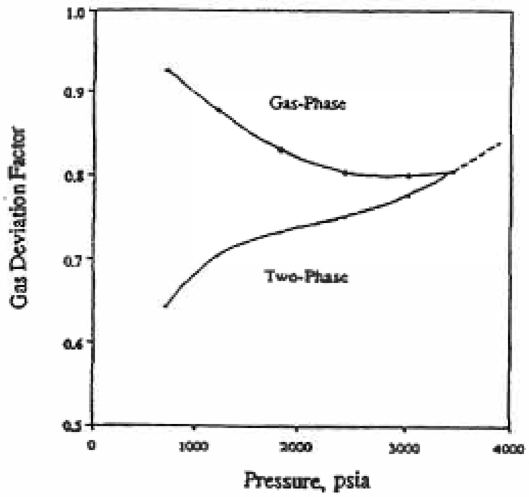

Fig. A-9—Example of equilibrium and two-phase gas deviation factors for a gas condensate reservoir (Lee and Wattenbarger 1996).

Two-phase *z* factors may be obtained from laboratory tests or estimated from fluid composition through use of an equation of state. Specifically, two-phase *z* factors are measured from constant-volume depletion tests (Lee and Wattenbarger 1996).

4A.9.1 Considerations Related to Liquid Recovery Comments. When estimating liquid recovery from gas condensate reservoirs, note that the condensate yield changes as the reservoir pressure is depleted. A typical condensate yield curve is shown in **Fig. A-10.** Estimating liquid recovery using a gas EUR estimated from material balance and an initial condensate gas ratio may lead to significant overestimation of liquid recovery.

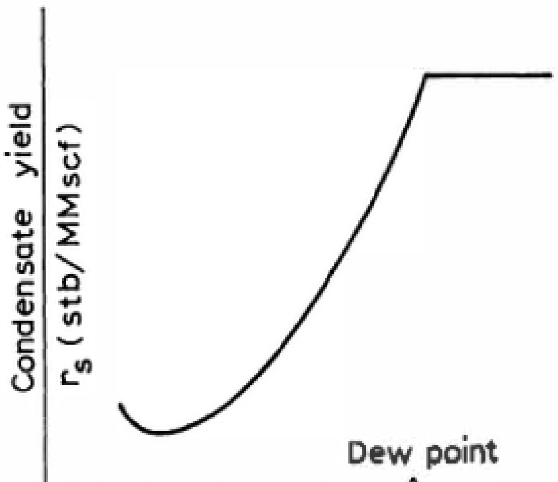

Fig. A-10—Example of condensate yield curve (Dake 2001).

To properly provide an economic estimate of natural gas liquid reserves and/or resource volumes, the following must be known:

- The reference point:
  - As described in § 3.2.3.1 of the PRMS, the reference point location will define if produced gas will be sold as wet gas or as dry gas and extracted liquids. The