Reservoir Engineering II

Reservoir Fluid Distribution

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Resources & Materials

Fundamentals of Reservoir Engineering by LP Dake.

Reservoir Engineering by Ahmed Tarek.(Recommended)

https://www.sciencedirect.com/science/article/pii/S1110062118304549
(Hydrocarbon Estimation, Case Study)

Outline

Part 1: Reservoir Fluid Distribution

- Reservoir content: oil, water & gas
- Reservoir types: undersaturated, saturated and gas-cap reservoirs
- Fluid zonation and contacts
- Fluid pressure gradient regimes, RFT

Part 2: Estimation of Hydrocarbon Volumes and Recovery Factors

- Oil reservoirs: STOIIP
- Gas reservoirs: GIIP

Some Terminologies Used in Reservoir Engineering

- **Initial pressure:** The pressure of the reservoir at the beginning of its productive life. This is the pressure before any production activities, such as drilling and extracting hydrocarbons have taken place.
- **Bubble point pressure (saturation pressure):** The bubble point pressure, also known as saturation pressure, is a critical pressure point in a petroleum reservoir. It represents the pressure at which the first gas bubbles begin to form in the oil phase.
- **Free-gas:** Free gas refers to natural gas that exists independently as a separate phase from oil and water within a reservoir.
- **Gas-cap:** When the reservoir is at pressure below the bubble point, gas is liberated from the oil,we will notice not only the first gas bubble, but a whole lot of gas bubbles depending on how far below the bubble point it has gone; such collection of gas bubbles is called gas cap.

Some Terminologies Used in Reservoir Engineering

- **Gas Solubility or Solution Gas-Oil Ratio Rs**: The amount of surface gas that can be dissolved in a stock tank oil when brought to a specific pressure and temperature. Denoted mathematically as R_s **SCF/STB**.

- **Oil formation volume factor:** is defined as the ratio of the volume of oil (including its dissolved gas) at reservoir conditions (Tres, Pres) to the volume of oil at standard surface conditions (Psur, Tsur). The unit of Bo is **RB/STB**.Bo (i.e. the ratio) is always greater than 1.0 suggests that the volume of a given oil is higher at the reservoir condition than it is at surface.

Some Terminologies Used in Reservoir Engineering

- **Oil shrinkage:** oil shrinkage is the reduction in the volume of oil due to the release of its dissolved gas as pressure reduces.
- **Free water level** is the highest elevation at which the pressure of the hydrocarbon phase is the same as that of water.
- **Hydrocarbon-water(oil-water or gas-water contact)** is the lowest elevation at which mobile hydrocarbons occur.
- **Transition zone** is the elevation range in which water is co-produced with hydrocarbons.
- **Gas-oil contact** is the elevation above which gas is the produced hydrocarbon phase.

Some Terminologies Used in Reservoir Engineering

- **Capillary Effect:** Capillary effect is the factor responsible for the existence of transition zones. By definition, capillary pressure is the difference in the pressures of two immiscible fluid phases in contact with each other.

- Oil-water capillary pressure, $P_{co\text{-}w}$ $(P_o - P_w)$ is the factor responsible for the oil-water transition zone whereas the gas-oil capillary pressure is the factor responsible for the gas-oil transition zone

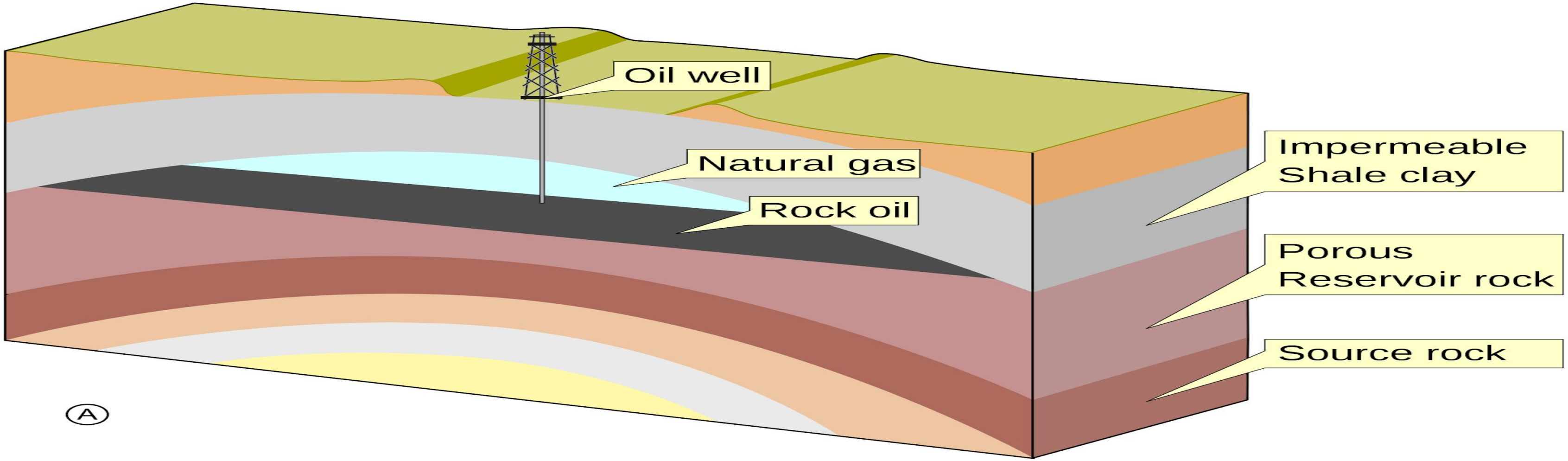
- **Density Effect:** The difference between the density of one fluid phase (denser) and another fluid phase (less dense) is called density effect. In simple terms then, we say density effects is the factor responsible for the relative positioning of less dense fluid (say gas) on top of denser fluid (say oil).

Some Terminologies Used in Reservoir Engineering

- **Gas-Oil Ratio (GOR):** This is the volume of gas produced at standard temperature and pressure, in relation to the volume of oil produced at standard temperature and pressure, used as a measurement for reservoir fluids or simply say, it is the ratio of produced gas to produced oil.
- **Connate water saturation S_{wc}:** The connate water saturation is the minimum water saturation which would remain adhered to the pore and are immobile.

Reservoir Content

The reservoirs contain a mixture of hydrocarbons (oil and gas) and often water. The distribution of these fluids within the reservoir varies and is a critical factor in extraction.



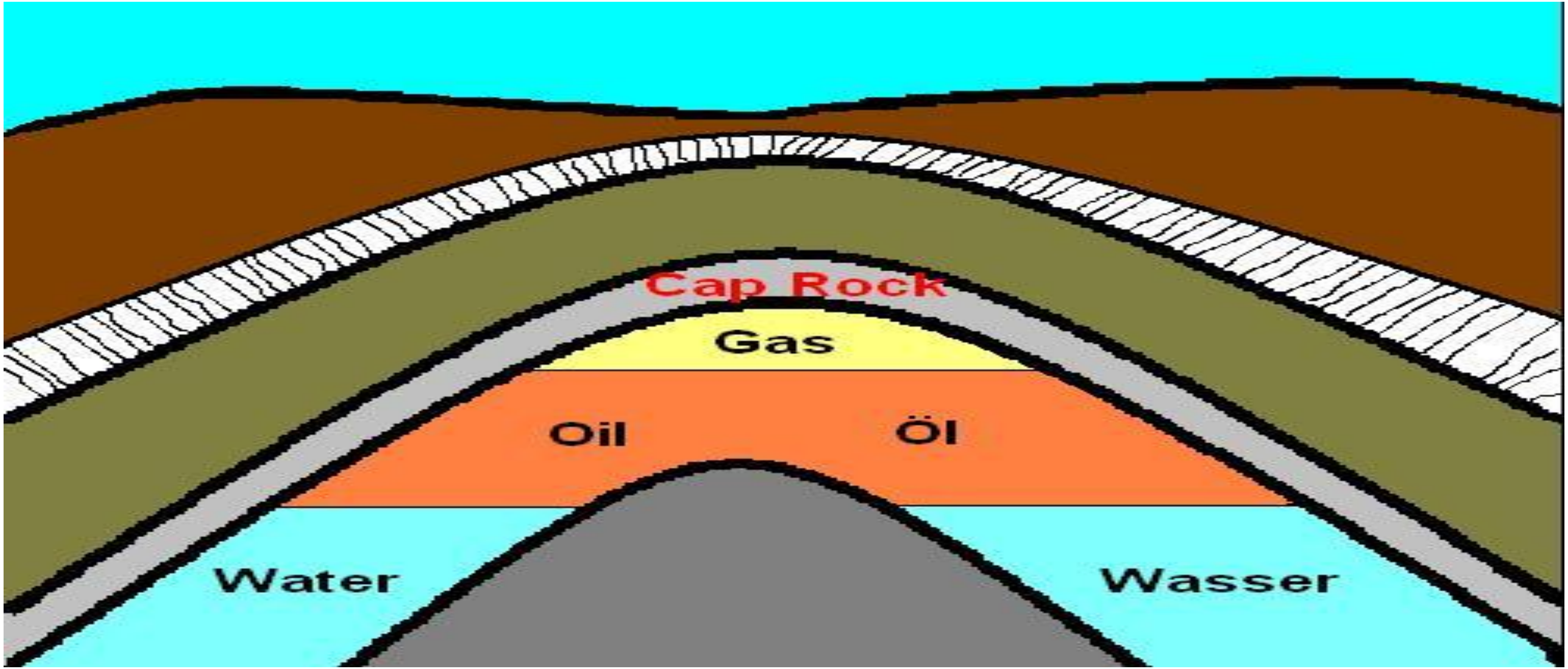
Src:https://upload.wikimedia.org/wikipedia/commons/thumb/a/af/Oil_traps.svg/2000px-Oil_traps.svg.png

Reservoir Content

Introduction

- Fluid distribution refers to the positioning of the various fluid phases (oil, gas and water) present in the reservoir, relative to each other.
- The two factors responsible for the fluid distribution as noticed in the reservoir are:
  - Density effects.
  - Capillary effects.

Reservoir Content



Source:https://upload.wikimedia.org/wikipedia/commons/7/78/2010-11-16_Oil_reservoir_1.JPG

Reservoir Types

- **Undersaturated**
    - An undersaturated oil is one that can dissolve more gas if it is available. The volume of oil increases as the pressure drops, until the bubble point is reached (the oil becomes saturated).
- **Saturated**
    - A saturated oil is defined as one that cannot hold any more gas. This means oil at, or below, the bubble point, when gas first comes out of solution. The volume of the oil decreases as the pressure drops.

Reservoir Types

- **Gas-cap**
    - Gas cap reservoirs are a special class of hydrocarbon reservoirs that have segregated gas caps and are examples of reservoirs that are at their saturation pressures. The gas and the oil are in equilibrium at reservoir pressure and temperature.

Undersaturated Reservoir ($P_i > P_b$)

How do you identify an undersaturated reservoir?

- **Pressure:** It has initial pressure P_i above the bubble point pressure P_b

  Pressure Decline Rate: In an undersaturated reservoir, the pressure decline may be more rapid compared to a saturated reservoir.

  GOR: Exhibit a lower GOR compared to a saturated reservoir.

- **Reservoir content:** This type of reservoir only contains **oil**, but **may contain some gas dissolved in it.**

- **Volume:** The volume of **oil increases as the pressure drops**, until the bubble point is reached.

Undersaturated Reservoir ($P_i > P_b$)

Volume and Saturation Analysis:

- **Reservoir Saturation Profile**: Undersaturated reservoirs may show a zone where gas dissolution occurs in the oil phase.
- **Reservoir Volume Changes:** An undersaturated reservoir may experience volume changes associated with gas expansion in the oil phase.

Saturated Reservoir ($P_i \leqslant P_b$)

How do you identify a saturated reservoir?

- **Pressure:**

  Initial Reservoir Pressure: Saturated reservoirs are **at bubble point pressure or below bubble point pressure.** In a saturated reservoir, the pressure may be influenced by the balance of oil, water, and gas.

  Pressure Decline Rate: Reservoir pressure declines over time. Saturated reservoirs may show a relatively stable pressure decline as the fluids are produced.

- **Reservoir content:** A saturated reservoir existing at pressure below the bubble point **will have oil & gas cap** in it. A typical characteristic is the presence of a gas cap and an underlying water zone.

Saturated Reservoir ($P_i \leqslant P_b$)

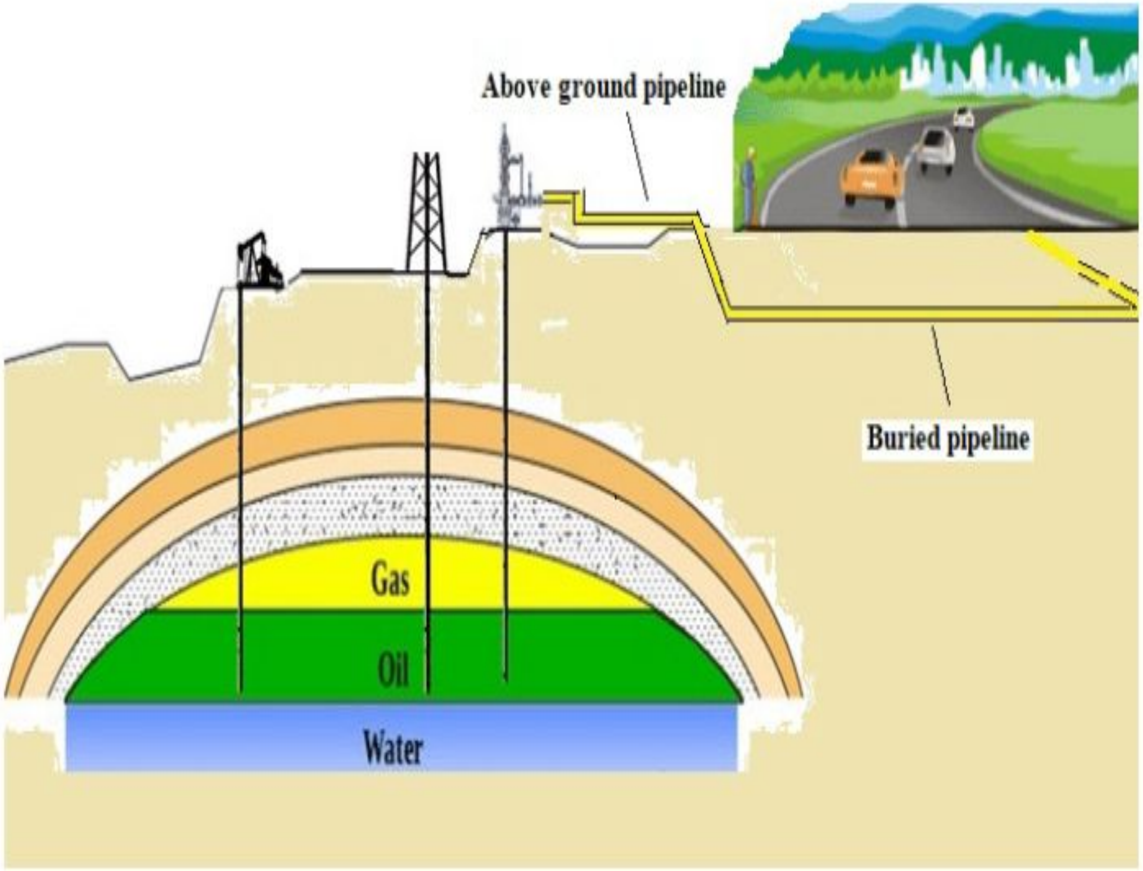
A saturated reservoir would produce a combination of oil, water, and gas, with variations depending on the reservoir properties.

- **Volume:** The volume of the **oil decreases as the pressure drops**. A saturated reservoir may exhibit changes in volume due to production but without significant expansion or contraction associated with a gas-cap reservoir.
- **Reservoir Saturation Profile:** saturated reservoir typically has a balanced distribution of oil, water, and gas throughout the reservoir.

Gas-Cap Reservoir

How do you identify a gas-cap reservoir?

- If the initial reservoir pressure is below the bubble point pressure of the reservoir fluid.
- The reservoir is termed a gas-cap or two-phase reservoir, in which the gas or vapor phase is underlain by an oil phase.



Gas-Cap Reservoir

- **Pressure**

Initial Reservoir Pressure: The initial pressure of a gas-cap reservoir typically exhibits a higher initial pressure compared to an oil reservoir. This is because the gas in the cap contributes to the overall pressure.

Pressure Decline Rate: Reservoir pressure declines over time. In a gas-cap reservoir, the pressure decline may be more gradual compared to oil reservoirs, where pressure tends to drop faster.

GOR: A high GOR may indicate the presence of a gas cap, as gas is being produced along with oil.

Gas-Cap Reservoir

- **Volume**

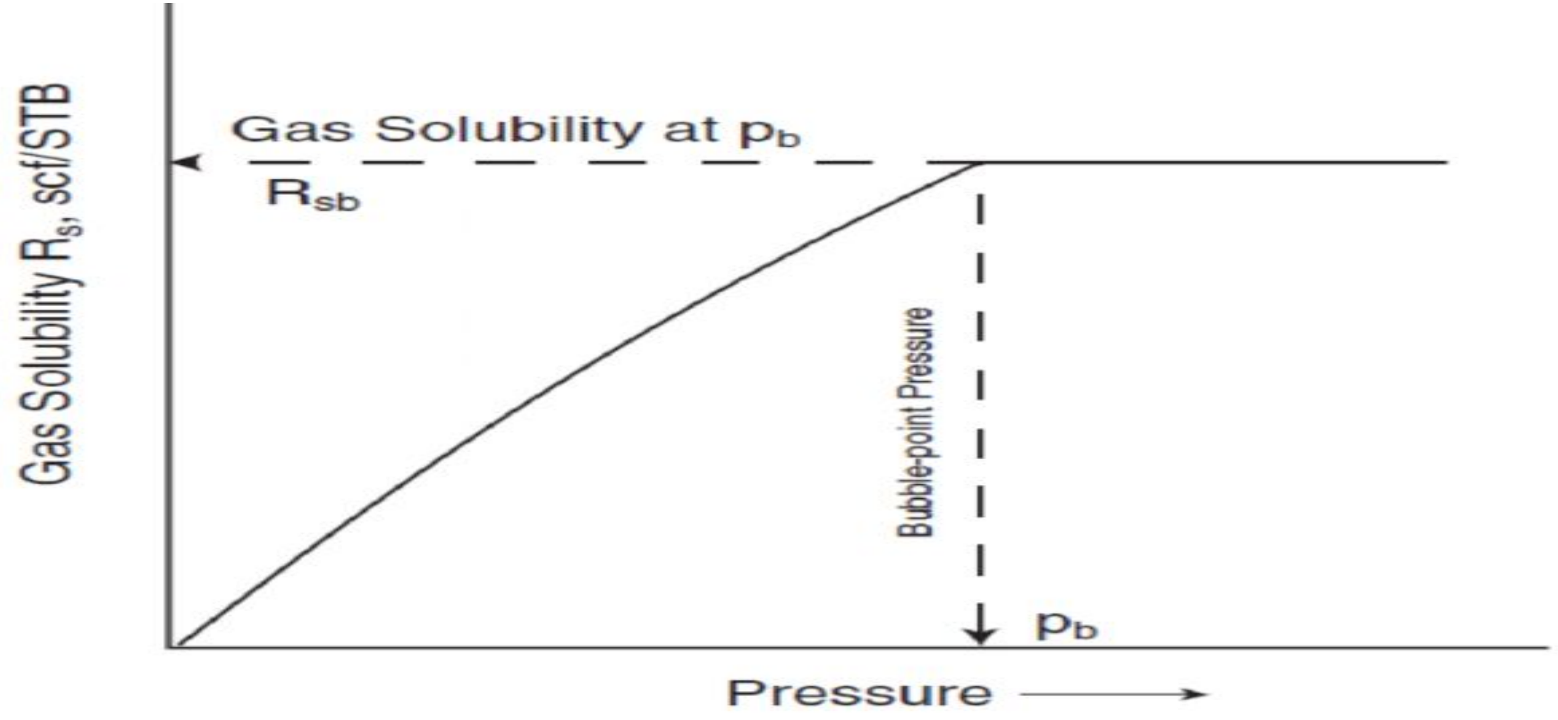
  Reservoir Volume Changes: If the reservoir experiences an expansion in volume, it may suggest the presence of gas expansion in the gas cap.

- **Saturation**

  Reservoir Saturation Profile: A gas-cap reservoir will exhibit a distinct zone with high gas saturation above the oil zone.

Variation of Gas Solubility Rs with Pressure

Rs varies with pressure and the diagram represented below explains how.



https://www.researchgate.net/figure/Gas-solubility-pressure-diagram_fig45_321038126

Variation of Gas Solubility Rs with Pressure

- From the diagram above, **it is observed that at the reservoir initial pressure, the solution GOR, Rs is at a value known as Rsi.**
- **As the pressure reduces due to production, this value of Rs remains constant until the bubble point pressure is reached;** hence **Rsi = Rsb.**
- The constancy is due to the fact that the oil is not giving away any of its gas since the bubble point is not yet reached.
- As the pressure drops beyond the bubble point however, the Rs begins to drop in value; **the reason for the drop is due to the fact that below the bubble point, any pressure drop will result in the oil giving away part of its dissolved gas, hence the ratio of dissolved gas to oil will consequently reduce.**
- Correlations exist that may be used to estimate Rs at and below the bubble point. **For Rs at pressures above bubble point, the Rs at bubble point (Rsb) applies since there is no change in value at this pressure range.**

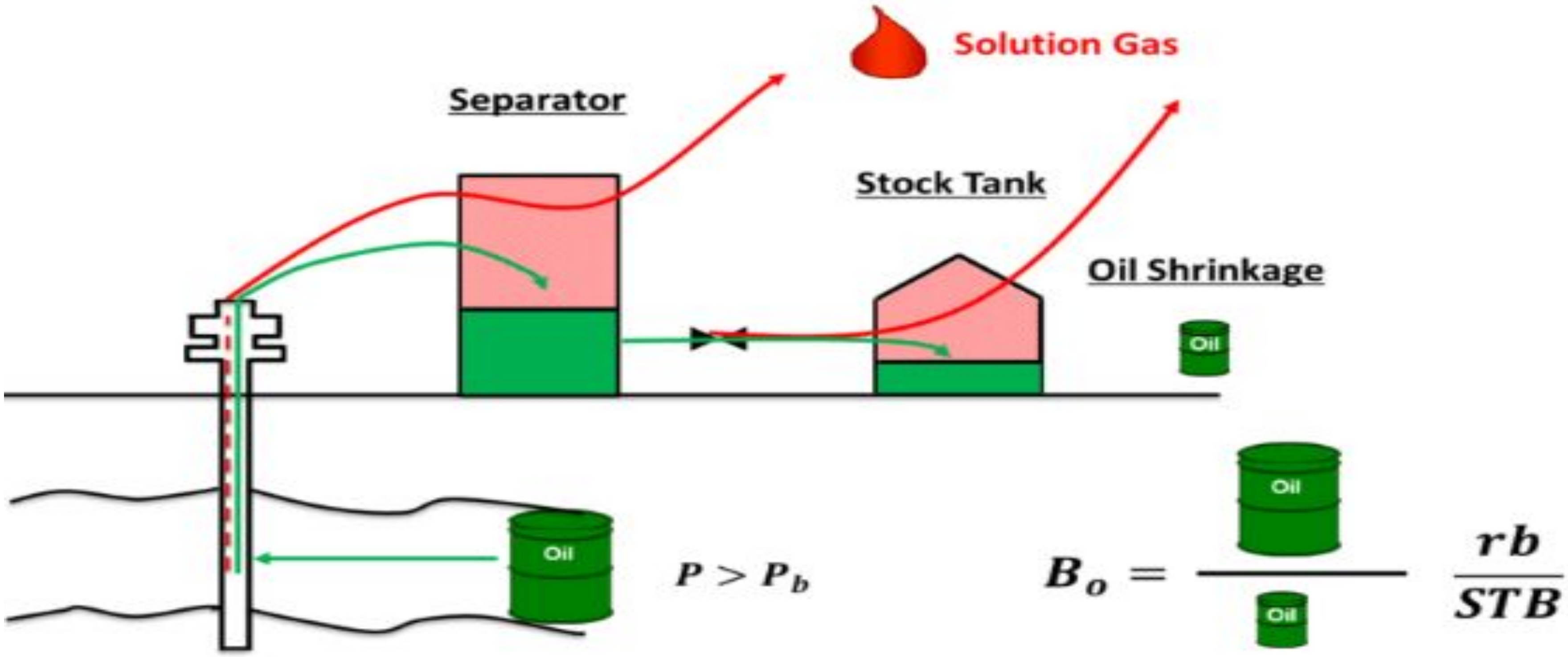
Oil Formation Volume Factor Bo

- The volume of oil at reservoir condition is not equal to the volume of same oil at surface condition.
- **Bo is always greater than 1.0, that means the volume of a given oil is higher at the reservoir condition than it is at surface due to oil shrinkage. as the oil travels from the reservoir to the surface, pressure reduces and therefore the gas that has been hitherto dissolved is released (vaporized) leaving only the genuine oil. This phenomenon is termed oil shrinkage.**
- Bo is significantly useful in accomplishing one of the core functions of the reservoir engineer – estimating the amount of oil in place in a reservoir. It is required that the amount of oil in place be reported in terms of surface condition.

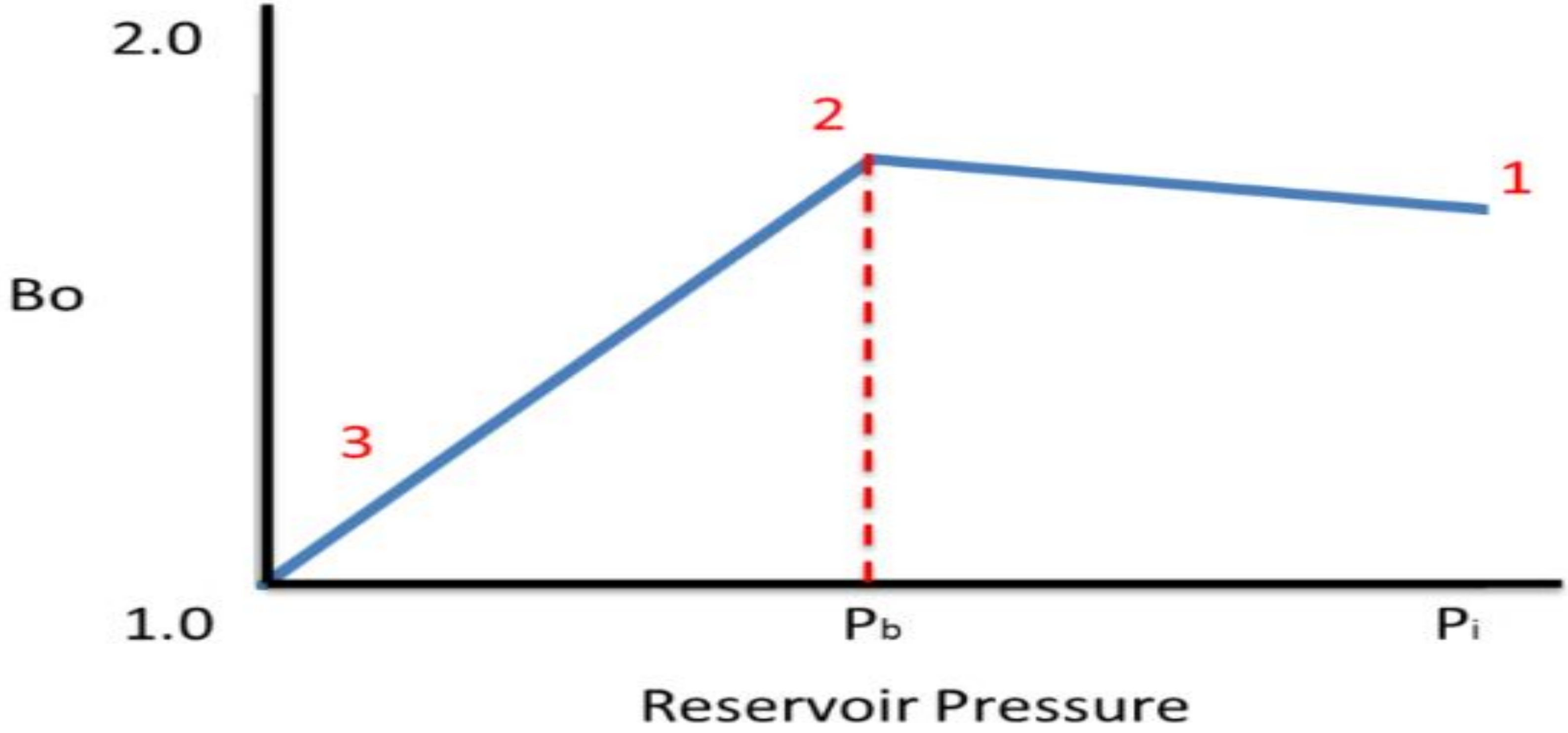
Oil Formation Volume Factor Bo

- Bo is only valid for a particular reservoir pressure at a time; this is because the amount of gas dissolved (and available to be vaporized) in the oil is a function of pressure.
- Hence the increase in Bo between Pi and Pb is attributable to LIQUID EXPANSION.
- The decrease in Bo at pressures below the bubble point is attributable to LIBERATION OF DISSOLVED GAS.
- **The maximum value of Bo will occur at bubble point as Bob**. Different equations are used to calculate Bo for the two regimes.
- **At Pi > pb, the factor for determining Bo is the oil compressibility due to liquid expansion while for Pi < Pb, the correlations used in calculating Bo is Rs due to dissolved gas liberation .**

Oil Formation Volume Factor Bo



Oil Formation Volume Factor Bo



https://topdogengineer.com/test-post/

Pressure Variation with Bo

The figure above shows how the formation volume factor changes as a function of pressure at constant reservoir temperature. The process can be described in steps:

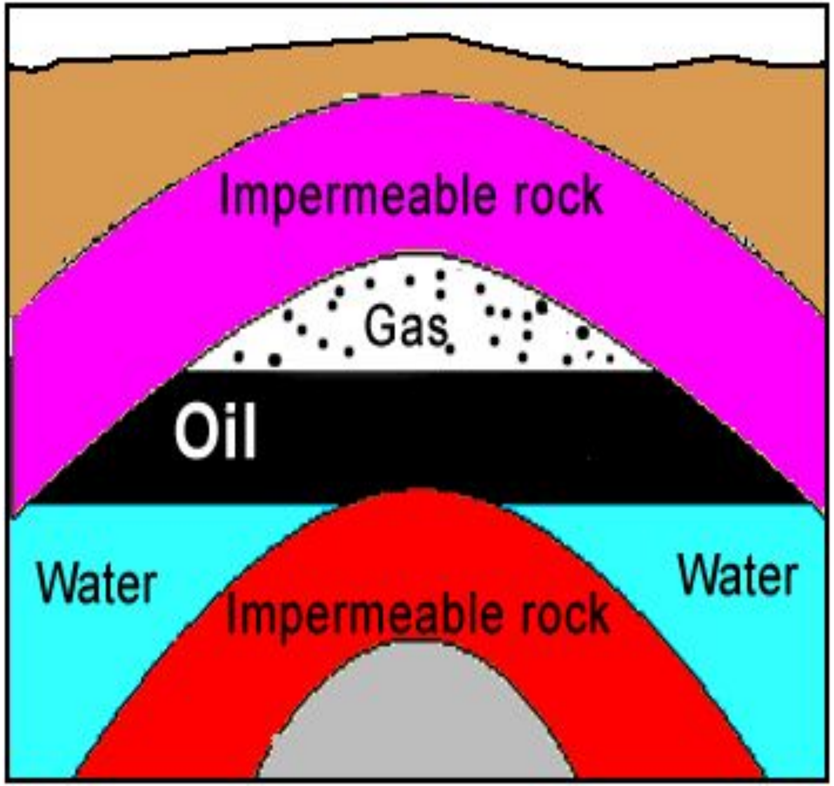
- **1-2:** As the reservoir pressure is decreased from initial reservoir pressure to bubble point pressure, there is a slight expansion of liquid in the reservoir, thus results in a higher formation volume factor.
- **2-3:** As the reservoir pressure falls below bubble point pressure, gas comes out of solution and the formation volume factor decreases. **As reservoir pressure steadily declines, the formation volume factor approaches a value of 1.0**.

Watch Video

https://youtu.be/K05k9uGapFs Hydrocarbon Phase Behaviour.

Take your time to understand this topic better. Make sure to write what you have learnt.

Fluid Zonation and Contacts



Fluid Zonation and Contacts

- **Fluid Contacts:** The interface that separates fluids of different densities in a reservoir. Horizontal contacts are usually assumed, although tilted contacts occur in some reservoirs. The contact between fluids is usually gradual rather than sharp, forming a transition zone of mixed fluid.
- **Fluid Zonation:** Fluid zonation in a reservoir refers to the distribution and arrangement of different fluids, such as oil, water, and gas, within the subsurface rock formations. These fluids are often stratified in layers, creating zones with varying saturations.
- Fluid zonation is like reading the layers of this underground cake. It helps us to

    Know where each type of fluid is.

    How much there is.

Fluid Zonation and Contacts

Where they meet.

- How these fluids are arranged helps us plan how to extract them efficiently, **If you know where these fluids are, you can plan where to drill wells and how to manage the reservoir to get the most out of it.**

Fluid Contacts

- In the volumetric estimation of a field's reserve, the initial location of the fluid contacts and also for the field development, the current fluid contacts are very critical factor for adequate evaluation of the hydrocarbon prospect.
- Typically, the position of fluid contacts are first determined within control wells and then extrapolated to other parts of the field. Once initial fluid contact elevations in control wells are determined, the contacts in other parts of the reservoir can be estimated.
- Initial fluid contacts within most reservoirs having a high degree of continuity are almost horizontal, so the reservoir fluid contact elevations are those of the control wells.

Fluid Contacts

- **Estimation of the depths of the fluid contacts, gas/water contact (GWC), oil/water contact (OWC), and gas/oil contact (GOC) can be made by equating the pressures of the fluids at the said contact**. Such that at GOC, the pressure of the gas is equal to the pressure of the oil and the same concept holds for OWC.

- Mathematically, at GOC:

- $\mathbf{P_{oil} = P_{gas}}$

  Therefore, $(dP/dD)_{oil} D + C_o = (dP/dD)_{gas} D + C_g$

Methods of Determining Initial Fluid Contacts

A. **Fluid Sampling Methods:** This is a direct measurement of fluid contact such as: Production tests, drill stem tests, repeat formation tester (RFT) tests (Schlumberger, 1989).

These methods have some limitation which are:

- Rarely closely spaced, so contacts must be interpolated.
- Problems with filtrate recovery on DST and RFT
- Coring, degassing, etc. may lead to anomalous recoveries

Methods of Determining Initial Fluid Contacts

B. Saturation Estimation from Wireline Logs: It is the estimation of fluid contacts from the changes in fluid saturations or mobility with depth, it is low cost and accurate in simple lithologies and rapid high resolution.

limitations:

- Unreliable in complex lithologies or low resistivity sands
- Saturation must be calibrated to production

C. Estimation from Conventional and Sidewall Cores: Estimates fluid contacts from the changes in fluid saturation with depth which can be related to petrophysical properties.

Methods of Determining Initial Fluid Contacts

It can estimates saturation for complex lithologies (Core Laboratories, 2002).

Limitations:

Usually not continuously cored, so saturation profile is not as complete

Saturation measurements may not be accurate

Methods of Determining Initial Fluid Contacts

Pressure Methods

There are basically two types of pressure methods from pressure profiles:

- **repeat formation tester**

  It estimates free water surface from inflections in pressure versus depth curve.

- **reservoir tests, production tests and drill stem tests**

  It estimates free water surface from pressures and fluid density measurements which makes use of widely available pressure data.

Methods of Determining Initial Fluid Contacts

Both pressure techniques are pose with limitations

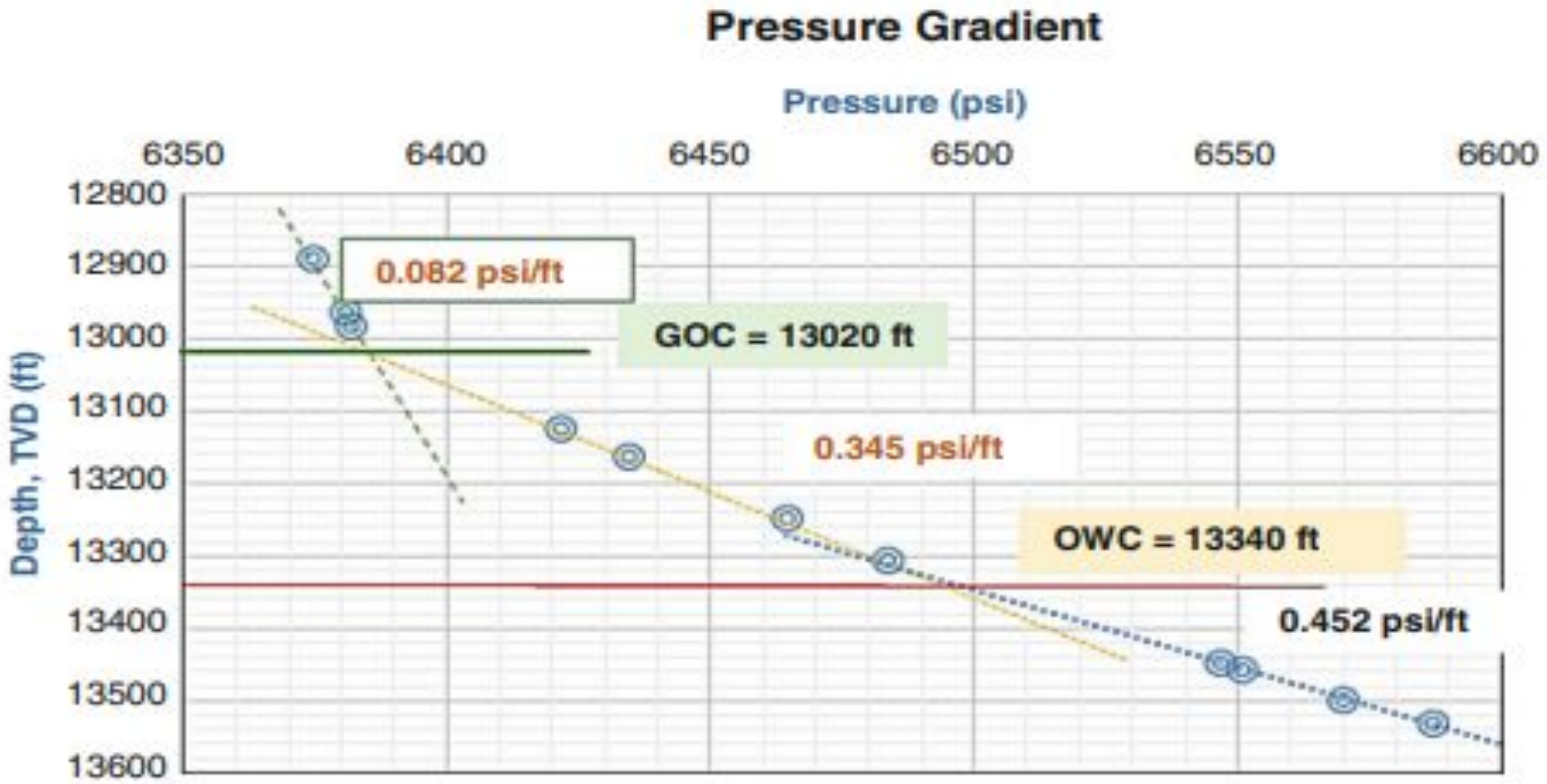
- Data usually require correction
- Only useful for thick hydrocarbon columns
- Most reliable for gas contacts, Requires many pressure measurements for profile, Requires accurate pressures.

Example 1

The result of an RFT tests conducted on an appraisal well in a field located in the Niger Delta region is presented in the table below. Determine the types of hydrocarbons present and find the fluid contacts.

Depth TVD (ft)	Formation Pressure (psia)
12,893	6375
12,966	6381
12,986	6382
13,128	6422
13,166	6435
13,249	6465
13,308	6484
13,448	6547
13,458	6551
13,500	6570
13,532	6587

Solution 1



Pressure Gradient
Pressure (psi)
6350
6400
6450
6500
6550
6600
Depth, TVD (ft)
12800
12900
13000
13100
13200
13300
13400
13500
13600
0.082 psi/ft
GOC = 13020 ft
0.345 psi/ft
OWC = 13340 ft
0.452 psi/ft

Solution 1

The gas gradient is:

$(dP/dD)_{gas} = \Delta P/ \Delta D = P_2 - P_1/ D_2 - D_1$

$(dP/dD)_{gas} = 6381 - 6375/12966 - 12893$

$= 0.082$ psia/ft

The oil gradient is:

$(dP/dD)_{oil} = 6484 - 6435/13308 - 13166$

$= 0.345$ psia/ft

The water gradient is:

$(dP/dD)_{water} = 6570 - 6551/ 13500 - 13458$

$=0.452$ psia/ft

Example 2

A pressure survey was carried out on a well that penetrates through the gas zone in a reservoir at FUPRE. The result of test 1 recorded a pressure of 4450 psia at 9825 ft with fluid gradient of 0.35 psi/ft while test 2 at 9500 ft recorded a pressure of 4180 psia with fluid gradient of 0.11 psi/ft Calculate:

- Estimate the fluid contacts (GOC & OWC) in the reservoir
- The thickness of the oil column
- Calculate the pressures at GOC and OWC respectively

Hint: take the water gradient as 0.445 psi/ft and atmospheric pressure as 14.69 psia

Solution 2

Solution

From test 1

$$P_{oil} = \left(\frac{dP}{dD}\right)_{oil} D + C_o$$

$$4450 = 0.35 * 9825 + C_o$$

$$C_o = 4450 - 3438.75 = 1011.25\ psia$$

$$\therefore \quad P_{oil} = 0.35D + 1011.25$$

From test 2

$$P_{gas} = \left(\frac{dP}{dD}\right)_{gas} D + C_o$$

$$4180 = 0.11 * 9500 + C_g$$

$$C_g = 4180 - 1045 = 3135\ psia$$

$$\therefore \; P_{gas} = 0.11D + 3135$$

Solution 2

Recall: **at GOC**

$$P_{oil} = P_{gas}$$

$$0.35D + 1011.25 = 0.11D + 3135$$

$$0.35D - 0.11D = 3135 - 1011.25$$

$$0.24D = 2123.75$$

$$\therefore\ D = GOC = \frac{2123.75}{0.24} = 8848.96\,ft$$

The water pressure is

$$P_{water} = 0.445D + 14.69$$

Solution 2

At OWC

$$P_{oil} = P_{water}$$

$$0.35D + 1011.25 = 0.445D + 14.69$$

$$1011.25 - 14.69 \quad = 0.445D - 0.35D$$

$$0.095D = 996.56$$

$$D = OWC = \frac{996.56}{0.095} = 10490.11\ ft$$

The thickness of the oil column is

$$= OWC - GOC$$

$$= 10490.11 - 8848.96 = 1641.15\ ft$$

The pressures at the fluid contacts are:

$$P@GOC = (0.35*8848.96) + 1011.25 = 4108.39\ psia$$

$$P@OWC = (0.445*10490.11) + 14.69 = 4682.79\ psia$$

Assignment 1

The result of an RFT tests conducted on an appraisal well in a field located in the Niger Delta region is presented in the table below. Determine the types of hydrocarbons present and find the fluid contact.

Depth TVD (ft)	Formation Pressure (psia)
11,200	4648
11,300	4656
11,450	4664
11,500	4672
11,600	4730
11,700	4745
11,820	4778
11,900	4810

Assignment 2

The result of an RFT tests conducted on an appraisal well in a field located in the Niger Delta region is presented in the table below. Determine the types of hydrocarbons present and find the fluid contacts

Depth TVD (ft)	Formation Pressure (psia)
11,762	5816
11,829	5821
11,847	5822
11,977	5859
12,011	5871
12,087	5898
12,141	5915
12,269	5973
12,278	5976
12,316	5994
12,345	6009

Assignment 3

A pressure survey was carried out on a well that penetrates through the gas zone in a reservoir at FUPRE. The result of test 1 recorded a pressure of 3830 psia at 9525 ft with fluid gradient of 0.352 psi/ft while test 2 at 9200 ft recorded a pressure of 3560 psia with fluid gradient of 0.118 psi/ft.

Calculate:

- Estimate the fluid contacts (GOC & OWC) in the reservoir
- During history match, it was observed that the fluid contacts given by the geologists were wrong which was traceable to wrong fluid gradient. After careful analysis, it was observed that the oil gradient is 0.341 psi/ft recomputed the fluid contacts and estimate the absolute relative error.
- The thickness of the oil column
- Calculate the pressures at GOC and OWC respectively

Hint: take the water gradient as 0.445 psi/ft and atmospheric pressure as 14.69 psia

Fluid Pressure Regime

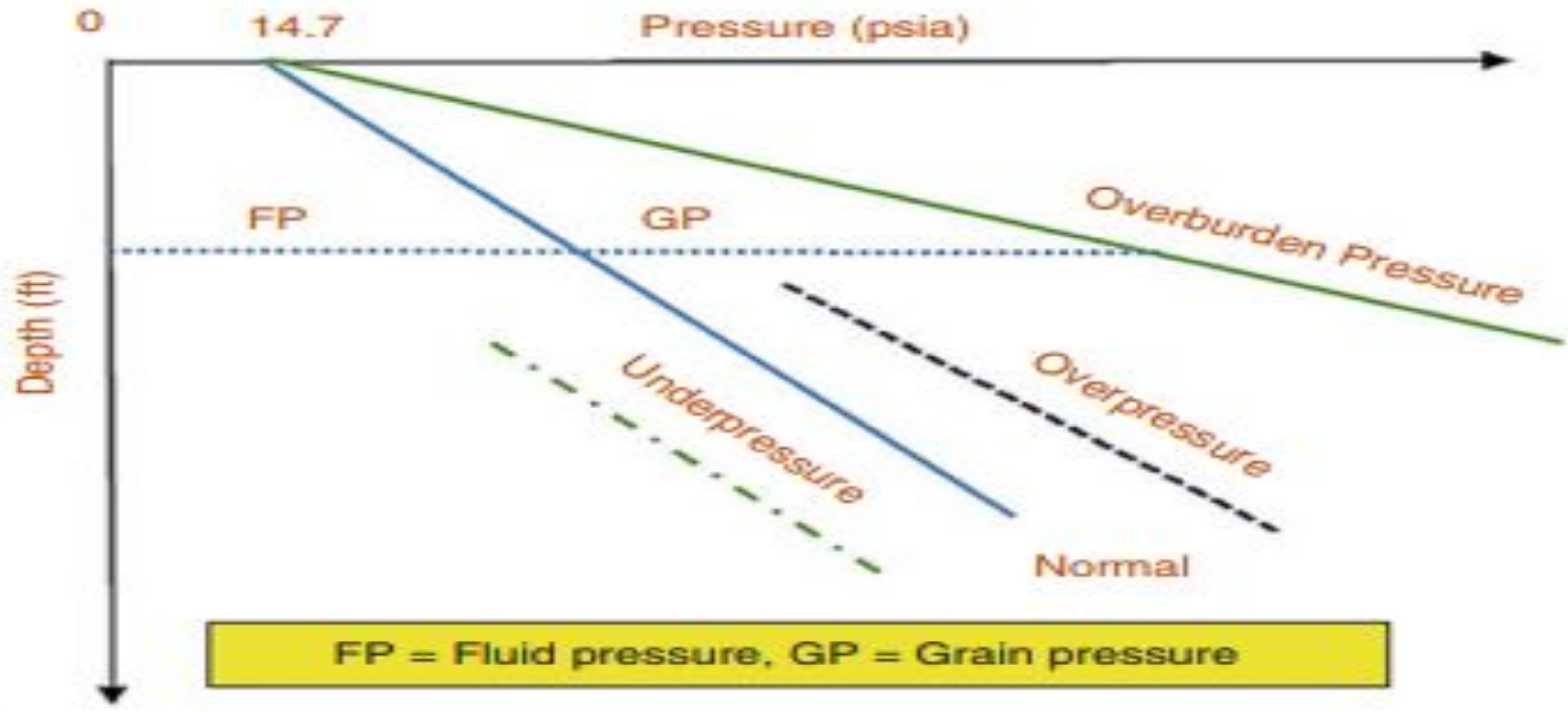
- At any given time in the reservoir, the average reservoir pressure is an indication of how much gas, oil or water is remaining in the porous rock media.
- Hydrocarbon reservoirs are discovered at some depths beneath the earth crust as a result of depositional process and thus, the pore pressure of a fluid is developed within a rock pore space due to physical, chemical and geologic processes through time over an area of sediments.

Fluid Pressure Regime

There are three identified pressure regimes:

- Normal (relative to sea level and water table level, i.e. hydrostatic)
- Abnormal or overpressure (i.e. higher than hydrostatic)
- Subnormal or underpressure (i.e. lower than hydrostatic)

FLUID PRESSURE REGIMES



1 Pressure regime

FLUID PRESSURE REGIMES

- **The total pressure at any depth, resulting from the combined weight of the formation rock and fluids, whether water, oil or gas, is known as the overburden pressure.**

OP= FP + GP

Where OP = Overburden Pressure.

FP = Fluid Pressure.

GP = Grain Pressure.

- At a given depth, the overburden pressure can be equated to the sum of the fluid pressure (FP) and the grain or matrix pressure (GP) acting between the individual rock particles, i.e.

d (FP) = -d(GP)

- The overburden pressure remains constant at any particular depth, then d FP d GP () ( ) = − (1.4) That is, a reduction in fluid pressure will lead to a corresponding increase in the grain pressure, and vice versa.

Fluid pressure gradient regimes, RFT

PRESSURE-DEPTH PLOTTING

Tools:

1. RFT – Repeat formation tester
2. MDT –Modular formation dynamic tester
3. DST – Drill Stem Test

Used in:

- HC columns (RFT & MDT)
- Aquifers (DST)

Reservoir Engineers need to, in the appraisal stage for oil and gas fields, determine:

1. The location of fluid contacts in the formation.
2. The calculation of the net rock volume V appearing in equations for STOIIP and GIIP

Fluid pressure gradient regimes, RFT

- Fluid pressure regimes in hydrocarbon columns are dictated by the prevailing water pressure in the vicinity of the reservoir .

- In a perfectly normal pressure zone, the water pressure at any depth can be calculated as:

$$P_{water} = (dP/\ dD)_{water}\ D + 14.7$$

- $(dP/\ dD)_{water}$ = water pressure gradient, which is dependent on the chemical composition (salinity), and for pure water has the value of 0.4335 psi/ft.

- The abnormal hydrostatic pressure is encountered and can be defined by mathematical equation as:

$$P_{water} = (dP/\ dD)_{water}\ D + 14.7 + C$$

Some Causes of Abnormal Pressure

- **Incomplete compaction of sediments**: fluids in sediments have not escaped and are still helping to support the overburden.
- **Aquifers in mountainous regions**: aquifer recharge is at higher elevation than drilling rig location.
- **Charged shallow reservoirs** due to nearby underground blowout.
- **Large structures** .
- **Tectonic movements.**

High pressure occurs at the upper end of the reservoir and the hydrostatic pressure gradient is lower in gas or oil than in water.

Some Causes of Abnormal Pressure

- Abnormally high pore pressures may result from local and regional tectonics.
- The movement of the earth's crustal plates, faulting, folding, lateral sliding and slipping, squeezing caused by down dropped of fault blocks, diapiric salt and/or shale movements, earthquakes, etc. can affect formation pore pressures.
- Due to the movement of sedimentary rocks after lithification, changes can occur in the skeletal rock structure and interstitial fluids.

Fluid pressure gradient regimes, RFT

Where C is a constant that is positive if the water is overpressured and negative if it is underpressured.

FLUID PRESSURE REGIMES

Fluid Equations

Gas Equation: $P_{gas} = (dP/dD)_{gas} * D + C$

Oil Equation $P_{oil} = (dP/dD)_{oil} * D + C$

Water Equation $P_{water} = (dP/dD)_{water} * D + 14.7$

Fluid pressure gradient regimes, RFT

Fluid Gradients

$(dP/dD)_{water}$ =0 .45 psi/foot

$(dP/dD)_{oil}$ =0 . 35 psi/foot

$(dP/dD)_{gas}$ =0 .08 psi/foot

Fluid Equations

Gas Equation: $P_{gas} = 0.08D + C$

Oil Equation $P_{oil} = 0.35D + C$

Water Equation $P_{water} = 0.45D + 14.7$

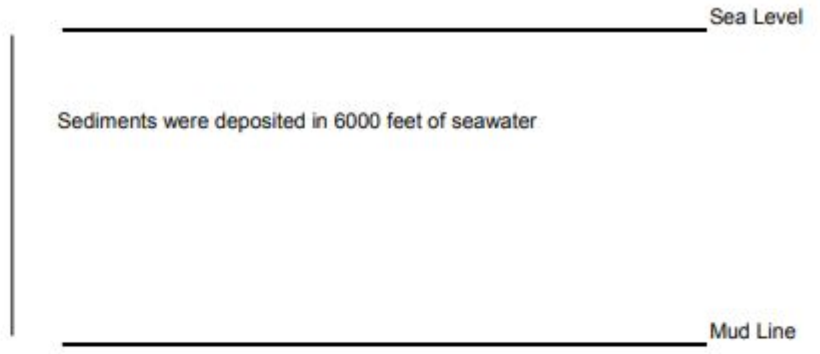
Some Causes of Abnormal Pressure

- A fault may vertically displace a fluid bearing layer and either create new conduits for migration of fluids giving rise to pressure changes or create up-dip barriers giving rise to isolation of fluids and preservation of the original pressure at the time of tectonic movement.
- When crossing faults, it is possible to go from normal pressure to abnormally high pressure in a short interval. Also, thick, impermeable layers of shale (or salt) restrict the movement of water. Below such layers abnormal pressure may be found

Fluid pressure gradient regimes, RFT

The Concept of Reservoir Fluid Pressure

A sand/shale sequence was formed, resulting in the seawater being sealed off top and bottom in the sand by impermeable shale.

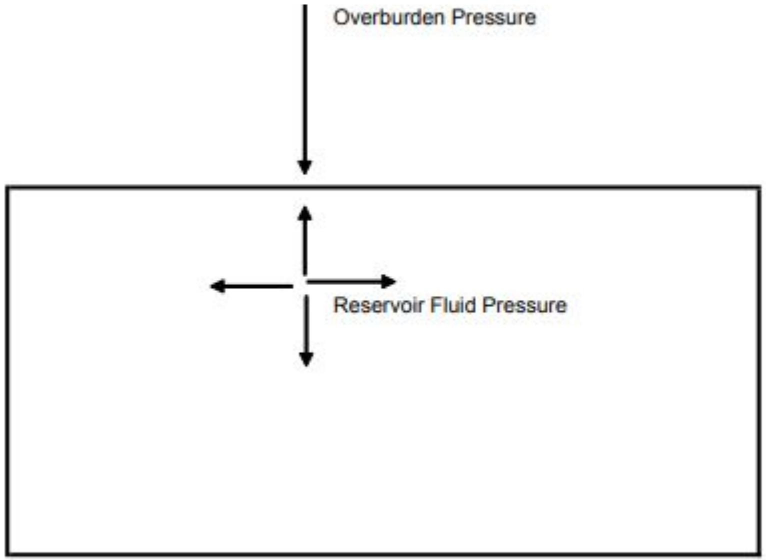


Thus water was sealed in the sand with a pressure of 6000 x 0.45 = 2700 psia This is the reservoir fluid pressure.

Fluid pressure gradient regimes, RFT

The overburden pressure is 6000 x 1 psi/foot = 6000 psia

The effective pressure = 6000 – 2700 = 3300 psia



Example 3

1) An exploration well was drilled and tested at a depth of 5,250 feet. Given that the Gas-Oil Contact in the reservoir was located at a depth of 5,200 feet and the oil-water Contact was located at 5,500 feet:

a) Derive the linear equations for gas, oil and water, assuming a gas gradient of 0.08 psi/ft, an oil gradient of 0.35 psi/ft and a water gradient of 0.45 psi/ft. b) Calculate the reservoir pressure at depths of

: i) 5, 125 feet

ii) 5,350 feet

iii) 5,600 feet.

c) Given that the top of the reservoir is at a depth of 5,000 feet, calculate the reservoir pressure at depths of:

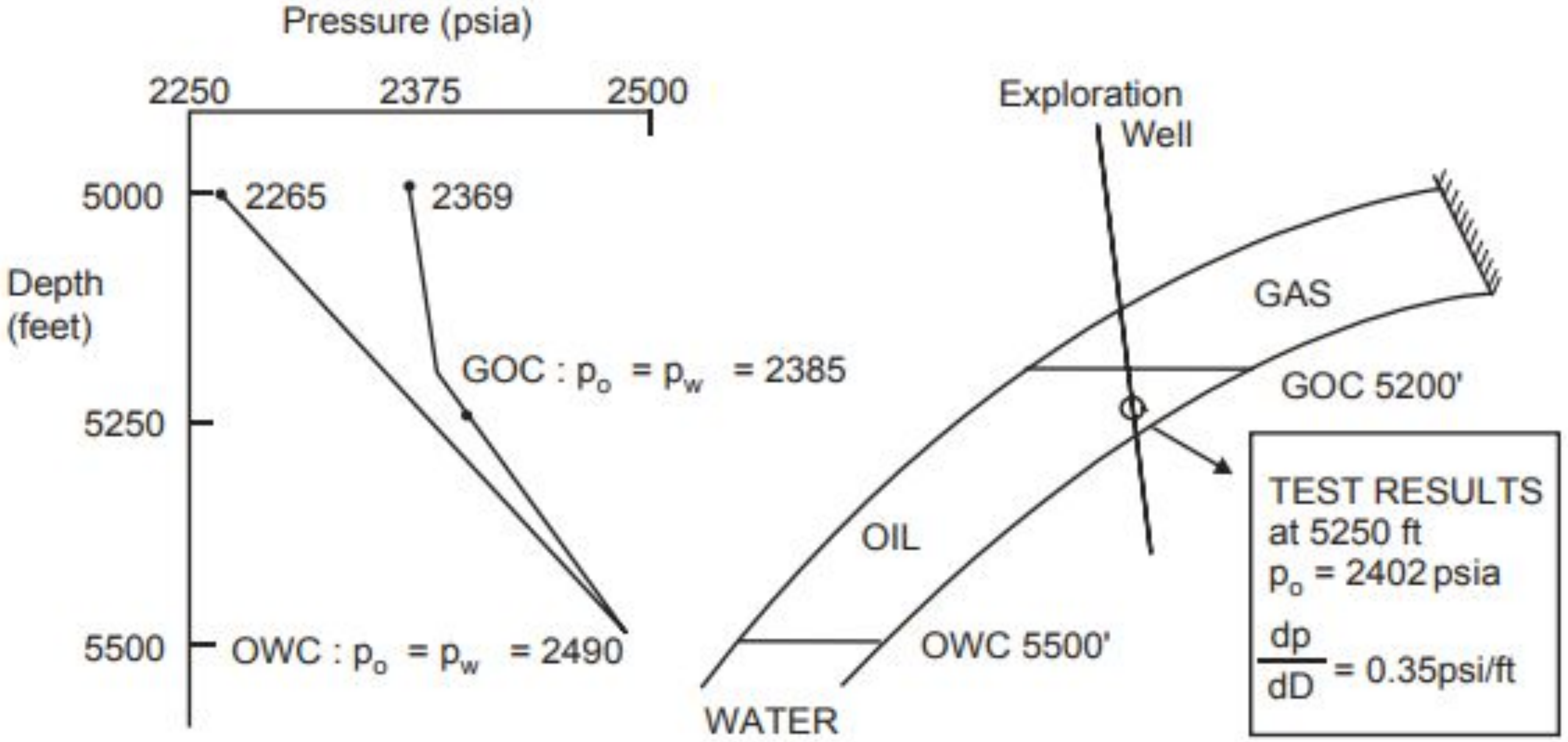
Example 3

a) The top of the structure

b) 5,400 feet

c) Draw a Pressure-Depth graph to represent the reservoir.

Solution 3



Pressure (psia)
2250
2375
2500
5000
2265
2369
Depth
(feet)
GOC : p_o = p_w = 2385
5250
5500
OWC : p_o = p_w = 2490
Exploration
Well
GAS
GOC 5200'
OIL
OWC 5500'
WATER
TEST RESULTS
at 5250 ft
p_o = 2402 psia
$\frac{dp}{dD}$ = 0.35psi/ft

Solution 3

i)

$(dP / dD)_{water} = 0.45$ psi/foot

$(dP / dD)_{oil} = 0.35$ psi/foot

$(dP / dD)_{gas} = 0.08$ psi/foot

Gas Equation: $P_g = 0.08D + C$

Oil Equation $P_o = 0.35D + C$

Water Equation $P_w = 0.45D + 14.7$

Solution 3

Water Equation: Pw = 0.45D + 14.7

At OWC:

Pw = 0.45D + 14.7

Pw = (0.45*5500) + 14.7 = 2490 psia

AT OWC, Pw = Po

Oil Equation :

Po = 0.35D + C = 2490 psia

Po = (0.35*5500) + C = 2490

1925 + C = 2490

C = 565

Solution 3

Oil Equation: Po = 0.35D + 565

AT GOC

Po = (0.35*5200) + 565 = 2385 psia

AT GOC, Pg = Po

Gas Equation: Pg = 0.08D + C

Pg = (0.08*5200) + C = 2385 psia

416 + C = 2385 C = 1969

Gas Equation: Pg = 0.08D + 1969

Solution 3

ii)

a) At a depth of 5125 feet:

Fluid is gas

$P_g = (0.08*5125) + 1969 = 2379$ psia

b) At a depth of 5350 feet:

Fluid is oil

$P_o = (0.35*5350) + 565 = 2437.5$ psia

c) At a depth of 5600 feet

Fluid is water

$P_w = (0.45*5600) + 14.7 = 2534.7$ psia

Solution 3

iii) a) At the top of the reservoir

Fluid is gas

Pg = (0.08*5000) + 1969 = 2369 psia

b) At 5,400 feet

Fluid is oil

Po = (0.35*5400) + 565 = 2455 psia

Solution 4

iv)

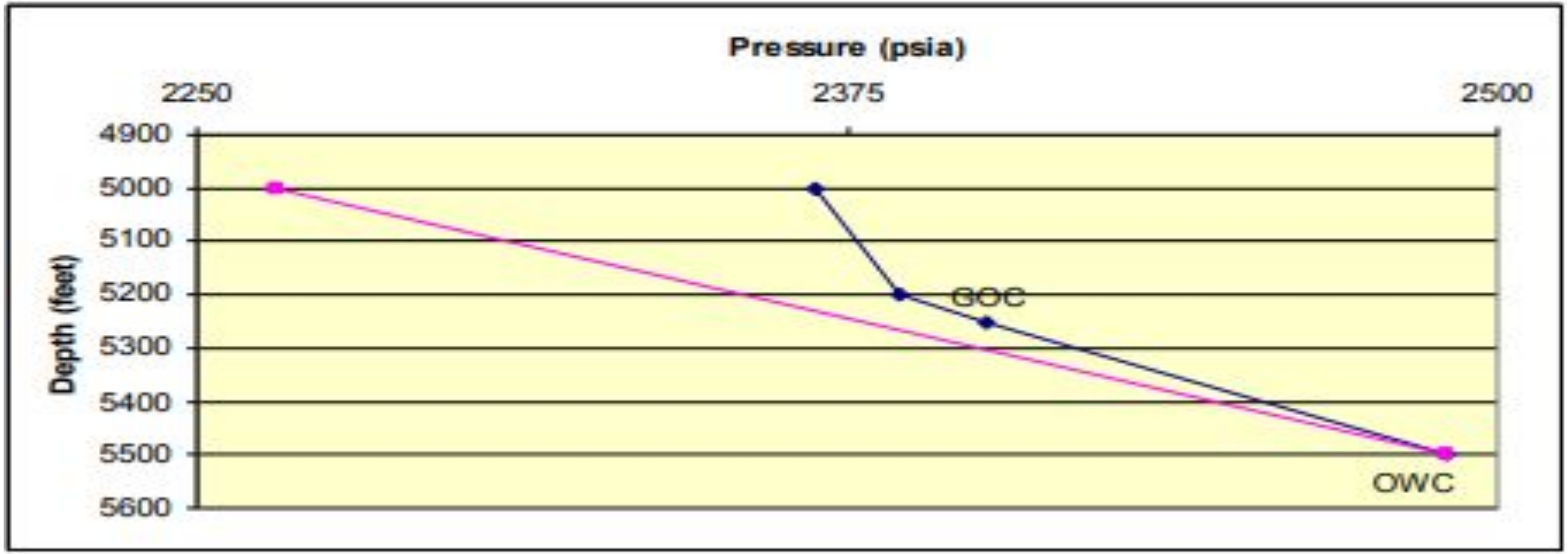
Blue line

Depth, ft	Fluid Type	Pressure, psia
5000	TOS – Gas	2369
5125	Gas	2379
5200	GOC	2385
5350	Oil	2438
5400	Oil	2455
5500	OWC	2490
5600	Water	2535

Pink line

Depth, ft	Fluid Type	Pressure, psia
5000	TOS – Water	2265
5500	OWC	2490

Solution 3



Pressure (psia)
2250
2375
2500
4900
5000
5100
5200
5300
5400
5500
5600
Depth (feet)
GOC
OWC

Example 4

An exploration well, drilled to a depth of 5,150 feet, tested gas down to TD. An RFT done at a depth of 5,100 feet, yielded a reservoir pressure of 2,377 psi and a gas gradient of 0.08 psi/ft. The top of the reservoir was located at a depth of 5,000 feet.

Calculate:

a) The Deepest Possible Gas-Water Contact

b) The Deepest Possible Oil-Water Contact

c) The Maximum Possible Oil Column

d) The Maximum Possible Gas in Place for a 10-acre plot with reservoir porosity of 30% and an irreducible water saturation of 0.24

e) The Maximum Possible Oil in Place for the reservoir listed above

Solution 4

a) The Deepest Possible Gas-Water Contact

For test data:

Gas Equation: $P_g = 0.08D + C$

$P_g = 0.08*5100 + C = 2377$

$408 + C = 2377$

$C = 1969$

Solution 4

Gas Equation: Pg = 0.08D + 1969

CASE 1

ASSUMPTION: No oil Present

Water Equation: Pw = 0.45D + 14.7

Gas Equation: Pg = 0.08D + 1969

At GWC, Pg = Pw

Therefore, 0.45D + 14.7 = 0.08D + 1969

0.45D - 0.08D = 1969 - 14.7

0.37D = 1954

D = 5281 feet

Solution 4

This is the deepest at which we will encounter gas, for if there is an oil column, the OWC will be higher.

D is called the Deepest Possible Gas Water Contact (DPGWC)

DPGWC = 5281 feet

The Maximum gas column is the DPGWC minus the Top of the Reservoir Maximum Gas Column = 5281 – 5000 = 281 feet.

Solution 4

b) The Deepest Possible Oil-Water Contact

CASE 2

ASSUMPTION: Gas Oil Contact is at Total Depth (TD) or Gas Down To (GDT) of the well

GOC is at 5150 feet

. AT GOC, $P_g = P_o$

Gas Equation: $P_g = 0.08D + 1969$

$P_g = (0.08*5150) + 1969 = 2381$ psia

Oil Equation : $P_o = 0.35D + C = 2381$ psia

$(0.35*5150) + C = 2381$

$1802 + C = 2381$; $C = 579$

Solution 4

Oil Equation : Po = 0.35D + 579

AT OWC, Po = Pw

0.35D + 579 = 0.45D + 14.7

0.45D - 0.35D = 579 – 14.7

0.10D = 564 D = 5640 feet

D is called the Deepest Possible Oil Water Contact (DPOWC)

DPOWC = 5640 feet

Solution 4

c) The Maximum Possible Oil Column The Maximum Possible Oil Column is the DPOWC - GOC = 5640 – 5150 = 490 feet.

d) The Maximum Possible Gas in Place

MPGIP = 43560Ahφ(1-Sw)/Bg

If Bg is not given, leave the value in cubic feet

h = Maximum Gas Column

MPGIP = 43560*A*h*φ*(1-Sw)

= 43560*10*281*0.3*(1-0.24)

= 27,908,021 cubic feet

= 27.908 MMCF

Solution 4

e) The Maximum Possible Oil in Place

MPOIP = $7758Ah\varphi(1-Sw)/Bo$

If Bo is not given, leave the value in barrels

h = Maximum Oil Column

MPOIP = $7758*A*h*\varphi*(1-Sw)$

$= 7758*10*490*0.3*(1-0.24)$

= 8,667,238 barrels =

= 8.667 MMBO

Assignment 5

A static pressure survey on a well yields the following information:

Depth, ft	Pressure, psig
0	1709
1000	1759
2000	1810
3000	1870
4000	1920
5000	1970
6000	2190
6500	2400
7000	2600
7200	2685
7400	2770
7500	2800
7800	2920

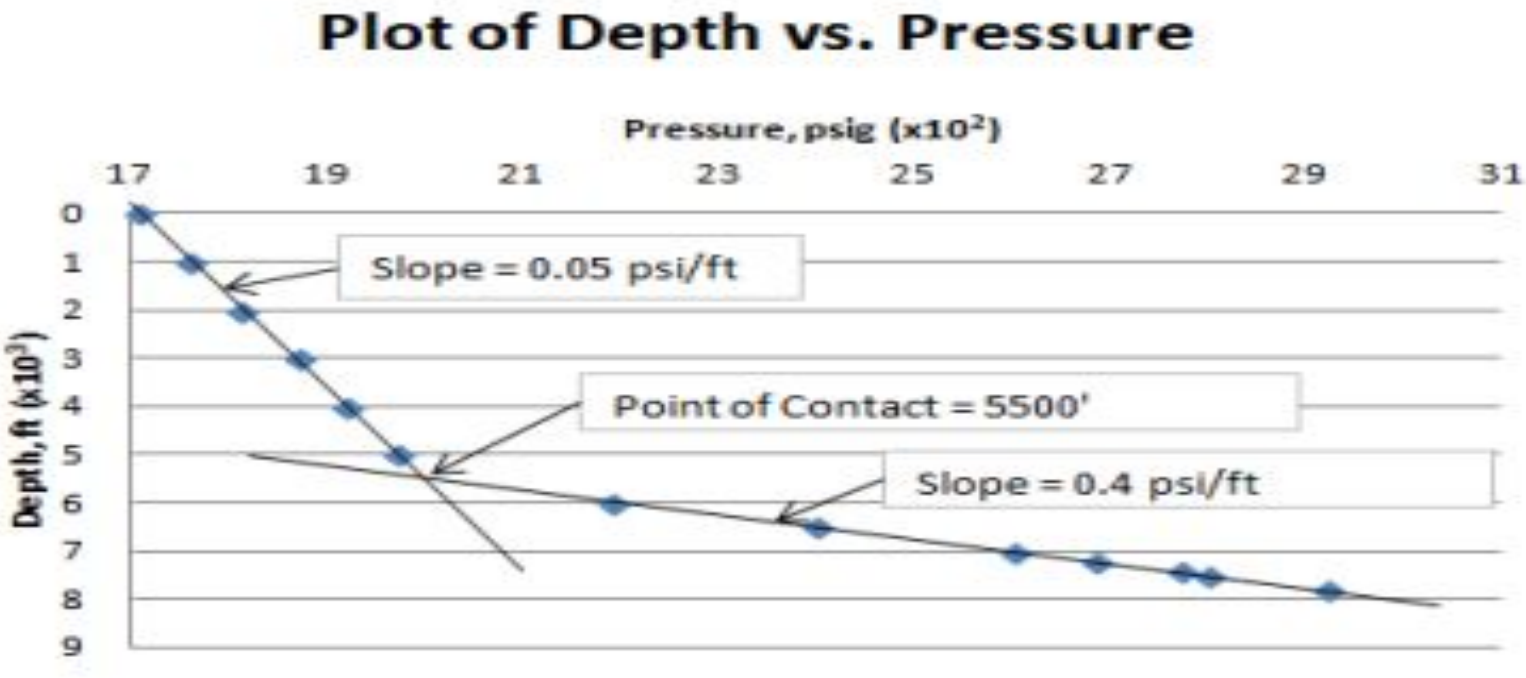
a. Determine the gradients of the different fluids present in the wellbore.

b. Determine the point of liquid contact within the wellbore

. c. Will the well produce if opened at the surface? Why?

d. If the Kelly Bushing (KB) elevation is 90' and the top of the producing formation is at 7864'(KB), correct the pressure value back to the datum level at the top of the formation.

Solution 5



Plot of Depth vs. Pressure
Pressure, psig (x10²)
17
19
21
23
25
27
29
31
Depth, ft (x10³)
0
1
2
3
4
5
6
7
8
9
Slope = 0.05 psi/ft
Point of Contact = 5500'
Slope = 0.4 psi/ft

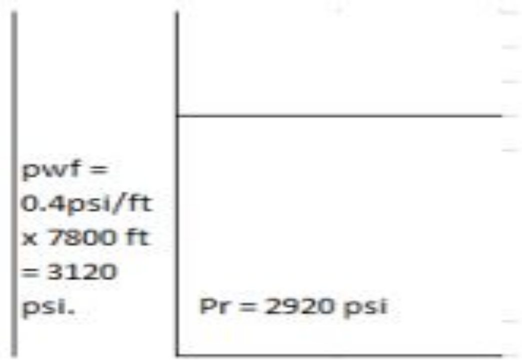
Solution 5

a. 0.05 psi/ft - Assumption gas

0.4 psi/ft - Assumption oil

b. Point of liquid contact = 5500' +/-

c. Most unlikely. Formation pressure of 2920 psi (pressure at 7800') cannot sustain a fluid liquid column 7800' high with a gradient of 0.4 psi/ft and a pressure of 0.4psi/ft x 7800 ft = 3120 psi. May require artificial lift.



Solution 5

d. KB elevation = 90’

Top of formation = 7864’ KB

Top of formation = 7864 – 90 = 7774’ ss (datum)

Recorder run-depth = 7800’KB = 7800 – 90 = 7710’ ss

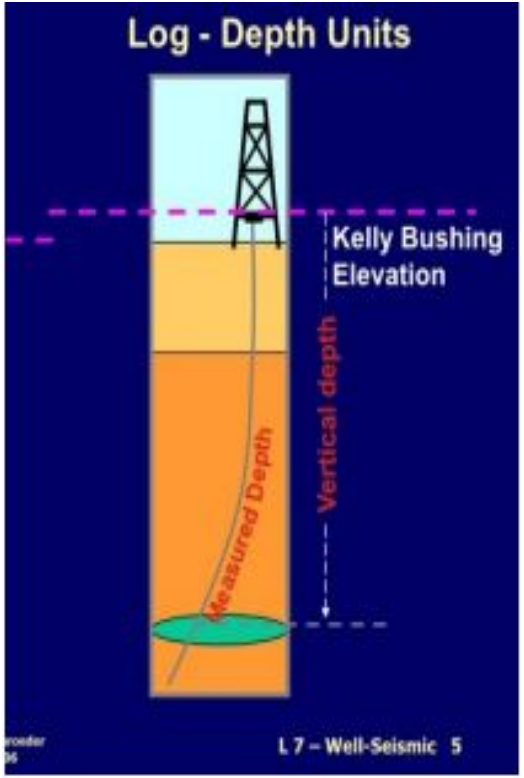
Pressure recorded at 7800’KB (7710’ss) = 2920 psi

Pressure gradient = 0.4 psi/ft

Pressure

difference at datum = (7774’ – 7710’) x 0.4 psi/ft = 64’ x 0.4 psi/ft

= 25.6 psi Therefore, pressure at datum = 2920 + 25.6 = 2945.6 psi



Solution 5


Pressure recorded @ 7800' KB = 2920 psi
Recorder run-depth = 7800'KB = 7800' – 90' = 7710' ss
Pressure difference at datum
=(7774' – 7710') x 0.4 psi/ft = 25.6 psi
Top of formation = 7864 'KB = 7864'-90' = 7774'ss
Pressure at datum
= 2920 + 25.6 = 2945.6 psi

Reflection Activity

Reservoir Types:

- Reflect on the characteristics of undersaturated, saturated, and gas-cap reservoirs. How do these different reservoir types influence the behavior of fluids in the subsurface?
- Consider real-world examples of each reservoir type. How might the choice of extraction methods vary for different reservoir types, and what challenges could arise?

Fluid Contact:

- Imagine you are an engineer conducting reservoir analysis. How would you determine fluid contacts within a reservoir, and why is this information crucial for reservoir management?
- Discuss the significance of fluid contacts in the context of maximizing hydrocarbon recovery. How might fluid contacts impact the efficiency of extraction operations?

Reflection Activity

Fluid Pressure Regime:

- Explore the concept of fluid pressure regimes, including overpressure and underpressure conditions. How do these pressure regimes influence well drilling and reservoir engineering decisions?
- Consider the implications of identifying different fluid pressure gradients in a reservoir. How might this information be used to optimize well placement and enhance oil or gas recovery?

Overall Reflection:

- Reflect on the interconnectedness of reservoir types, fluid contacts, and fluid pressure regimes. How do these factors collectively contribute to the challenges and opportunities in the field of reservoir engineering?
- Imagine you are presenting your findings to a team of colleagues. How would you communicate complex concepts related to reservoirs, fluid contacts, and pressure regimes in a way that is accessible to a non-specialist audience?

Estimation of Hydrocarbon Volumes and Recovery Factors

- The description of the calculation of oil in place concentrates largely on the determination of fluid pressure regimes and the problem of locating fluid contacts in the reservoir.
- **Primary recovery** is described in general terms by considering the significance of the isothermal compressibilities of the reservoir fluids; while the determination of the recovery factor and attachment of a time scale are illustrated by describing volumetric gas reservoir engineering.

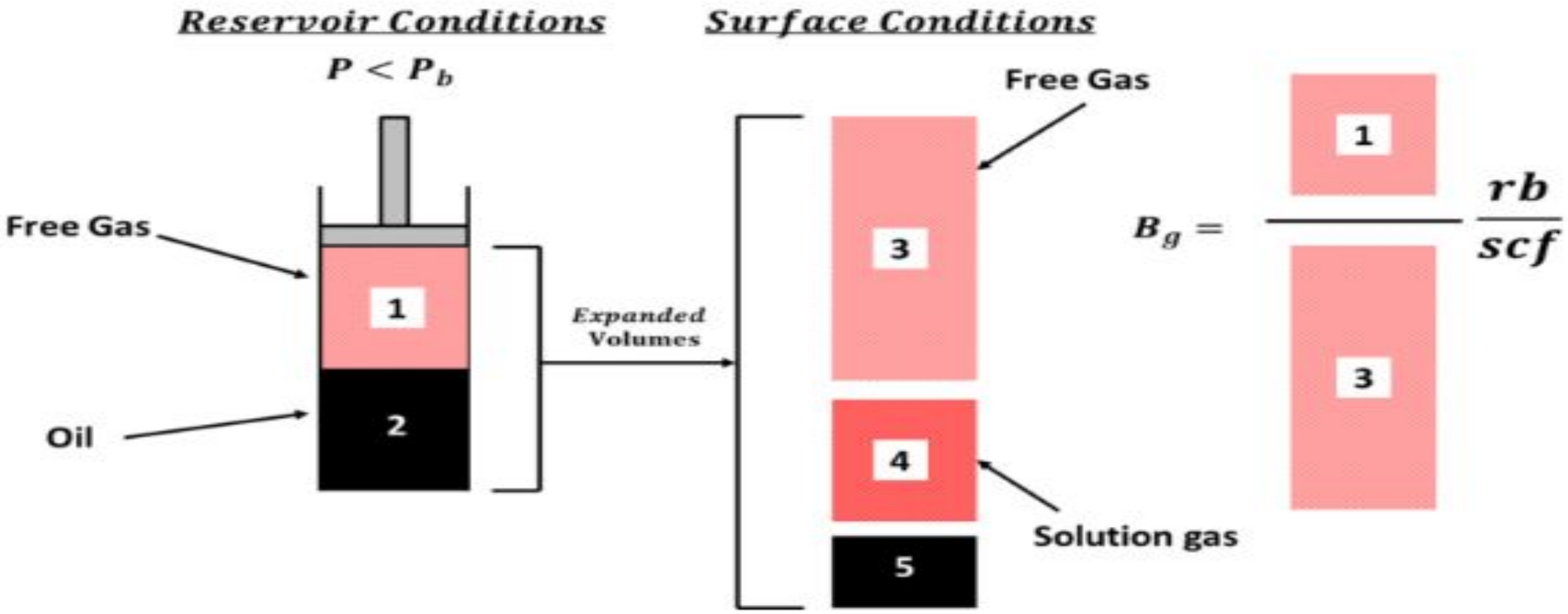
Estimation of Hydrocarbon Volumes and Recovery Factors

- Estimating hydrocarbon reserves is a complex process that involves integrating geological and engineering data. Depending on the amount and quality of data available, one or more of the following methods may be used to estimate reserves:
  - **Volumetric**
  - **Material balance**
  - **Production history**
  - **Analogy**

Estimation of Hydrocarbon Volumes and Recovery Factors

- Volumetric gas reservoirs are defined as completely isolated, closed systems with approximately constant hydrocarbon pore volumes.
- Volumetric gas reservoirs are presumed not to gain significant pressure support or fluid influx from outside sources, such as water influx from aquifers or neighboring shale (non-reservoir) layers.
- On the other hand, non volumetric gas reservoirs exhibit evidence of pressure support or influx of fluids (mostly water) from outside sources, such as aquifers or neighboring shale intervals.

Estimation of Gas In Place



https://topdogengineer.com/lesson/gas-formation-volume-factor-bg/

Estimation of Oil in Place in an Oil Reservoir

Consider a reservoir which is initially filled with liquid oil. The oil volume in the reservoir (oil in place) is

$OIP = V\varphi(1 - S_{wc})$(res.vol.)

Where

V = The net bulk volume of the reservoir rock

φ = The porosity, or volume fraction of the rock which is porous and

S_{wc} = The connate or irreducible water saturation and is expressed as fraction of the pore volume.

The pore volume(PV) which is the total volume in the reservoir which can be occupied by fluids can be obtained from the expression below:

$PV = V\varphi$

Estimation of Oil in Place in an Oil Reservoir

Similarly,

Hydrocarbon pore volume (HCPV) which is defined as the total reservoir volume which can be filled with hydrocarbons either oil, gas or both can be expressed mathematically by

$HCPV = V\varphi(1\text{-}S_{wc})$

Since all oils, at the high prevailing pressures and temperatures in reservoirs, contain different amounts of dissolved gas per unit volume, it is more meaningful to express oil volumes at stock tank (surface) conditions, at which the oil and gas will have separated. Thus the stock tank oil initially in place is

$STOIIP = N = 7758Ah\varphi\,(1\text{-}S_w) / B_{oi}$

Estimation of Oil in Place in an Oil Reservoir

where

- STOIIP = N = (STB)
- 7758 = conversion factor from acre-ft to bbl
- A = area of reservoir (acres)
- h = height or thickness of pay zone (ft)
- ø = porosity
- S_w = connate water saturation
- B_{oi} = formation volume factor for oil at initial conditions (reservoir bbl/STB)

Calculation on Gas Oil in Place

- The standard cubic feet of gas in a reservoir with a gas pore volume of V_g ft^3 is simply V_g / B_g, where B_g is expressed in units of cubic feet per standard cubic foot.
- As the gas volume factor B_g changes with pressure, the gas in place also changes as the pressure declines. The gas pore volume V_g may also be changing, owing to water influx into the reservoir. The gas pore volume is related to the bulk, or total, reservoir volume by the average porosity φ and the average connate water S_w.

The standard cubic feet of gas in place G is given by

Calculation on Gas Oil in Place

GIIP = G = $43560 V_b \Phi (1-S_w) / B_{gi}$

Or GIIP = $43560 Ah\Phi(1-S_w) / B_{gi}$

V_b = bulk reservoir volume commonly expressed in acre-feet (ac-ft)

Φ = average porosity expresses in percentage(%)

B_{gi} = Gas formation volume factor at initial conditions (ft^3/SCF)

S_w = water saturation in percentage(%)

G = GIIP(SCF)

43560 = conversion factor from acre-ft to ft^3

Calculations on Gas Oil in Place

- The areal extent of the Bell Field gas reservoir was 1500 acres. The average thickness was 40 ft, so the initial bulk volume was 60,000 ac-ft. Average porosity was 22%, and average connate water was 23%. Bg at the initial reservoir pressure of 3250 psia was calculated to be 0.00533 ft3 /SCF. Therefore, the initial gas in place was

$$G = 43{,}560 \times 60{,}000 \times 0.22 \times (1 - 0.23) \div 0.00533$$

$$= 83.1 \text{ MMM SCF}$$

Gas Volume Calculation

Example 6

A volumetric gas reservoir located offshore Niger Delta with the following data in the table below, determine the following:

Initial reservoir pressure, P_i	*3800 psia*
Cumulative gas production, G_p	*24.6 MMMscf*
Reservoir thickness, h	*25 ft*
Wellbore flowing pressure, P_{wf}	*2750 psia*
Connate water saturation, S_{wc}	*23%*
Gas gravity, γ_g	*0.68*
Porosity, ∅	*18%*
Reservoir temperature	*170^0F*

Example 6

- Area extent of the reservoir
- The gas reserve at 2750 psia.
- The recovery factor at 2750 psia.

Solution 6

The amount of gas produced at 2750 psia is calculated mathematically as

$$G_{p@2750\ psia} = G - G_{reserve@2750\ psia}$$

$$G_{p@2750\ psia} = G - G_{reserve@2750\ psia}$$

Recall:

$$G = \frac{43560Ah\varnothing(1 - S_{wc})}{B_{gi}}$$

$$G_{reserve} = \frac{43560Ah\varnothing(1 - S_{wc})}{B_g}$$

Solution 6

$$G_{p@2750\ psia} = 43560Ah\varnothing(1 - S_{wc})\left[\frac{1}{B_{gi}} - \frac{1}{B_g}\right]$$

$$B_g = \frac{0.0283zT}{P}$$

To calculate the compressibility factor, z
If yg < = 0.7 Then

$$T_c = 168 + (325 * \gamma_g) - (12.5 * \gamma_g{}^2)$$

$$T_c = 168 + (325 * 0.68) - (12.5 * 0.68^2) = 383.22^0\text{R}$$

$$P_c = 677 + (15 * \gamma_g) - (37.5 * \gamma_g{}^2)$$

$$P_c = 677 + (15 * 0.68) - (37.5 * 0.68^2) = 669.86 \text{ psia}$$

$$T_r = \frac{(T + 460)}{T_c} = \frac{(170 + 460)}{383.22} = \frac{630}{383.22} = 1.64$$

$$P_{ri} = \frac{P_i}{P_c} = \frac{3800}{669.86} = 5.67$$

Solution 6

Calculate z from Standing and Katz compressibility factors chart.

$$z_i(P_{ri}, T_r) = z_i(5.67, 1.64) = 0.89$$

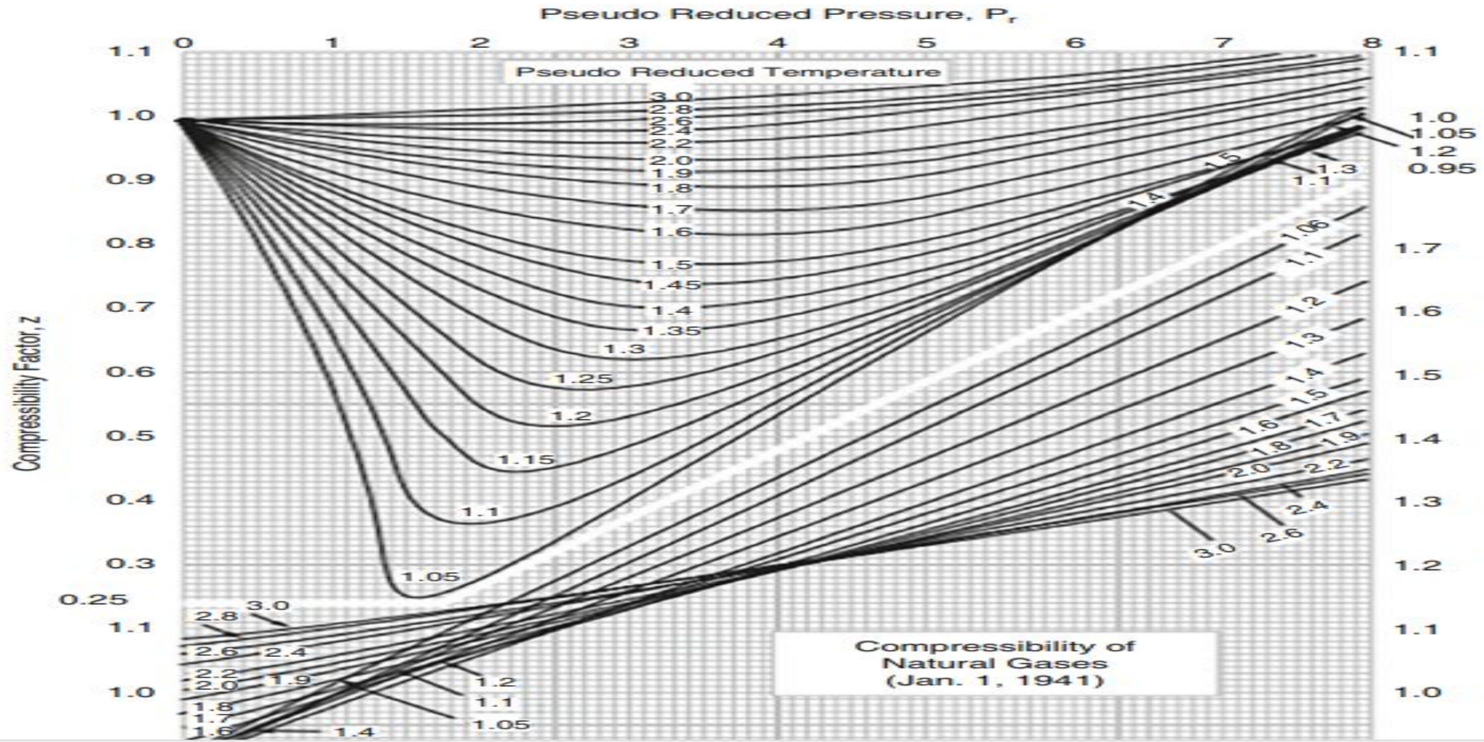
$$P_r = \frac{P}{P_c} = \frac{2750}{669.86} = 4.11$$

$$z(P_r, T_r) = z(4.11, 1.64) = 0.83$$

Therefore,

$$B_{gi} = \frac{0.0283 z_i T}{P_i} = \frac{0.0283 * 0.89 * (170 + 460)}{3800} = 0.004176 \ cuft/scf$$

Solution 6



Src: https://www.researchgate.net/figure/Standing-and-Katzs-compressibility-factor-chart_fig2_288141819

Solution 6

$$B_g = \frac{0.0283zT}{P} = \frac{0.0283*0.83*(170+460)}{2750} = 0.005381\ cuft/scf$$

$$G_p = 43560Ah\varnothing(1-S_{wc})\left[\frac{1}{B_{gi}} - \frac{1}{B_g}\right]$$

The area extent is

$$A = \frac{G_{p@2750\ psia}}{43560h\varnothing(1-S_{wc})}\left[\frac{B_{gi}B_g}{B_g - B_{gi}}\right]$$

$$A = \frac{24.6*10^9}{43560*25*0.18*(1-0.23)}\left[\frac{0.005381*0.004176}{0.005381-0.004176}\right] = 3039.348\ acres$$

Solution 6

To calculate the gas reserve at 2750 psia

$$G_{reserve} = \frac{43560Ah\varnothing(1 - S_{wc})}{B_g} = \frac{43560*3039.348*25*0.18*(1 - 0.23)}{0.005381}$$

$$= 8.52527*10^{10}scf = 85.253 \ \ MMMscf$$

$$G = \frac{43560Ah\varnothing(1 - S_{wc})}{B_{gi}}$$

$$G = \frac{43560*3039.348*25*0.18*(1 - 0.23)}{0.004176} = 109,852,779,243.1030 \ scf$$

$$= 109.8528 \ MMMscf$$

$$RF = \frac{G_p}{G} = \frac{24.6*10^9}{109852779243.1030} = 0.2239 = 22.39\%$$