Volumetric Estimates in Natural Gas Reservoirs

Course No: P03-005
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Volumetric Estimates in Natural Gas Reservoirs

Introduction

The purpose of this course is to educate one on the volumetric method used to estimate original gas-in-place (OGIP) and recoverable gas from a volumetric drive gas reservoir. A volumetric drive gas reservoir is the most common type of reservoir containing gas. A volumetric drive gas reservoir has the following characteristics:

- Fixed reservoir boundary – no change in reservoir size over the life of production
- Drive mechanism is expansion – pressure drops in the reservoir as gas is produced

The other major gas reservoir types are gas cap and water drive. A gas cap reservoir expands downward as oil is produced causing loss of pressure in addition to pressure lost due to production. A water drive reservoir remains at fairly constant pressure over its life as water moves toward producing wells to fill the void left by produced gas. Neither of these will be discussed in this course.

The contents of this course are as follows:

- Volumetric Equation for Estimating Original Gas-in-Place and Recoverable Gas
- Ideal Gas Law
- What is natural gas
- Components of natural gas
- Properties of natural gas components
- Calculation of natural gas properties from gas composition
- Determination of the gas deviation factor (z-Factor)
- Calculation of the gas expansion factor (Eg) and gas formation volume factor
- Discussion of reservoir area and thickness
- Discussion of porosity and water saturation
- Estimation of abandonment pressure
- Estimation of original gas-in-place (OGIP)
- Estimation of recoverable gas
- Conclusion

Along with the text material for this course is an Excel spreadsheet that will be used to calculate some of the parameters needed to calculate OGIP and recoverable gas. There are also two worksheets that can be used to calculate OGIP and recoverable gas in both Imperial and Metric units.

Volumetric Equation for Estimating Original Gas-in-Place and Recoverable Gas

The volumetric estimation of original gas-in-place (OGIP) and recoverable gas uses an equation composed of various parameters of the original static condition of the reservoir. Each of the parameters and units of measurement will be discussed in this course. The amount of gas in a reservoir is quite large and the volumes are usually calculated in millions or billions of standard cubic feet (MMscf or Bscf). The equation used to calculate OGIP is as follows:

$$OGIP = \frac{0.04356 * A * h * \emptyset * (1 - S_w)}{B_g}$$

where,

OGIP = Original gas-in-place (Million standard cubic feet or MMscf)

A   = reservoir area (acres)

h   = reservoir thickness (feet)

$\emptyset$ = reservoir porosity (decimal)

S_w = reservoir water saturation (decimal)

B_g = gas formation volume factor (reservoir cubic feet per standard cubic feet)

This equation can alternately be written as:

$$OGIP = 0.04356 * A * h * \emptyset * (1 - S_w) * E_g$$

where,

E_g = gas expansion factor (standard cubic feet per reservoir cubic feet)

Recoverable gas is the portion of OGIP that can be recovered at a given recovery factor and calculated as:

$$Recoverable\ Gas = OGIP * RF$$

where,

RF = recovery factor (decimal)

The recovery factor for a volumetric drive gas reservoir (to be discussed later) is based on recovery to a reservoir abandonment pressure. Due to the depth of the reservoir and an economic producing rate, the reservoir will cease producing at an "abandonment pressure". The choice of abandonment pressure will vary with each reservoir, gas composition, gas price, operating expenses, etc. Many times, production forecasts will be performed at various abandonment pressures to determine the optimal economic recovery. The recovery factor is calculated by:

$$RF = \frac{\frac{P_i}{z_i} - \frac{P_{ab}}{z_{ab}}}{\frac{P_i}{z_i}}$$

where,

   RF = recovery factor (decimal)
   P_i = original reservoir pressure (psia)
   P_{ab} = abandonment reservoir pressure (psia)
   z_i = original gas deviation factor (no units)
   z_{ab} = abandonment gas deviation factor (no units)

To understand the conditions in which gas exists in reservoirs we will review all the parameters presented above. To begin, we will first need to discuss how gases, and in particular hydrocarbon gases behave under pressure and temperature.

The Ideal Gas Law

In order to understand gas properties, one must understand how gases behave. Gas molecules, unlike the other phases of matter – liquids and solids, are not bound together by intermolecular and viscous forces. As such, gases completely fill whatever container in which they reside. This property is very important and can be used to determine how gases behave under the effects of pressure, temperature, and volume.

The Ideal Gas Law is an equation of state that relates pressure, temperature, and volume. This equation is the results of combining Boyle's law, Charles' law, Avogadro's law, and Gay-Lussac's law. Shown below is the Ideal Gas Law equation of state:

$$PV = nRT$$

where,

   P = pressure (psia – pounds per square inch absolute)
   V = volume (scf – standard cubic feet)

T = temperature (ºR - degrees Rankine)

n = number of moles of gas (moles)

R = ideal gas constant (10.73 scf-psia/mole-ºR)

The purpose of R, the ideal gas constant is to convert to consistent units. Depending on the units used, R will change. It should always be remembered that when dealing with gases, temperature is always in absolute units (i.e., Kelvin or Rankine). In the USA, we use units of Rankine (Fahrenheit plus 459.67 degrees).

Based on the Ideal Gas Law, one can derive a very important relationship. If a gas is composed of different types of molecules (i.e., nitrogen, oxygen, etc.), the volume percentage of each gas is equal to the molar percentage of that gas. This can be shown as follows:

Let V be the total gas volume and N be the total number of moles. The Ideal Gas Law equation is then:

$$PV = NRT$$

Let v be the volume of a single gas component and n be the moles of that component. The Ideal Gas Law for that component is then:

$$Pv = nRT$$

Taking a ratio of the individual gas component to the total gas gives the following:

$$\frac{Pv}{PV} = \frac{nRT}{NRT}$$

Since P, R, and T are all equal, this equation can be simplified as:

$$\frac{v}{V} = \frac{n}{N}$$

This clearly shows that the ratio of an individual component to the total volume is the same as the number of moles of a component to the total number of moles of gas. This is very important because gas samples are analyzed in the laboratory and the results presented as mole percentages, which in effect are volume percentages. This equation of state works well under normal ranges of pressure and temperature when the interaction between molecules is relatively small. In the case of hydrocarbon gases, however, the molecular interactions are not small and must be taken into account. For that purpose, the Ideal Gas Law is modified to account for these interactions. Shown below is the Ideal Gas Law equation modified for hydrocarbon gases:

$$PV = nRTz$$

where,

z = gas deviation factor

This course will discuss how to determine z based on the reduced pressure and temperatures. The value for z does depend on the constituents that make up the natural gas. Specifically, the value of z depends on the gas specific gravity and the reduced pressure and reduced temperature. The reduced pressure is the measured pressure divided by the critical pressure and the reduced temperature is the measured temperature divided by the critical temperature. The determination of the critical pressure and temperature will be discussed in a later section of this course. However, shown below are the equations for the reduced pressure and temperature.

$$Pr = P/Pc$$

$$Tr = T/Tc$$

where,

Pr = reduced pressure
P = measured pressure (psia)
Pc = critical pressure (psia)
Tr = reduced temperature
T = measured temperature (ºR)
Tc = critical temperature (ºR)

Example Problem 1:

How many moles of gas are there in the container given the following data:

Container volume = 2 scf
Temperature = 80 ºF
Pressure = 500 psia

Answer:

The first thing to do is calculate the temperatures in absolute temperature degrees, so the temperature is:

T = 80 + 459.67 = 539.67 ºR

Rearrange the Ideal Gas Law equation to solve for "*n*" as shown below:

$$n = \frac{PV}{RT} = \frac{(500) * (2)}{(10.73) * (539.67)} = 0.17 \; moles$$

What is Natural Gas

Most of us think of natural gas as something we use in our homes for heating or cooking. It is true that we tend to call gas delivered to our homes as "natural gas", but in reality, it is a nearly single component called "methane" that is derived from natural gas. So, what is natural gas and what is it composed of?

Webster's Dictionary defines natural gas as

> *"gas issuing from the earth's crust through natural openings or bored wells, especially a combustible mixture of methane and other hydrocarbons used chiefly as a fuel and raw material"*

Natural gas is created in the earth's crust by the decay and reduction of organic material. As organic material is deposited on the earth's surface and subsequently buried, it is subjected to increased pressure and temperature. As this process continues, the organic material is reduced to petroleum. Depending on the composition of the original organic matter, the temperature, and pressure, the petroleum is either gaseous or liquid. As this petroleum forms, it begins to seep and being lighter than water, begins to move toward the earth's surface. This seeping petroleum moves along faults or through porous rocks and either makes it to the surface or is trapped along the way. There are various ways petroleum can be trapped, but most commonly with some type of seal like an impervious rock layer that prevents its further upward movement. The trapped petroleum exists in porous rocks known as reservoirs. Natural gas can exist in reservoirs as a gas or can be liberated from oil as it is produced. Natural gas can also exist in coal seams and is referred to as coalbed methane or coal seam gas. In the case of gas existing in coal seams, the coal is both the source rock and reservoir and the gas is actually attached to the surface of the coal.

Although there are gases emanating from the earth that do not contain hydrocarbons (i.e., nitrogen and carbon dioxide), the discussions in this course will be concerned only with hydrocarbon natural gases. Unlike non-hydrocarbon gases, hydrocarbon gases behave quite differently to pressure and temperature. With the exception of very high pressures and temperatures, non-hydrocarbon gases closely follow the Ideal Gas Law. The Ideal Gas Law is an equation of state that relates pressure, temperature and volume. Due to the interaction of hydrocarbon molecules, hydrocarbon gases deviate from the Ideal Gas Law. By analyzing the composition of natural gas, one can adjust the

Ideal Gas Law to account for these interactions and properly calculate the relationship between pressure, temperature and volume.
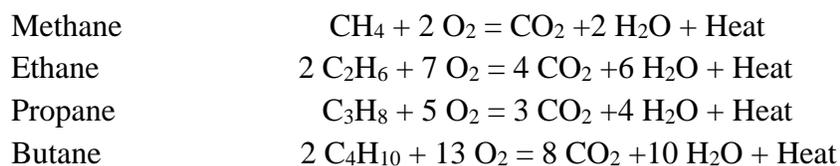
Components of Natural Gas

The most common hydrocarbon constituents of natural gas are known as alkanes or paraffins. An alkane is a molecule composed of carbon and hydrogen with single bonds between the atoms and forming a chain-like structure. The simplest alkane is methane, which consists of a single carbon atom connected to four hydrogen atoms. Alkanes are named by the number of carbon atoms that make up the molecule. After methane, the next molecule containing two carbon atoms is called ethane. An alkane containing three carbon atoms is propane. Shown below are diagrams of the first four alkanes.
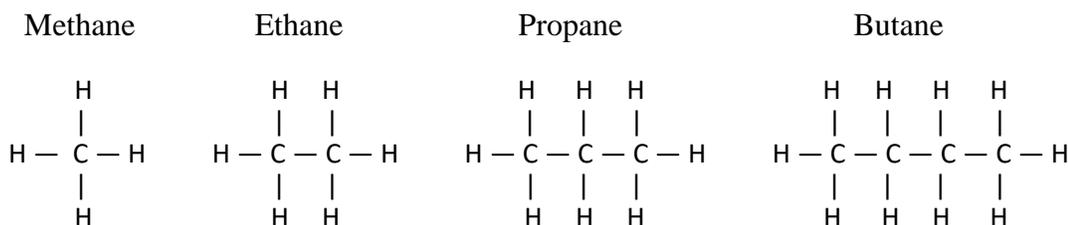
The first thing to notice is that there is a relationship between the number of hydrogen atoms and the number of carbon atoms. If n is the number of carbon atoms, then the number of hydrogen atoms is 2n+2. Since there is a direct relationship between the carbon and hydrogen atoms that comprise alkane molecules, there is also a direct relationship between the molecular weight and heating content of the alkanes.

The molecular weight of carbon is approximately 12 pounds per pound-mole and the molecular weight of hydrogen is approximately 1 pound per pound-mole. Using the formula for the relationship between the number of carbon and hydrogen atoms gives an increase of 14 pounds per pound-mole for each increment in alkanes. Hydrocarbons create energy by reacting with oxygen (i.e., burning or combustion). If one combines a hydrocarbon with oxygen, the result is carbon dioxide (CO_2), water (H_2O), and heat. The amount of heat is directly proportional to the amount of carbon, hydrogen, and oxygen consumed in the process. Shown below are the equations for combustion for the first four alkanes.

Methane	$CH_4 + 2\ O_2 = CO_2 + 2\ H_2O + Heat$
Ethane	$2\ C_2H_6 + 7\ O_2 = 4\ CO_2 + 6\ H_2O + Heat$
Propane	$C_3H_8 + 5\ O_2 = 3\ CO_2 + 4\ H_2O + Heat$
Butane	$2\ C_4H_{10} + 13\ O_2 = 8\ CO_2 + 10\ H_2O + Heat$

Example Problem 2:

    a) How many hydrogen atoms are in a molecule of octane (8 carbons atoms)?
    b) What is the estimated molecular weight?

Answer:

    a) Using the equation that hydrogen atoms are 2n+2 carbon atoms:

       2 x 8 + 2 = 18 hydrogen atoms in octane

    b) The estimated molecular weight is 12 times the number of carbon atoms plus 1 times the number of hydrogen atoms as:

       Estimated molecular weight of octane = 12 x 8 + 1 x 18 = 114 pound per pound-mole

Besides the major alkane hydrocarbons, there are other constituents of natural gas that occur. The most common of these are: Air, Nitrogen (N_2), Oxygen (O_2), Carbon Dioxide (CO_2), Hydrogen Sulfide (H_2S), Hydrogen (H_2), Argon (Ar), Helium (He).

When computing properties of natural gas, these constituents must be taken into account as they affect the overall properties of the gas. As a rule, most of these constituents occur in minor amounts. The exception to this rule are carbon dioxide (CO_2) and nitrogen (N_2) which can sometimes occur in large amounts. Although some gas contracts allow for small amounts of non-hydrocarbons in the gas stream, prior to sale or use for commercial purposes, the major portion of these constituents must be removed. In gases containing hydrogen sulfide (H_2S), this constituent is extremely toxic and must always be removed prior to transmission or sale.

Table 1 shown on the next page lists the most common constituents of natural gas along with their molecular formula, molecular weight, critical pressure, and critical temperature. Occasionally, a natural gas contains other gases such as benzene or toluene. If these are present, their properties can be added to the table and used to calculate overall properties of the gas. The footnote on Table 1 gives the source of the gas property data and can be referenced for additional constituents.

Component	Molecular Formula	[1,2]Molecular Weight	[1,2]Critical Pressure (psia)	[1,2,3]Critical Temperature (^{o}R)
Methane	CH_4	16.042	667.00	343.01
Ethane	C_2H_6	30.069	706.60	549.59
Propane	C_3H_8	44.096	615.50	665.59
Iso-Butane	C_4H_{10}	58.122	527.90	734.08
N-Butane	C_4H_{10}	58.122	550.90	765.22
Iso-Pentane	C_5H_{12}	72.149	490.40	828.67
N-Pentane	C_5H_{12}	72.149	488.80	845.47
Hexane	C_6H_{14}	86.175	436.90	913.47
Heptane	C_7H_{16}	100.202	396.80	972.57
Octane	C_8H_{18}	114.229	360.70	1,023.87
Nonane	C_9H_{20}	128.255	330.70	1,070.47
Decane	$C_{10}H_{22}$	142.282	304.60	1,111.87
Air		28.959	551.90	238.70
Nitrogen	N_2	28.014	492.50	227.14
Oxygen	O_2	31.999	731.40	278.24
Carbon Dioxide	CO_2	44.010	1,070.00	547.45
Hydrogen Sulfide	H_2S	34.082	1,306.50	672.48
Hydrogen	H_2	2.016	190.70	59.77
Argon	Ar	39.948	705.32	271.24
Helium	He	4.003	33.00	9.35

Notes:

 1 - From Gas Processors Suppliers Association Engineering Data Book, Twelfth Edition, 2004

 2 - From NIST Chemistry WebBook, SRD 69 https://webbook.nist.gov/chemistry/fluid/

 3 - Degrees Rankine = Degrees Fahrenheit + 459.67

Table 1. Common Constituents of Natural Gases

Calculation of Natural Gas Properties from Gas Composition

The composition of a natural gas is made by analyzing a sample of the gas. The sample can be taken directly form the reservoir using a special device or can be taken at the surface from the production facilities. Once the sample is taken it is sent to a laboratory where measurements of the components and their proportion of the total gas are made.

The amount of each component of the gas sample is reported as "Mole %" which is the percentage of the number of molecules of the component divided by the total number of gas molecules. For a gas, the Mole % is the same as the volume percent.

Shown below in Table 2 is an example of a gas sample.

Component	Measured Mole %
Methane	79.28
Ethane	3.55
Propane	3.43
I-C4	1.80
N-C4	1.54
I-C5	1.66
N-C5	1.30
C6	1.92
C7	0.88
C8	0.75
C9	0.00
C10	0.00
O2	0.00
N2	2.44
CO2	1.30
H2S	0.00
Ar	0.15
Total	100.00

Table 2. Example Gas Sample

Notice that many of the components are simply listed as the number of carbon atoms in the molecule. This is common practice in some labs. It is fortunate that for this gas sample the total of the constituents add up to 100 percent. In some cases, the total is not 100% and must be adjusted so the total is equal to 100 percent. Due to the methods used and the percision of the instruments making the measurements, the totals do not always add to 100 percent. In those cases, an adjustment to the percentage of each component must be made. Table 3 shows a gas sample where the components do not add up to 100 percent and the method used to correct the tabel values.

Component	Measured Mole %	Adjusted Mole %
Methane	78.20	78.61
Ethane	3.66	3.68
Propane	3.40	3.42
I-C4	1.84	1.85
N-C4	1.62	1.63
I-C5	1.65	1.66
N-C5	1.22	1.23
C6	1.88	1.89
C7	0.91	0.91
C8	0.82	0.82
C9	0.25	0.25
C10	0.14	0.14
O2	0.00	0.00
N2	2.44	2.45
CO2	1.30	1.31
H2S	0.00	0.00
Ar	0.15	0.15
Total	99.48	100.00

Notes:
  Adjusted Mole% = Measured Mole % / Total Measured Mole %

Table 3. Example Gas Sample Adjustment

The adjusted mole percentages are just the measured mole percentages divided by the total of the measured mole percentages. When the total of the measured mole % is 98 percent or greater, this method can be used with fair accuracy. If the sum is less than 98 percent, the accuracy of this method decreases and might warrant an new gas sample.

Calculating the gas properties of the sampled gas is done by combining the results of the gas sample with the properties shown in Table 1. For the purpose of showing how to calculate gas properties of a gas sample, we will use the gas sample shown in Table 2. Table 4 on the next page combines the mole percentages of the gas sample in Table 2 and the properties of each component from Table 1 into a single table.

Component	Molecular Formula	Mole Fraction (%)	Molecular Weight	Critical Pressure (psia)	Critical Temperature (°R)
Methane	CH_4	79.28	16.042	667.00	343.01
Ethane	C_2H_6	3.55	30.069	706.60	549.59
Propane	C_3H_8	3.43	44.096	615.50	665.59
Iso-Butane	C_4H_{10}	1.80	58.122	527.90	734.08
N-Butane	C_4H_{10}	1.54	58.122	550.90	765.22
Iso-Pentane	C_5H_{12}	1.66	72.149	490.40	828.67
N-Pentane	C_5H_{12}	1.30	72.149	488.80	845.47
Hexane	C_6H_{14}	1.92	86.175	436.90	913.47
Heptane	C_7H_{16}	0.88	100.202	396.80	972.57
Octane	C_8H_{18}	0.75	114.229	360.70	1,023.87
Nonane	C_9H_{20}	0.00	128.255	330.70	1,070.47
Decane	$C_{10}H_{22}$	0.00	142.282	304.60	1,111.87
Air		0.00	28.959	551.90	238.70
Nitrogen	N_2	2.44	28.014	492.50	227.14
Oxygen	O_2	0.00	31.999	731.40	278.24
Carbon Dioxide	CO_2	1.30	44.010	1,070.00	547.45
Hydrogen Sulfide	H_2S	0.00	34.082	1,306.50	672.48
Hydrogen	H_2	0.00	2.016	190.70	59.77
Argon	Ar	0.15	39.948	705.32	271.24
Helium	He	0.00	4.003	33.00	9.35
Total		**100.00**			

Table 4. Gas Composition from Table 2 and Gas Properties from Table 1

To determine the properties of the gas sample, we will now add some columns to Table 4 so we can calculate the mole percentage weighted properties of each component. Table 5 shows the additional columns where the weighted values are tabulated and accumulated. To calculate the mole weighted value of each property, multiply the value for that property by the mole percentage for the given component. This table can be created manually, or it can be created using a spreadsheet program.

In this example, the mole percentage for ethane is 3.55%. The value for the critical pressure of ethane is 706.6 psia. Multiplying 706.6 psia by 3.55% give a mole weighted value of 25 psia as shown in mole weighted critical pressure column for ethane. Once we have calculated the mole weighted values for each component in the gas sample, the values are summed to arrive at the properties for the gas sample.

Component	Molecular Formula	Mole Fraction (%)	Molecular Weight	Critical Pressure (psia)	Critical Temperature (°R)	Mole Fraction Weighted		
						Molecular Weight	Critical Pressure (psia)	Critical Temperature (°R)
Methane	CH_4	79.28	16.042	667.00	343.01	12.72	529	272
Ethane	C_2H_6	3.55	30.069	706.60	549.59	1.07	25	20
Propane	C_3H_8	3.43	44.096	615.50	665.59	1.51	21	23
Iso-Butane	C_4H_{10}	1.80	58.122	527.90	734.08	1.05	10	13
N-Butane	C_4H_{10}	1.54	58.122	550.90	765.22	0.90	8	12
Iso-Pentane	C_5H_{12}	1.66	72.149	490.40	828.67	1.20	8	14
N-Pentane	C_5H_{12}	1.30	72.149	488.80	845.47	0.94	6	11
Hexane	C_6H_{14}	1.92	86.175	436.90	913.47	1.65	8	18
Heptane	C_7H_{16}	0.88	100.202	396.80	972.57	0.88	3	9
Octane	C_8H_{18}	0.75	114.229	360.70	1,023.87	0.86	3	8
Nonane	C_9H_{20}	0.00	128.255	330.70	1,070.47	0.00	0	0
Decane	$C_{10}H_{22}$	0.00	142.282	304.60	1,111.87	0.00	0	0
Air		0.00	28.959	551.90	238.70	0.00	0	0
Nitrogen	N_2	2.44	28.014	492.50	227.14	0.68	12	6
Oxygen	O_2	0.00	31.999	731.40	278.24	0.00	0	0
Carbon Dioxide	CO_2	1.30	44.010	1,070.00	547.45	0.57	14	7
Hydrogen Sulfide	H_2S	0.00	34.082	1,306.50	672.48	0.00	0	0
Hydrogen	H_2	0.00	2.016	190.70	59.77	0.00	0	0
Argon	Ar	0.15	39.948	705.32	271.24	0.06	1	0
Helium	He	0.00	4.003	33.00	9.35	0.00	0	0
Total		**100.00**				**24.08**	**649**	**411**
Sp. Gravity =		**0.832**						

Table 5. Calculation of Mole Fraction Weighted Properties

For this sample, the gas sample molecular weight is 24.08, the critical pressure is 649 psia, and the critical temperature is 411 °R. Now that the properties for the gas sample have been calculated, we can use these values to determine gas deviation factor and gas expansion factor.

The specific gravity of gas is the weight of the gas relative to the weight of air. Once the molecular weight of the gas sample is known, we can simply divide it by the molecular weight of air to obtain its specific gravity. The specific gravity is calculated as follows.

$$Specific\ Gravity = \frac{Molecular\ Weight\ of\ Gas\ Sample}{28.595}$$

The Excel workbook that is part of the course material has a tab labeled **"Gas Composition"**. The gas sample shown in Table 5 has been input into that spreadsheet. The area of the spreadsheet highlighted in yellow is available for input. The remainder of the spreadsheet is calculated.

Determination of the Gas Deviation Factor

As mentioned in the previous sections, due to the molecular interactions of hydrocarbon molecules, hydrocarbon gases deviate from the ideal gas law. To account for this deviation, the gas deviation factor, z is used in the Ideal Gas Law. The relationship between pressure, volume, temperature and moles of gas then becomes:

$$PV = nRTz$$

where,

P = pressure (psia – pounds per square inch absolute)
V = volume (scf – standard cubic feet)
T = temperature (°R - degrees Rankine)
n = number of moles of gas (moles)
R = ideal gas constant (10.73 scf-psia/mole-°R)
z = gas deviation factor

The determination of z is based on a chart created from the results of experiments with hydrocarbon gases and first published by Katz and Standing in 1942. A copy of the gas deviation factor chart is shown below.
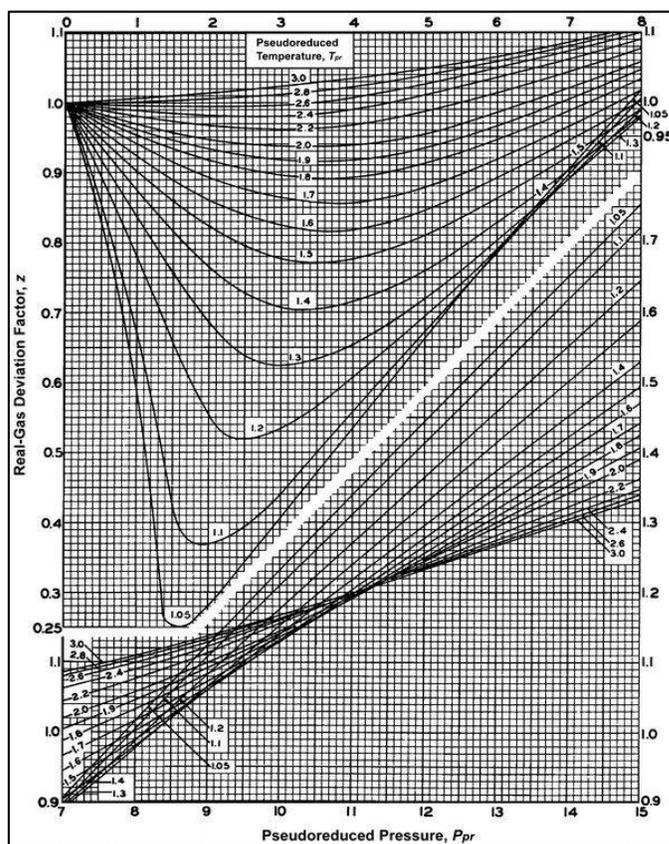

Figure 1. Gas Deviation Factor Chart

The axes of the chart are Pseudoreduced Pressure (Pr) and Gas Deviation Factor (z). There are various lines on the chart for the Pseudoreduced Temperature (Tr). The term "pseudo" is used to denote that the values of Critical Pressure and Critical Temperature are derived from gas composition data, as shown in Table 5, for example. From here on we will use the terms Reduced Pressure and Reduced Temperature.

To use this chart to find z, we must first calculate the reduced pressure and temperature using the following equations:

$$P_r = P/P_c$$

$$T_r = T/T_c$$

where,

   P_r = reduced pressure
   P = measured pressure (psia)
   P_c = critical pressure (psia)
   T_r = reduced temperature
   T = measured temperature (°R)
   T_c = critical temperature (°R)

The most efficient method to show how to determine the z, the gas deviation factor is to use an example.

Example Problem 3:

A reservoir contains the gas whose composition is given in Table 5. The reservoir pressure is 1,950 psia and the temperature is 106 °F. What is the gas deviation factor of the reservoir?

Answer:

The reservoir temperature is given in °F and must be converted to °R as follows:

$$T = 460 + 106 = 566 \text{ R}$$

From Table 5, the critical pressure is 649 psia and the critical temperature is 411 °R.
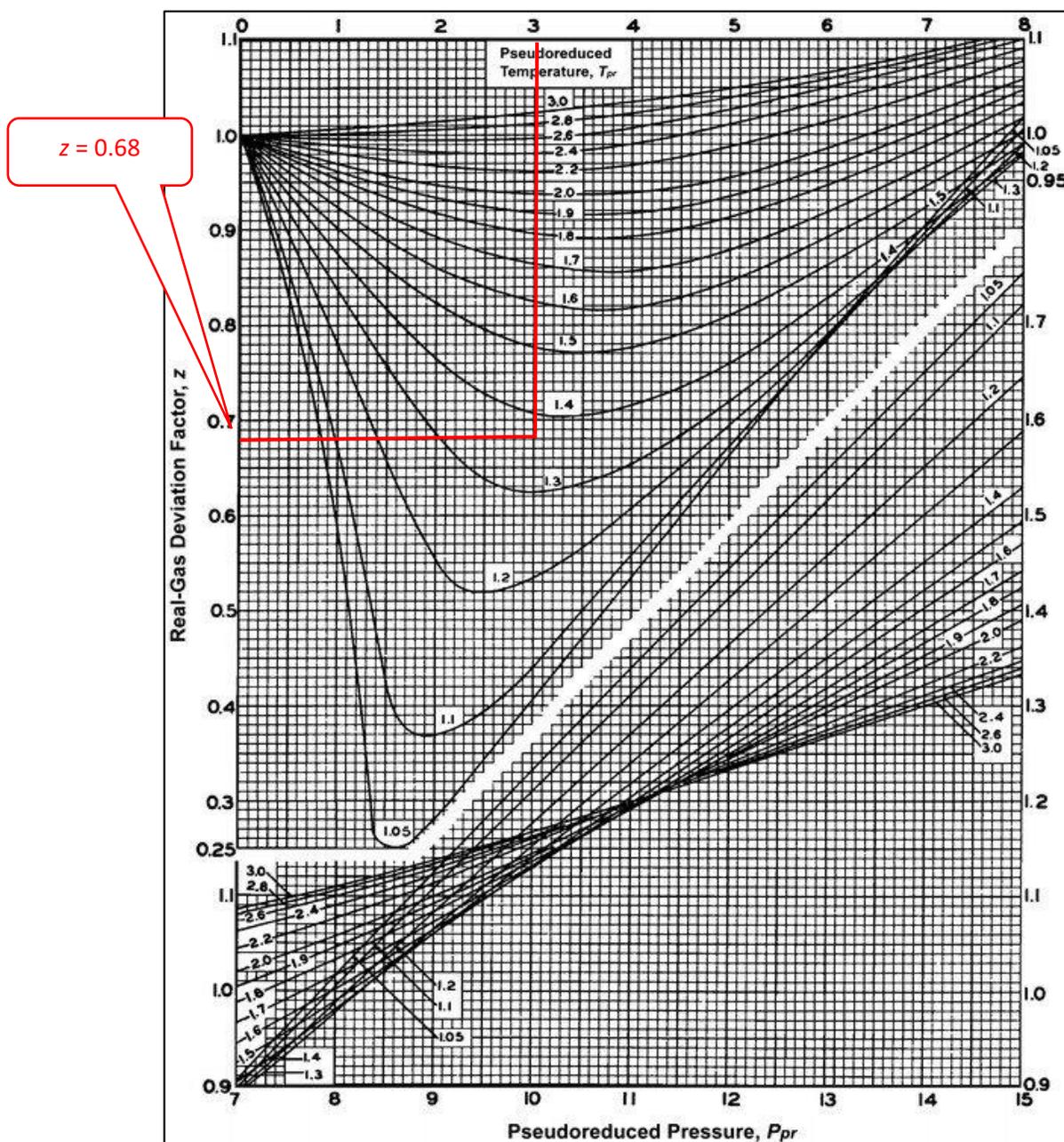
The reduced pressure is:

$$P_r = \frac{1950}{649} = 3.00$$

and the reduced temperature is:

$$T_r = \frac{566}{411} = 1.38$$

Entering the chart as shown below with a reduced pressure of 3.00 and moving downward to an interpolated reduced temperature of 1.38 gives a gas deviation factor, z of 0.68.

The gas deviation chart is rather small and difficult to work with as shown in the above example. However, a copy of the gas deviation chart is found the Excel workbook under the tab **"z Factor Chart"**. The chart is in picture format and can be expanded, copied or printed in any desired scale for more accurate use.

Calculation of the Gas Expansion Factor

As gas is produced from a reservoir under pressure and temperatures higher than those at the surface, gas expands. In layman's terms, a given number of molecules of gas take up less space in the reservoir than they do at the surface.

To account for the expansion of gas from the reservoir to the surface the expansion factor, E_g is used. The units for Eg are standard cubic feet per reservoir cubic feet, or scf/ft^3. To relate the compression of gas from the surface to the reservoir, the gas formation volume factor, B_g is used. The units for B_g are reservoir cubic feet per standard cubic feet, of ft^3/scf.

As is should be obvious, the relationship between E_g and B_g are as follows:

$$B_g = \frac{1}{E_g}$$

Both parameters use the units of "standard cubic feet". A standard cubic foot is defined by both a standard gas pressure and a standard gas temperature. In the United States, the standard temperature is 60 ºF (520 ºR). The standard pressure, however, changes with each state. For example, in Oklahoma, the standard pressure is 14.65 psia and in Louisiana it is 15.025 psia. A table of standard pressures for each state is provided in the Excel workbook under the tab "State Pressure Bases". For the purpose of this course, we will always use a pressure base of 14.65 psia unless otherwise stated.

The gas expansion factor, Eg is calculated as follows:

$$E_g = \frac{T_{sc}}{P_{sc}} * \frac{P}{zT}$$

and the gas formation volume factor, Bg as,

$$B_g = \frac{P_{sc}}{T_{sc}} * \frac{zT}{P}$$

where,

  T_{sc} = standard temperature (ºR)

  P_{sc} = standard pressure (psia)

  z = gas deviation factor

  T = reservoir temperature (ºR)

  P = reservoir pressure (psia)

Example Problem 4:

A reservoir contains the gas whose composition is given in Table 5. The reservoir pressure is 1,950 psia and the temperature is 106 ºF.

 a) What is the gas expansion factor of the reservoir?

 b) What is the gas formation volume factor?

Answer:

 a) The gas expansion factor is:

$$E_g = \frac{T_{sc}}{P_{sc}} * \frac{P}{zT} = \frac{520}{14.65} * \frac{1950}{(0.68) * 566} = 179.8 \; scf/ft^3$$

This means that 1 cubic foot of gas in the reservoir expands 179.8 times as it is produced to surface conditions.

 b) The gas formation volume factor, Bg is the inverse of the gas expansion factor, or:

$$B_g = \frac{1}{E_g} = \frac{1}{179.8} = 0.0056 \; ft^3/scf$$

Discussion of Reservoir Area and Thickness

This course will not discuss how to determine the reservoir area or thickness. We will, however, discuss some of the methods used to obtain those values.

The area of the reservoir is defined as the areal extent of the reservoir known to contain gas. The thickness is defined as the vertical thickness of the reservoir containing gas. Multiplied together, the area times the thickness is the total rock volume of the reservoir. In the United States, areas are measured in acres and thickness in feet.

The reservoir area can be determined or estimated using information from wells drilled into the reservoir. The reservoir area can also be found using seismic methods. The data from either wells or seismic, or both, is mapped and the extent of the reservoir is found by extrapolating contours. The area of the reservoir can be determined using a planimeter or other method. Most 3-D geologic modeling software can calculate the area within given contour intervals.

The thickness of the reservoir can be determined in a similar manner to area, using well data and/or seismic data. The common method is to contour the thickness at each data point (either well or seismic) and overlay it on the reservoir contour map. To arrive at an average thickness, the area of each thickness interval is calculated and summed for the entire reservoir. The result of this is the rock volume of the reservoir, typically calculated as acre-feet. In the volumetric formula for OGIP, these are the parameters A x h.

Discussion of Porosity and Water Saturation

Porosity is defined as the portion of the reservoir void of rock expressed as a percentage of the rock volume. It is essentially the percentage of "holes" in the rock. If the porosity of a rock is 15%, it means that 15% of the rock is void space and 85% of the rock is solid material. Porosity is the portion of the rock where all fluids exist. Porosity is given the symbol phi and can be in the units of decimal or percent.

Water saturation is the percentage of the pore space that is taken up by water. The remainder, or 100% less the water saturation, is the portion of the pore space that contains gas (typically referred to as hydrocarbon saturation). Water saturation, rather than hydrocarbon saturation has become a standard because it is typically derived from well logs which detect the presence of water, not hydrocarbons.

The most common method of obtaining porosity and water saturation is from well logs. Occasionally, cores are taken while drilling and sent to a lab where porosity and water saturations

are determined. Well logs are obtained by running an electrical device on a cable to the bottom of a newly drilled well and pulling it up to the surface. During the pull to the surface, various rock properties are measured by the different types of devices connected to the cable. Typically measured are the natural radioactivity of the rock, the density of the rock, the electrical conductivity of the rock, hydrogen in the rock, travel of sound through the rock, etc. Based on these measurements, porosity and water saturation of the various rock layers can be calculated.

Both porosity and water saturations can vary throughout the thickness of the rock. They can also vary across the area of the reservoir. As such, the estimation of porosity and water saturation in a reservoir can be a very complicated process.

The most common way to account for the variations in porosity and water saturation is to create data points for each well of porosity times feet (porosity-feet) and porosity times feet times hydrocarbon saturation. These values are then contour mapped and the volumes measured and summarized. This results in the value of A x h x $\emptyset$ x (1-Sw) in the volumetric equation. Table 6 below gives an example for a particular well of the calculation of porosity-feet and porosity x hydrocarbon-feet. The values are calculated as decimals, rather than percents.

Depth (ft)	h (ft)	Porosity (%)	S_w (%)	S_{hc} (%)	Porosity Feet	Por x S_{hc} Feet
3614	2	20.5	19.9	80.1	0.410	0.328
3616	4	14.0	24.1	75.9	0.560	0.425
3620	6	11.4	25.3	74.7	0.684	0.511
3626	4	16.2	27.0	73.0	0.648	0.473
3630	2	17.9	26.7	73.3	0.358	0.262
3632	6	15.2	28.4	71.6	0.912	0.653
3638	5	13.8	26.7	73.3	0.690	0.506
3643	2	13.4	33.4	66.6	0.268	0.178
3645	3	12.8	36.8	63.2	0.384	0.243
TOTAL	**34**				**4.914**	**3.580**

Notes:
S_{hc} = Hydrocarbon saturation

Table 6. Calculation of Porosity-Feet and Water Saturation-Feet

For this well, the average porosity and hydrocarbon saturation can be calculated as:

$$\emptyset = \frac{\emptyset * h}{h} = \frac{4.914}{34} = 0.144 = 14.4\%$$

In a similar fashion, the hydrocarbon saturation can be calculated by the following:

$$S_{hc} = \frac{\emptyset * h * S_{hc}}{\emptyset * h} = \frac{3.580}{4.914} = 0.729 = 72.9\%$$

Therefore, water saturation for this well is:

$$S_w = 100 - S_{hc} = 100 - 72.9 = 27.1\%$$

Notice that an arithmetic average of porosity that ignores the number of feet gives an incorrect value. Similarly, since water saturation and therefore hydrocarbon saturation are percentages of a given porosity, calculating the average value must take into account both the porosity and the number of feet of porosity. I will leave it to you to verify, but the arithmetic averages of porosity and water saturation from Table 6 are 15.0% and 27.6%, respectively. Although the values appear to be fairly close to the weighted values (the correct ones) in this instance, they can be quite different in some cases.

Estimation of Abandonment Pressure

The determination of when to cease producing a well is a purely economic one. Essentially, a well is plugged and abandoned when the production from the well can no longer pay the expenses and yield a profit. This is dependent on many factors including the gathering system pressure, permeability of the reservoir, price for the gas, the severance tax rate, the royalty rate, and operational costs. As these will likely be unknown at the time when estimating OGIP and recoverable gas, there needs to be a way to estimate an abandonment pressure.

The best method to use when little data is available is to look for offset reservoirs that have produced to abandonment. Based on my experience, one will find that wells in a given area tend to be abandoned within a fairly narrow range of final production rates and pressures. This is probably because wells in a given area produced into common gathering systems with a fixed pressure. The only difference in abandonment pressure in those reservoirs would be determined by reservoir depth. This is true even when compression was used to lower the gathering line pressure.

What one finds is that the abandonment pressures will typically range from 50 psi to 100 psi per thousand feet of depth.

Example Problem 5:

A reservoir contains the gas whose composition is given in Table 5. The average reservoir depth is 4,500 feet. The reservoir covers an area of 2,860 acres at a thickness of 28 feet. The porosity of the reservoir is 18.6% and the average water saturation is 32%. The reservoir pressure is 1,950 psia and the temperature is 106 °F. The standard conditions are 14.65 psia and 60 °F.

    a) What is the original gas-in-place?

    b) If the abandonment pressure is estimated to be 100 psi per 1,000 feet, what is the recoverable gas?

    c) What is the recoverable gas at an abandonment pressure gradient of 50 psi per 1,000 feet?

Answer:

    a) From prior calculations and determinations from the examples above, we already know the following:

$z = 0.68$

$E_g = 179.8 \text{ scf/ft}^3$

$$OGIP = 0.04356 * A * h * \emptyset * (1 - S_w) * E_g$$

$$= 0.04356 * 2860 * 28 * .186 * (1 - .32) * 179.8 = 79,327 \; MMscf$$

    b) At an abandonment pressure of 100 psi per 1,000 feet, the abandonment pressure is:

$$P_{ab100} = \frac{100 * 4500}{1000} = 450 \; psia$$

Using the previously determined P_c and T_c of 649 psia and 411 °R, the reduced pressure and temperature are:

$$P_r = \frac{450}{649} = 0.69$$

$$T_r = \frac{566}{411} = 1.38$$

Entering the z chart, z is found to be z=0.91. The recovery factor can now be calculated as:

$$RF = \frac{\frac{P_i}{z_i} - \frac{P_{ab}}{z_{ab}}}{\frac{P_i}{z_i}} = \frac{\frac{1950}{0.68} - \frac{450}{0.91}}{\frac{1950}{0.68}} = 0.828 = 82.8\%$$

The recoverable gas can not be calculated below as:

$$Recoverable\ Gas = OGIP * RF = 79,327 * 0.828 = 65,683\ MMscf$$

c) At an abandonment pressure of 500 psi per 1,000 feet, the abandonment pressure is:

$$P_{ab50} = \frac{50 * 4500}{1000} = 225\ psia$$

Using the previously determined P_c and T_c of 649 psia and 411 ºR, the reduced pressure and temperature are:

$$P_r = \frac{225}{649} = 0.35$$

$$T_r = \frac{566}{411} = 1.38$$

Entering the z chart, z is found to be z=0.93. The recovery factor can now be calculated as:

$$RF = \frac{\frac{P_i}{z_i} - \frac{P_{ab}}{z_{ab}}}{\frac{P_i}{z_i}} = \frac{\frac{1950}{0.68} - \frac{225}{0.93}}{\frac{1950}{0.68}} = 0.916 = 91.6\%$$

The recoverable gas can now be calculated below as:

$$Recoverable\ Gas = OGIP * RF = 79,327 * 0.916 = 72,664\ MMscf$$

The Excel workbook that is part of the course instruction materials has a tab labeled **"Vol Imperial Units"** that will make all the calculations shown above. Take the time to input the data and check the results this problem. A similar tab labeled **"Vol Metric Units"** can be used to calculate OGIP and recoverable gas in metric units.

Conclusion

The purpose of this course has been to teach one how to estimate original gas-in-place and recoverable gas from a volumetric drive gas reservoir. As has been shown, there are several parameters that must be determined or calculated in order to properly estimate original gas-in-place and recoverable gas. In this course, we have provided the data so that one can concentrate on calculations without having to deal with data acquisition or qualification.

When using actual available field data, one will find that some parameters are more difficult to acquire than others. To obtain good estimates, one must acquire as much data as possible to narrow the range of each parameter. This might require obtaining several gas samples, logs or cores on a number of wells may be needed to determine porosity and water saturation, and enough wells drilled or seismic data taken to define the boundaries of the reservoir.

Although the estimations of original gas-in-place and recoverable gas appear to be static, they are really an estimate based on the available data at a certain point in time. As such, these calculations must be updated each time some new data becomes available (i.e., drilling of new wells).

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