Gas Reservoirs
NG 502

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COURSE CONTENTS

Section I
DR. Helmy
1-Properties of N.G and Condensate Systems
2-Gas Reservoirs and Calculations of Gas In Place
SECTION I

- Chapter I : IMPORTANCE OF PETROLEUM ENGINEERING
- Chapter II : RESERVOIR ROCK/FLUID PROPERTIES AND INTERACTIONS:
  - RESERVOIR ROCK PROPERTIES
  - RESERVOIR FLUID PROPERTIES
  - RESERVOIR ROCK/FLUID INTERACTIONS
- Chapter III : GAS RESERVOIRS and CALCULATIONS OF GAS INPLACE
IMPORTANCE OF PETROLEUM ENGINEERING
What is Petroleum Engineering?

Petroleum Engineering is the most interesting and complex branches of engineering because of the wide variety of disciplines it encompasses.
Petroleum engineering is important because of the unique role it plays in our Arabic countries economy.

Petroleum engineering will play an increasingly important role in order to maintain a high income level to support the vast industrial development of the country, and to maximize recovery by means of the best producing methods.
Objectives

- The chief objectives of petroleum engineering are:
  - To increase the hydrocarbon recovery above the current level.
  - To device recovery methods for recovering of some of the remaining hydrocarbon
  - To develop the marginal reservoirs
  - To find ways of utilizing gas.
Recovery

- **Primary recovery** means production of oil and gas by forces already present in the reservoir.

- The fraction of hydrocarbon that can be produced by primary methods depends upon the type of oil, type of rock, types of natural forces present and the reservoir development scheme.

- Good engineering, possibly employing laboratory research and reservoir simulation, can increase recovery.
Secondary recovery means recovering some of remaining hydrocarbons by water injection and gas repressuring.

Tertiary recovery is concerned with recovering a portion of the hydrocarbon still left after secondary recovery.
Costs and Economics of Recovery

- by secondary and tertiary methods is:
- a high investment
- high risk
- low profit operation.
Conclusions

We need to high quality petroleum engineers to:
- maximize primary recovery (cheapest)
- develop secondary and tertiary recovery methods.

We also need to:
- greatly expand research funding and effort.
- increase job opportunities.
RESERVOIR ROCK/FLUID PROPERTIES AND INTERACTIONS
I-RESERVOIR ROCK PROPERTIES
The essential rock properties in reservoir engineering are those that govern the rock’s storage capacity and spatial distribution; its ability to conduct fluids; and its spatial and directional distributions.
Porosity

- Porosity is a measure of a rock’s storage capacity.

- Effective porosity is a dimensionless quantity, defined as the ratio of interconnected pore volume to the bulk volume.
Permeability

- Absolute permeability is a measure of a rock’s ability to transmit fluid.

- Since it is a measure of resistance to flow, a higher permeability reservoir experiences less pressure drop than a corresponding low permeability reservoir.

- Permeability of a medium is a strong function of the local pore size and a weak function of the grain size distribution.
Permeability varies widely in naturally occurring reservoirs, from a fraction of a millidarcy to several darcies.

Similar to porosity, the permeability of a reservoir could be a function of pressure.
Darcy Equation

\[ \frac{q}{A} = -k \mu \left[ \frac{dP}{dx} \right] \]

Where:

\( q \) = Volume Flow Rate

\( A \) = Area Perpendicular to Flow Direction

\( k \) = Permeability in Darcy

\( \mu \) = Dynamic Viscosity of Flowing Fluid

\( \frac{dP}{dx} \) = Pressure Gradient in the Flow Direction \( x \)
Homogeneous vs. heterogeneous systems

- Homogeneous systems feature uniform spatial distribution, while heterogeneous systems exhibit non-uniform distribution.

- We often assume homogeneity in reservoir calculations, even though many reservoirs are heterogeneous.
A reservoir exhibits isotropic property distribution if that property has the same value regardless of the direction in which we measure it.

If a property’s value does vary with direction, then the reservoir is anisotropic with respect to that property.
II-RESERVOIR FLUID PROPERTIES
Fluid properties, like rock properties, significantly affect fluid flow dynamics in porous media.

Unlike rock properties, however, fluid properties exhibit significant pressure dependency.
Gas properties

- The properties of the gas flow equation are:

  - Density appears in the gravity term, and it is often neglected.

  - The compressibility factor introduces an important non-linearity, in that it appears in the formation volume factor.

  - Gas viscosity is also strongly dependent on pressure, and needs to be calculated as pressure varies spatially.
Gas properties are measured in a variety of ways.

Gas samples are taken from the field to the laboratory and then subjected to tests in chromatographs and heated pressure cells.
Dew point

- The dew point conditions occur when the first drop of liquid forms in a gas phase.

- This occurs as a result of pressure and temperature change.
The formation of liquids (i.e., reaching the dew point) in petroleum fields as pressure decreases is known as retrograde conditions.
Gas Gravity

- Gas gravity is a measure of how “heavy” a gas is.
- Gas gravity = (gas molecular weight) / (air molecular weight).
- Gas gravities are usually less than one.
Gas Deviation Factor

- **Gas deviation factor or z factor** represents the deviation of real gas behavior from the ideal gas law.
The real gas flow in oilfield units is:

\[ PV = z \, n \, RT \]

Where:

- \( P \) = pressure, psia
- \( V \) = volume, cub. ft
- \( Z \) = deviation factor
- \( n \) = number of lb moles
- \( R \) = gas constant = 10.73 psia ft\(^3\)/lb mole \(^\circ\)R
- \( T \) = absolute temperature, \(^\circ\)R
The z factor can be:

- measured in the laboratory for a given natural gas measure.
- determined from correlations if laboratory data is not available.
- These correlations relate the z factor to gas gravity, pseudo-reduced pressure and pseudo-reduced temperature.
Gas formation volume factors relate the volumes that fluids occupy at standard conditions to volumes that fluids occupy in the reservoir.

\[ B_g = 0.028 \frac{z T}{P} \]

in units Rcf / scf
Gas Viscosity

- *Gas viscosities* are:
  - much lower than liquids.
  - estimated with correlations.

- The correlations relate gas viscosity to gas gravity, pressure and temperature.
Gas Density

- Density is a measure of weight per unit volume of a gas at a particular temperature and pressure.

- *Gas density* in lb / cub. ft can be calculated by:

\[ \rho_g = 0.0136 \ \gamma_g / B_g \]
The equations and correlations necessary for determining gas properties

- **Real Gas Law**
  \[ PV = ZnRT \]

- **Density**
  \[ \rho = \frac{PM}{ZRT} \]

- **Compressibility**
  \[ c = \frac{1}{P} - \frac{1}{Z} \frac{\partial Z}{\partial P} \]

- **Compressibility Factor**
  \[ Z = f(P, T) \]

- **Formation Volume Factor**
  \[ B_g = \frac{ZTP_{sc}}{T_{sc}P} \]

- **Viscosity**
  \[ \mu = f(P, T) \]
Oil properties

- Oil properties that appear in the governing flow equations for the oil phase are density, compressibility, formation volume factor, viscosity and solubility of gas in oil.

- In the absence of gas, these oil properties can be treated as constants, because the compressibility of gas-free oil is very small.
A recent review of the available correlations has been provided by McCain (1991).

Modern equations of state to calculate these properties can be used.
**Bubble point pressure**

- When pressure reduced in an oil reservoir by oil production, gas bubbles form in the reservoir.
- The pressure at which these gas bubbles first appear is *called the bubble point pressure*.
- The behavior of an oil reservoir changes dramatically as the pressures fall below the bubble point because the behavior of oil properties changes.
Solution Gas/Oil Ratio

- This is a measure of how much gas an oil can keep in solution at a certain pressure.

- The higher the pressure, the more gas that oil can hold.
**Saturated oil:**

- gas cannot all dissolved in the oil.

**Under-saturated oil:**

- oil can dissolve more gas but no free gas is available to be dissolved.
Oil Formation Volume Factor

- Is used to relate the volumes that fluids occupy at surface conditions to volumes that fluids occupy in the reservoir.

- Oil exhibits the opposite behavior of the gas.
Total Formation Volume Factor

- Is the volume at reservoir conditions occupied by one stock tank barrel of oil, its gas in solution and liberated free gas.

- **Above the bubble point:**
  \[ B_t = B_o \]

- **Below the bubble point:**
  \[ B_t = B_o + B_g (R_{si} - R_s) \]
Oil Viscosity

- Oil viscosity is influenced by the amount of gas in solution.
- As pressure increases, increasing amounts of dissolved gas lower the oil viscosity until it reaches a minimum at the bubble point.
- Viscosity increases above the bubble point because the liquid is being compressed.
Oil densities are usually measured at surface conditions and reported as either specific gravity or API.

API = \( \frac{141.5}{\gamma_o} - 131.5 \)

or

\( \gamma_o = \frac{141.5}{131.5 + \text{API}} \)
Oil density at stock tank conditions:

$$\rho_{osc} = 62.4 \ Y_o$$

Oil density at reservoir conditions:

$$\rho_o = (\rho_{osc} / Bo) + (R_s \rho_{gsc} / 5.61 Bo)$$
Water properties

- McCain (1991) provides correlations for estimating such water properties as density, compressibility, formation volume factor, viscosity and gas solubility.

- Since gas solubility in water is very small compared to oil, for, we assume constant values for these properties.
Water properties are similar in all reservoirs and thus may be estimated by correlations.
Water Salinity

*Can be:*
- measured in the laboratory.
- Estimated from well log resistivity readings in water saturated zones.
The water holds gas in solution, but the amount is very small.

Are estimated from charts.
Water Formation Volume Factor

- Is used to relate the volumes that fluids occupy at surface conditions to volumes that fluids occupy in the reservoir.
Water viscosity as a function of temperature and salinity can be estimated from charts.
III-RESERVOIR ROCK/FLUID INTERACTIONS
Reservoir fluid flow is governed by complex interactions between the fluids and the reservoir rock. These interactions become more complicated when, two or more fluids are present in the same pore.

To appropriately describe the simultaneous flow of two or more fluids in a porous medium requires a good understanding of both the fluid-fluid and rock-fluid interactions.
When two immiscible fluids co-exist in the same pore space, one preferentially adheres to the rock surface.

This phenomenon is known as wetting, and the fluid that is preferentially attracted is referred to as having a higher wettability index.

The parameter which determines the wettability index is called adhesion tension, and it is directly related to interfacial tension.
Amott test

- Wettability is determined by the amount of oil or water imbibed in a core sample compared to the same values when flooded.

- Amott wettability values range from +1 for complete water wetting to -1 for complete oil wetting.
Wettability index $W$ is the logarithm of the ratio of the areas under $P_c$ curves in both imbibitions and drainage processes.

This index can range between -1.5 and +1.
Contact angle test

- Can be measured directly on polished surfaces.

- Ranges are from 0 to 75° for water wet, from 105 to 180° for oil wet, and from 75 to 105° for intermediate wettability.
As a means of estimating wettability, none of these tests is entirely satisfactory:

The Amott index and the W index can be taken in actual permeable medium, but their correspondence to capillary pressure is not direct.

But both of these methods are measures of aggregate rather than local wettability.
The contact angle method is direct but it is not clear to what extent a polished surface represents the internal surface of the permeable medium.
Most sandstone reservoirs tend to be water wet or intermediate wet, whereas most carbonate reservoirs tend to be intermediate wet or oil wet.
Interfacial tension is a measure of the surface energy per unit area of the interface between two immiscible fluids.
Relative permeability appears prominently in the flow equations used in reservoir engineering.
Two-phase relative permeability.

If a third phase is present, then each fluid has its own relative permeability, which differs from the corresponding two-phase relative permeability.
Darcy's law may be integrated over a finite distance $\Delta x$ to give

$$V_j = -\lambda_j \frac{\Delta \Phi_j}{\Delta x}$$

Where:

- $\lambda_j$ is the mobility of phase $j$. 
This mobility is the constant of proportionality between the flux of \( V_j \) and the potential difference

\[ \Delta \Phi_j = \Delta (P_j - \rho_j g D). \]
Mobility can be decomposed into

- a rock property, the absolute permeability,
- a fluid property, the viscosity, and
- the rock-fluid property, the relative permeability

\[ \lambda_j = K \left( \frac{K_{rj}}{\mu_j} \right) \]
The relative permeability is a strong function of the fluid saturation of phase $S_j$.

Relative mobility can be defined as

$$\lambda_{rj} = \frac{K_{rj}}{\mu_j}$$

and the phase permeability

$$K_j = K_{Krj}$$

$K_j$ is a tensorial property in three dimensions.
The trapped water saturation is the irreducible water saturation.

It is not the connate water saturation, which is the water saturation in a reservoir before any water is injected.
The end point relative permeability's are the constant relative permeability of a phase at the other phase's residual saturation.
The end points are measures of wettability.

The wetting phase endpoint relative permeability will be smaller than the nonwetting phase endpoint.

Other view the crossover saturation of the relative permeability's as a more appropriate indicator of wettability.
Capillary pressure

- The water in the capillary tube rises above the water level in a container to a height that depends on the capillary size.

- The adhesion force allows water to rise up in the capillary tube while gravity opposes it.

- The water rises until there is a balance between these two opposing forces.

- The differential force between adhesion and gravity is the capillary force.
Capillary pressure is the most basic rock-fluid characteristic in multiphase flow.

\[ P_c = \frac{2\gamma_{WN}}{R} \cos \theta \]
Capillary pressure is important in porous media flow description because of the saturation distribution in the capillary-like pore spaces.
Residual Phase Saturation
The mechanism for residual phase saturation may be illustrated through two simplified models:
The pore doublet model

The interface of the small-radius path will reach the outflow end before the large-radius path, and the nonwetting phase will be trapped in the large-radius path.
Snap-off Model

For certain values of the potential gradient and pore geometry, the potential gradient in wetting phase across the path segment can be less than the capillary pressure gradient across the same segment.
The condition for reinitializing the flow of any trapped globule is

\[ \Delta \Phi_w + \Delta \rho g \Delta L \sin \alpha \geq \Delta P_c \]

Where:

- \( \Delta L \) is the globule size and \( \alpha \) is the angle between the globule's major axis and the horizontal axis.
Capillary Desaturation Curve (CDC)

- Typically these curves are plots of percent residual saturation for the non-wetting or wetting phases on the y axis versus a capillary number on a logarithmic x axis.
The capillary number $N_c$ is a dimensionless ratio of viscous to capillary forces and can be written as:

\[
N_c = \frac{V \mu}{\delta \cos \theta}
\]

or

\[
N_c = \frac{k \Delta P}{\delta \cos \theta}
\]
GAS RESERVOIRS
Natural gas is a mixture of hydrocarbon gases and impurities.

The hydrocarbon gases normally found in natural gases are methane, ethane, propane, butanes, pentanes, and small amounts of hexanes, heptanes, octane's and the heavier components.
The impurities found in natural gases include carbon dioxide, hydrogen sulfide, nitrogen and vapor water.

What usually reaches the transmission line for sale as natural gas is mostly a mixture of methane and ethane.
What are oil and gas?

- Petroleum consists of paraffin series together with lesser quantities of naphthalene's and aromatics.

- In general oils contain a higher fraction of heavy molecules, while at the end of the scale, methane and other molecules predominate in gases.
<table>
<thead>
<tr>
<th></th>
<th>GOR</th>
<th>API GRAVITY</th>
<th>Composition</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>C1</td>
<td>C2</td>
</tr>
<tr>
<td>Dry Gas</td>
<td>no liquid</td>
<td>0.9</td>
<td>0.05</td>
</tr>
<tr>
<td>Wet Gas</td>
<td>1B/100 MCF  50-70</td>
<td>50-70</td>
<td></td>
</tr>
<tr>
<td>Condensate</td>
<td>5-100 MCF/B  50-70</td>
<td>50-70</td>
<td>0.75</td>
</tr>
<tr>
<td>Volatile oil</td>
<td>3000 CF/B  40-50</td>
<td>40-50</td>
<td>0.625</td>
</tr>
<tr>
<td>Black Oil</td>
<td>100-2500 CF/B  30-40</td>
<td></td>
<td>0.44</td>
</tr>
<tr>
<td>Heavy Oil</td>
<td>20-25</td>
<td>0.2</td>
<td>0.03</td>
</tr>
</tbody>
</table>
Classification of Oil

- One classification widely used distinguishes between “paraffin's predominate”, and such an “asphalt-base” oils.

- Specific gravity Classification

  \[
  \text{API}^\circ = \frac{141.5 - \text{S.G.}(@60^\circ\text{F})}{131.5}
  \]
Classification of Gases

- **Chemical analysis:** chromatography - spectroscopy
- **Specific gravity classification:**

S.G. = \( \frac{\rho_{g}}{\rho_{air}} \) @ the same temperature.
Gas condensate production may be thought of as a type intermediate between oil and gas.

The liquid is sometimes called by an older name distillate, and sometimes simply oil.

The term wet gas is sometimes used as more or less equivalent to gas condensate.

Exist in the reservoir as a vapor (more or less).
Rule of thumb: a gas condensate exists, if $\text{GOR} > 5000$ scf/bbl and $\text{API} \geq 50$. Exceptions.

Production with $\text{GOR} > 100,000$ scf/bbl is commonly called lean or dry gas.

Most known retrograde gas-condensate reservoirs are in the range of 3000 to 8000 psi and 200-400°F.
Composition is important.
Correlation between MW of C7+ and °API of ST liquids.
No correlation between GOR and \(^0\)API of ST liquids.

Well completion interval is important: gas cap, oil zone, both? Gas cap may contain gas-condensate or dry gas.

Classification of condensate reservoirs depends upon: the composition of hydrocarbon accumulation, temperature and pressure.
Phase Diagram

- Defined for a given fluid composition. If the composition changes, diagram changes.

- Why “retrograde“?

- The term retrograde is used because vaporization occurs during isothermal expansion, rather than condensation.

- Condensed liquid is immobile – phase envelop shifts – to right.
The over-all retrograde loss will be greater:

- for lower reservoir temperatures
- for higher abandonment pressures
- for greater shift of the phase diagram to the right.
CALCULATIONS OF GAS INPLACE
Natural gas reservoirs are reservoirs in which the contained hydrocarbons fluids exist wholly as a vapor phase at pressure values equal to or less than the initial value.

Reservoir gas is a constant-composition fluid.

**Non-associated gas**: is free gas not in contact with oil in the reservoir.

**Associated gas**: is free gas in contact with oil in the reservoir.

**Dissolved gas**: is gas in solution with oil in the reservoir.
Volumetric

\[ \text{OOIP or OGIP} = (\text{Rock Volume}) \times (\text{Porosity}) \times \left(1 - \text{Water Saturation}\right) / (\text{Formation Volume Factor}) \]
Material Balance

- Material balance in terms of standard cubic feet:
  - SCF Produced = SCF Initially - SCF Remaining in the reservoir in the reservoir
  - $G_p = b - m \left( \frac{P}{Z} \right)$
  - Where: $b = \frac{P_i V_i T_{sc}}{Z_i P_{sc} T}$ and $m = \frac{V_i T_{sc}}{P_{sc} T}$
  - This equation indicates that for a volumetric gas reservoir the graph of the cumulative gas produced $G_p$ versus $P/Z$ is a straight line of negative slope $m$. 
P/Z Vs. Gp

Initial P/IZ

P/Z

Initial Gas In place

Cumulative Production, MMMSCF
Material balance in water drive gas reservoirs can be written as:

\[ G_{p \ Bgf} = G \ (Bgf - Bgi) + We - Wp \]

Where:

- \( G_{p \ Bgf} \) is the volume of the produced gsd at Pf.
- \( G \ (Bgf - Bgi) \) is the change in volume of the initial gas when expanded from Pi to Pf.
- \( We \) is the volume of the water influx and \( Wp \) is the volume of the water produced.
The reservoir gas production $G_p$ used in the previous section must include the separator gas production, the stock tank gas production, and the stock tank liquid production converted to its gas equivalent, $GE$:

$$GE = 133,000 \frac{\beta_o}{M_o}$$

- $\beta_o = \text{specific gravity of condensate}$
- $M_o = \text{molecular weight of condensate}$
Limitations and Errors

- Accuracy of data enter in computations such as porosity, connate water, pressure, gas deviation factor, and gas volume factor, etc.
- Errors in gas production measurements.
- Pressure errors are due to gauge errors and the difficulties in averaging.
- Water-drive reservoirs require the estimate of the volume of the reservoir invaded at abandonment and the average residual gas saturation.
- Assumptions in equations derivation.
Exercises
Exercise-1

Determine average permeability (linear, horizontal, steady-state, incompressible flow)

Data:

Flow rate = 10 cm³ water in 500 sec
Test temperature = 70°F
Upstream pressure = 1.45 atmosphere gauge
Downstream pressure = 1.00 atmosphere gauge
Viscosity of water (μ_w) @ 70°F = 0.984 cp
Core area = 2.0 cm²
Core length = 2.0 cm

Determine:

k_{absolute}
**Exercise-3**

**DETERMINATION OF EFFECTIVE PERMEABILITY (FROM FIELD DATA)**

**GIVEN:**
- \( q_o = 510 \text{ STB/DAY} \)
- \( \mu_o = 0.14 \text{ cp @ reservoir conditions} \)
- \( B_o = 1.95 \text{RB/STB} \)
- \( h = 15 \text{ ft} \)
- \( r_e = 750 \text{ ft} \)
- \( r_w = 4 \text{ in} \)
- \( P_e = 5,170 \text{ psia} \)
- \( P_w = 4,500 \text{ psia} \)

**DETERMINE:**

a) \[ k_o = \frac{q_o \mu_o B_o \ln \left( \frac{r_e}{r_w} \right)}{7.08 h \left( P_e - P_w \right)} = \]

b) Capacity = \( k_o h = \)

c) Productivity Index = \( J = \frac{q_o}{\left( P_e - P_w \right)} \left( \frac{\text{STB/DAY}}{\text{psi}} \right) = \)
Exercise-4

On the above pressure-temperature phase diagram:

a) Define:
   i) The points $T_1$, $T_2$, $P_1$ and $P_2$
   ii) The regions I, II and III and indicate the B.P.L and D.P.L.

b) Name the reservoirs represented by $AA_1$, $AA_2$, $BB_1$ $C$, $E$, $D$ and $F$. 
Exercise-5

**K_{rw} / K_{ro} FROM STEADY-STATE MEASUREMENTS**

**TEST DATA:**

- \( L = 7.50 \text{ cm} \)  
  - \( M_d = \text{Mass of Dry Core} = 178.8830 \text{ gm} \)
- \( A = 7.89 \text{ cm}^2 \)  
  - \( M_w = \text{Mass of 100% Water Saturated Core} = 192.6580 \text{ gm} \)
- \( \mu_w = 0.766 \text{ cp} \)  
  - \( M_c = \text{Mass of Core with Both Oil and Water Present} \)
- \( \mu_o = 1.20 \text{ cp} \)  
  - \( \rho_w = 0.9945 \text{ gm/cm}^3 \)
  - \( \rho_o = 0.7494 \text{ gm/cm}^3 \)
- \( V_p = 13.86 \text{ cm}^3 \) (can be calculated from this data)

<table>
<thead>
<tr>
<th>Run No.</th>
<th>Volume Collected (cm³)</th>
<th>Time (sec)</th>
<th>( \Delta P ) (Atmosphere)</th>
<th>( M_o ) (gm)</th>
<th>( S_w ) (%)</th>
<th>( K_{rw}/K_{ro} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.70</td>
<td>9.32</td>
<td>311.6</td>
<td>0.983</td>
<td>190.5363</td>
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<td>2</td>
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<td>1.020</td>
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<tr>
<td>4</td>
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<tr>
<td>5</td>
<td>7.90</td>
<td>2.10</td>
<td>336.5</td>
<td>1.340</td>
<td>191.4252</td>
<td></td>
</tr>
</tbody>
</table>

\[
S_w = \frac{V_p - \frac{M_w - M_c}{\rho_w - \rho_o}}{V_p}
\]

1. Evaluate \( \frac{K_{rw}}{K_{ro}} = \frac{k_w}{k_o} \) and then plot \( \frac{K_{rw}}{K_{ro}} \) versus \( S_w \) on Semi-Log graph paper.
Exercise-6

**Capillary Pressure**

**TEST DATA:**

\[ \sigma_{w0} = 33 \text{ Dynes/cm} \quad \gamma_w = 0.45 \text{ psi/ft} \]
\[ \sigma_{wa} = 71 \text{ Dynes/cm} \quad \gamma_o = 0.31 \text{ psi/ft} \]

**Core Data**

<table>
<thead>
<tr>
<th>Run No.</th>
<th>( P_{ci} ) (psia)</th>
<th>( S_w ) (%)</th>
<th>( h ) (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5</td>
<td>61.5</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>10</td>
<td>51.0</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>25</td>
<td>41.0</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>50</td>
<td>33.0</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>75</td>
<td>27.0</td>
<td></td>
</tr>
</tbody>
</table>

\[ P_{ci} = (\gamma_w - \gamma_o) h \]

Assume: \( \frac{P_{ci}}{\sigma_{w0}} = \frac{P_{ci}}{\sigma_{wa}} \)

1. Plot \( h \) vs. \( S_w \).
2. Approximate \( S_{w_{irr}} \) \[ S_{w_{irr}} = \]
3. At approximately what height will only clean oil flow? \( h = \)
4. Using the relative permeability previously given and the reservoir fluid viscosities

\[ \mu_w = 0.766 \text{ cp} \]
\[ \mu_o = 1.20 \text{ cp} \]

at what height would we expect a WOR of: (a) WOR = 0.1 \( h = \)

(b) WOR = 1.0 \( h = \)