Reservoir Engineering Fact Sheet

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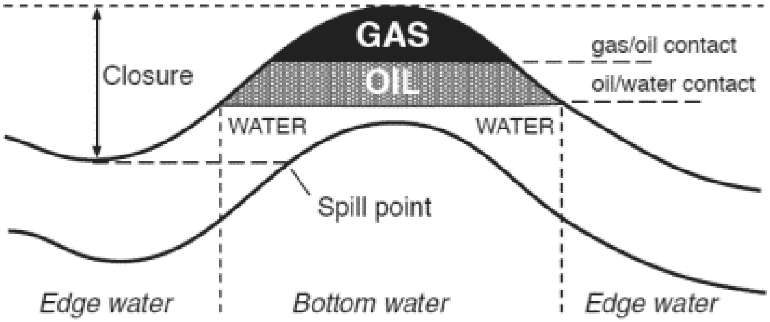
"The art of developing and producing oil and gas fluids in such a manner as to obtain a high economic recovery" (Calhoun, 1960)

- A **Reservoir** is a subsurface accumulation of hydrocarbons, contained in **porous rock** formations, bounded by a barrier of **impermeable** rock (seal), characterised by **natural pressure**.

Variable	Oilfield Unit	SI Unit	Conversion (Multiply SI Unit)
Area	acre	m^2	2.475×10^{-4}
Length	ft	m	3.28
Permeability	md	m^2	1.01×10^{15}
Pressure	psi	Pa	1.45×10^{-4}
Rate (oil)	STB/d	m^3/s	5.434×10^{5}
Rate (gas)	Mscf/d	m^3/s	3049



Rock Properties

Porosity ϕ

A measure of the rock storage capacity (pore volume) that can hold fluids.

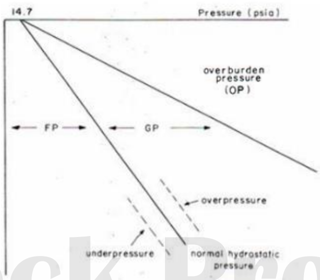
$$\phi = \frac{\text{pore volume}}{\text{bulk volume}}$$

Absolute ϕ: total pore space in a rock.
Effective ϕ: interconnected pore space.

Recent sands (loosely packed)	35 - 45%
Sandstones (more consolidated)	20 - 35%
Tight/well cemented sandstones	15 - 20%
Limestones (e.g. Middle East)	5 - 20%
Dolomites (e.g. Middle East)	10 - 30%
Chalk (e.g. North Sea)	5 - 40%

Formation Pressure

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



- Overburden pressure increases linearly with depth & typically has a pressure gradient of 1 psi/ft.
- OB = FP + GP
  $= p + p_{eff}$
  $P_{eff} = OB - p$

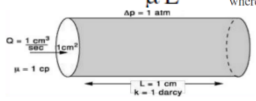
p = *internal pressure*
p_{eff} = *effective pressure*

Permeability *k*

A measure of a porous medium's (rock's) ability to transmit or conduct a fluid.

Darcy's Law:

$$q = \frac{0.001127\, kA\left(p_1 - p_2\right)}{\mu L}$$



where q = flow rate, bbl/day
k = absolute permeability, md
p = pressure, psia
μ = viscosity, cp
L = distance, ft
A = cross-sectional area, ft²

Absolute *k*: **100%** saturation of single fluid
Effective *k*: a particular fluid in the presence of another. k_o, k_g, k_w.
Relative *k*: ratio of *Effective k* to *Absolute k* for each fluid. $\mathbf{k_{ro}} = k_o/k$ $\mathbf{k_{rg}} = k_g/k$ $\mathbf{k_{rw}} = k_w/k$

Resistivity

The resistivity of a porous material is defined by:

$$R = \frac{rA}{L}$$

where r = resistance, Ω
A = cross-sectional area, m^2
L = length, m
resistivity is expressed in Ohm-meter ($\Omega.m$)

Resistivity of the reservoir is therefore related to the amount of **water occupying** a pore space. This gives a means of calculating S_w

True resistivity R_t: depends upon ϕ, S_w and the resistivity of the formation water R_w.

Tortuosity is usually estimated from electrical resistivity measurements. The tortuosity is in the range of 2 to 5 for most reservoir rocks.

Saturation

Saturation is defined as that fraction of the pore volume occupied by a particular fluid:

$$\text{fluid saturation} = \frac{\text{total volume of the fluid}}{\text{pore volume}}$$

$$S_o = \frac{\text{volume of oil}}{\text{pore volume}}$$

$$S_g = \frac{\text{volume of gas}}{\text{pore volume}}$$

$$S_w = \frac{\text{volume of water}}{\text{pore volume}}$$

All saturation values are based on pore volume. Saturations range from 0 to 1 (or 0 to 100%) where the **sum** of the saturations is equal to **1.0** (100%).

$$S_g + S_o + S_w = 1.0$$

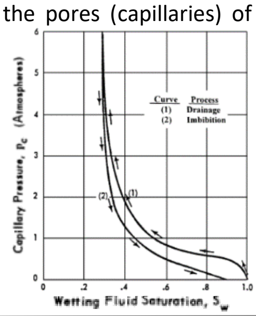
where S_o = oil saturation
S_g = gas saturation
S_w = water saturation

Capillary Pressure

Capillary pressure is the **difference** in pressure which exists at the **interface** between two immiscible fluids in the pores (capillaries) of the reservoir rock.

The displacement of one fluid by another is either **aided** or **opposed** by capillary pressure.

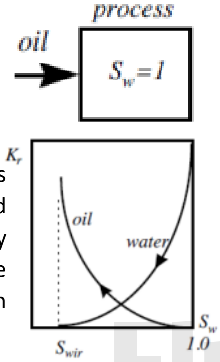
It can **influence** the **distribution** of fluids in the reservoir.



Drainage

Drainage describes the **displacement** of the **wetting** phase from the porous medium by a **non-wetting** phase.

Starting with the porous rock filled with water, and **displacing** this **water** by **oil**, the drainage relative permeability curves can be illustrated:



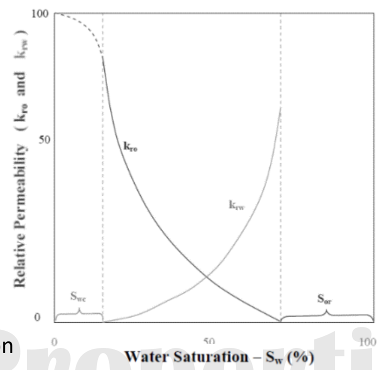
Relative Permeability *kro krg krw*

$\mathbf{k_{ro}} = k_o/k$ (Oil)
$\mathbf{k_{rg}} = k_g/k$ (Gas)
$\mathbf{k_{rw}} = k_w/k$ (Water)

$\boldsymbol{S_{or}}$ = Residual oil saturation
$\boldsymbol{S_{wc}}$ = Connate water saturation

Estimated using:

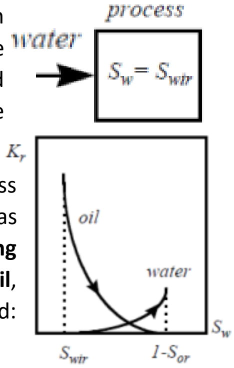
1. ***Corey*** function
2. ***Buckley*** and ***Leverett*** function



Imbibition

Imbibition is process in which the **wetting** phase saturation increases, and the **non-wetting** phase saturation decreases.

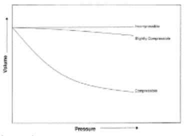
Reversing the process when all mobile **water** has been displaced, **injecting water** to displace the **oil**, imbibition curves defined:



Fluid Properties

Reservoir Fluid Types

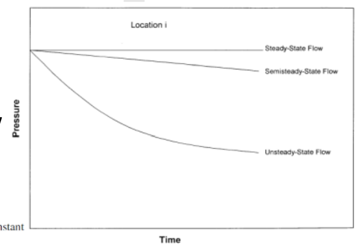
1. ***Incompressible** fluids*: A fluid whose **volume** (or **density**) does **not** change with **pressure**.



2. ***Slightly compressible** fluids*: These "slightly" compressible fluids exhibit small changes in volume, or density, with changes in pressure. Crude oil and water systems fit into this category.
3. ***Compressible** fluids*: Are fluids that experience large changes in volume as a function of pressure. All gases are considered compressible fluids.

Reservoir Flow Regimes

1. **Steady-state** flow $\left(\frac{\partial p}{\partial t}\right)_i = 0$
2. **Unsteady-state** (Transient) flow $\left(\frac{\partial p}{\partial t}\right) = f(i,t)$
3. **Pseudosteady-state** flow $\left(\frac{\partial p}{\partial t}\right)_i = \text{constant}$



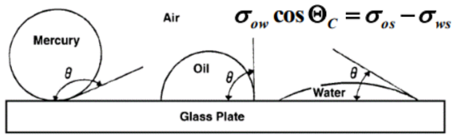
There are **three** types of flow regimes that must be recognized in order to describe the fluid flow behaviour and **reservoir pressure distribution** as a function of **time**.

Wettability

Homogenous *Heterogeneous*

The tendency of one fluid to spread on or **adhere** to a solid **surface** in the presence of **other** immiscible fluids.

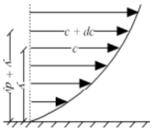
$$\sigma_{ow} \cos \Theta_C = \sigma_{os} - \sigma_{ws}$$



By measuring the angle of contact at the liquid-solid surface, the angle, which is always measured through the liquid to the solid, is called the **contact angle θ**.

Viscosity

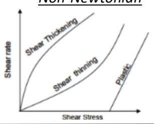
A measure of a fluids internal **resistance** to flow and can be measured as the proportionality of **shear rate** to **shear stress**, which is a form of **internal friction.**



- ***Dynamic Viscosity (poise)***: Expressed in the metric CGS ***[N s/m², Pa.s or kg/m.s]***
- ***Kinematic Viscosity (stoke)***: The ratio of absolute or dynamic viscosity to density. $v = \mu / \rho$ ***[m²/s or Stoke S$_t$]***

1 St (Stokes) = 10^{-4} m²/s = 1 cm²/s

Non-Newtonian

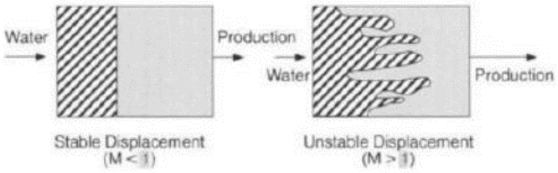


Mobility Ratio

The mobility ratio ***M*** is defined as the mobility of the **displacing** fluid to the mobility of the **displaced** fluid.

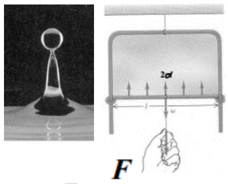
$$M = \frac{k_w \mu_o}{k_o \mu_w} = \frac{(k_{rw} k)\mu_o}{(k_{ro} k)\mu_w} = \frac{(k_{rw})\mu_o}{(k_{ro})\mu_w}$$

$$\lambda_o = \frac{k_o}{\mu_o} = \frac{k\,k_{ro}}{\mu_o} \qquad \lambda_g = \frac{k_g}{\mu_g} = \frac{k\,k_{rg}}{\mu_g} \qquad \lambda_w = \frac{k_w}{\mu_w} = \frac{k\,k_{rw}}{\mu_w}$$



Tension

Surface Tension

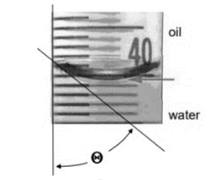


$$\sigma = \frac{F}{l}$$

(N/m)

$$w + T = F = 2\sigma l$$

Interfacial Tension



$$\sigma_{ow} \cos\Theta = \sigma_{os} - \sigma_{ws}$$

$$F = l\sigma_{ow}\cos\Theta = 2\pi r \sigma_{ow}\cos\Theta$$

$$p = \frac{F}{A} = \frac{2\pi r \sigma_{ow}\cos\Theta}{\pi r^2} = \frac{2\sigma_{ow}\cos\Theta}{r}$$

Compressibility

A measure of the relative **volume change** of a **fluid** or **solid** as a response to a **pressure change.**

Isothermal Compressibility c

$$c = -\frac{1}{V}\left(\frac{\partial V}{\partial p}\right)_T$$

Typical values:

Oil:	5	to	20	x10^{-6} psi^{-1}	($p > p_b$)
	30	to	200	x10^{-6} psi^{-1}	($p < p_b$)
Gas:	50	to	1000	x10^{-6} psi^{-1}	
Water:	3	to	5	x10^{-6} psi^{-1}	

Formation Compressibility c$_f$

$$c_f = \frac{1}{\phi}\frac{d\phi}{dp}$$

Typical values:

Normal:	2	to	10	x10^{-6} psi^{-1}
Abnormal:	10	to	100	x10^{-6} psi^{-1}

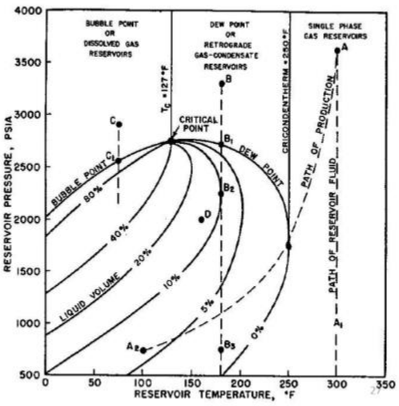
Phase Diagrams

Undersaturated **vs** *Saturated*

Phases:

- **Solid**
- **Compressible Liquid**
- **Vapour**
- **Gaseous**
- **Supercritical Fluid**

Isothermal conditions in the reservoir



API Gravity

API gravity is related to the density of the crude oil and is the preferred method for classifying crude systems.

$$°API = \frac{141.5}{\gamma_o} - 131.5$$

- where γ_o = the specific gravity of the oil

light	$°API > 31.1$	$\rho_o < 870$
medium	$31.1 > °API > 22.3$	$870 < \rho_o < 920$
heavy	$22.3 > °API > 10.0$	$920 < \rho_o < 1000$

Gas Specific Gravity γ_g

The specific gravity is defined as the **ratio** of the **gas density** to that of the **air**. Both densities are measured or expressed at the same pressure and temperature.

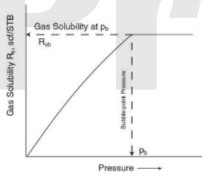
$$\gamma_{gas} = \frac{\rho_{gas}}{\rho_{air}}$$

Commonly, the **standard pressure** p_{sc} and **standard temperature** T_{sc} are used in defining the gas specific gravity.

Gas Solubility R_s

The **solubility** of natural gas in crude oil is dependent upon **pressure, temperature,** and **composition** of both the gas and oil.

R_s Defined as the number of standard [cu ft] of natural gas which will dissolve in one [stock tank bbl] of oil at a particular pressure and temperature (units = scf/STB)



Standing's Correlation for R$_s$:

$$R_s = \gamma_g \left[\left(\frac{p}{18.2} + 1.4\right)10^x\right]^{1.2048}$$

$$x = 0.0125\ \text{API} - 0.00091(T - 460)$$

where T = temperature, °R
p = system pressure, psia
γ_g = solution gas specific gravity

Oil Specific Gravity γ_o

Fluid gravity or specific gravity of oil is the **ratio** of the density of the oil to the density of water (where both densities are measured at atmospheric pressure 60F)

$$\gamma_o = \frac{\rho_o}{\rho_w}$$

where γ_o = specific gravity of the oil
ρ_o = density of the crude oil, lb/ft³
ρ_w = density of the water, lb/ft³

Bubble-point Pressure p_b

The bubble-point pressure p_b of a is defined as the **highest pressure** at which a **bubble** of **gas** is **first liberated** from the **oil**.

Standing's Correlation for p$_b$:

$$p_b = 18.2\,[(R_s/\gamma_g)^{0.83}\,(10)^a - 1.4]$$

$$a = 0.00091\,(T - 460) - 0.0125\,(\text{API})$$

where p_b = bubble-point pressure, psia
T = system temperature, °R

A **central aspect** of PVT analysis is understanding how gas **evolves** from oil when the pressure falls below the bubble-point.

Gas Formation Volume Factor B_g

B_g is used to relate the volume of gas measured at reservoir conditions to the volume of gas measured at standard conditions (60F, 14.7 psi)

$$B_g = \frac{\text{Volume of gas at reservoir conditions}}{\text{Volume of gas at standard conditions}} = \frac{(V_g)_{p,T}}{(V_g)_{sc}}$$

Standing's Correlation for B$_g$:

$$B_g = 0.02827\frac{zT}{p}$$

where B_g = gas formation volume factor, ft³/scf
z = gas compressibility factor
T = temperature, °R

Oil field units $B_g = 0.005035\dfrac{zT}{p}$ **[bbl/scf]**

Oil Formation Volume Factor B_o

B_o is defined as the ratio of the **volume** of **oil** (plus the gas in solution) at the prevailing **reservoir temperature** and **pressure** to the volume of oil at **standard conditions**.

$$B_o = \frac{\text{Volume of oil at reservoir conditions}}{\text{Volume of oil at standard conditions}} = \frac{(V_o)_{p,T}}{(V_o)_{sc}}$$

Standing's Correlation for B$_o$:

$$B_o = 0.9759 + 0.000120\left[R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25(T - 460)\right]^{1.2}$$

where T = temperature, °R
γ_o = specific gravity of the stock-tank oil
γ_g = specific gravity of the solution gas

Water Formation Volume Factor B_w

B_w is used to relate the volume of produced water measured at reservoir conditions to the volume of water measured at standard conditions (60F, 14.7 psi)

$$B_w = \frac{\text{Water Volume at reservoir conditions}}{\text{Water Volume at standard conditions}}$$

[bbl/scf]

B_w **is generally taken to be equivalent to 1**

(B_w ~ 1)

$$B_o = B_t - (R_{si} - R_s)B_g$$

B_t is defined as the **volume in bbl's** of one STB and its initial dissolved gas.

Ideal Gas Law

Assuming that the **behaviour** of both the gas and air can be described the ideal gas equation:

$$pV = nRT$$

where

- p = absolute pressure [psia]
- V = volume [ft³]
- T = absolute temperature [°R]
- n = number of moles of gas [lb-mol]
- R = universal gas constant [10.73 psia.ft³/lb-mol.°R]

$$n = \frac{m}{M}$$

- ***m*** = mass [lb]
- ***M*** = molecular weight [lb/lb-mol]

The number of moles (***n***) is related to the mass of gas under consideration (***m***) and its molecular weight (***M***)

Density ρ

Gas density ***ρ*** is defined as the **mass** of the **gas** occupying a **certain volume** at **specified pressure** and **temperature**. The density is usually represented in units of **[lbm/ft³]**.

$$\rho_{g,sc} = \frac{M}{23.645}\,kgm^{-3} \qquad \rho_{g,sc} = \frac{M}{380}\,lbft^{-3}$$

$$pV = znRT \qquad \rho_g(p,T) = \frac{\rho_{g,sc}}{B_g}$$

where ***z*** is a dimensionless quantity and is defined as the **ratio** of the **actual volume** of **n-moles** of gas at ***T*** and ***p*** to the **ideal volume** of the same number of moles at the same ***T*** and ***p***

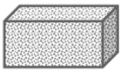
Oil Reservoirs

$$OIIP = 7758Ah\phi(1-S_{wi})$$

- **Bulk Volume** [bbl or rb]

$$N = \frac{7758Ah\phi(1-S_{wi})}{B_{oi}} \text{ [STB]}$$

- **Pore Volume**



- **Oil Volume**

7758 = Conversion Factor
A= Reservoir Area [ac]
h = Net Thickness [ft]
ϕ = Porosity
S_{wi} = Initial Water Sat. [at p_i]
B_{oi}= Initial Formation Volume Factor [at p_i] [rb/STB]

Reserves Estimation

Volumetric Methods provide a static measure of oil or gas in place. Accuracy depends on data for: porosity, net thicknesses, areal extent, hydrocarbon saturation.

Methods:

- ***Material Balance approach*** [sufficient production history is available by accounting for]
- ***Decline Curve Analysis*** [means of predicting future oil or gas well production based on past production history]
- ***Reservoir simulation*** [Numerical modelling used to quantify and interpret physical phenomena with the ability to extend these to project future performance]

Gas Reservoirs

At Reservoir Conditions:

$$GIIP = 43560Ah\phi(1-S_{wi}) \quad [\text{cf or ft}^3]$$

At Surface Conditions:

$$GIIP = \frac{43560Ah\phi(1-S_{wi})}{B_{gi}} \quad [\text{scf}]$$

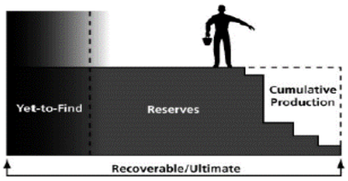
Abandonment:

$$G_a = \frac{43560Ah\phi(1-S_{wi})}{B_{ga}} \quad [\text{scf}]$$

Gas produced:

$$G_p = 43560Ah\phi(1-S_{wi})\left(\frac{1}{B_{gi}} - \frac{1}{B_{ga}}\right)$$

S_{wi} = initial average water saturation, fraction
B_{gi} = initial gas formation volume factor, cu. ft/scf



Resource: *All of the hydrocarbons, both discovered and undiscovered, whether it can be recovered or not.*

Recoverable Resource: The part of the resource that is considered recoverable. This depends on: oil price, technology.

Reserves: The recoverable resource that has been found.

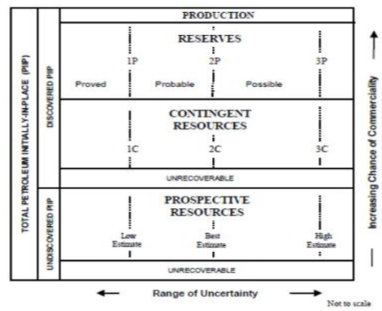
Reserves

Proved Reserves [P90 or 1P]: *Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions. The lowest figure, the amount that the geologists are 90% sure is there.*

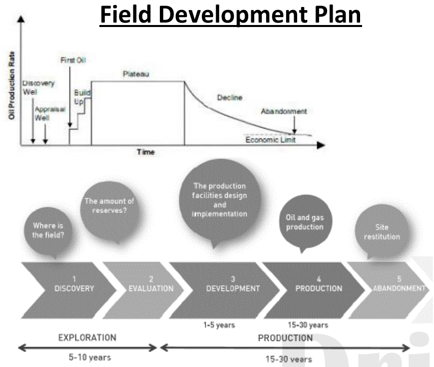
Probable Reserves [P50 or 2P]: *The average figure (median or mean), the figure that is expected to be closest to the true reserves.*

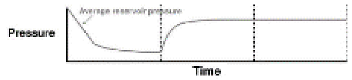
Possible Reserves [P10 or 3P]: *The highest figure, the amount that the geologists are 10% sure is there.*

Reserves = HCIIP x Recovery Factor

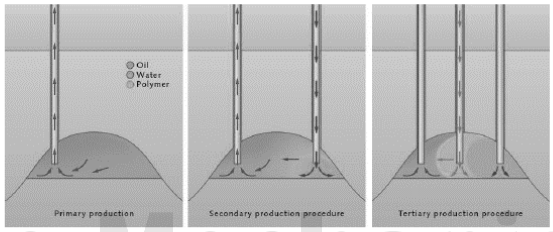


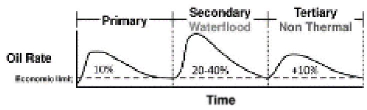
Field Development Plan

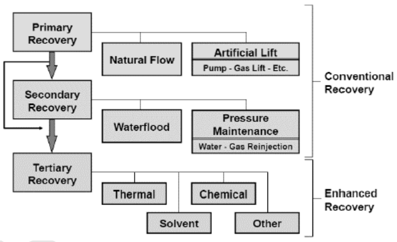




Primary recovery natural energy. Secondary and Tertiary, add energy.



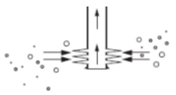




- ***Rock and Liquid Expansion Drive***

Rock and Fluid expand due to compressibility. As the expansion of the fluids and reduction in the pore volume occur with decreasing reservoir pressure, the crude oil and water will be forced out of the pore space to the wellbore. the reservoir will experience a rapid pressure decline.

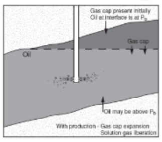
- ***Depletion Drive***



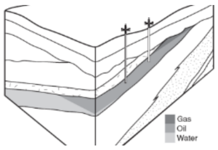
Solution, Dissolved, Internal Gas Drive

- ***Gas Cap Drive***

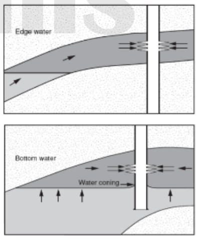
Decline due to the pressure reduction in the reservoir, but also due to the impact of solution gas drive on the relative permeability around the well bore.



- ***Water Drive***



Driving energy comes primarily from the expansion of water as the reservoir is produced. Pressure drop is related to the size of the aquifer: the larger, the slower the decline.



DDI + SDI + WDI + EDI = 1.0

where DDI = depletion-drive index
SDI = segregation (gas-cap)-drive index
WDI = water-drive index
EDI = expansion (rock and liquid)-drive index

Combination Drive

$$\frac{N(B_o - B_{oi}) + N(R_{si} - R_s)B_g}{N_p\left[B_o + (R_p - R_s)B_g\right] + W_pB_w} = DDI$$

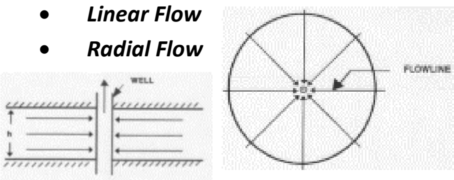
$$\frac{mNB_{oi}\left(\frac{B_g}{B_{gi}} - 1\right)}{N_p\left[B_o + (R_p - R_s)B_g\right] + W_pB_w} = SDI$$

$$\frac{(W_e + B_wW_i)}{N_p\left[B_o + (R_p - R_s)B_g\right] + W_pB_w} = WDI$$

$$\frac{\frac{(1+m)NB_{oi}}{(1-S_{wi})}(S_{wi}c_w + c_f)\Delta p}{N_p\left[B_o + (R_p - R_s)B_g\right] + W_pB_w} = CDI$$

$$EDI = \frac{NB_{oi}(1+m)\left[\frac{c_wS_{wi} + c_f}{1-S_{wi}}\right](p_i - p)}{A}$$

- ***Linear Flow***
- ***Radial Flow***

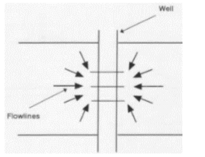


Flow is parallel to top and bottom of reservoir, and converges uniformly towards wellbore.

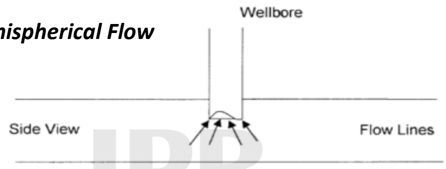
It occurs when flow paths are parallel and the fluid flows in a single direction e.g. hydraulic fracture.

- ***Spherical Flow***

A well that only partially penetrates the pay zone could result in hemispherical flow. where coning of bottom water is important.



- ***Elliptical Flow***
- ***Hemispherical Flow***



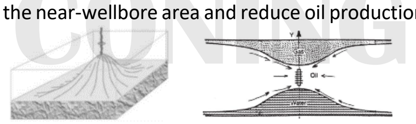
EOR Methods:

- Waterflooding
- Thermal
- Chemical
- Miscible Gas

Chemical EOR Methods:

- Surfacant-Polymer
- Alkaline
- Alkali-surfactant
- Alkali-surfactant poly
- Polymer

Coning causes production issues because the gas cap or bottom water can reach the perforation zone in the near-wellbore area and reduce oil production.

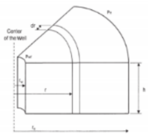


IPR

The **pressure** in the formation at the wellbore of a producing well is known as the ***bottom-hole Flowing*** pressure (***flowing BHP, p_{wf}***).

$$Q_o = \frac{0.00708\, k\, h\, (p_e - p_w)}{\mu_o B_o \ln(r_e/r_w)} \qquad p = p_{wf} + \left[\frac{Q_o B_o \mu_o}{0.00708\, kh}\right]\ln\left(\frac{r}{r_w}\right)$$

where Q_o = oil, flow rate, STB/day
p_e = external pressure, psi
p_{wf} = bottom-hole flowing pressure, psi
k = permeability, md
μ_o = oil viscosity, cp
B_o = oil formation volume factor, bbl/STB
h = thickness, ft
r_e = external or drainage radius, ft
r_w = wellbore radius, ft

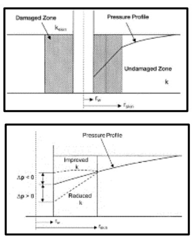


- ***Steady State Radial Flow***

- ***Darcy Law P_{wf}***

Flow Regime	No Skin	Skin Present (Damage or Stimulation)
Steady State	$(p_i - p_{wf}) = \frac{141.2Q_oB_o\mu_o}{kh}\left[\ln\left(\frac{r_e}{r_w}\right)\right]$	$(p_i - p_{wf}) = \frac{141.2Q_oB_o\mu_o}{kh}\left[\ln\left(\frac{r_e}{r_w}\right) + s\right]$
Transient	$(p_i - p_{wf}) = \frac{162.6Q_oB\mu}{kh}\left[\log\left(\frac{kt}{\phi\mu c_t r_w^2}\right) - 3.23\right]$	$(p_i - p_{wf}) = \frac{162.6Q_oB\mu}{kh}\left[\log\left(\frac{kt}{\phi\mu c_t r_w^2}\right) - 3.23 + 0.87s\right]$
PSS	$(\bar{p}_r - p_{wf}) = \frac{141.2Q_o\mu_oB_o}{k_oh}\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75\right]$	$(\bar{p}_r - p_{wf}) = \frac{141.2Q_o\mu_oB_o}{k_oh}\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]$

Skin



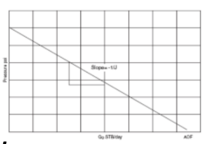
- ***Drainage Radius r_e*** $\quad r_e = \sqrt{\frac{43{,}560\,A}{\pi}}$ where A is the well spacing in acres

The external (drainage) radius is usually determined by equating the area of the well spacing with that of a circle.

- ***Productivity Index J*** $\quad Q_o = J(\bar{p}_r - p_{wf}) = J\Delta p$

$$J = \frac{Q_o}{(\bar{p}_R - p_{wf})} = \frac{Q_o}{\Delta p}$$

where Q_o = oil flow rate [STB/day]
J = productivity index, [STB/(day-psi)]
$\bar{p}_R$ = average reservoir pressure [psi]
p_{wf} = bottom hole flowing pressure [psi]
$(\bar{p}_R - p_{wf}) = \Delta p$ = drawdown [psi]



- ***Vogel's Method J***

$$\frac{Q_o}{Q_{o,max}} = 1 - 0.2\left(\frac{p_{wf}}{\bar{p}_R}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}_R}\right)^2$$

where Q_o = oil rate at p_{wf} [STB/day]
$Q_{o,max}$ = AOF
$\bar{p}_R$ = average reservoir pressure [psi]
P_{wf} = well bore pressure [psi]

$$J = \frac{Q_o}{(\bar{p}_R - p_B) + \frac{p_B}{1.8}\left[1 - 0.2\left(\frac{p_{wf}}{p_B}\right) - 0.8\left(\frac{p_{wf}}{p_B}\right)^2\right]}$$

$$FE = \frac{\text{ideal drawdown}}{\text{actual drawdown}} = \frac{(\bar{p}_R - p'_{wf})}{(\bar{p}_R - p_{wf})} = \frac{Q_o/J'}{Q_o/J} = \frac{J}{J'}$$

- ***Standings Modification Vogel's J***

Material Balance

Initial Mass		Final Mass
Pore volume occupied by the oil initially in place at p_i NB_{oi}	=	Pore volume occupied by the remaining oil at p $(N-N_p)B_o$
		Pore volume occupied by the gas in the gas cap at p $GB_g=\left(\frac{mNB_{oi}}{B_{gi}}\right)B_g$
		Pore volume occupied by the evolved solution gas at p $(NR_{si}-(N-N_p)R_s-N_pR_p)B_g$
+ Pore volume occupied by the gas in the gas cap at p_i $GB_{gi}=mNB_{oi}$		Pore volume occupied by the net water influx at p $W_e=W_pB_w$
		Change in P.V due to connate water expansion and pore volume reduction due to rock expansion $(PV)S_{wi}c_w\Delta p+(PV)c_f\Delta p$ $=\frac{(1+m)NB_{oi}}{(1-S_{wi})}(S_{wi}c_w+c_f)\Delta p$
		Pore volume occupied by the injected gas at p $G_{inj}B_{ginj}$
		Pore volume occupied by the injected water at p $W_{inj}B_w$

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

$$m=\frac{\textit{initial volume of gas cap}}{\textit{initial volume of oil in place}}=\frac{GB_{gi}}{NB_{oi}}\qquad R_{si}=\frac{G_{dissolved}}{N}\left[\frac{scf}{STB}\right]$$

$$\therefore G_{dissolved}=NR_{si}$$

- p_i Initial reservoir pressure, psi
- p Volumetric average reservoir pressure
- Δp Change in reservoir pressure = $p_i - p$, psi
- p_b Bubble point pressure, psi
- N Initial (original) oil in place, STB
- N_p Cumulative oil produced, STB
- G_p Cumulative gas produced, scf
- W_p Cumulative water produced, bbl
- R_p Cumulative gas-oil ratio, scf/STB
- GOR Instantaneous gas-oil ratio, scf/STB
- R_{si} Initial gas solubility, scf/STB
- R_s Gas solubility, scf/STB
- B_{oi} Initial oil formation volume factor, bbl/STB
- B_o Oil formation volume factor, bbl/STB
- B_{gi} Initial gas formation volume factor, bbl/scf
- B_g Gas formation volume factor, bbl/scf
- W_{inj} Cumulative water injected, STB
- G_{inj} Cumulative gas injected, scf
- W_e Cumulative water influx, bbl
- m Ratio of initial gas-cap-gas reservoir volume to initial reservoir oil volume, bbl/bbl
- G Initial gas-cap gas, scf
- $P.V$ Pore volume, bbl
- c_w Water compressibility, psi^{-1}
- c_f Formation (rock) compressibility, psi^{-1}

Havlena-Odeh Method

$$\boxed{N=\frac{F-W_e}{E_o+mE_g+E_{fw}}}\ \text{[rb]}$$

F = Underground Withdrawal

= oil prod. + gas prod. + water prod

$= N_pB_o+N_p(R_p-R_s)B_g+W_p$

E_o = Oil Expansion

$=(B_o-B_{oi})+(R_{si}-R_s)B_g \quad = B_t - B_{oi}$

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

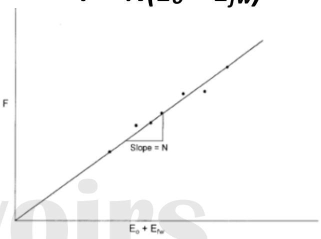
$$E_{fw}=(1+m)B_{oi}\left[\frac{c_wS_{wi}+c_f}{1-S_{wi}}\right]\Delta p$$

where $\Delta p = p_i - p$

Case 1: Undersaturated, No Gas Cap

W_e is neglected

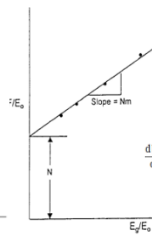
$F = N(E_o + E_{fw})$



Case 2: Saturated, Gas Cap

W_e and W_p is neglected

$F/E_o = N + mN(E_g/E_o)$



$W_e = (c_w + c_f)\, W_i\, (p_i - p)$

$\frac{dW_e}{dt}=e_w=\left[\frac{0.00708\,kh}{\mu_w \ln(r_e/r_a)}\right](p_i-p)$

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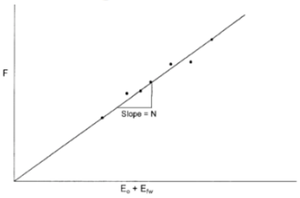
Case 3: Saturated, At Bubble Point

W_e and W_p is neglected

$$N=\frac{F}{E_o}\quad\rightarrow\quad F=NE_o$$



Cumulative GOR

$$R_p=\frac{\textit{Volume of gas produced}}{\textit{Volume of oil produced}}=\frac{G_p}{N_p}$$

Instantaneous GOR

$$GOR=R_s+\left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{\mu_oB_o}{\mu_gB_g}\right)$$

where GOR = instantaneous gas-oil ratio, scf/STB
R_s = gas solubility, scf/STB
k_{rg} = relative permeability to gas
k_{ro} = relative permeability to oil
B_o = oil formation volume factor, bbl/STB
B_g = gas formation volume factor, bbl/scf
μ_o = oil viscosity, cp
μ_g = gas viscosity, cp

Case 4: Water Drive Reservoirs

No initial gas cap m = 0

$$\underset{y}{\frac{F}{E_o}}=\underset{c}{N}+\underset{x}{\frac{W_e}{E_o}}$$

Initial gas cap E_{fw} = 0

$$\underset{y}{\frac{F}{E_o+mE_g}}=\underset{c}{N}+\underset{x}{\frac{W_e}{E_o+mE_g}}$$

Water Influx W_e Pot Aquifer Model

- Water influx (water encroachment, W_e)
  - offsets pressure decline
  - changes the position of the OWC
- Affected by
  - degree of pressure maintenance
  - outer boundary conditions
  - flow geometries
  - flow regimes

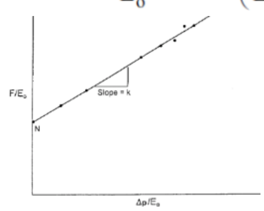
Active Water Drive

$$e_w=\frac{dW_e}{dt}=B_o\frac{dN_p}{dt}+(GOR-R_s)\frac{dN_p}{dt}B_g+\frac{dW_p}{dt}B_w$$

where W_e = cumulative water influx, bbl
t = time, days
N_p = cumulative oil production, STB
GOR = current gas-oil ratio, scf/STB
R_s = current gas solubility, scf/STB
B_g = gas formation volume factor, bbl/scf
W_p = cumulative water production, STB
dN_p/dt = daily oil flow rate Q_o, STB/day
dW_p/dt = daily water flow rate Q_w, STB/day
dW_e/dt = daily water influx rate e_w, bbl/day
$(GOR-R_s)dN_p/dt$ = daily free gas flow rate, scf/day

Steady State Pot Aquifer

$$W_e = K\,\Delta p\qquad \frac{F}{E_o}=N+K\left(\frac{\Delta p}{E_o}\right)$$



Gas Reservoirs

Case 1: Volumetric gas reservoirs

$$\frac{p_{sc}G_p}{RT_{sc}}=\frac{p_iV}{z_iRT}-\frac{p[V-(W_e-W_p)]}{zRT}$$

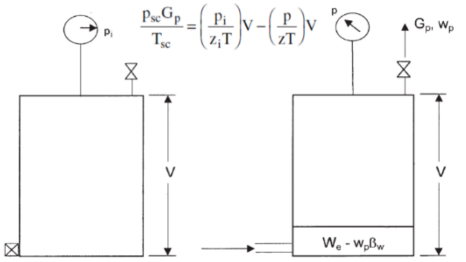
where p_i = initial reservoir pressure
G_p = cumulative gas production, scf
p = current reservoir pressure
V = original gas volume, ft^3
z_i = gas deviation factor at p_i
z = gas deviation factor at p
T = temperature, °R
W_e = cumulative water influx, ft^3
W_p = cumulative water production, ft^3

no. of moles

$n_p = n_i - n_f$ where n_p = moles of gas produced
n_i = moles of gas initially in the reservoir
n_f = moles of gas remaining in the reservoir

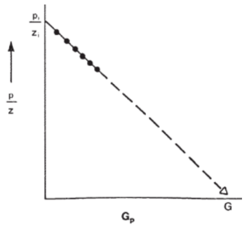
No water production

$$\frac{p_{sc}G_p}{T_{sc}}=\left(\frac{p_i}{z_iT}\right)V-\left(\frac{p}{zT}\right)V$$



In terms p/z

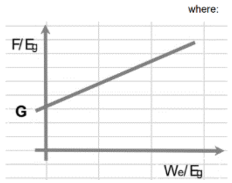
$$\frac{p}{z}=\frac{p_i}{z_i}-\left(\frac{p_{sc}T}{T_{sc}V}\right)G_p$$



In terms B_g

$$G_pB_g+W_pB_w=G(B_g-B_{gi})+GB_{gi}\frac{(c_wS_{wi}+c_f)}{1-S_{wi}}\Delta p+W_eB_w$$

$$F=G\,(E_g+E_{f,w})+W_e\,B_w$$



where:
Underground fluid withdrawal F:
$F=G_pB_g+W_pB_w$
Gas expansion E_g:
$E_g=B_g-B_{gi}$
Water and rock expansion $E_{f,w}$:
$E_{f,w}=B_{gi}\frac{(c_wS_{wi}+c_f)}{1-S_{wi}}$

DCA

Natural Decline, D

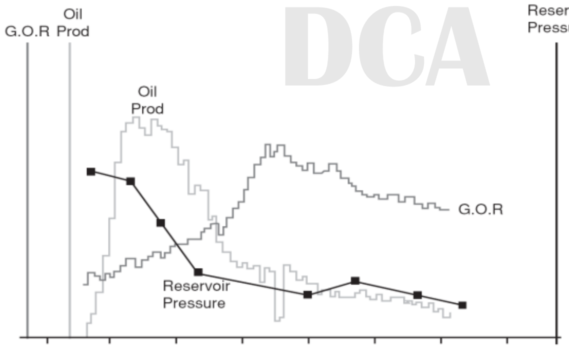
$$D=-\frac{dq/dt}{q}=-\lim_{\Delta t\to 0}\frac{\Delta q/\Delta t}{q}$$

Cumulative N_p

$$N_p=\int_0^t q(t)dt=\int_{q_i}^{q} q\frac{dt}{dq}dq$$

Cumulative N_p as a function of q

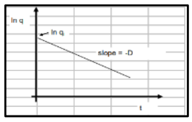
$$N_p=\int_{q_i}^{q}-\frac{1}{D_i}\left(\frac{q_i}{q}\right)^n dq$$



$$\Rightarrow t=\frac{-\ln\left(\frac{q}{q_i}\right)}{D}$$

$$\Rightarrow N_p=\frac{q_i-q}{D}$$

$$\ln q=\ln q_i+\ln e^{-Dt}$$
$$\Rightarrow \ln q=\ln q_i-Dt$$
$$\Rightarrow \ln q=(-D)t+\ln q_i$$



Decline Exponent	Type of Decline	Rate:Time Relationship	Rate: Cumulative relationship	D_it
0	Exponential	$q(t)=q_i\exp(-D_it)$	$N_p=\frac{q_i-q}{D_i}$	$D_it=\ln(\frac{q_i}{q_t})$
1	Harmonic	$q(t)=\frac{q_i}{(1+D_it)}$	$N_p=\frac{q_i}{D_i}\ln(q_i/q)$	$D_it=\left(\frac{q_i}{q_t}\right)-1$
0<n<1	Hiperbolic	$q(t)=\frac{q_i}{(1+nD_it)^{1/n}}$	$N_p=\frac{q_i^n}{D_i(1-n)}\left(\frac{1}{q_i^{n-1}}-\frac{1}{q^{n-1}}\right)$	$D_it=\frac{(\frac{q_i}{q_t})^n-1}{n}$

Natural decline trend is dictated by:

Natural drive, Rock and fluid properties and well completion.

When the average reservoir pressure decreases with time due to oil and gas production, this causes the well and field production rates to decrease yielding a rate time relation similar to that in the following figure.

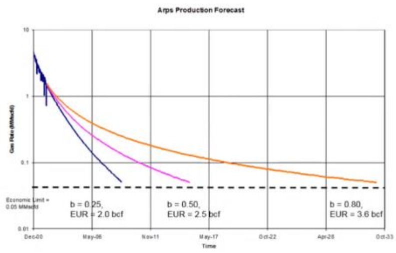
DCA

- ***Production rate only***
- ***Using historical data to predict***
- ***Production rate only***
- ***Deliverables:***

Production forecast
Recoverable reserves under current conditions.

- ***Limitations:***

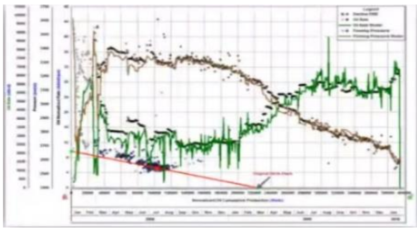
Assume constant opt cond.
Requires decline in prod rate
Can be uncertainly limited data



RTA

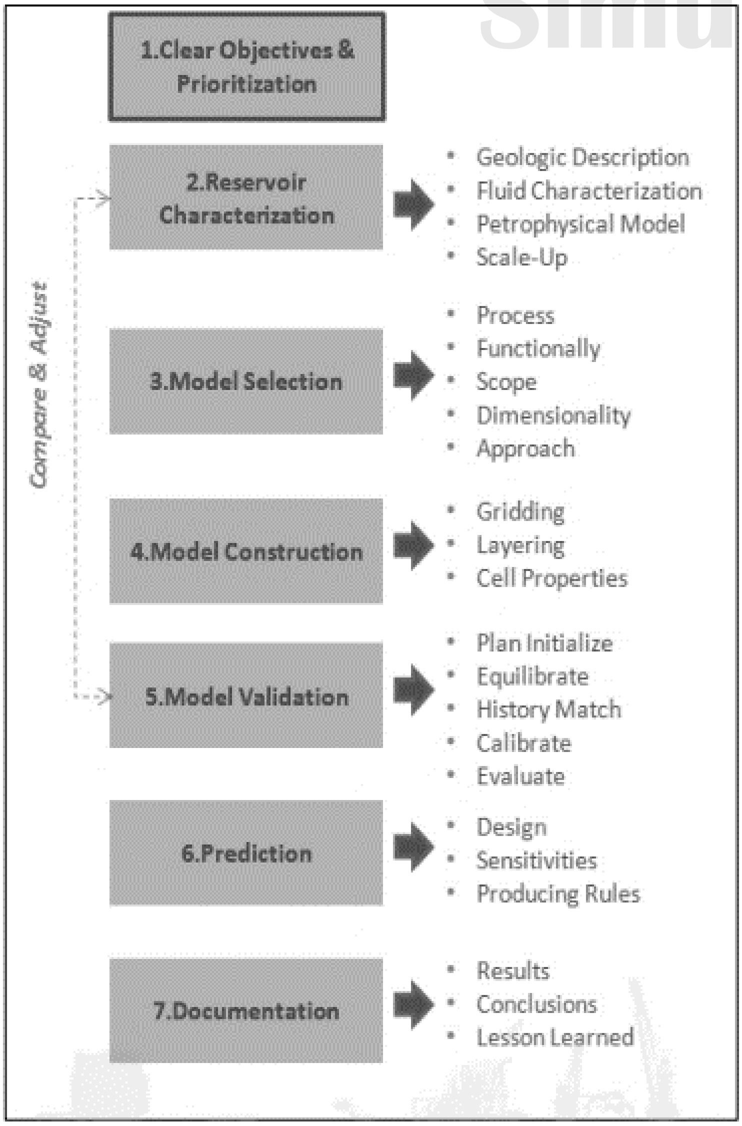
- Does not require wells to be shut in
- Uses rates & flowing pressure, applicable to variable operating cond.
- Based on physics and developed from PTA
- Reservoir signal extraction and characterization
- ***Deliverables:***

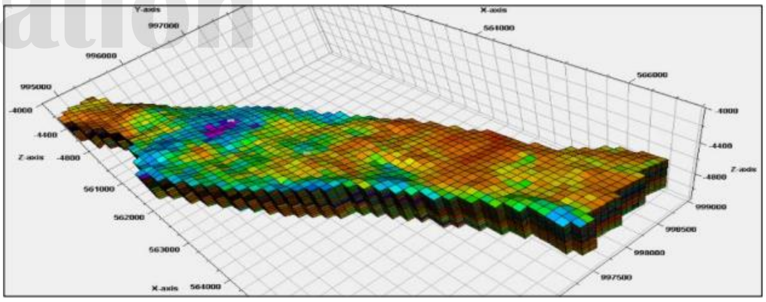
OGIP/OOIP and Reserves
Production optimization
Drainage area
Infill potential
Permeability and skin



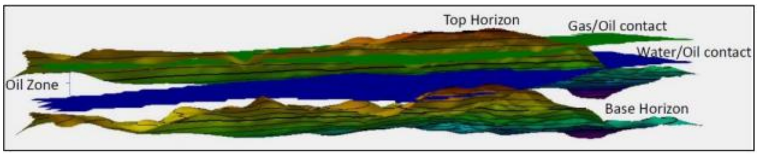
Simulation

- ***Reservoir Simulation Fundamentals***

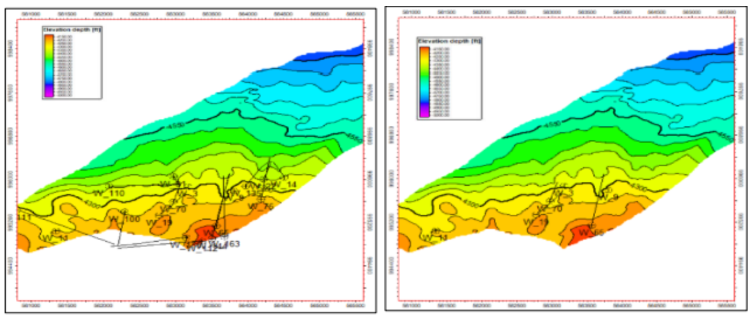




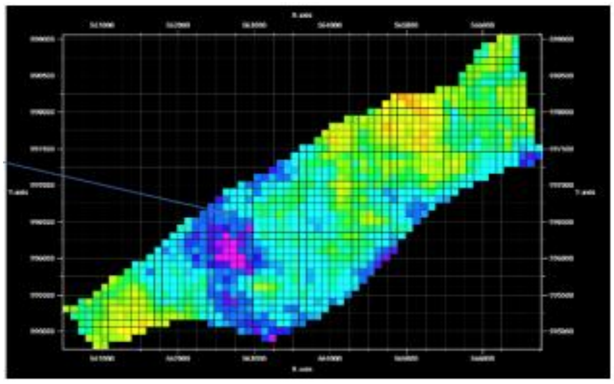
The reservoir formation 3D grid was divided at an optimum of 100m2 blocks. This qualifies the grid as Coarse Grid, thus enabling a fast and efficient simulation run as a result of the reduced volume in calculations required to complete the simulation. The target reservoir formation was evaluated from depth 4000m to 5200m.



It is vital to identify the relevant Water Oil Contact (WOC) and Gas Oil Contact (GOC) with regards to the Top and Base Horizons created using Petrel thus resulting in the outstanding Oil Zone. The relevant zones and contacts are vital to utilize when establishing development plans of the asset due to the constant threat of developing water and gas Coning because of increased production. Such parameters are key to identify due to the optimization of oil recovery as the development of water Coning immediately results in an increase of water invasion, thus reducing the efficiency of production because of an increased Water Cut.

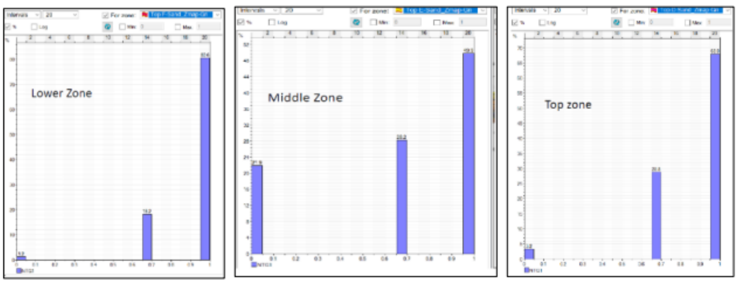


- ***Reservoir 3D Model***

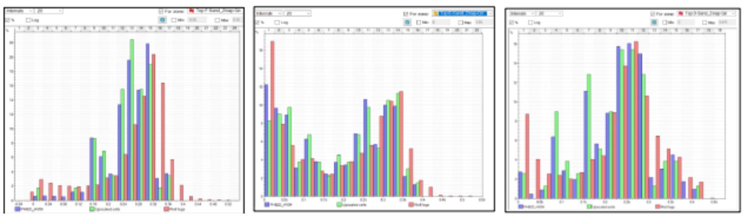


Reservoir simulation requires a precise balance between performance and simulation time duration. Due to the massive demand in calculations of material balance being carried out by the simulator a grid is created in order to breakdown the relevant reservoir formation area in blocks. The variation in size of blocks results in a simultaneous variation in uncertainty of simulation results. The larger the size of grid blocks results in a faster run time, however results in an increased uncertainty regarding the results due to a smaller amount of calculations taking place.

- ***Porosity distribution***



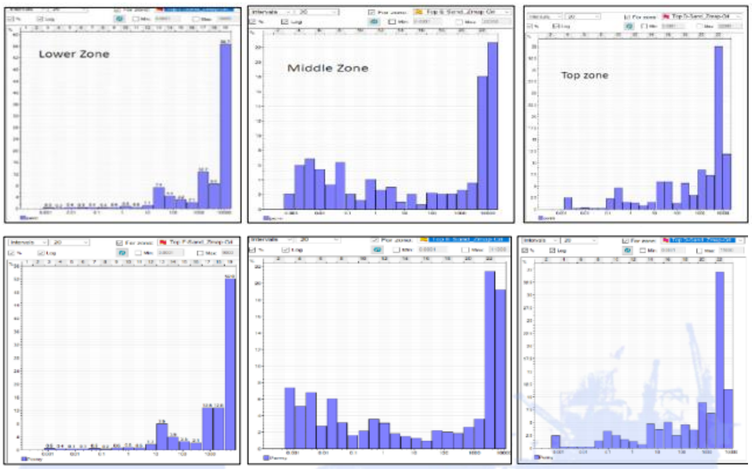
- ***Net-to-Gross***



- ***Permeability Distribution***

Permeability of a 3D Reservoir Model can be identified in all three directional axis X, Y and Z. As Z is a function of Perm X and Y these will be the focus of interpretation. The distribution of Permeability was established upon the relationships connecting Porosity and Permeability carried out via laboratory tests on formation samples (core analysis).

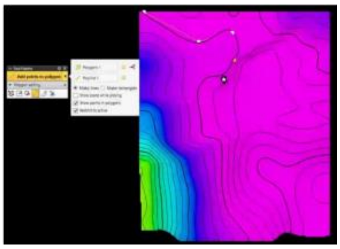
Permeability	**X**	**= Permeability**
	Y	**= Permeability X**
	Z	**= 0.5 * Permeability X**



- ***Schematic Workflow Initial Volume Calculation***

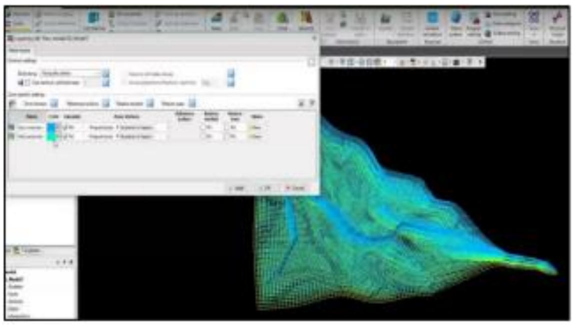
5. Import Data Polygon

Upon starting a new Petrel project, field units must be selected. This is followed by importing relevant assorted data regarding Well Logs, Well Deviations and Well Heads. Along with Well data, relevant surface maps of Top and Bottom sands must be imported. After the relevant data has been imported to the project, analyses of Logs must be interpreted in order to locate potentially commercial reservoirs. In order to obtain hydrocarbon volumes in place, various stages of Petrel workflow must take place following the standard steps when setting up the Petrel model. To begin with, potential reservoir zones of clean sands are identified by creating boundaries from closed Polygons, this sets the boundaries of the Reservoir.



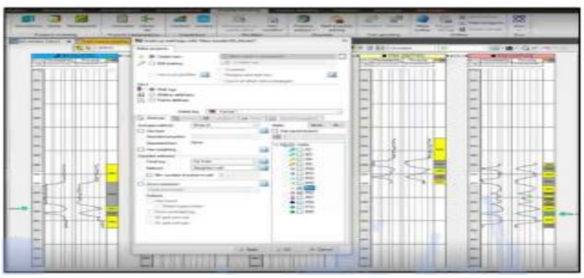
4. Gridding

A 3D grid is then created regarding the Reservoir formation, by completing the workflow procedure as follows. Select Make Simple Grid and insert surfaces, insert boundary values regarding the Geometry and increment in which the Grid will be created allocating value of nodes in the 3D Grid. In this case 100m2 increments were selected. By creating the 3D grid, the skeleton of the grid can be seen in a 3D window which also enables models of the fault to be viewed. Then, zones must be created in order to populate regions between the horizons. The zones will cover from Top-Mid and Mid-Base horizons. Layering is essential in order to select the amount of layers required to populate the 3D Skeleton.



3. Facies Workflow

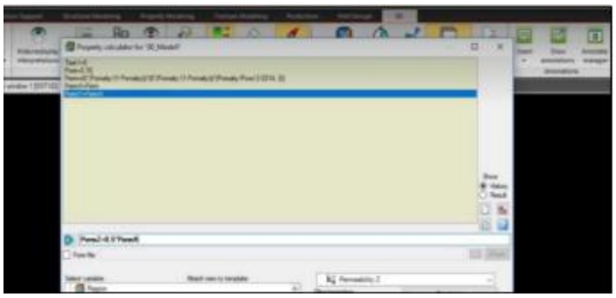
Now that the 3D grid has been created, Petrel Property Calculator must be utilized in order to populate relevant model properties to be modelled. The porosity can be populated by inputting value of porosity (e.g. Pore=0.18). This will generalise the 3D grid with this porosity value. In order to accurately interpret any model, contacts of Gas and Oil along with Oil and Water must be interpreted from Well log readings. By making a contact, proceed to contact set and input interpreted depths at which contacts will be set regarding GOC and WOC. After establishing relevant contacts of Gas, Oil and Water the properties calculator is employed in order to generate the facies logs. The format in which the cut-off's must be listed is as follows: [Facies= If(Porosity < 0.13, 3, 0)]. This is required in order to distribute the facies with regards to available porosity cut offs.



- ***Schematic Workflow Initial Volume Calculation***

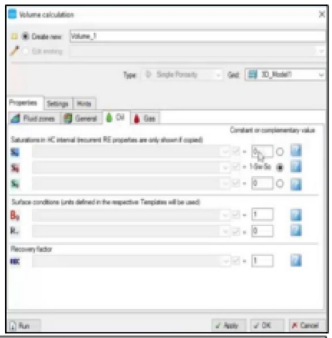
1. Property Calculator

Upscaling the well logs into the grid is necessary in order to populate the remainder of the 3D Grid with petrophysical properties such as porosity. By utilizing the well log upscaling function in Petrel, you can select Wells and relevant Logs in order to upscale properties to complete the 3D grid model with properties. By upscaling the facies and the porosity you can move forward towards populating the permeability properties by utilizing the properties calculator. After selecting Permeability, the calculation of Permeability inputted to the calculator must be in a similar format as follows: Perm= (6*(Porosity/(1-Porosity))) * (6*(Porosity/(1-Porosity))) * (Porosity/Pow0.0314, 2)). After populating Permeability, the remaining Perm Y, Perm X and Perm Z must be populated.



2. Volume workflow

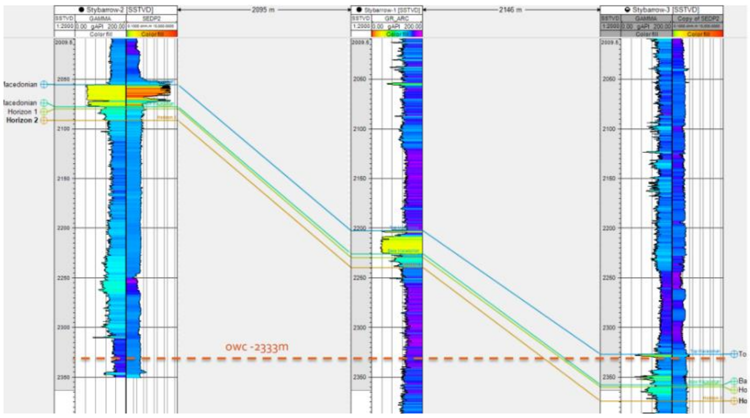
Having populated all relevant data regarding the 3D Grid, it is now possible to begin with initial volume calculations as no dynamic fluid properties have yet been utilized. Starting by selecting the Volume section under the Property modelling tab, name the Case. In the fluid contacts tab select the GOC and WOC set previously, and then move to the general tab. In the general tab the Net-ToGross and Porosity cut-off points can be detailed, as given previously in section 3.1.5 regarding NTG cut-offs. Then, the fluid properties can be detailed in the Oil window regarding the saturation of water (Sw), saturation of gas (Sg) and saturation of oil (So), including values regarding Bo and Rs. Refer to Figure 3.2E. After all data is confirmed, it is possible to run the case in order to calculate the initial Volume calculation regarding the base case. Figure 3.2A presents the results obtained regarding the initial volume calculation obtained.



Case	Bulk volume[*10^6 ft3]	Net volume[*10^6 ft3]	Pore volume[*10^6 RB]	HCPV oil[*10^6 RB]	HCPV gas[*10^6 RB]	STOIIP (in oil)[*10^6 STB]	STOIIP (in gas)[*10^6 STB]	STOIIP[*10^6 STB]	GIIP (in gas)[*10^6 MSCF]	GIIP (in oil)[*10^6 MSCF]	GIIP[*10^6 MSCF]	Recoverable oil[*10^6 STB]	Recoverable gas[*10^6 MSCF]
Case_1	8239	6591	256	177	36	177	0	177	35	31	66	177	66
Totals all result types													
Zones													
Top D-Sand_Zmap-Grid.txt - Top E-Sand_Zmap-Grid.txt	3219	2575	99	57	29	57	0	57	29	10	38	57	38
Top E-Sand_Zmap-Grid.txt - Top F-Sand_Zmap-Grid.txt	3138	2507	88	65	7	65	0	65	7	11	18	65	18
Top F-Sand_Zmap-Grid.txt - Bottom_F-Sand_Zmap-Grid.txt	1887	1510	69	55	0	55	0	55	0	10	10	55	10
Segments/Regions													
Segment 1	8239	6591	256	177	36	177	0	177	35	31	66	177	66

- ***Schematic Workflow Subsurface Storage Sleipner***

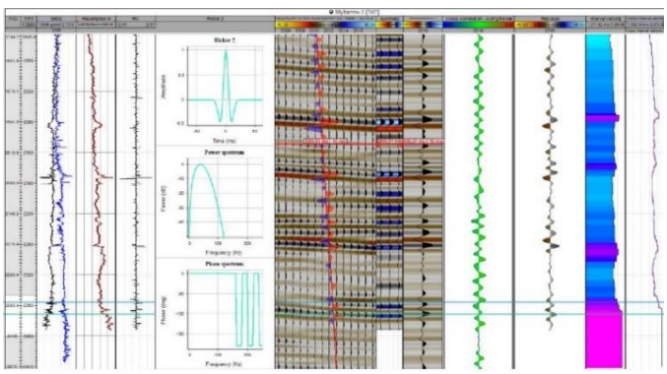
1. Seismic Well Ties



Synergistic Seismograms

- Velocity (V) and density(ρ) logs are required to calculate acoustic impedance:

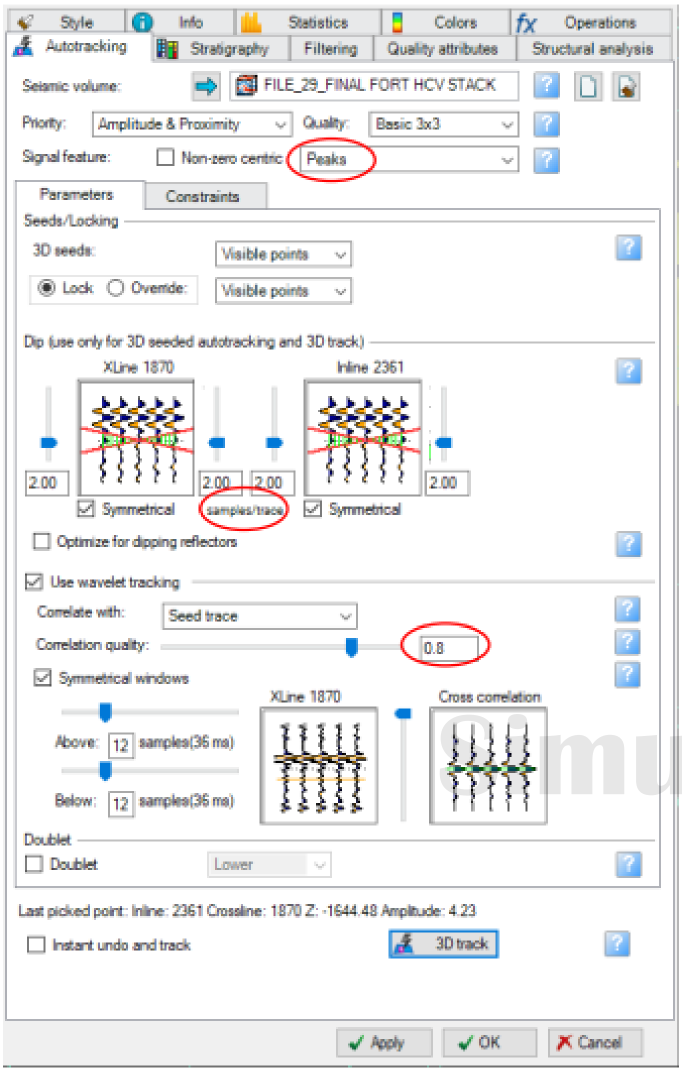
$$Acoustic\ Impedance = V\rho$$



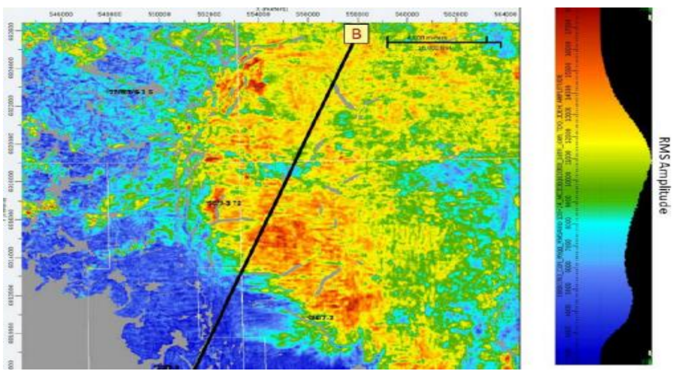
- *Schematic Workflow Subsurface Storage Sleipner*

- ***Volume attributes***

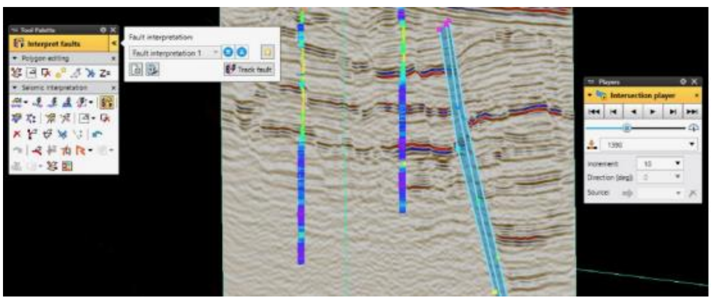
- ***Reservoir Mapping Auto Tracking Amplitude Extractions***



- ***Amplitude Extractions***

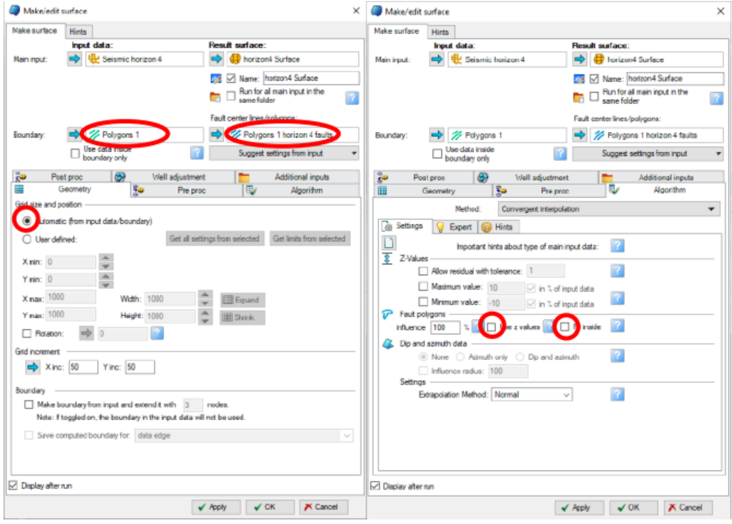


- ***Fault Interpretation***

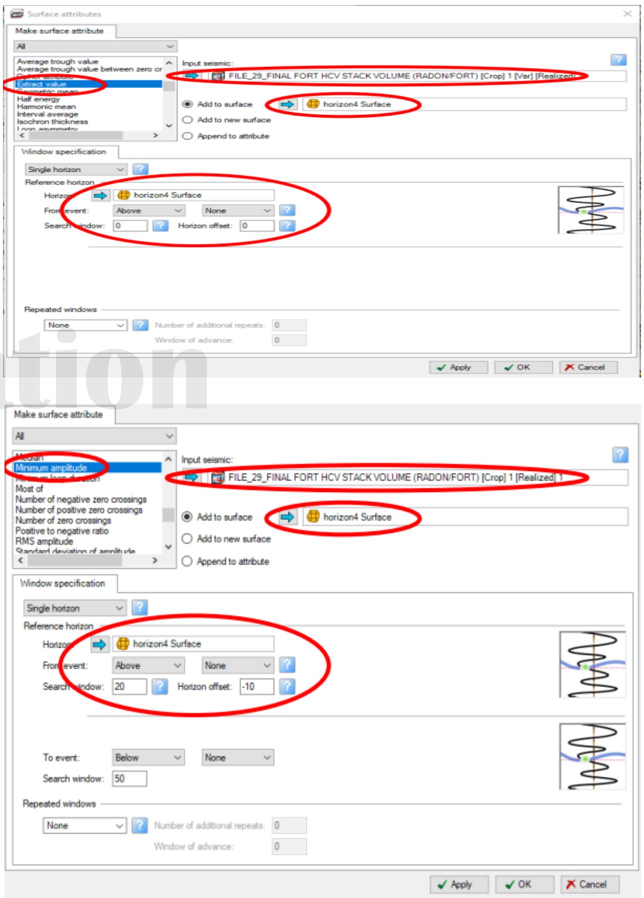


- *Schematic Workflow Subsurface Storage Sleipner*

- ***Create Surfaces***



- ***Amplitude Extraction***



- ***Storage Plume Volume***