

APPLICATION OF RESERVOIR ENGINEERING EQUATIONS IN GAS RESERVES ESTIMATION

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ABSTRACT

In order that a natural gas reservoir may be properly exploited, the amount of gas contained in the reservoir must be known. Since this quantity, commonly called the reserve, cannot be measured directly during the life of the reservoir, it must be estimated. This paper, which restricts itself to dry gas reservoirs, presents a detailed review of the various reserve estimation methods currently available. Specifically, it reviews the volumetric and pressure decline methods and presents a unified material balance approach designed to deal with reservoirs which exhibit water production and encroachment simultaneously. The latter is capable of dealing with reservoir aquifer systems where the rate of influx is constant, or the rate of influx is a function of time and the influx, either radial or linear, is from aquifers which are either finite or infinite.

INTRODUCTION

Compressibility factor

The accurate estimation of gas compressibility factor (z) is very important in estimation of free gas reserves. As the gas deviation factor varies usually between 0.70 to 1.20, this has got a great bearing on assessed gas reserves.

The most convenient method of computing the PVT relationship of natural gas, is by use of the compressibility factor, which represents the deviation of the gas in question from the ideal gas laws as expressed in the following equation (used for an imperfect gas):

The compressibility factor (Z) is an empirical factor, determined experimentally, which makes the above equation true at a particular temperature and pressure. For a perfect gas, Z is equal to one. For an imperfect gas (hydrocarbon gases), Z is greater or less than one, depending on the pressure and temperature.

At the same reduced temperature and pressure, all hydrocarbon gases have the same value of Z . the reduced temperature and pressures are finding as:

$$Pr = P/Pc \quad \text{and} \quad Tr = T/Tc$$

Where, Pc is the critical pressure and

Tc is the critical temperature

Value for the critical temperature and pressure of several hydrocarbon gases should be tabulated in a table to calculate T_r and P_r , all temperature and pressures must be in absolute unit ($^{\circ}R$ or $^{\circ}K$ and psia or atm).

Method of computing Z factor

The compressibility factor (Z) may be determined:

- Experimentally by PVT analysis of a gas sample
- From an analysis of the gas expressed in mole percent or volume percent.
- From the specific gravity of the gas.

Computation from gas analysis

In this method weighted average pseudo critical pressure and temperature are obtained for the gas by multiplying the individual critical pressure and temperature for each component, with the corresponding mole percent of such component.

The pseudo critical temperature T_c of this natural gas is $393.31^{\circ}R$ absolute and its pseudo critical pressure P_c is 667.65 psia. These values are constant for all computations involving the PVT relationship of this natural gas.

For this gas at a temperature of $100^{\circ}F$ and 2000 psia, the pseudo reduced temperature is:

$$T_r = T/T_c = 460 - 100 / 393.31 = 1.424$$

Similarly, the pseudo reduced pressure for the same conditions is :

$$P_r = P/P_c = 2000 / 667.65 = 2.996$$

In order to determine the compressibility factor, pseudo-reduced temperature and pressure are read from the standard charts and a value of $Z = 0.740$ is obtained. The same chart is applicable for CGS units also.

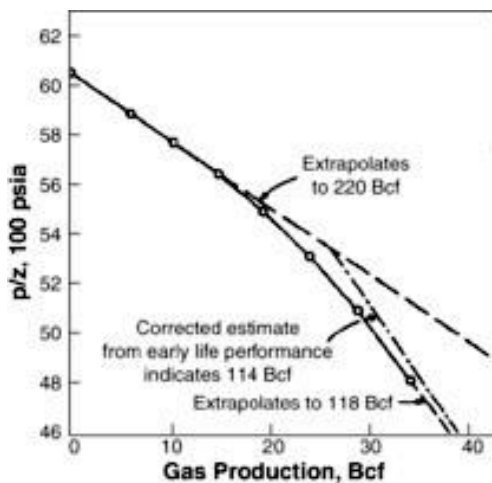
Computation from gas gravity

The gas deviation factor (Z) can also be computed from specific gravity of the gas. When the carbon dioxide, nitrogen and hydrogen sulphide content of the gas is known, the critical values may be corrected for these impurities. The pseudo reduced pressure and temperature are calculated using these critical values. The gas deviation factor is found from the reduced pressure and temperature using the correlation chart. This method gives good results where there is a less than 5% impurity and where the gas contains at least 50% methane by volume. The quantity and composition of the condensate contained in a natural gas also affect the results and therefore, separate curves for natural gas with low condensate and those containing appreciable condensate.

Volumetric estimates based on cores, well logs, fluid analyses, and geological estimates of reservoir size provide a "rock-based" estimate of gas in place, while material-balance relationships provide a "fluids-based" or "pressure-based" estimate. These two types of estimates are essentially independent (except for the use of consistent values of B_{gi}). Thus, when the two estimates are compared, there is greater certainty in the OGIP estimate. It is now a common practice to develop geologic and simulation models of a reservoir to determine reserves and depletion strategies and to evaluate alternative development scenarios

Highly compressive reservoirs

For some high-pressure gas reservoirs (e.g., geopressured or abnormally pressured reservoirs), the combined rock and water compressibility can result in a nonlinear p/z plot. Ignoring this effect can lead to large overestimates of the OGIP. Local knowledge is the best source of information about whether these effects should be considered. Such performances usually should be suspected for geopressured reservoirs.



Gas and gas-condensate reservoirs are compositionally distinguished from oil reservoirs by the predominance of lighter hydrocarbons, such as methane (60 to 95 percent) and ethane (4 to 8 percent). Three types of oil and gas reservoirs are identified based on their hydrocarbon fluid composition: (1) oil (with dissolved gas), (2) gas, and (3) gas condensate. In addition, a two-phase region exists between the bubble point and dew point lines; that is, oil reservoirs with a gas cap. Depending on the reservoir pressure and temperature and the fluid composition, some gas reservoirs may produce only gas, whereas others produce mostly gas with some condensate.

In contrast, gas-condensate reservoirs will always produce gas mixed with condensate, with the quantity of condensate varying from one reservoir to another. Gas condensate is a low-density mixture of liquid hydrocarbons that are present as gaseous components in the natural gas.

The reservoir management of gas-condensate reservoirs becomes challenging when the condensate begins to build up near the bottom of the wellbore, affecting well productivity due to the relative permeability effect of a two-phase flow.

Gas-in-place volume

Data required to estimates of the gas-in-place volume are:

- Reservoir pressure and temperature, or depth to calculate the required parameters,
- Compositions of oil and gas or their gravities and molecular weights,

- Gravities and production rates of separator condensate and gas,
- Rock porosity,
- Gas or interstitial water saturation, and
- Area and thickness

The volume of hydrocarbons in a reservoir can be calculated: *directly* by volumetric methods, *indirectly* by material balance methods

Volumetrics provide a *static* measure of oil or gas in place. Accuracy of volumetrics depends on data for:

- porosity
- net thickness
- areal extent
- hydrocarbon saturations

Material balance methods provide a *dynamic* measure of hydrocarbon volumes. Accuracy depends on quality of data for:

- pressure surveys
- temperature surveys
- analysis of recovered fluids

Normally mass balance methods increase in accuracy as the reservoir is produced.

VOLUMETRIC ANALYSIS

Also known as the *geologist's method* because it is based on geological maps, core logs and analysis of wireline logs. Isopach maps are used to compute the bulk volume of the reservoir (V). For

GAS VOLUMES

The volume of free gas in a gas reservoir or gas initially-in-place is given by:

$$GIIP = Gr = (V.n).(1 - Swi)$$

In terms of standard volumes at STP, the gas volume is:

$$G = (V.n).(1 - Swi) / Bg$$

$$G = (V.n).(1 - Swi).E$$

where Bg is the gas formation volume factor and E is the gas expansion factor.

For oil and gas reservoirs below the bubble point, the total hydrocarbon in place is given by the HCPV:

$$HCPV = (V.n).(1 - Swi)$$

The stock tank oil volume can be computed as:

$$STOIP = (V.n).(1 - Swi - Sg) / Bo$$

The standard gas volume at STP is given by:

$$G = (V.n).(1 - Swi - So) / Bg$$

Gas in place and recoverable volumes

Discusses various aspects of gas reservoir performance, primarily to determine initial gas in place and how much is recoverable. The equations developed can be used to form the basis of [forecasting future production rates](#) by capturing the relationship between cumulative fluid production and average reservoir pressure.

Material-balance determination of OGIP

Material-balance equations provide a relationship between original fluids in place, cumulative fluid production, and average reservoir pressure. For many gas reservoirs, a simple material-balance equation can be derived on the basis of the following assumptions:

- Gas-filled pore volume is constant
- Gas dissolved in water or liberated from the rock is negligible
- Reservoir temperature is uniform and constant

With these assumptions, the [real-gas law](#) can be used to derive

$$V_g = \frac{RT}{V_{msc}} \frac{z_i}{p_i} G = \frac{RT}{V_{msc}} \frac{z}{p} (G - G_p).$$

This equation can be rearranged to get the usual volumetric gas material-balance equation,

$$\frac{G_p}{G} = 1 - \frac{p/z}{p_i/z_i}.$$

This equation is the basis for the p/z -vs.- G_p graph used to analyze gas reservoirs.

In volumetric dry- and wet-gas reservoirs, p/z vs. cumulative gas production will be a straight line intercepting the gas-production axis at the OGIP.

An example is given in *Figure*. The intercept ($G_p = 0$) on the p/z axis is p_i/z_i , and the intercept on the G_p axis ($p/z = 0$) is G . This graph provides a convenient method of using average-reservoir-pressure data to estimate OGIP and recoverable reserves once an abandonment p/z is established. When these plots are applicable, results for OGIP are generally considered very accurate after approximately 10% of gas reserves have been produced (sometimes a bit earlier).

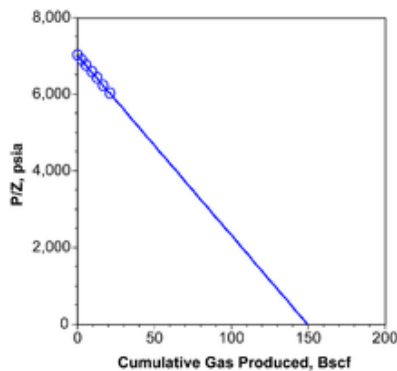


Fig. – Example p/z -vs.- G_p curve for a volumetric gas reservoir.

When only a small amount of early data is available, the OGIP can be determined from any point ($G_p, p/z$) by

$$G = \frac{G_p}{1 - \frac{p/z}{p_i/z_i}}$$

When placing the straight line through p/z data, it is usually prudent to consider the first point (i.e., at field discovery pressure) as more accurate than others. Because there has been little field depletion and there has been sufficient time for pressures to return to stabilized conditions, discovery-pressure measurements are generally reliable. Regression approaches to placing the p/z -s.- G_p line should take this into consideration.

CONCLUSION

The **compressibility factor (Z)** is a useful thermodynamic property for modifying the ideal gas law to account for behavior of real gases. It is a measure of how much the thermodynamic properties of a real gas deviate from those expected of an ideal gas. It may be thought of as the ratio of the actual volume of a real gas to the volume predicted by the ideal gas at the same temperature and pressure as the actual volume.

For an ideal gas, Z always has a value of 1. For real gases, the value may deviate positively or negatively, depending on the effect of the intermolecular forces of the gas. The closer a real gas is to its critical point or to its saturation point, the larger are the deviations of the gas from ideal behavior.

The upper graph in Figure 1 illustrates how the compressibility factor varies for different gases at the same temperature and pressure. The lower graph illustrates how the compressibility factor of a gas (for example, methane) at a given pressure varies with temperature.

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