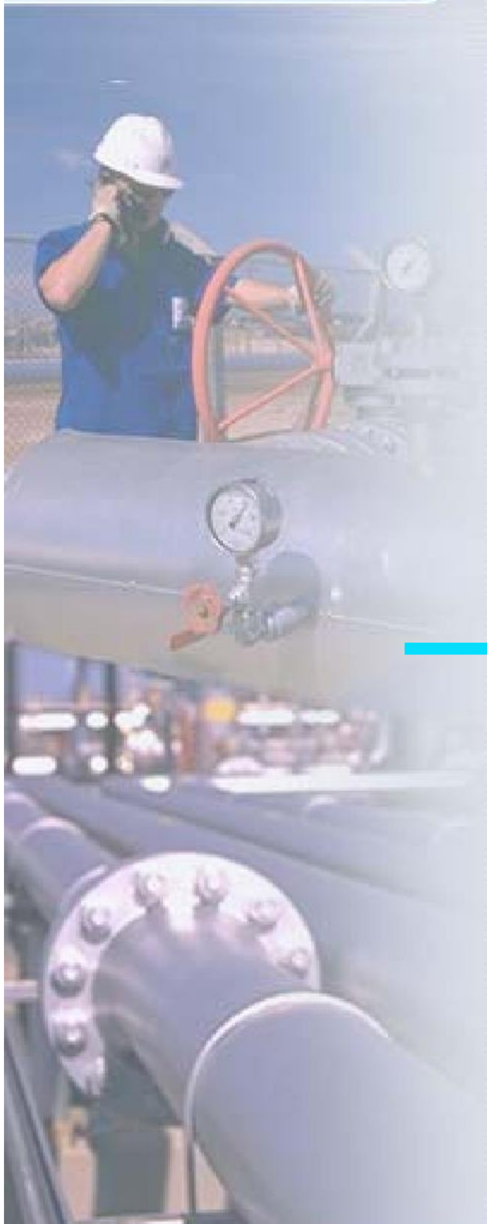


Basic Reservoir Engineering

Basic Reservoir Engineering

Rock Types

Types of Rocks

- Igneous Rocks (from Magma when cools and solidifies)
  - basalt (ext.), andesite, granite, gabbo (int.) etc.
- Sedimentary Rocks (compressed and cemented)
  - Clastic, Organic and Chemical
  - sandstone, limestone, dolomite, shale, halite, etc.
- Metamorphic Rocks (any type change by heat / pressure)
  - marble (metamorphosed limestone), schist, gneiss, etc.
- Majority of important hydrocarbon reservoirs rocks are sedimentary rocks

Sedimentary Rock Classification

Clastic Rock -

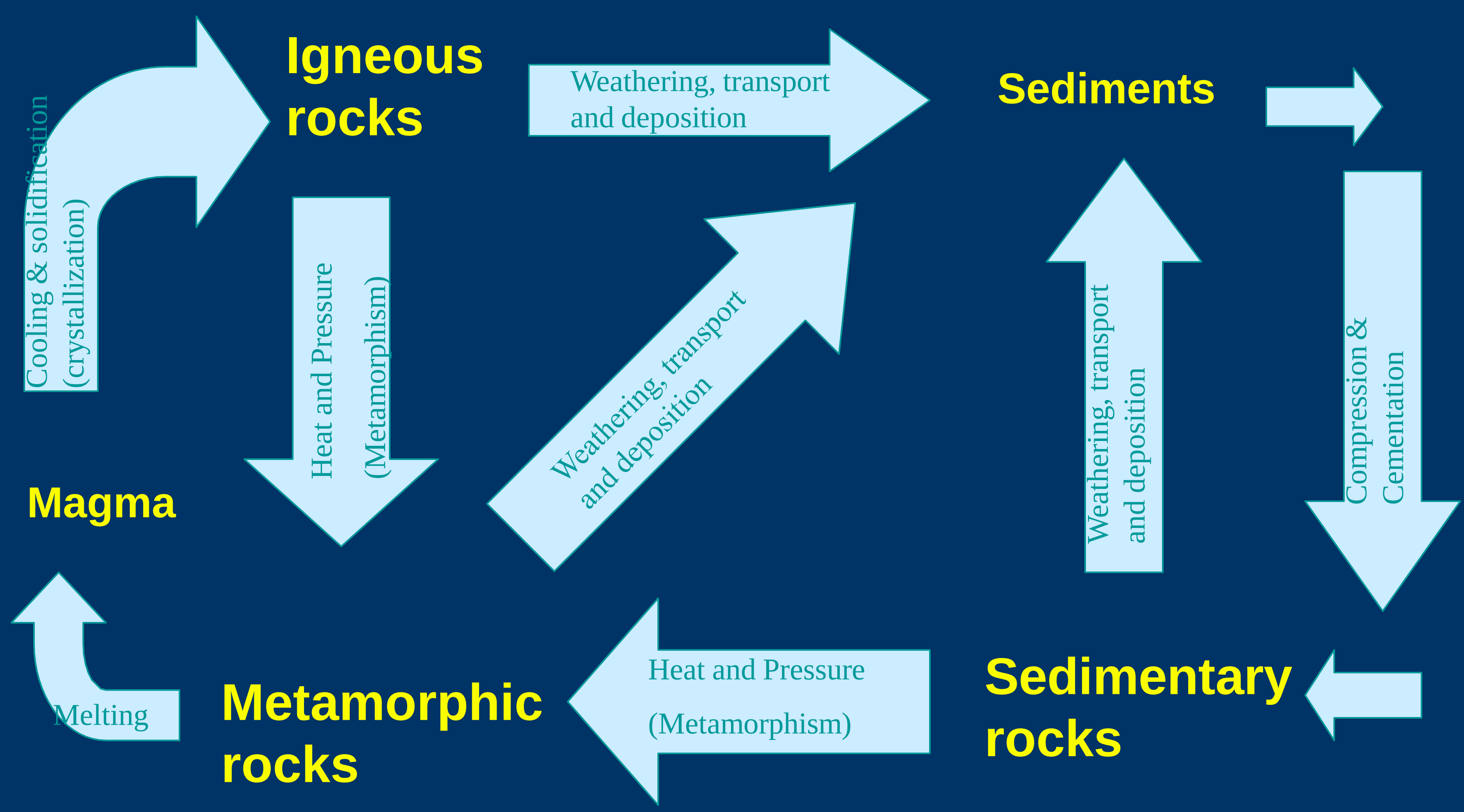
Formed From Debris (weathering and erosion) of Older Rock

Rock Type	Particular	Diameter
Conglomerate	Pebbles	- 2 to 64 mm
Sandstone	Sand	- 0.06 to 2 mm
Siltstone	Silt	- 0.003 to 0.06 mm
Shale	Clay	- Less than 0.003 mm

Nonclastic - Mostly of Chemical or Biochemical Origin

Rock Type	Composition	
Limestone	Calcite	- $CaCO_3$
Dolomite	Dolomite	- $CaMg(CO_3)_2$
Salt	Halite	- NaCI
Gypsum	Gypsum	- $CaSO_4.2H_2O$
Chert	Silica	- SiO_2
Coal	Chiefly Carbon	

The Rock Cycle

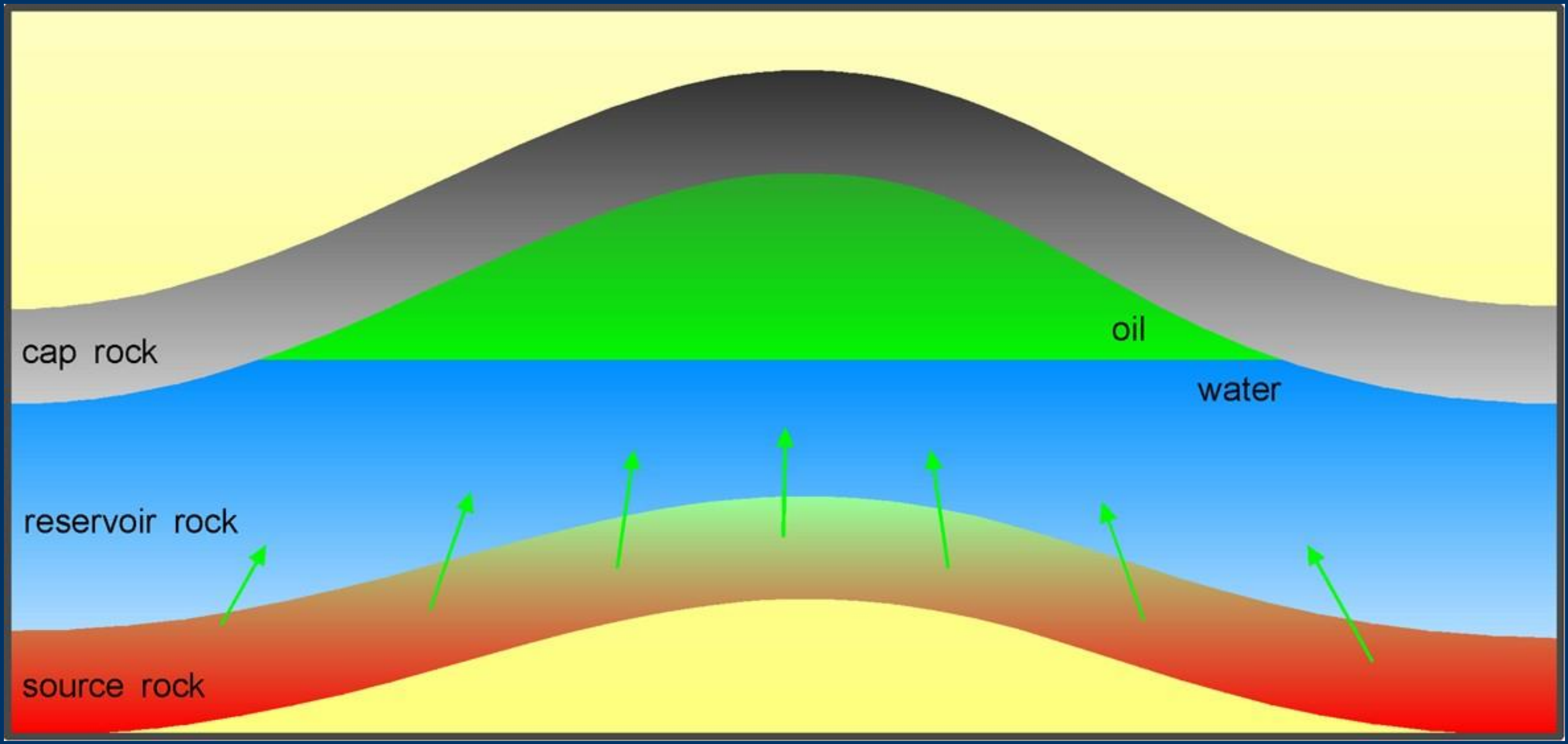


Hydrocarbon Traps

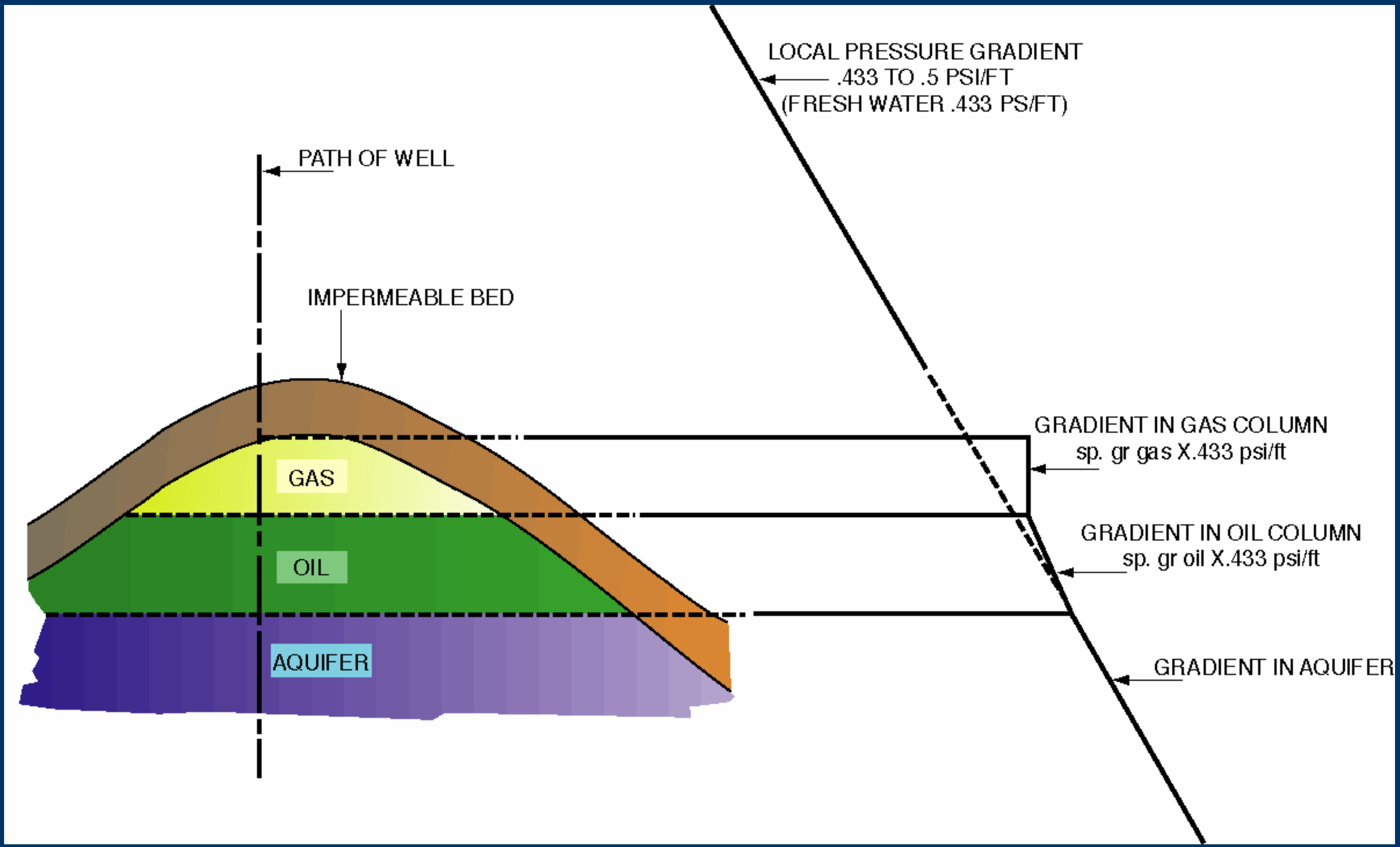
Conditions Required for Hydrocarbon Reservoir

- Mother rock
  – rich in organic material
- Alteration
  – molecular structure change by heat and hydrocarbon migrate through porous media or fracture
- Trap
  – trapped by a impermeable rock
- Reservoir Rock
  – porous and permeable

Accumulation of Oil & Gas into a Reservoir



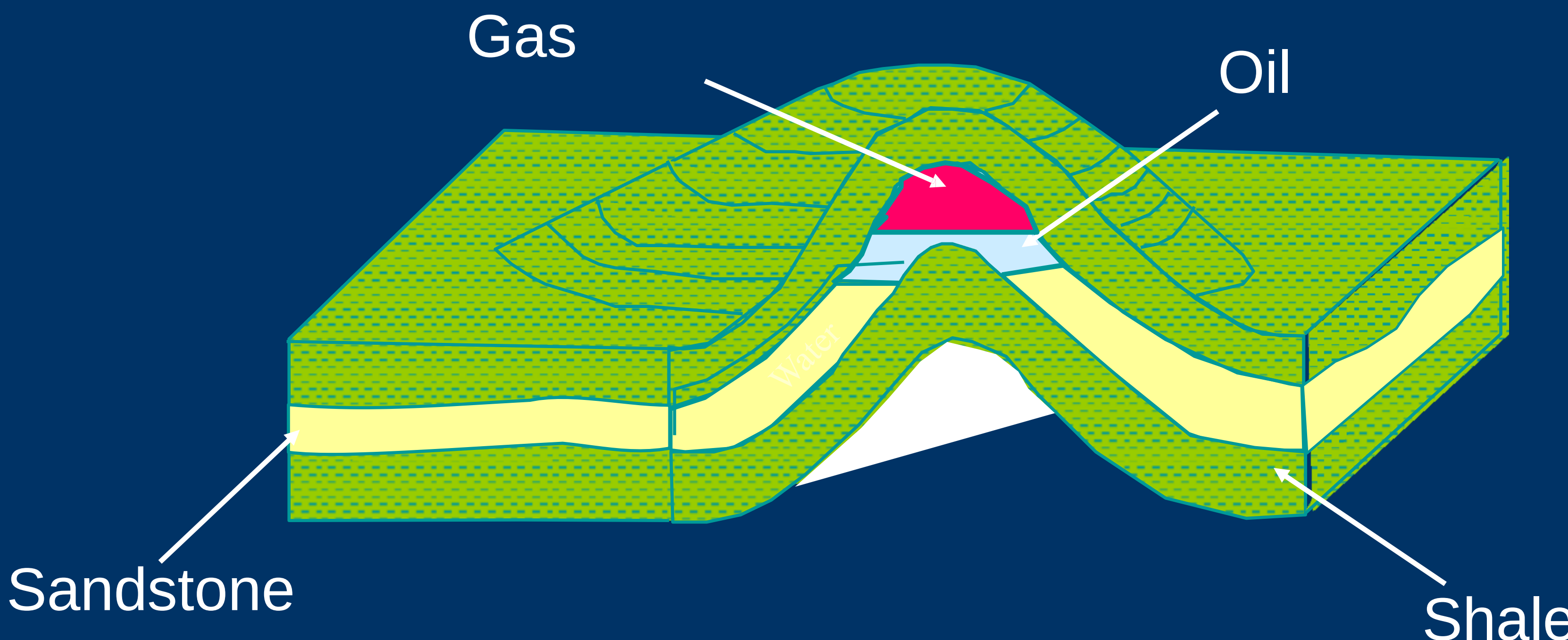
"Normal" Pressure Distribution from Surface through a Reservoir Structure



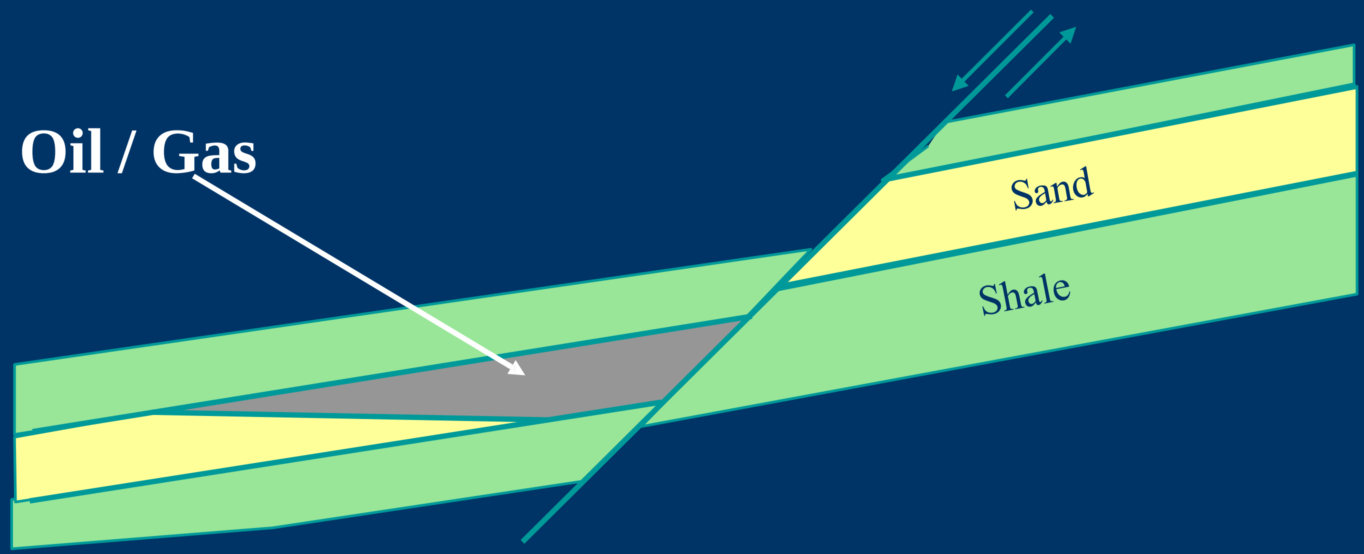
Hydrocarbon Traps

- Trap Types
  - Structural
  - Stratigraphical
  - Combined

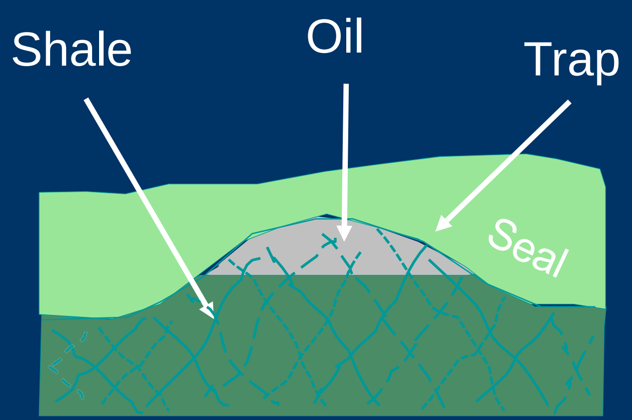
Dome Trap



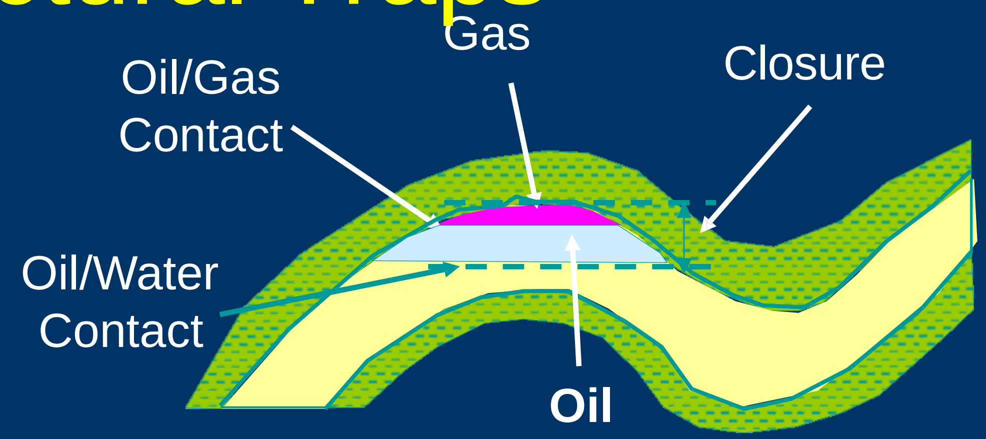
Fault Trap



Structural Traps

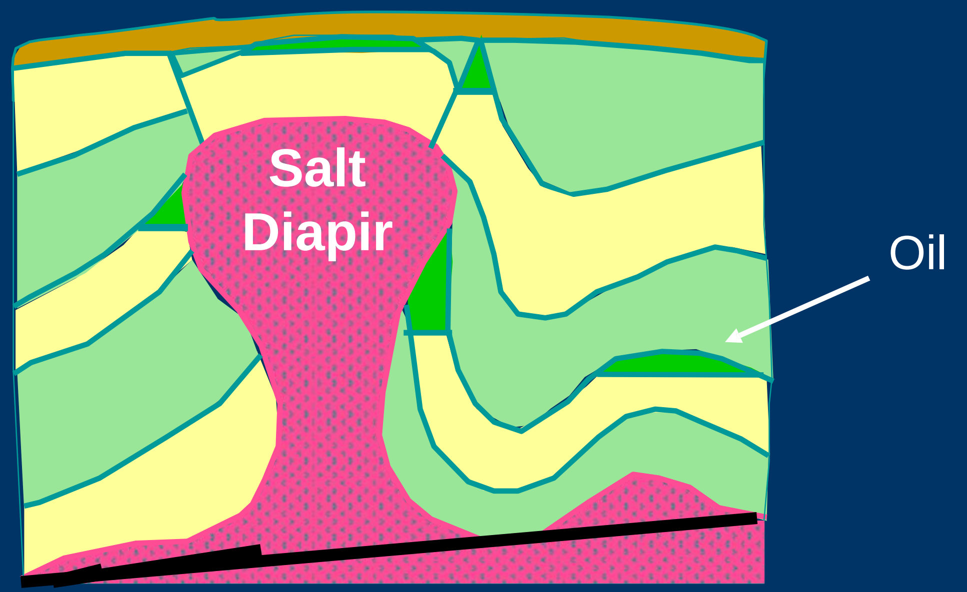


Fractured Basement



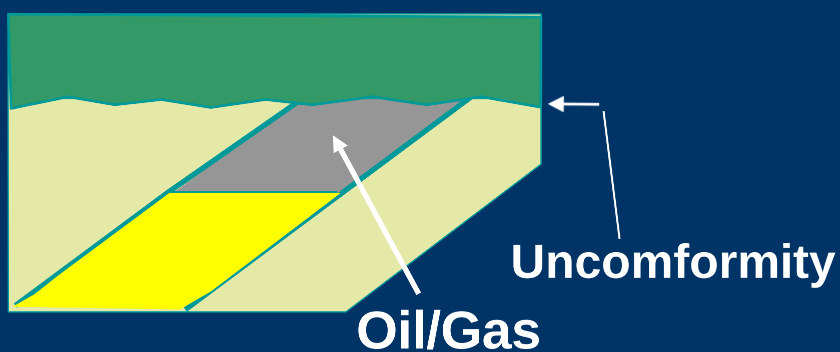
Fold Trap

Salt Dome

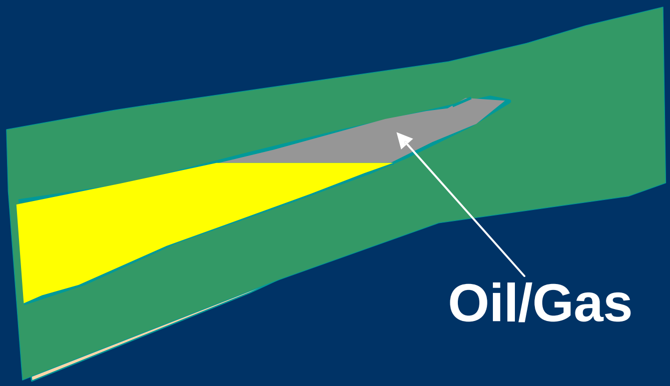


Stratigraphic Traps

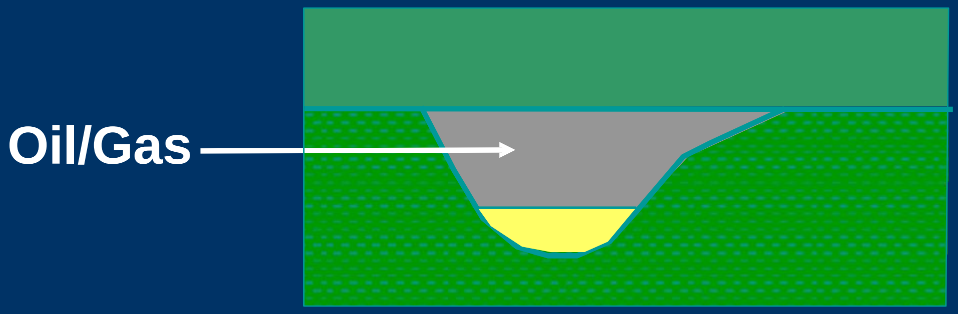
Unconformity



Pinch out



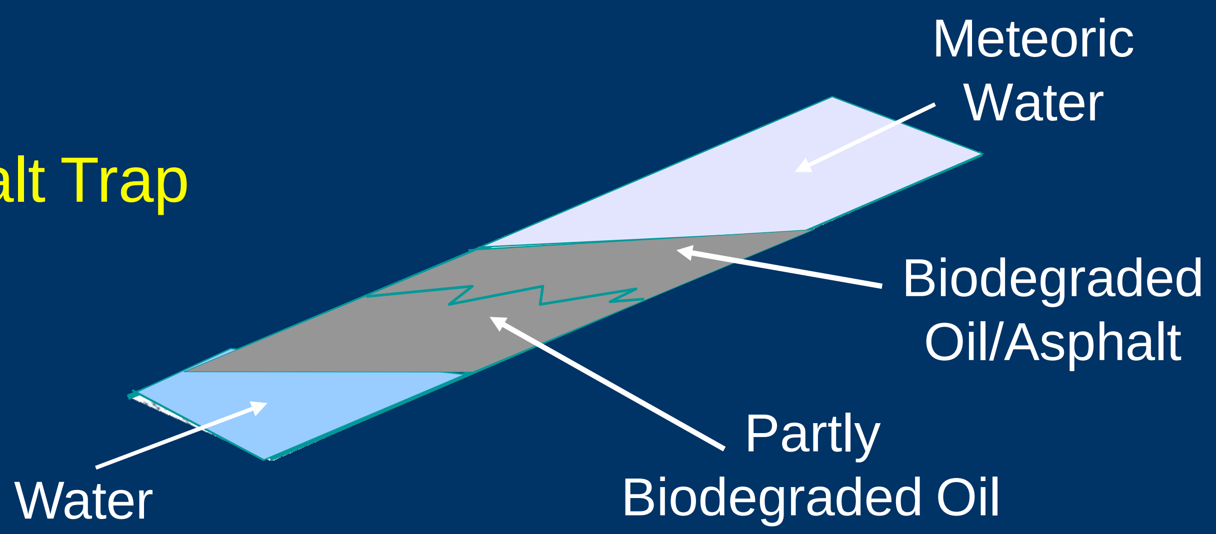
Channel Pinch Out



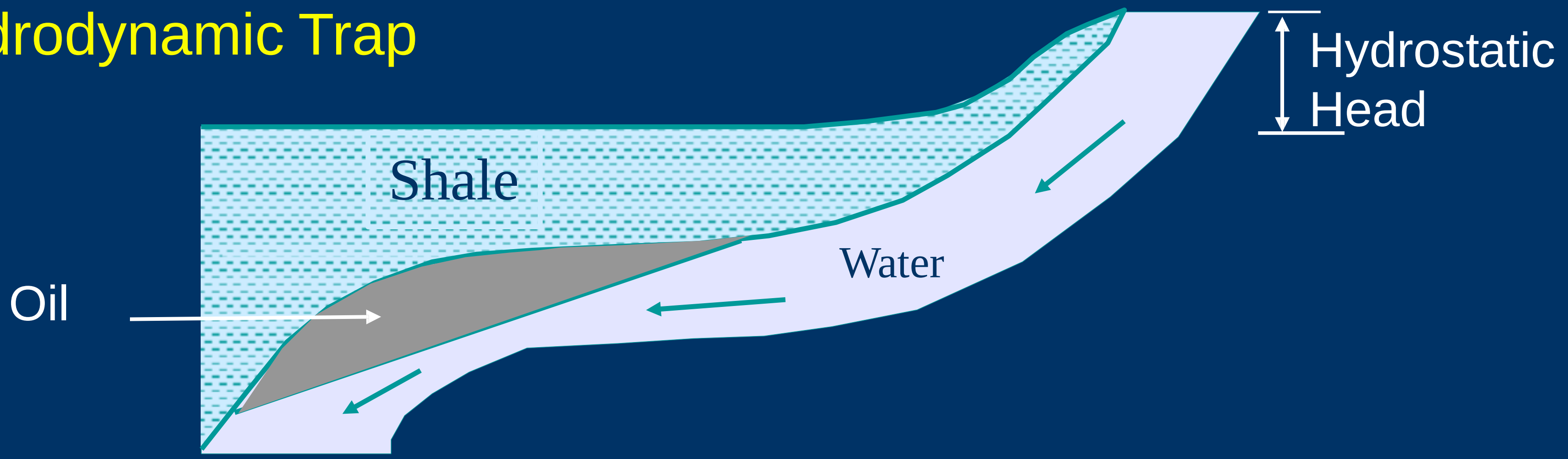
(modified from Bjorlykke, 1989)

Other Traps

Asphalt Trap



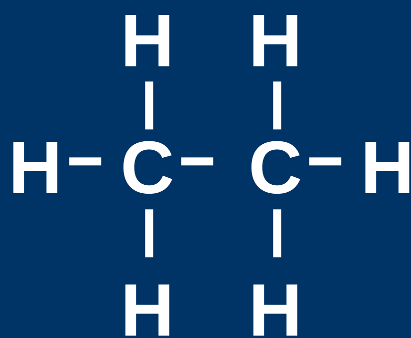
Hydrodynamic Trap



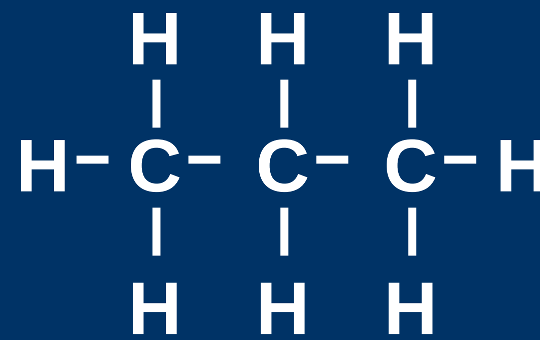
Reservoir Fluid Overview

Hydrocarbon

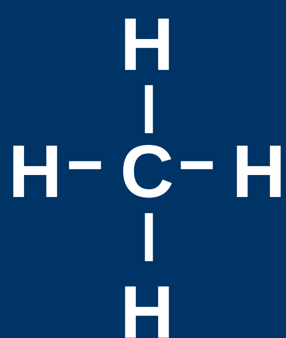
- Combination of C and H



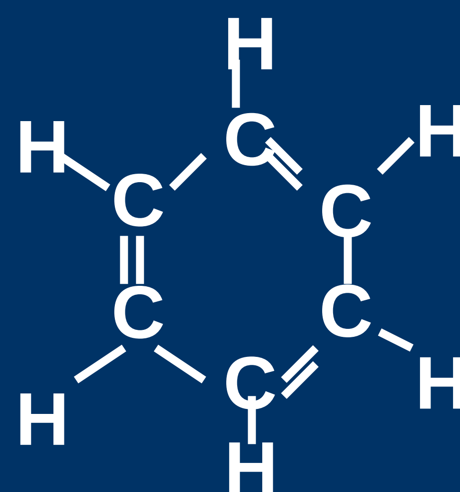
ETHANE



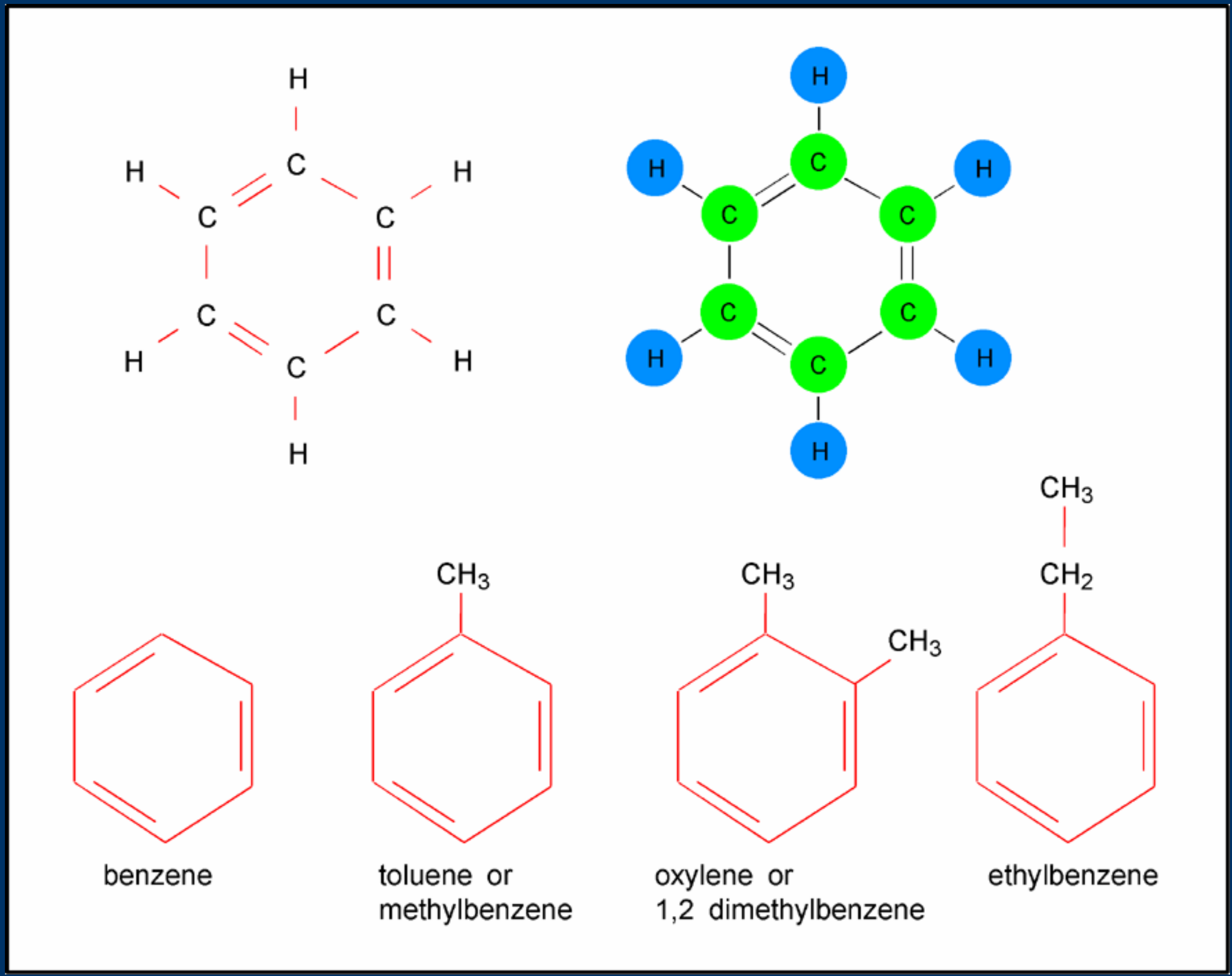
PROPANE



METHANE



Structure of Several Members of the Arene, or Aromatic, Series



Other elements found in Reservoir Fluids

- Water (Salinity)
- H_2S
- CO_2
- N_2
- Hg (Mercury)

API Gravity

$$API = \frac{141.5}{SG} - 131.5$$

or

$$SG = \frac{141.5}{API + 131.5}$$

Where

SG: Specific Gravity

API: API Gravity (60degF)

Classification of Hydrocarbon

	Black Oil	Volatile Oil	Retrograde Gas	Wet Gas	Dry Gas
Initial Producing Gas/Liquid Ratio, scf/STB	<1750	1750 to 3200	> 3200	> 15,000*	100,000*
Initial Stock-Tank Liquid Gravity, °API	< 45	> 40	> 40	Up to 70	No Liquid
Color of Stock-Tank Liquid	Dark	Colored	Lightly Colored	Water White	No Liquid

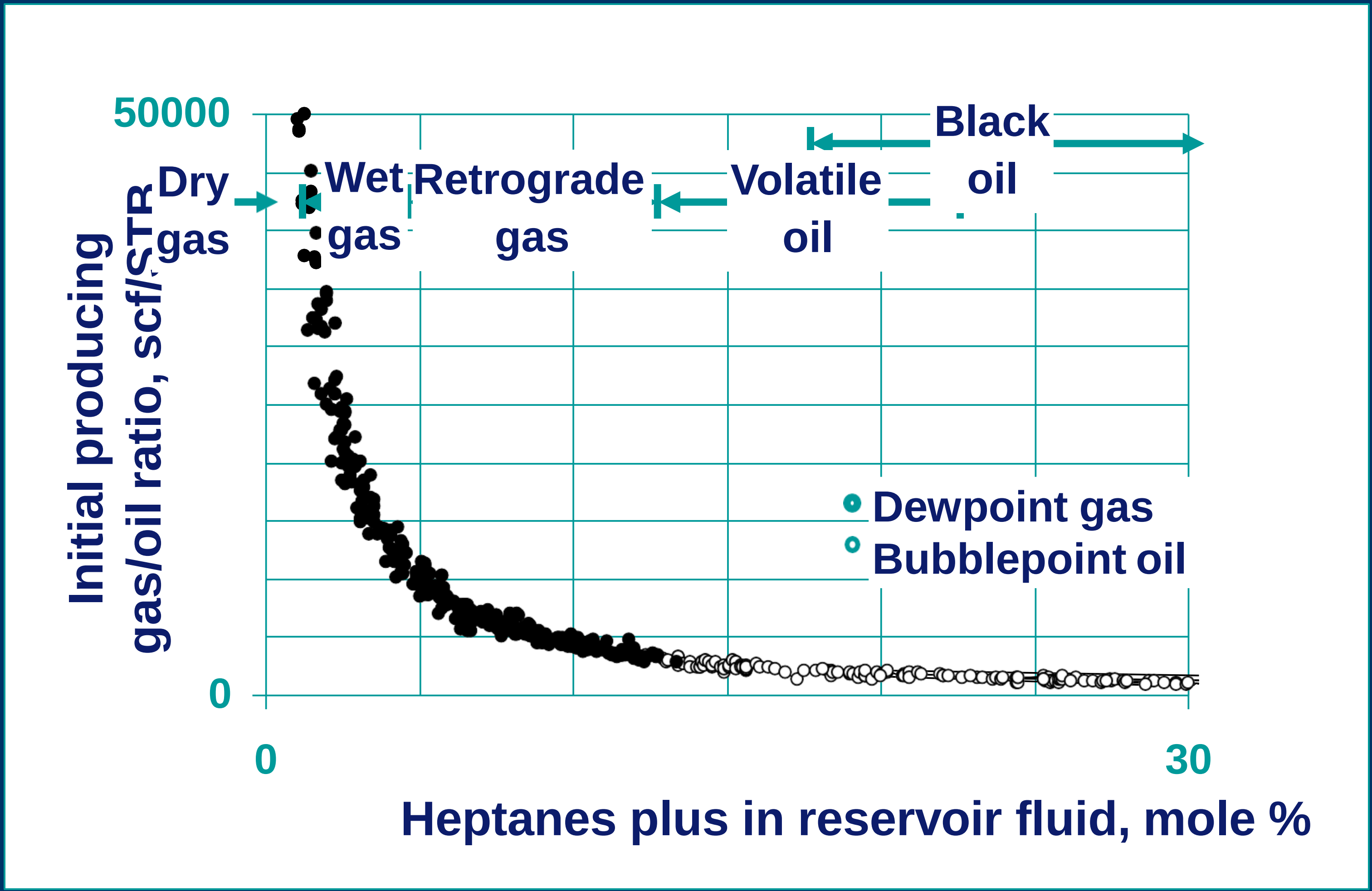
*For Engineering Purposes

Classification of Hydrocarbon

	Black Oil	Volatile Oil	Retrograde Gas	Wet Gas	Dry Gas
Phase Change in Reservoir	Bubblepoint	Bubblepoint	Dewpoint	No Phase Change	No Phase Change
Heptanes Plus, Mole Percent	> 20%	20 to 12.5	< 12.5	< 4*	< 0.8*
Oil Formation Volume Factor at Bubblepoint	< 2.0	> 2.0	-	-	-

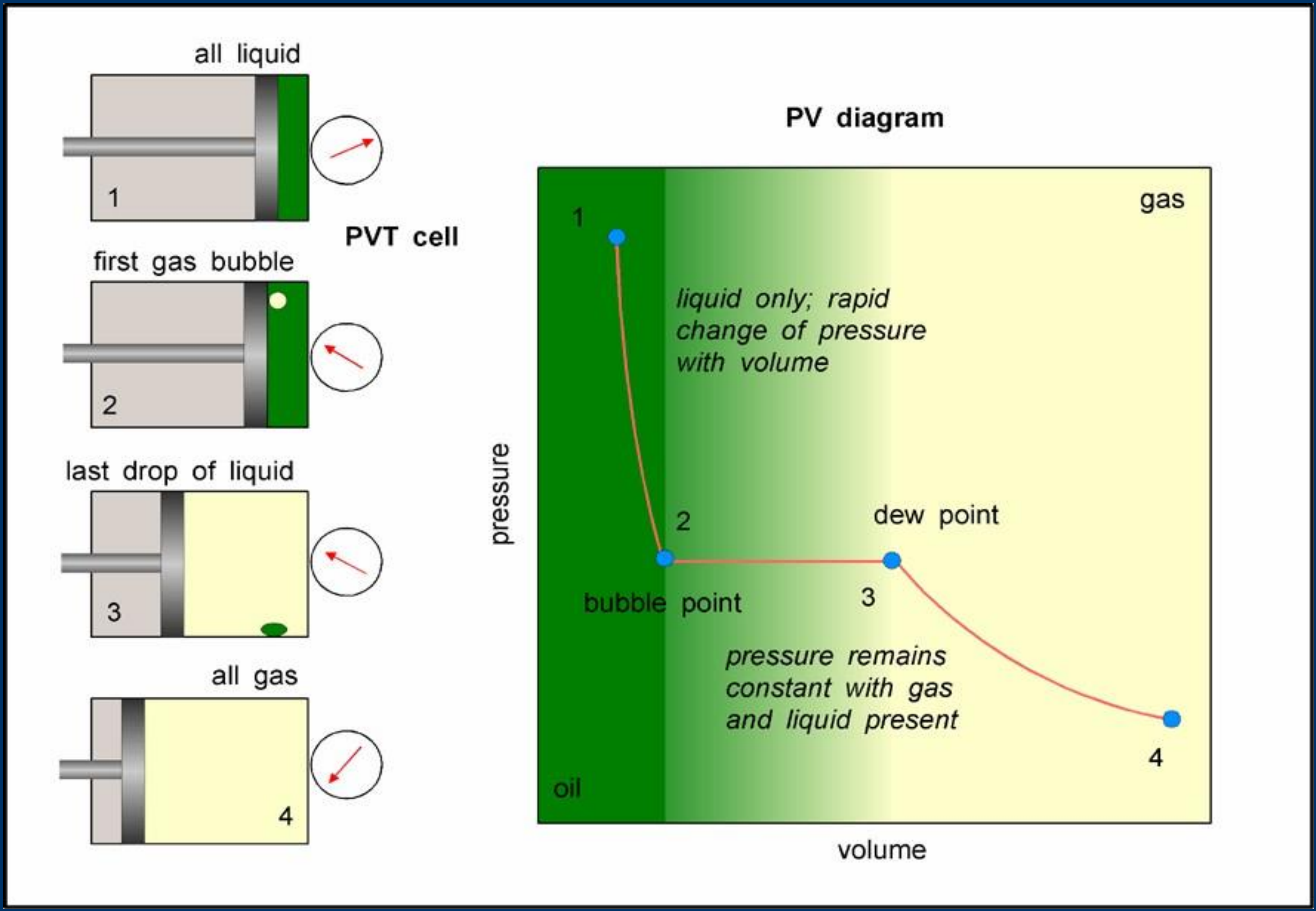
*For Engineering Purposes

Classification of Hydrocarbon



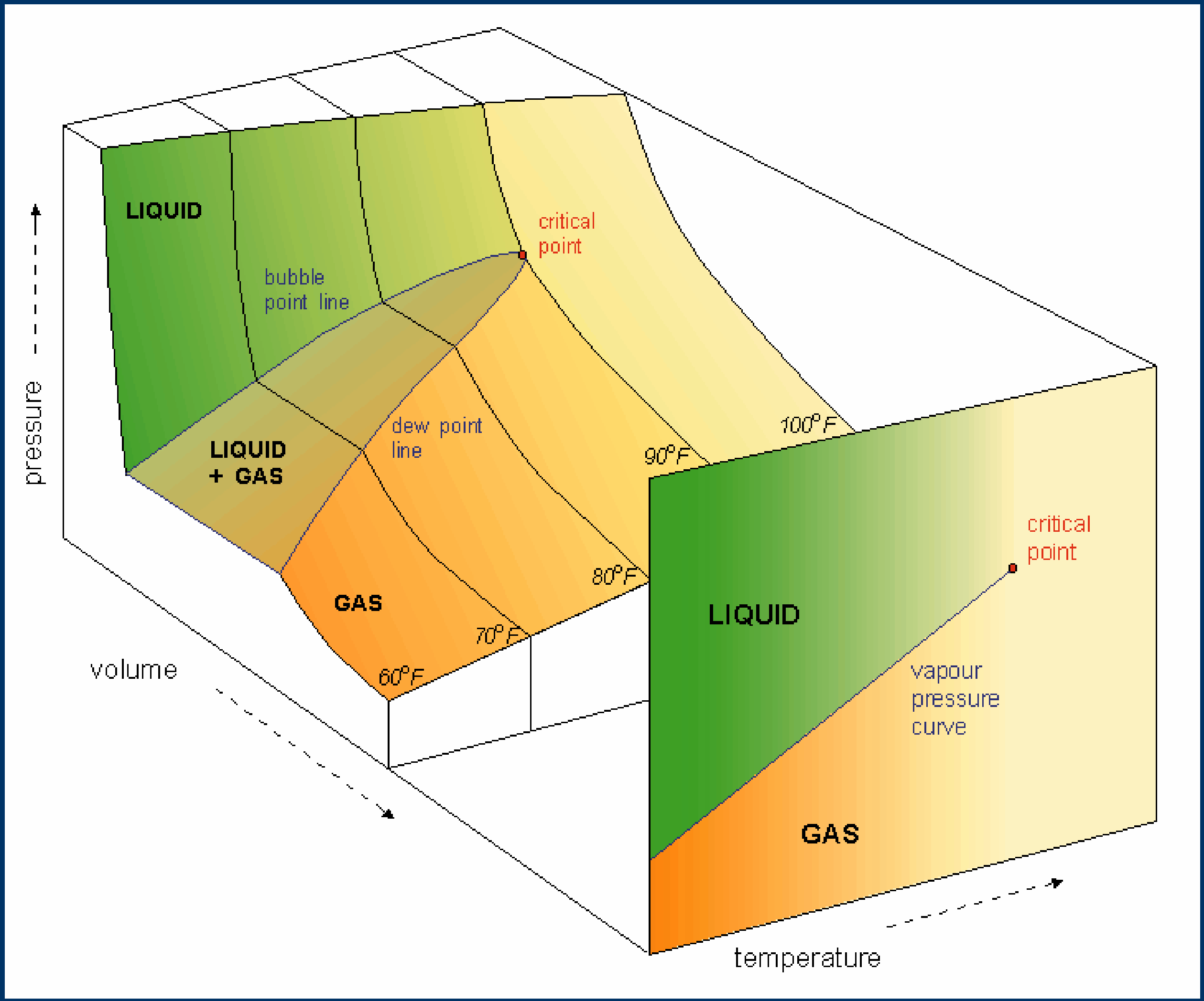
Hydrocarbon Behavior

(Single component / Constant temp.)

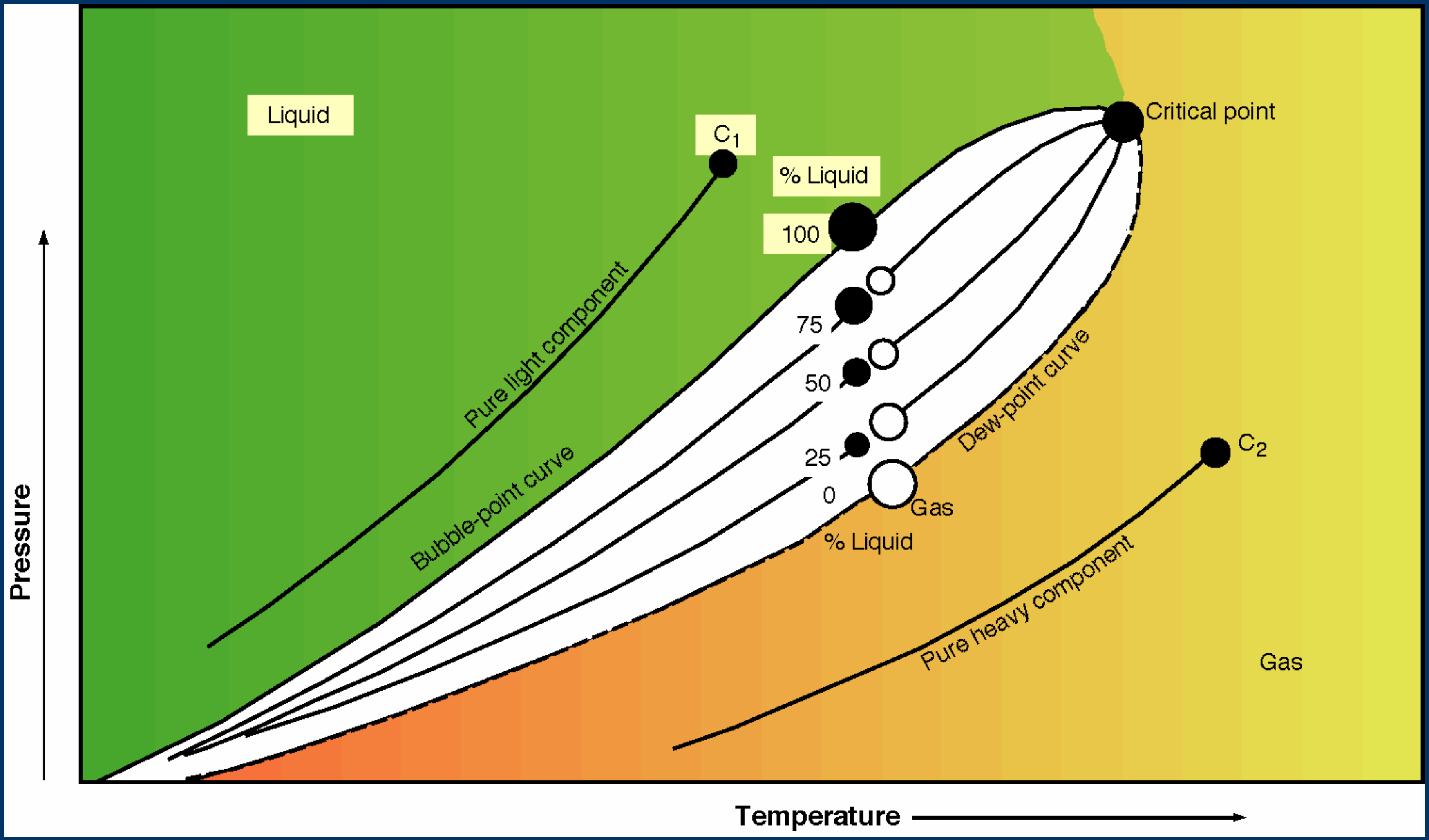


Hydrocarbon Behavior

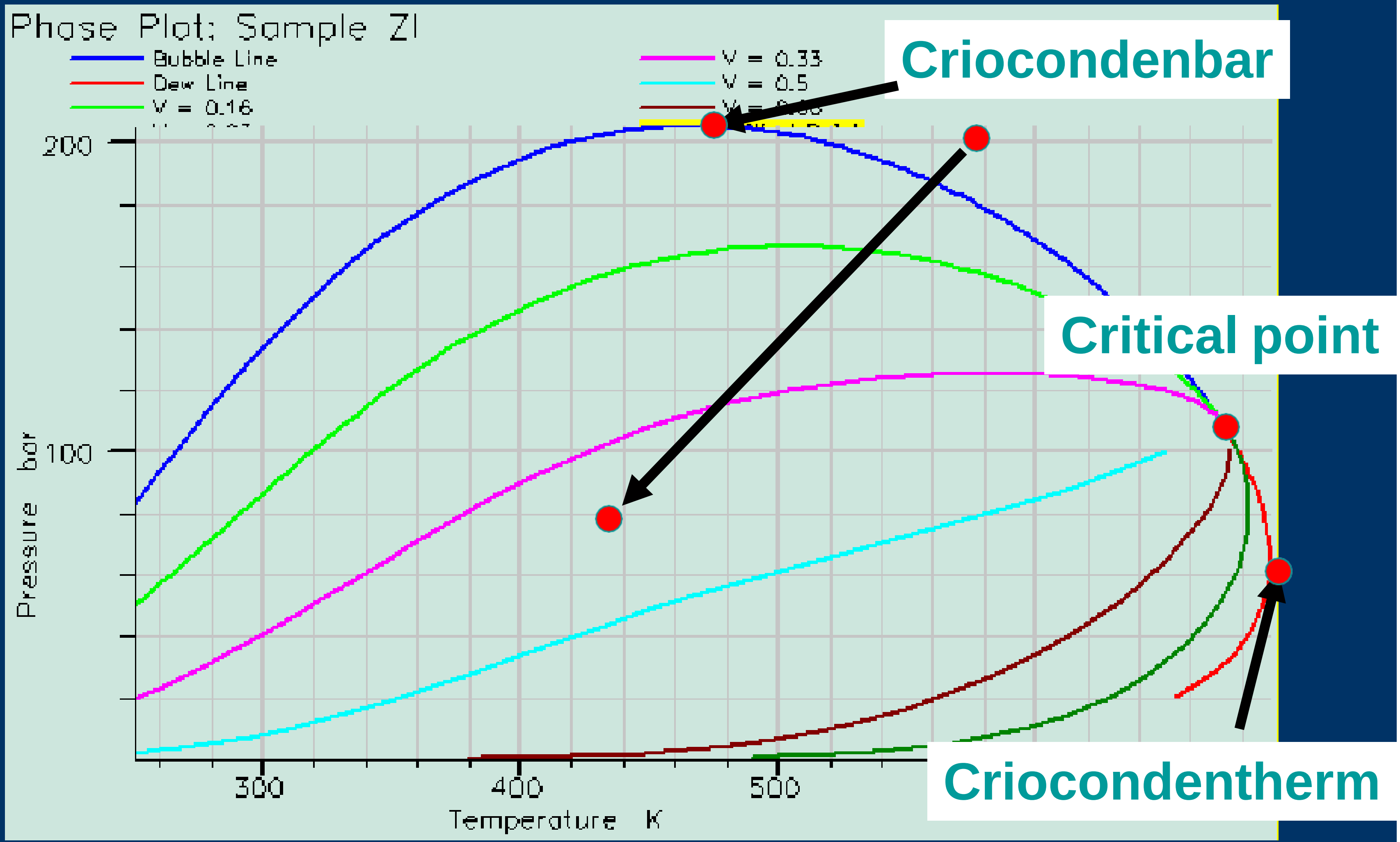
(Single component / Constant temp.)



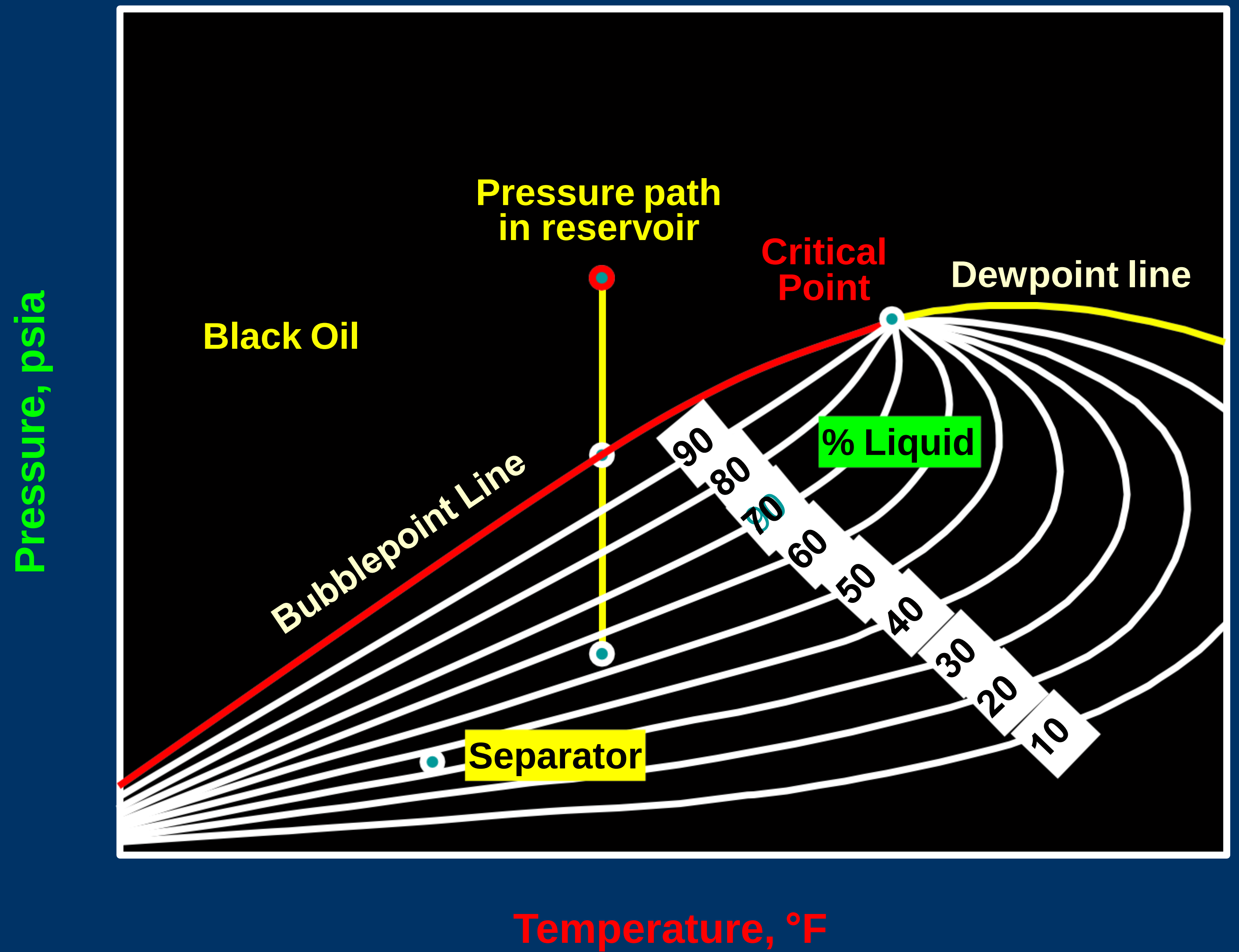
Vapor Pressure Curves for Two Pure Components and Phase Diagram for a 50:50 Mixture of the Same Components



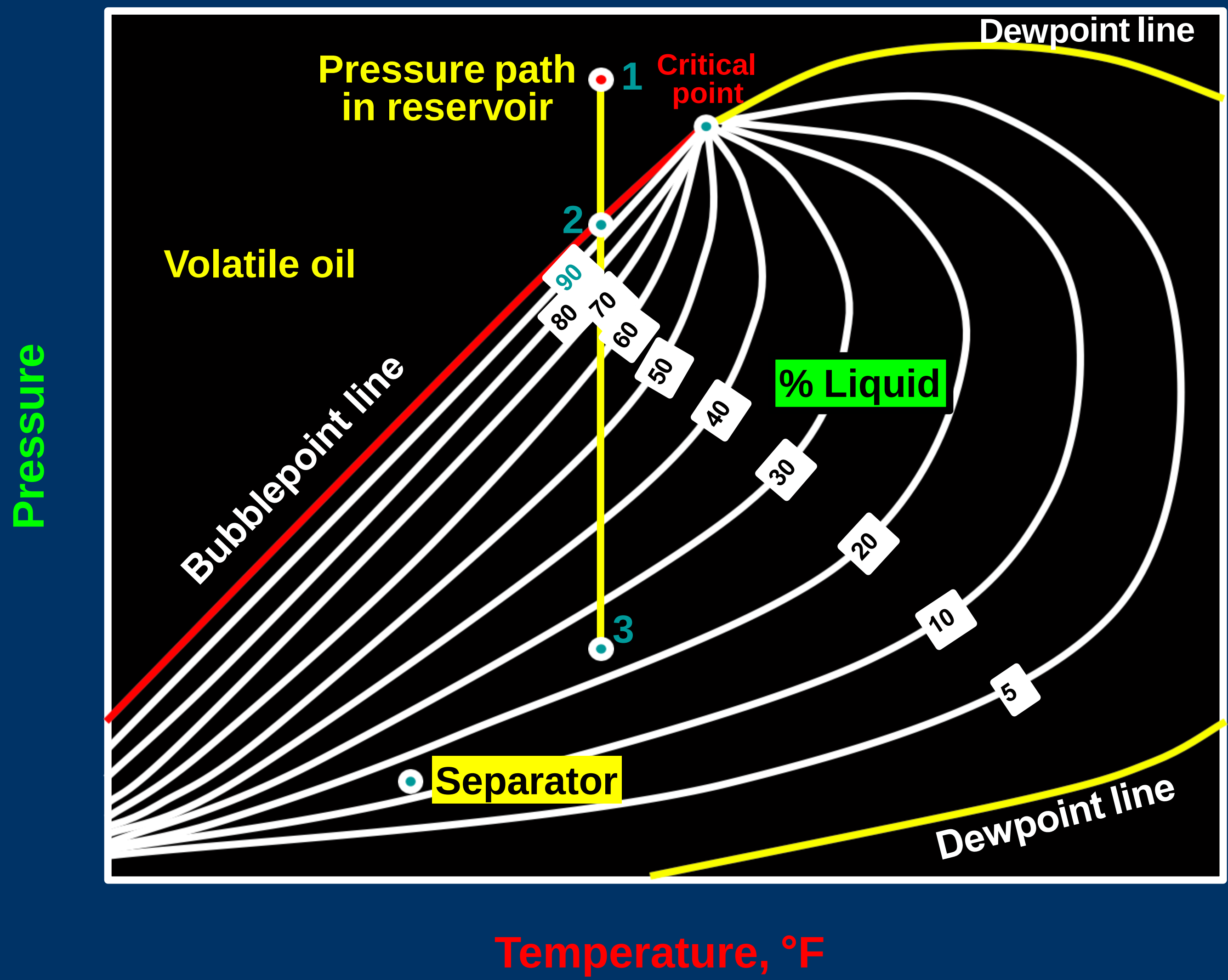
Reservoir Fluid PVT Diagram



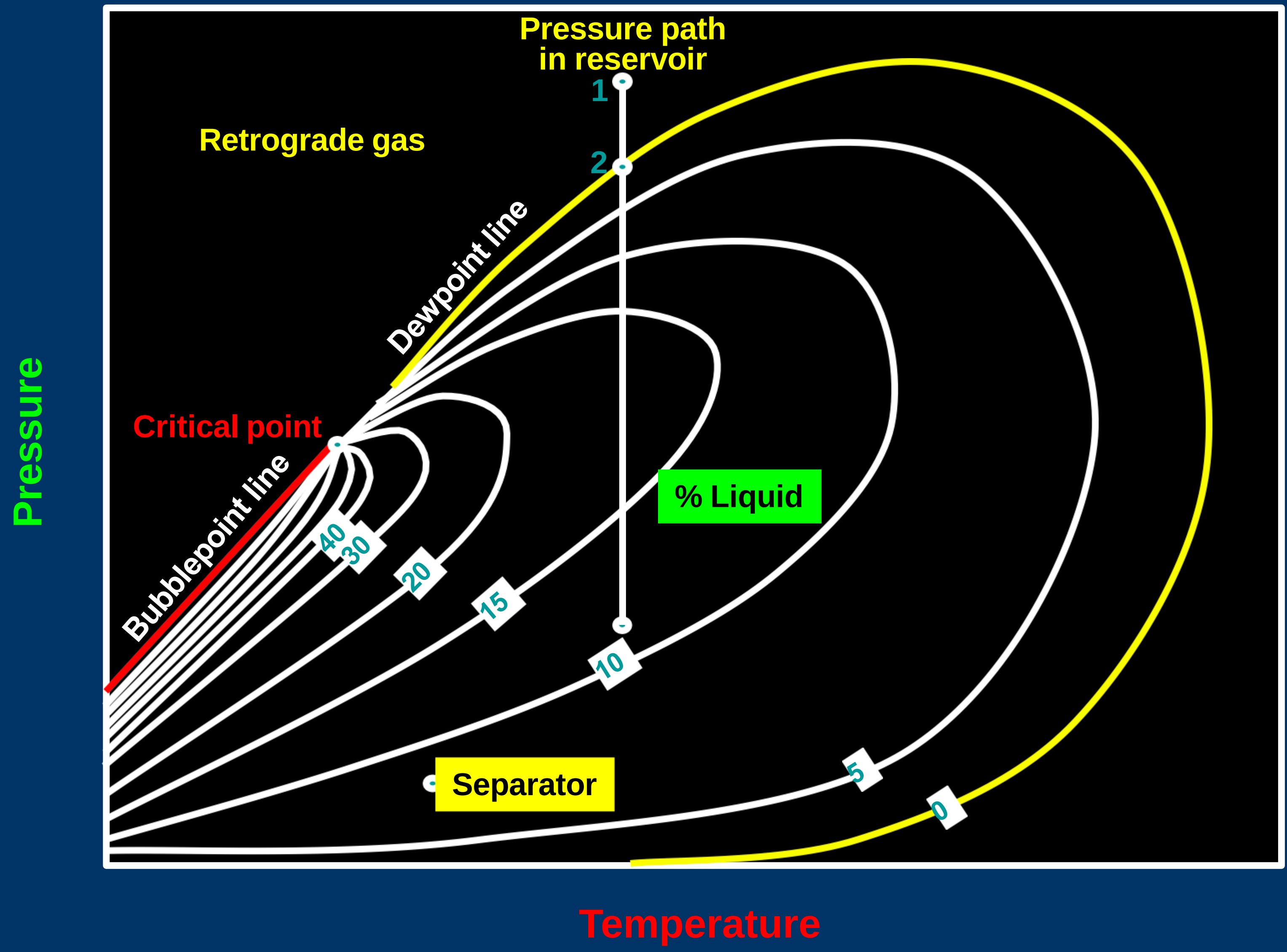
Phase Diagram of a Typical Black Oil



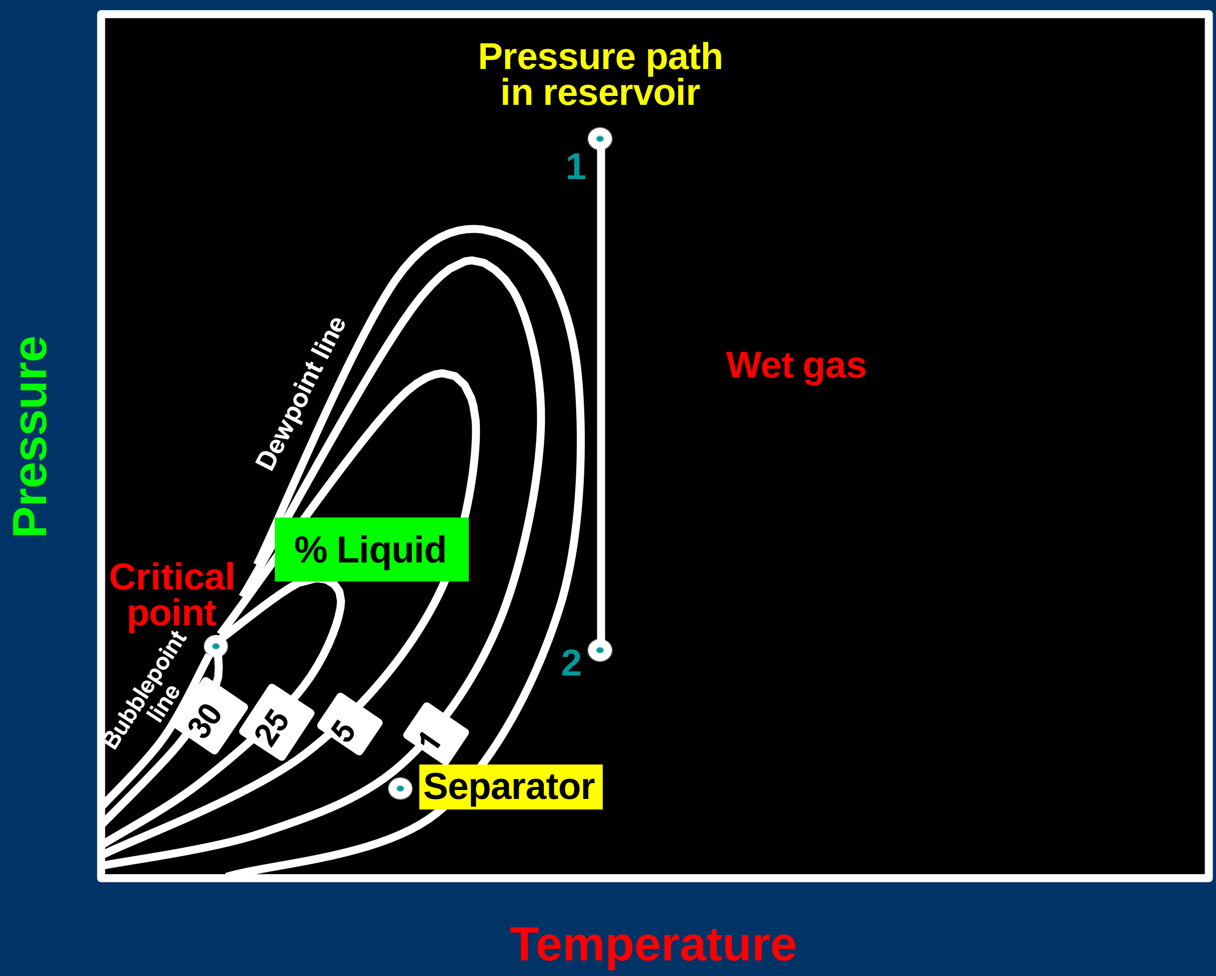
Phase Diagram of a Typical Volatile Oil



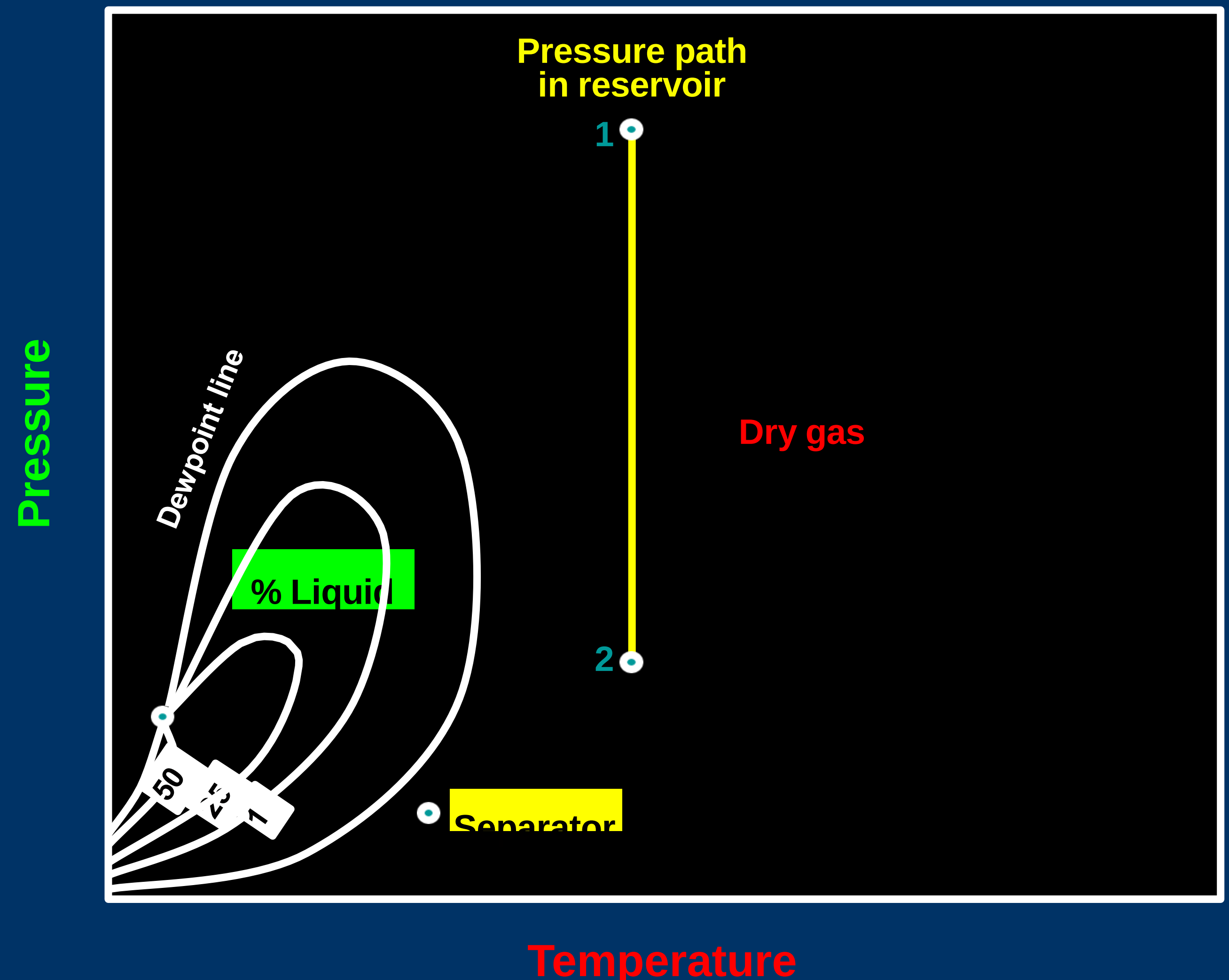
Phase Diagram of a Typical Retrograde Gas



Phase Diagram of a Typical Wet Gas



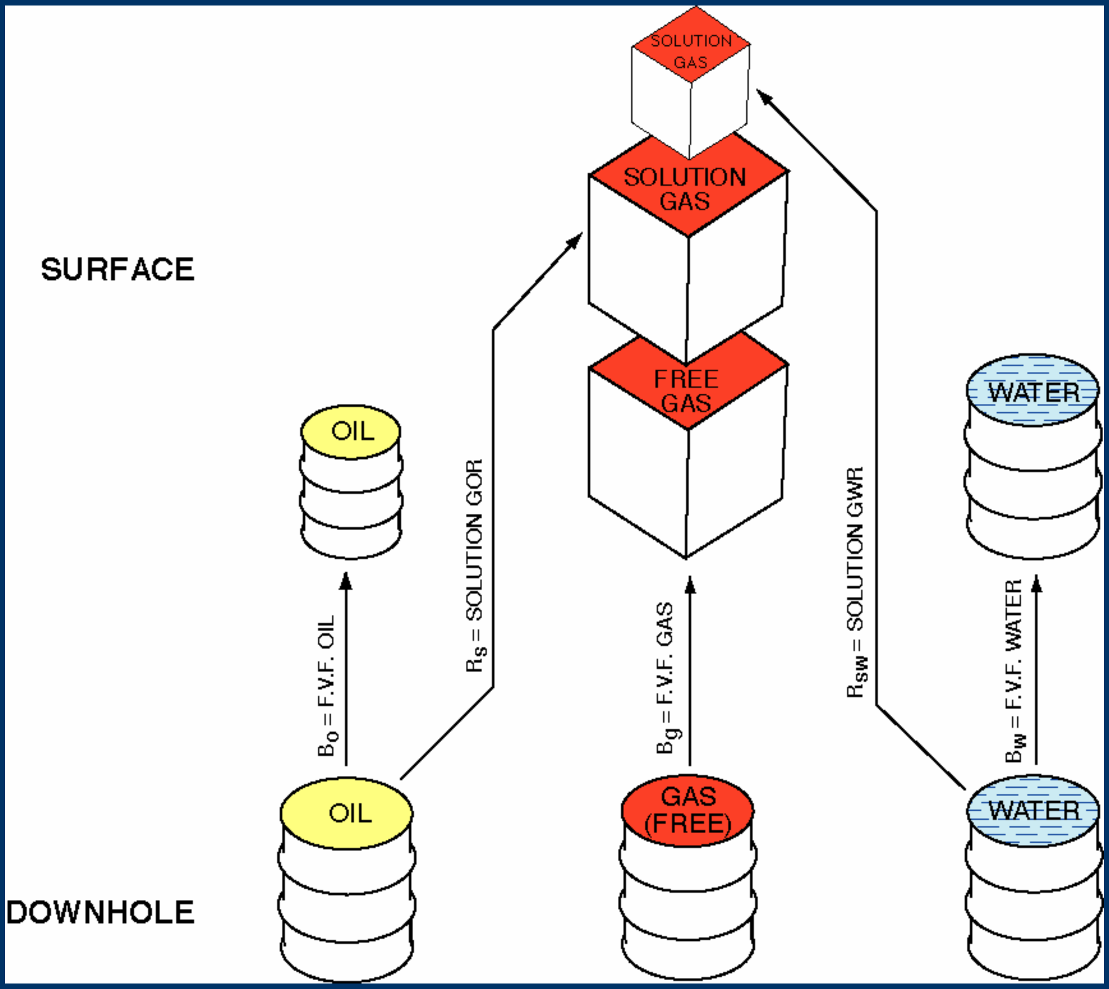
Phase Diagram of a Typical Dry Gas



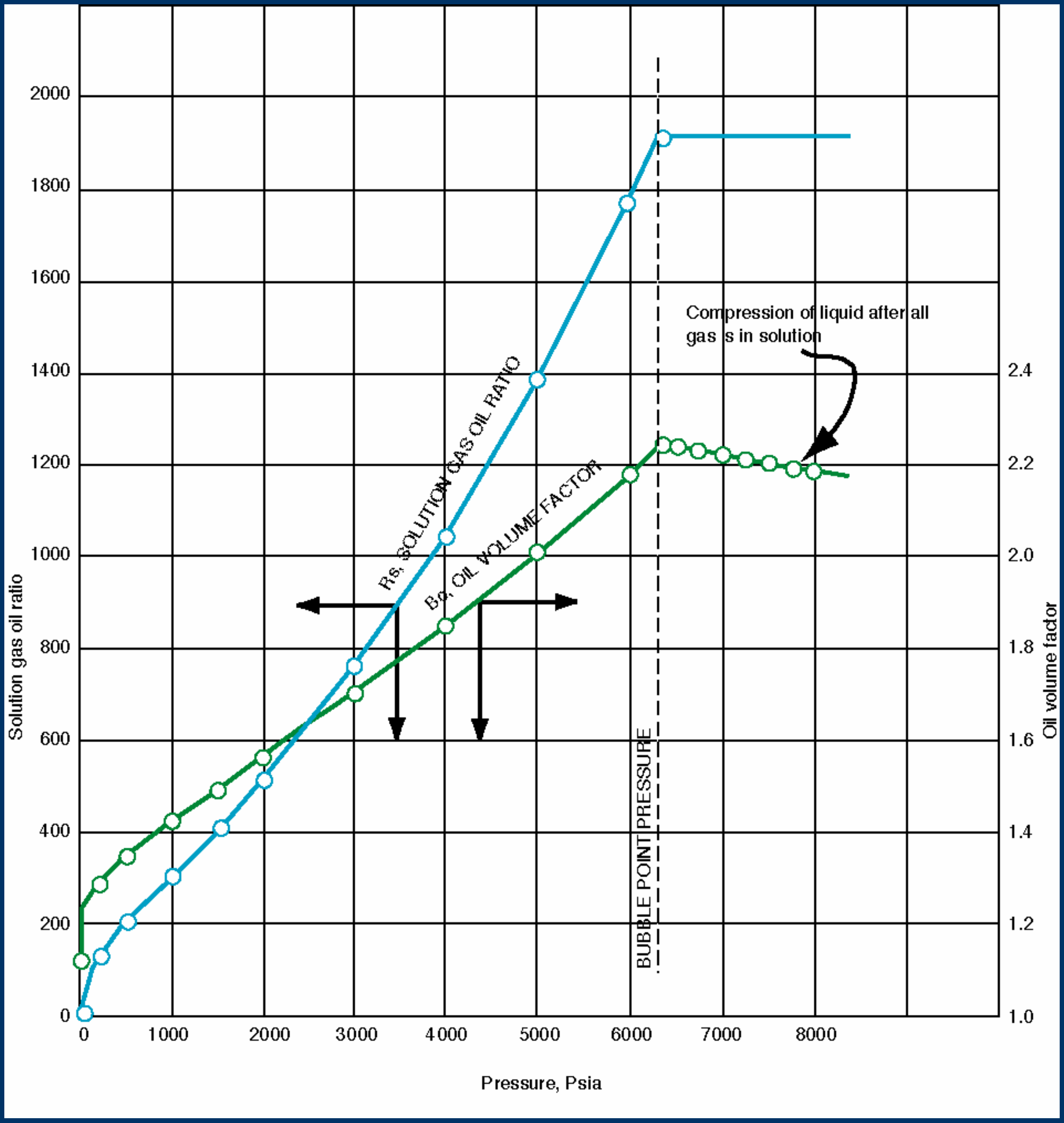
Three Gases

- Dry gas - gas at surface is same as gas in reservoir
- Wet gas - recombined surface gas and condensate represents gas in reservoir
- Retrograde gas - recombined surface gas and condensate represents the gas in the reservoir but not the total reservoir fluid (retrograde condensate stays in reservoir)

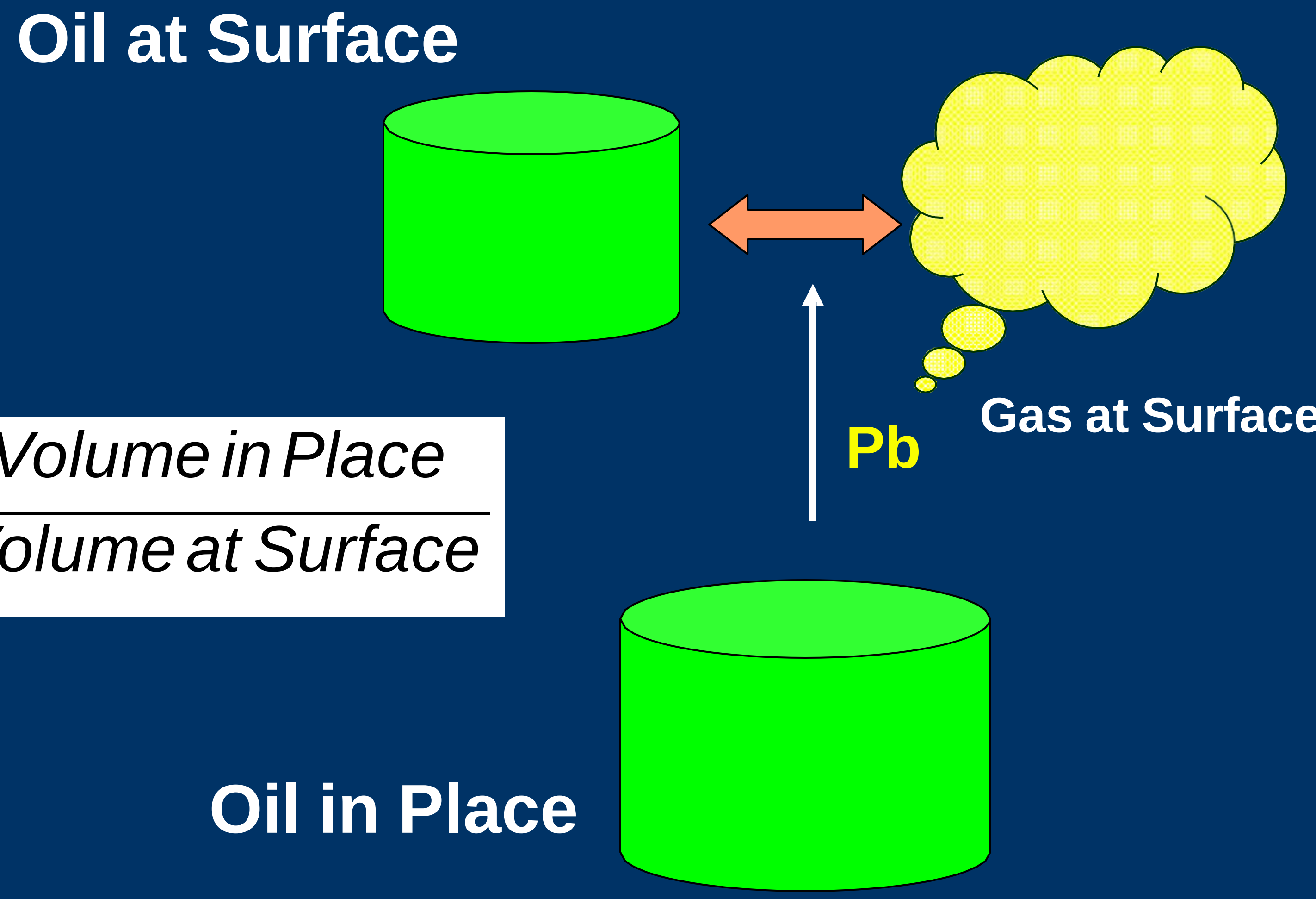
Relationships between Surface and Downhole Volumes — Dissolved Gas Systems



Typical PVT Data for Differential Vaporization of an Undersaturated Oil at Constant Temperature (305°F)

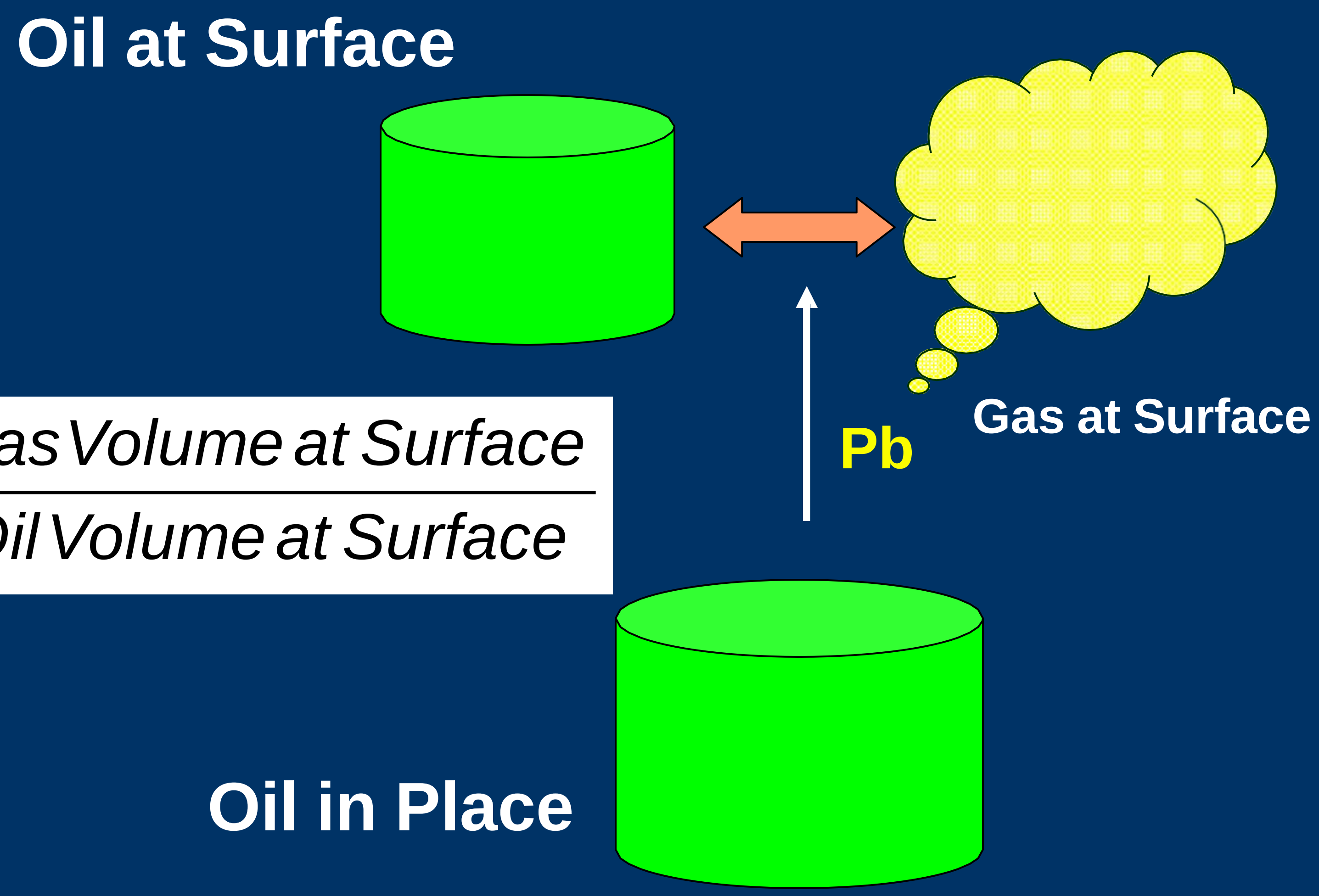


Oil Formation Volume Factor (Bo)



$$B_o = \frac{Oil\,Volume\,in\,Place}{Oil\,Volume\,at\,Surface}$$

Production Gas Oil Ratio (GOR)



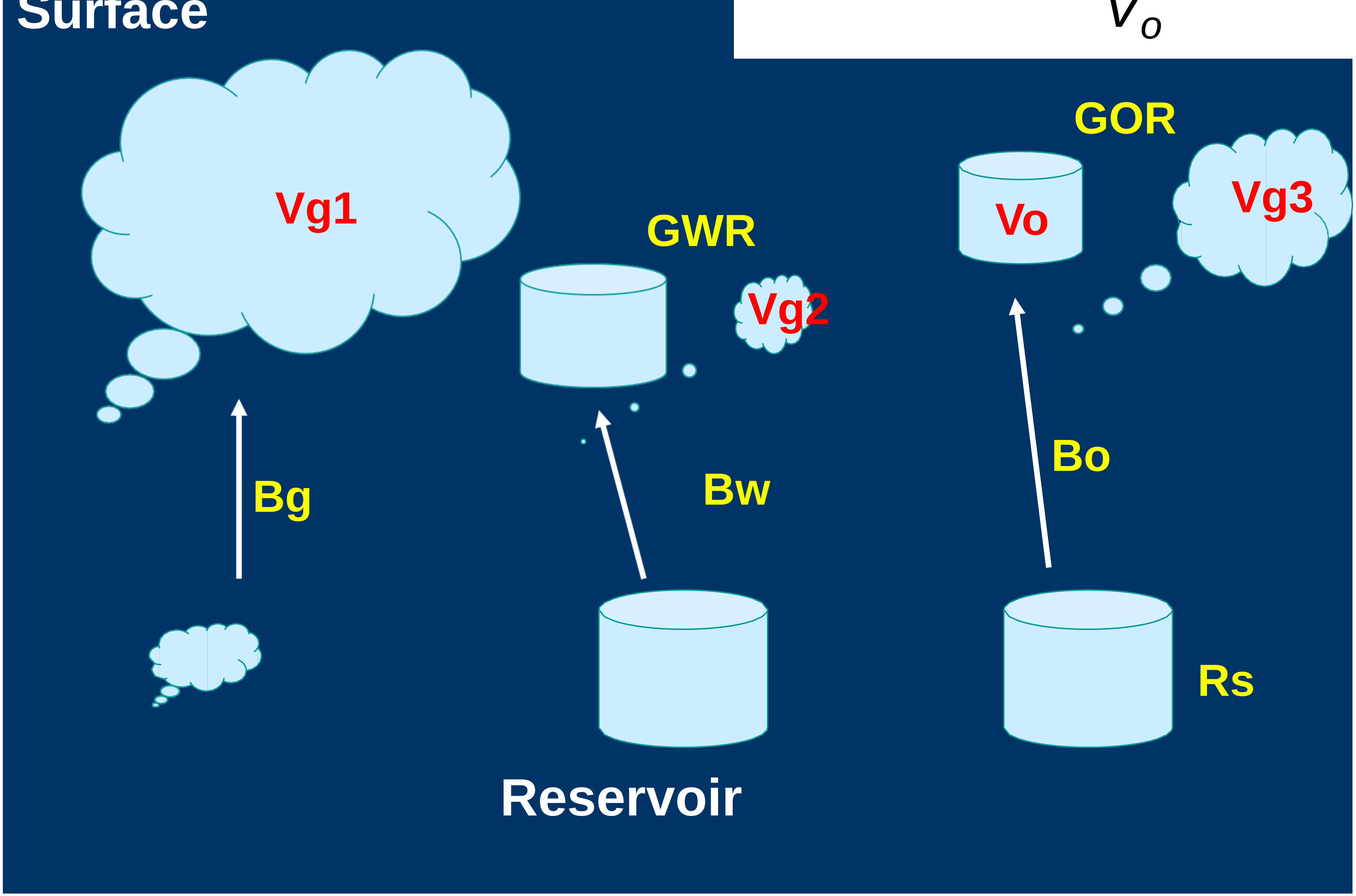
$$GOR = \frac{Gas\,Volume\,at\,Surface}{Oil\,Volume\,at\,Surface}$$

Excercise

- There is 1,000,000 bbls of recoverable oil in reservoir. If you recover all of the oil to the surface, how much stock tank volume of oil and gas (standard condition) you can obtain? Assume: Bo = 1.2, GOR = 600, reservoir is saturated and no free gas is drained.
- If the oil price is $25/bbl and gas price is $3/mscf, how much revenue can you get? (you do not have to consider production cost in this exercise).

GOR $\neq$ Rs

$$GOR = \frac{V_g 1 + V_g 2 + V_g 3}{V_o}$$



Gas-Oil Ratio
(for Pr < Pb and no Free Gas Cap)

$$GOR = R_s + \left(\frac{B_o}{B_g}\right)\left(\frac{\mu_o}{\mu_g}\right)\left(\frac{k_{rg}}{k_{ro}}\right)$$

where:

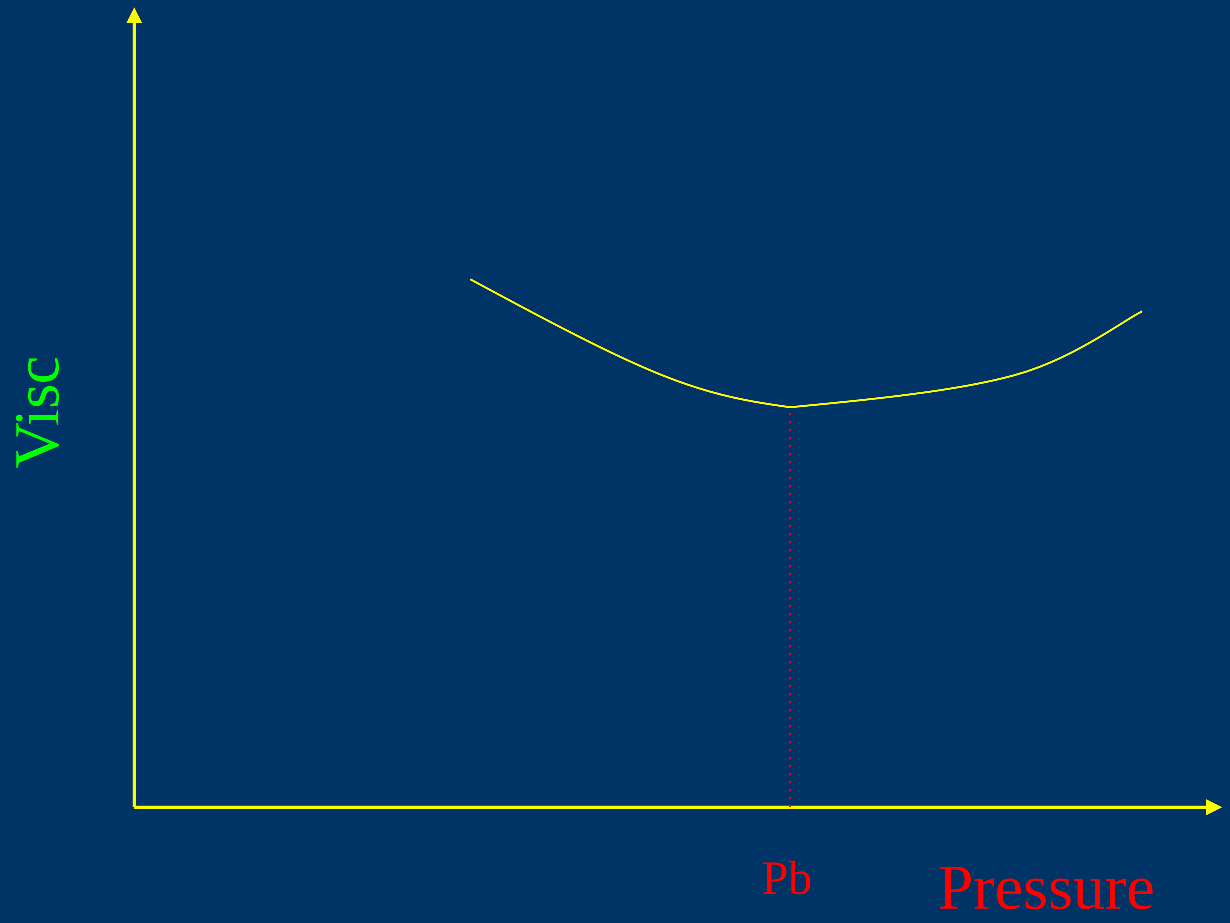
GOR	–	Production gas oil ratio
R_s	–	Gas in solution in oil
B_o and B_g	–	Oil and gas volume factors
μ_o and μ_g	–	Oil and gas viscosities
k_{rg}/k_{ro}	–	Gas/oil-relative permeability-ratio

Basic Parameters Used in Reservoir Engineering

Viscosity (μ)

- A measure of resistance to flow
- Symbols
  - μ_o, μ_g, μ_w
- Units – cp
- Source – Lab measurements, correlations
- Range and typical values
  - **0.25 – 10,000 cp, Black oil**
  - **0.5 – 1.0 cp, Water**
  - **0.012 – 0.035 cp, Gas**

Variation of Viscosity with Pr

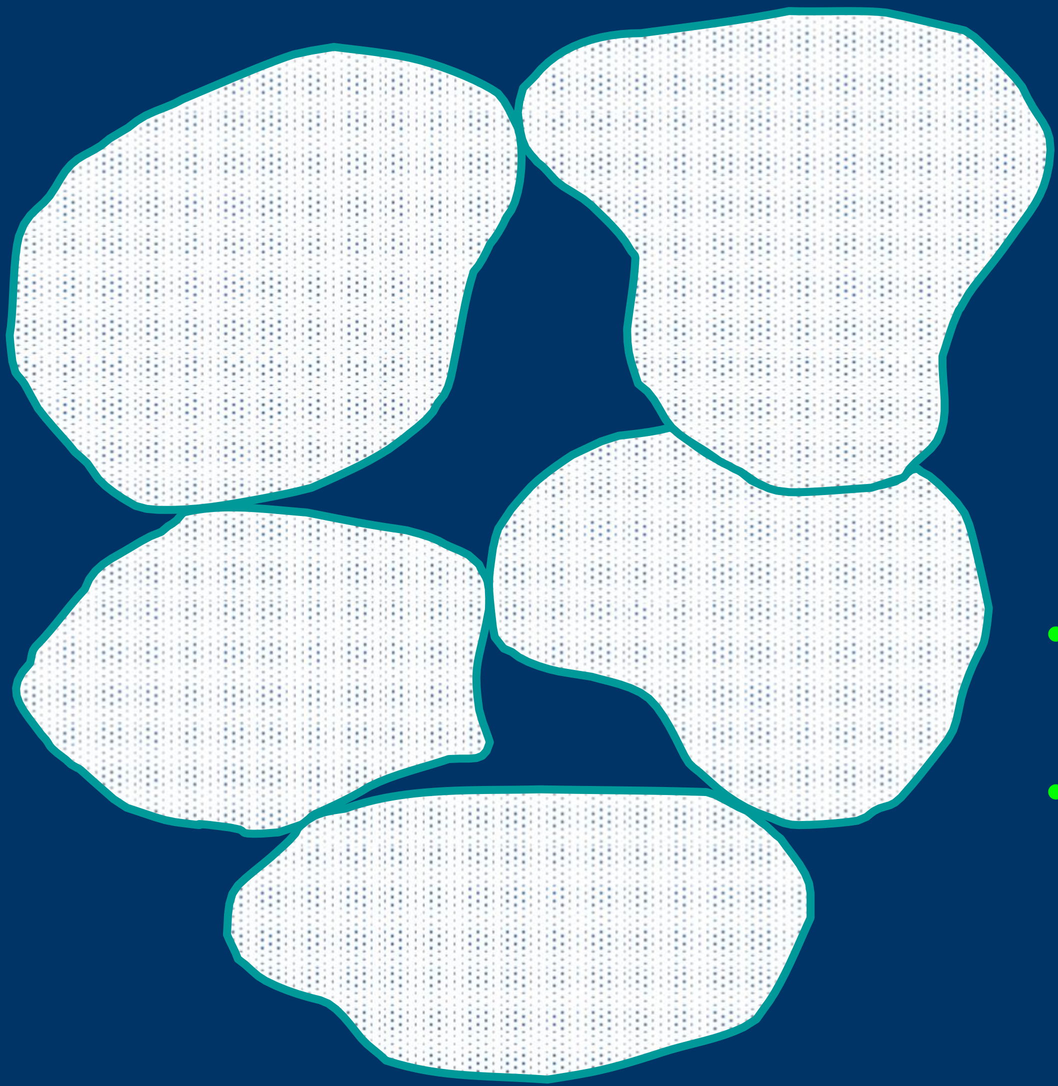


Fluid Compressibility (C_o, C_g, C_w)

$$c_o \equiv -\frac{1}{V_o}\frac{\partial V_o}{\partial p} = -\frac{\partial \ln(V_o)}{\partial p}$$

- Fractional change in volume due to a unit change in pressure
- Symbol – c_o, c_g, c_w
- Units – psi^{-1}, microsips (1 microsip = $1x10^{-6}$ psi^{-1})
- Source – Lab measurements, correlations

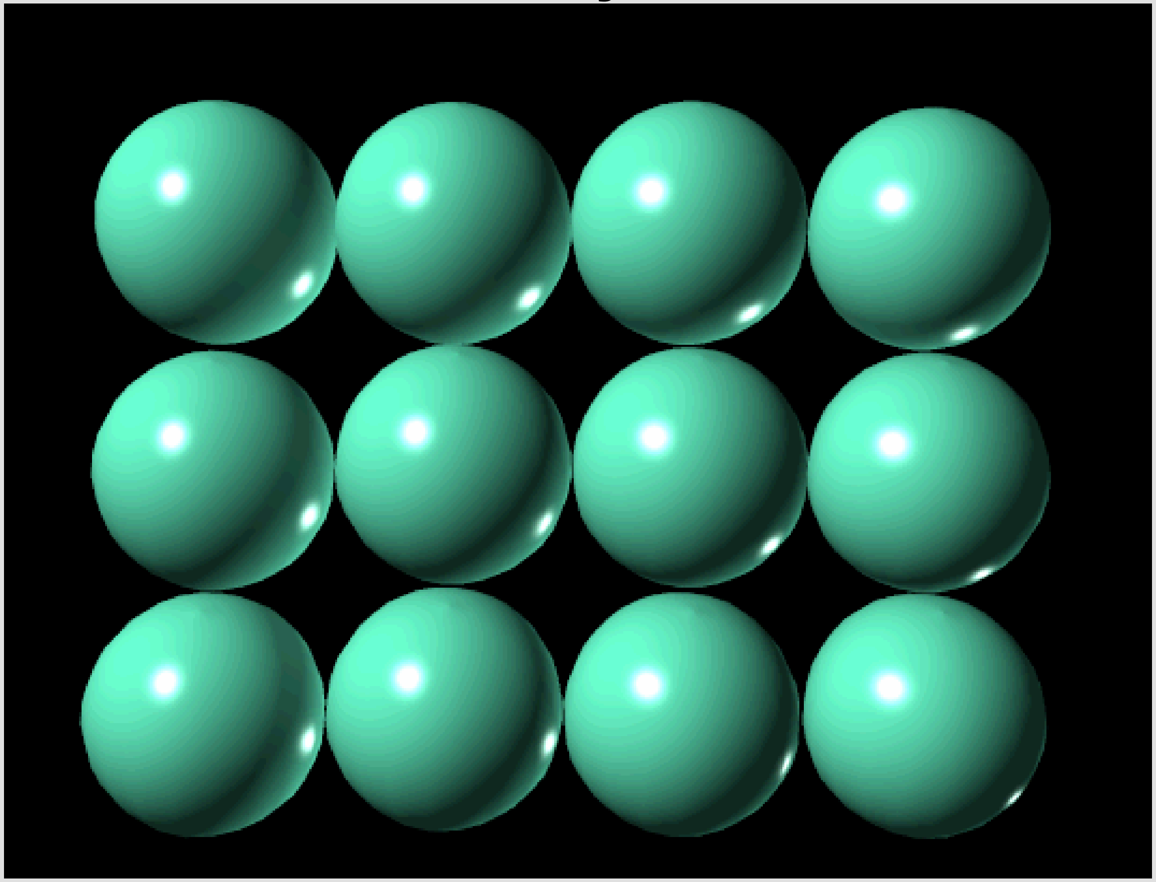
Porosity (ϕ)



- Total Porosity
- Effective Porosity

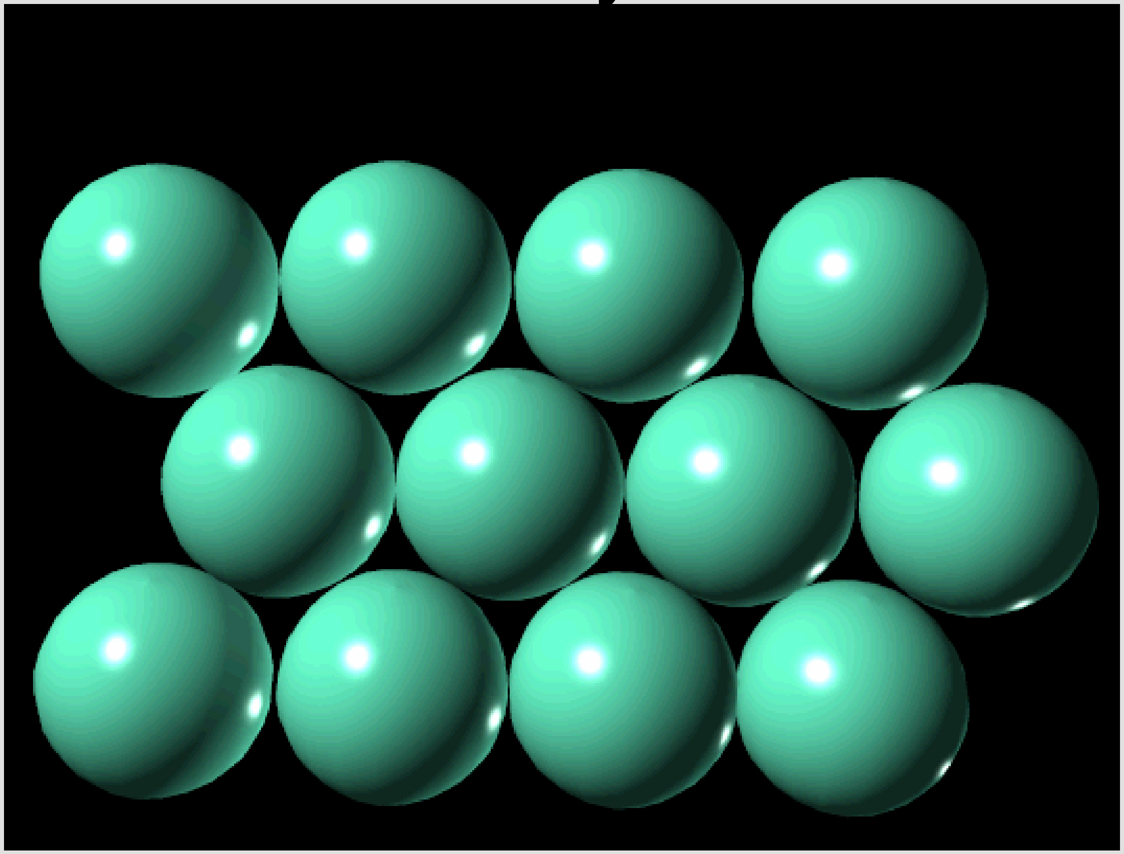
Cubic Packing of Spheres

Porosity = 48%



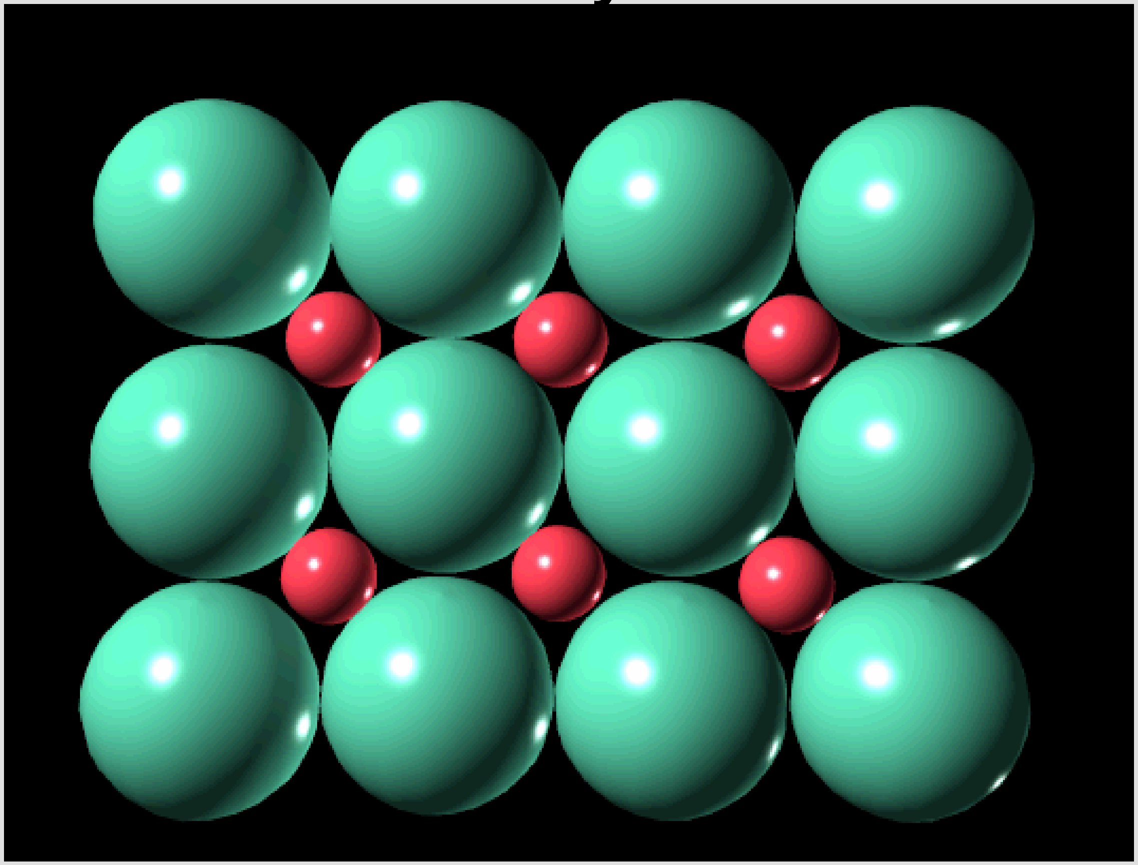
Rhombic Packing of Spheres

Porosity = 27 %

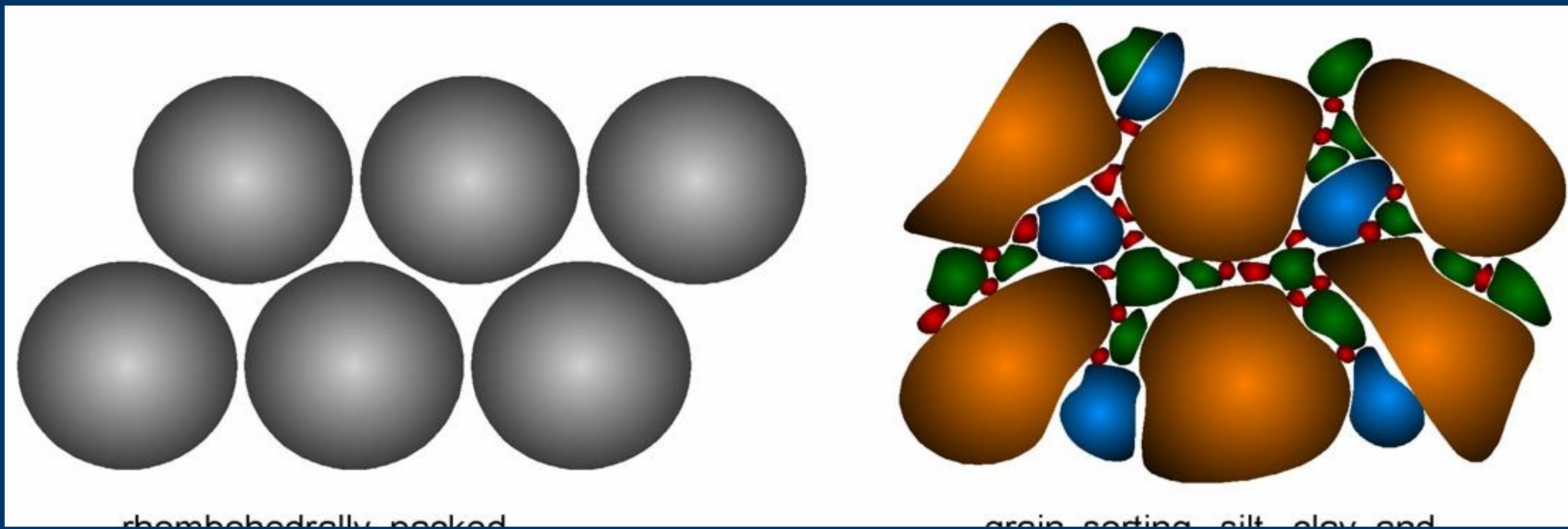


Packing of Two Sizes of Spheres

Porosity = 14%



Intergranular Porosity



rombohedrally packed spheres: ϕ = 26%

grain sorting, silt, clay and cementation effect porosity

Permeability (K)

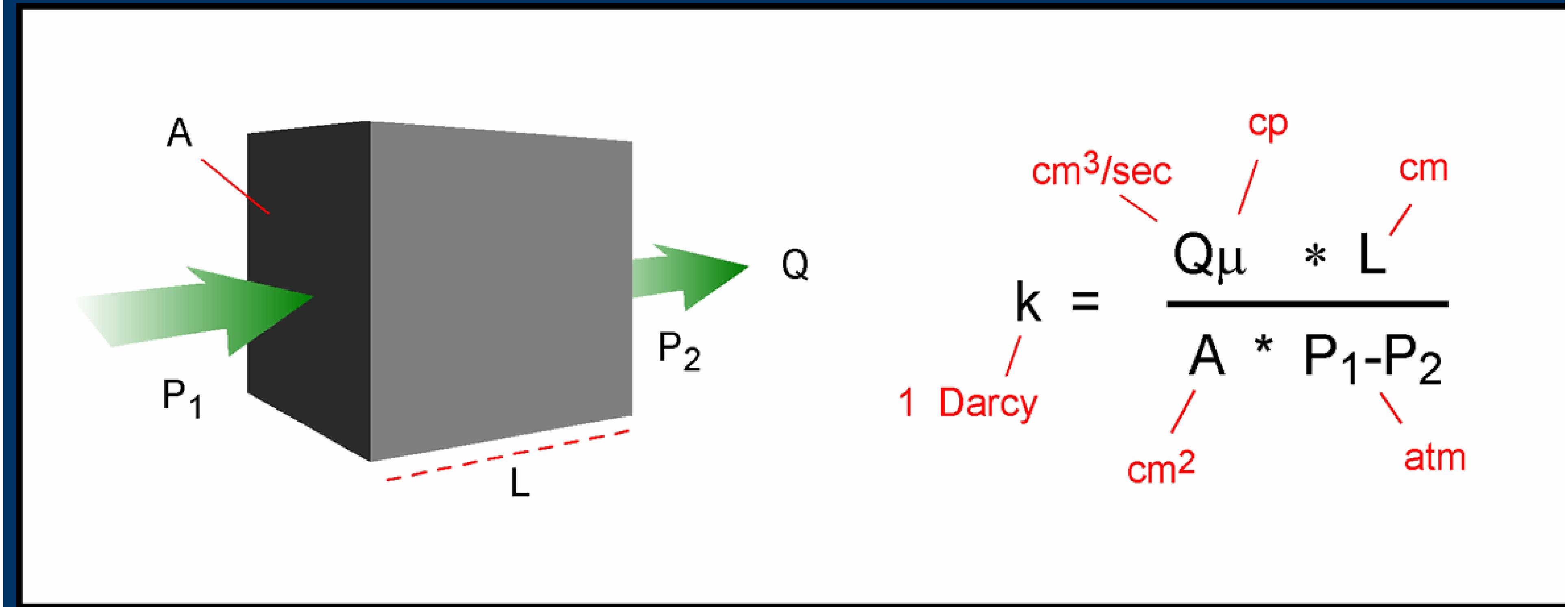
$$\mathbf{k} = \frac{\mathbf{q\mu L}}{\mathbf{A\Delta p}}$$

or

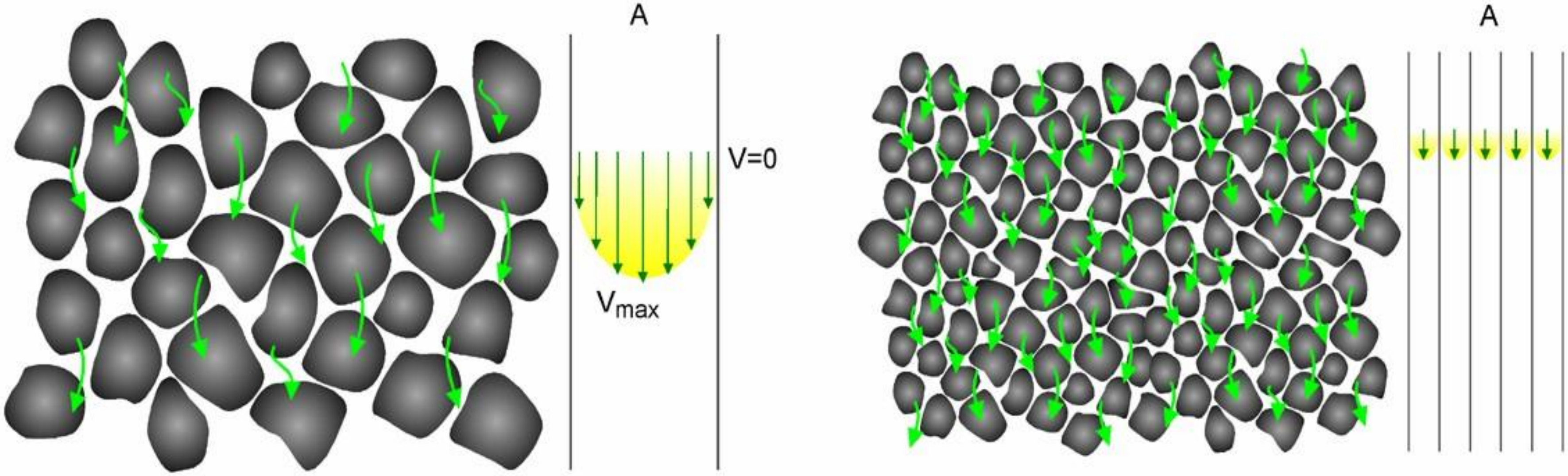
$$q = \frac{kA\Delta p}{\mu L}$$

- Permeability is the measure of capacity of rock to transmit fluid.
- Symbol : k
- Units : Darcy or milliDarcy (D or mD)
- Source : Well tests (eff.), core analysis (abs.)
- Range : 0.001 mD - 10,000 mD

Definition of a Darcy



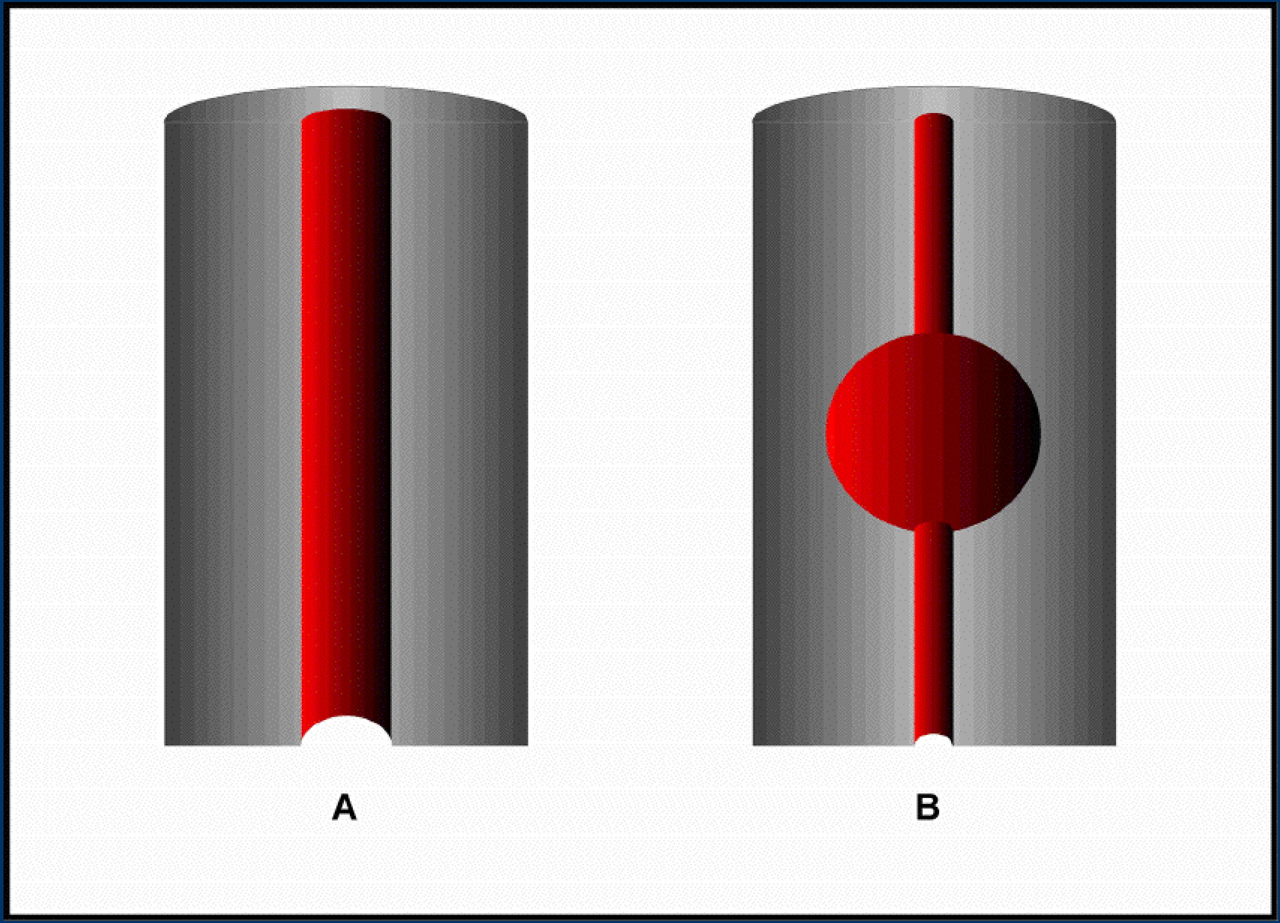
Effect of Grain Size on Permeability



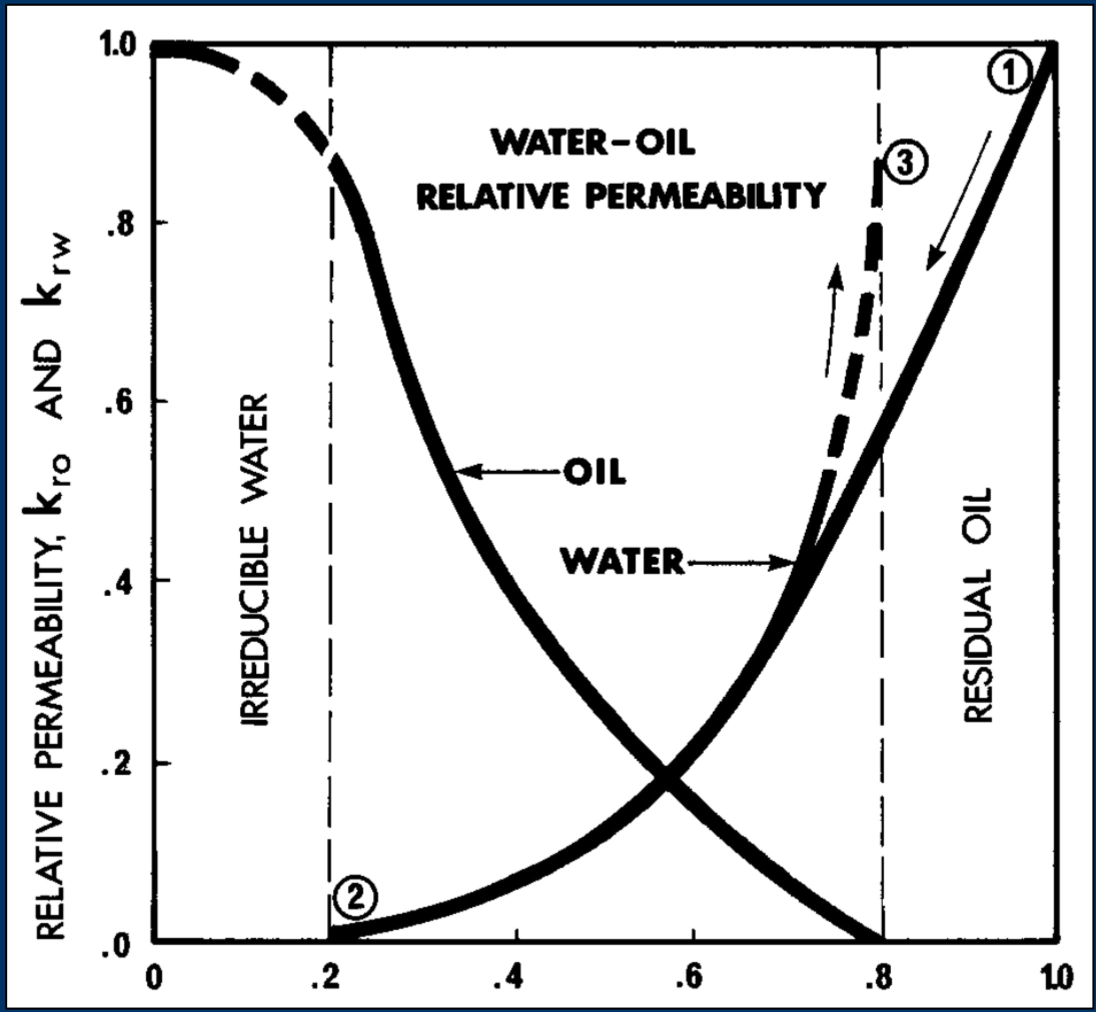
large grains - high permeability

small grains - low permeability

Same Effective Porosity – Different Permeabilities



Relative Permeability (K_{rw}, K_{ro})



Pore Compressibility (C_f)

$$c_f \equiv \frac{1}{\phi}\frac{\partial \phi}{\partial p} = \frac{\partial \ln(\phi)}{\partial p}$$

–4×10^{-6} psi^{-1}, well-consolidated sandstone

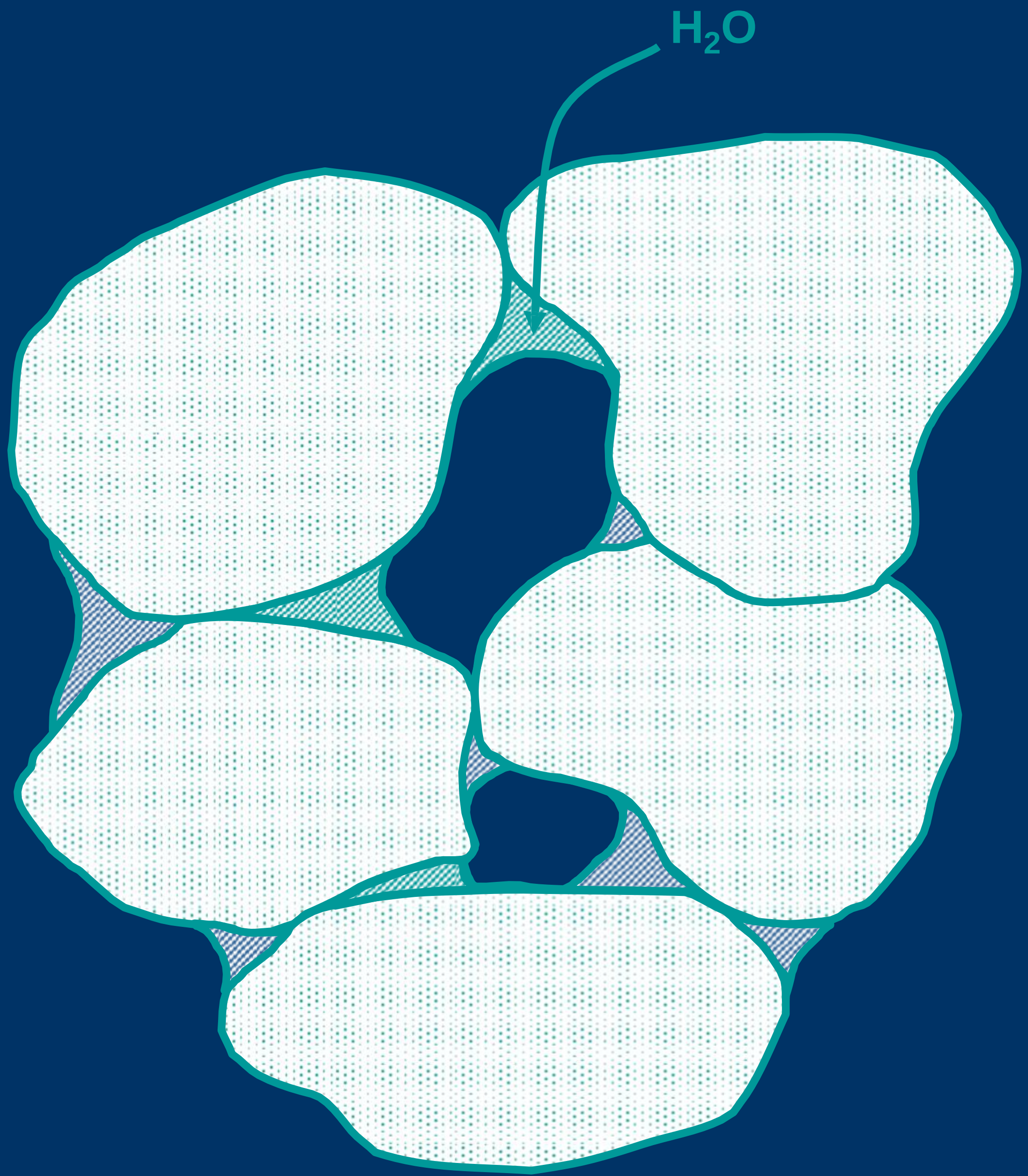
–30×10^{-6} psi^{-1}, unconsolidated sandstone

–4 to 50 x 10^{-6} psi^{-1} consolidated limestones

Net Pay Thickness

$$h_{net} = h_1 + h_2 + h_3$$

Saturations (S_w, S_o, S_g)



Archie's Equation

$$S_w^n = \frac{a}{\phi^m}\frac{R_w}{R_t}$$

(sandstone)

$$S_w^2 = \frac{0.62}{\phi^{2.15}}\frac{R_w}{R_t}$$

(limestone)

$$S_w^2 = \frac{1}{\phi^2}\frac{R_w}{R_t}$$

where:

- S_w: water saturation
- a: constant
- ϕ: porosity
- m: cementation factor
- R_w: formation water resistivity
- R_t: true resistivity (measured by deep resistivity measurement)

Types of Openhole Logs to Determine Saturation

- Resistivity log
  – Induction tools
  – Laterolog tools
- Porosity log
  – Neutron tools
  – Density tools
  – Sonic tools
  – Magnetic resonance tools

Exercise

- Calculate oil saturation in the following case

Rock type: sandstone

R_w: 0.0912 (at bottom hole temperature)

ϕ: 0.2

R_t: 20 ohm meter

Solution

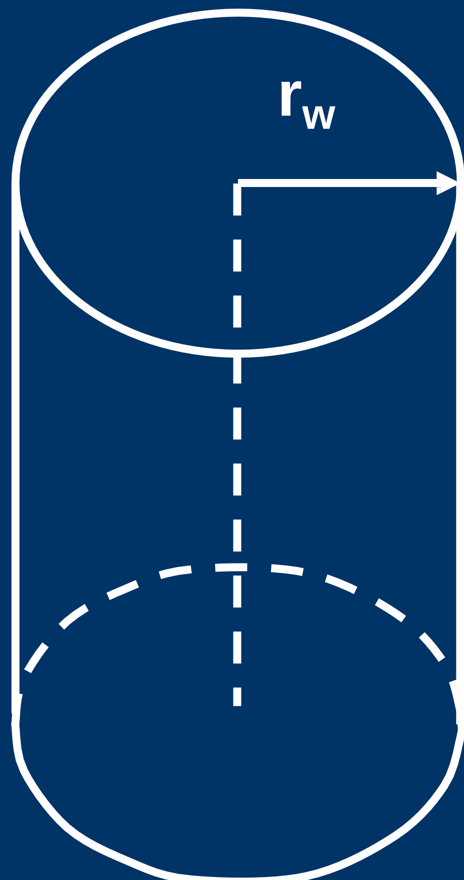
$$S_w^2 = \frac{0.62}{0.2^{2.15}} \frac{0.0912}{20}$$

$$S_w = \sqrt{\frac{0.62}{0.2^{2.15}} \frac{0.0912}{20}}$$

$$S_w = 0.3$$

$$\therefore S_o = 0.7$$

Wellbore Radius (r_w)



Bit Size

or

Caliper Reading

Total Compressibility (C_t)

$$c_t = c_f + S_o c_o + S_w c_w + S_g c_g$$

Typically,
C_w : 3E^{-6}
C_o : 3E^{-5}(Black oil)
C_g : 1/pressure
C_f : 4E^{-6}

Exercise

- Calculate total compressibility in the following case

- c_f : 3.6E-06
- c_o : 1.158E-05 S_o : 0.83
- c_w : 2.277E-06 S_w : 0.17
- c_g : 6.023E-05 S_g : 0

Exercise Solution

$$C_t = 1.36 \times 10^{-5}\ psi^{-1}$$

Exercise

- Calculate total compressibility in the following case

- c_f : 3.6E-06
- c_o : 1.158E-05 S_o : 0.73
- c_w : 2.277E-06 S_w : 0.17
- c_g : 6.023E-05 S_g : 0 .1

Compare solution with previous Example

Calculation of Hydrocarbon Volumes

Oil Initially In Place (OIIP or POES)

$$OIIP = Ah\phi(1 - S_w)$$

Where;

A: Area

h: Thickness

ϕ: Porosity

S_w: Water Saturation

Stock Tank Oil Initially In Place

$$STOIIP = \frac{Ah\phi\left(1 - S_W\right)}{B_O}$$

Where:

A: area

h: formation thickness

ϕ: porosity

S_w: water saturation

B_o: formation volume factor

What are Reserves?

- Oil and gas trapped beneath the earth's surface that can be recovered under existing economic conditions and with current technology.

Recovery Factor

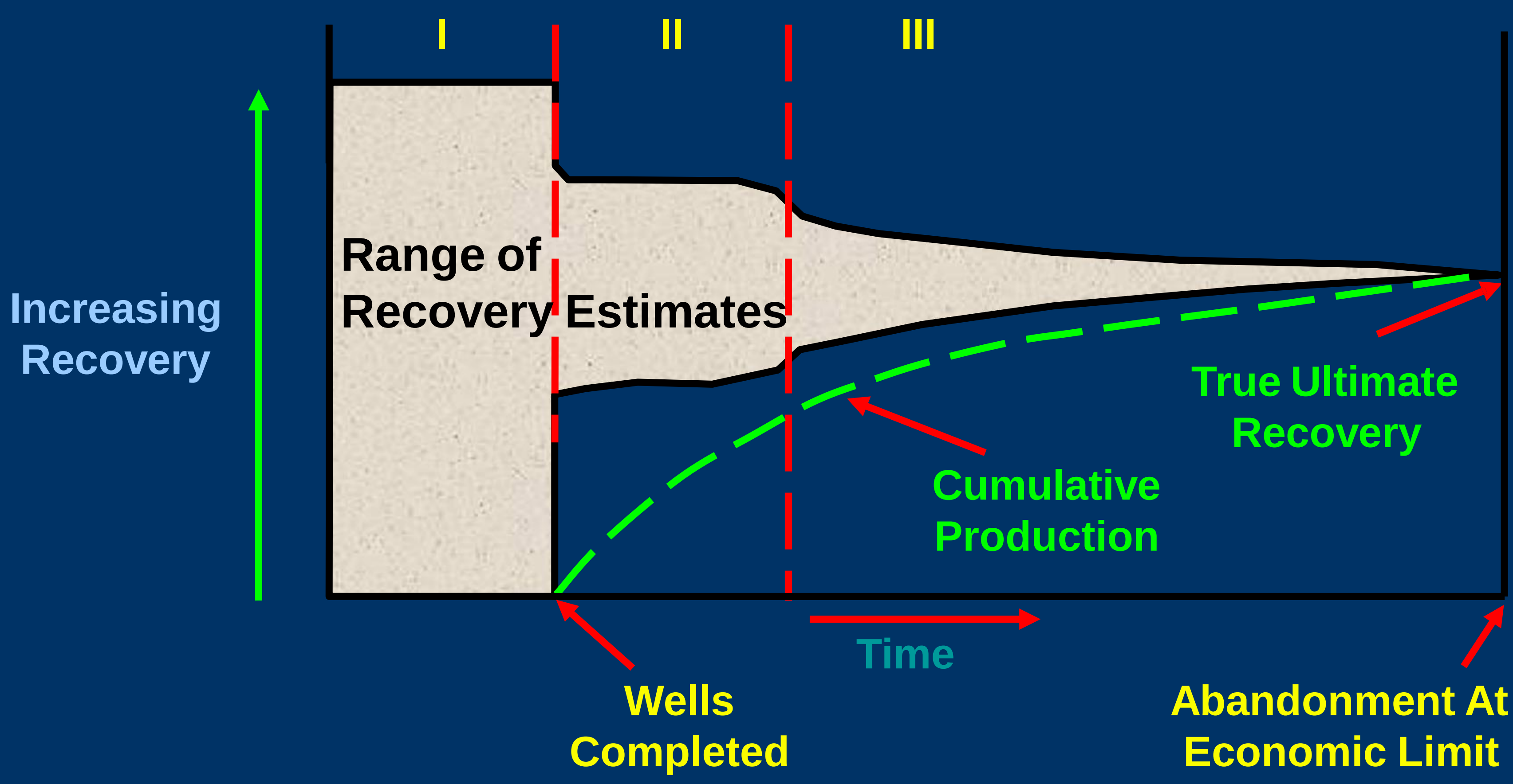
- Affected by:
  - Reservoir Rock
  - Fluid Properties
  - Reservoir Continuity, Heterogeneity
  - Economic Conditions

$$RF = \left.\frac{N_p}{N}\right]_{t,p}$$

where:

N: stock tank oil originally in place
Np: cumulative stock tank oil prod

Reserves Uncertainty



Exercise

- What is the STOIIP in the following case (in bbls)?

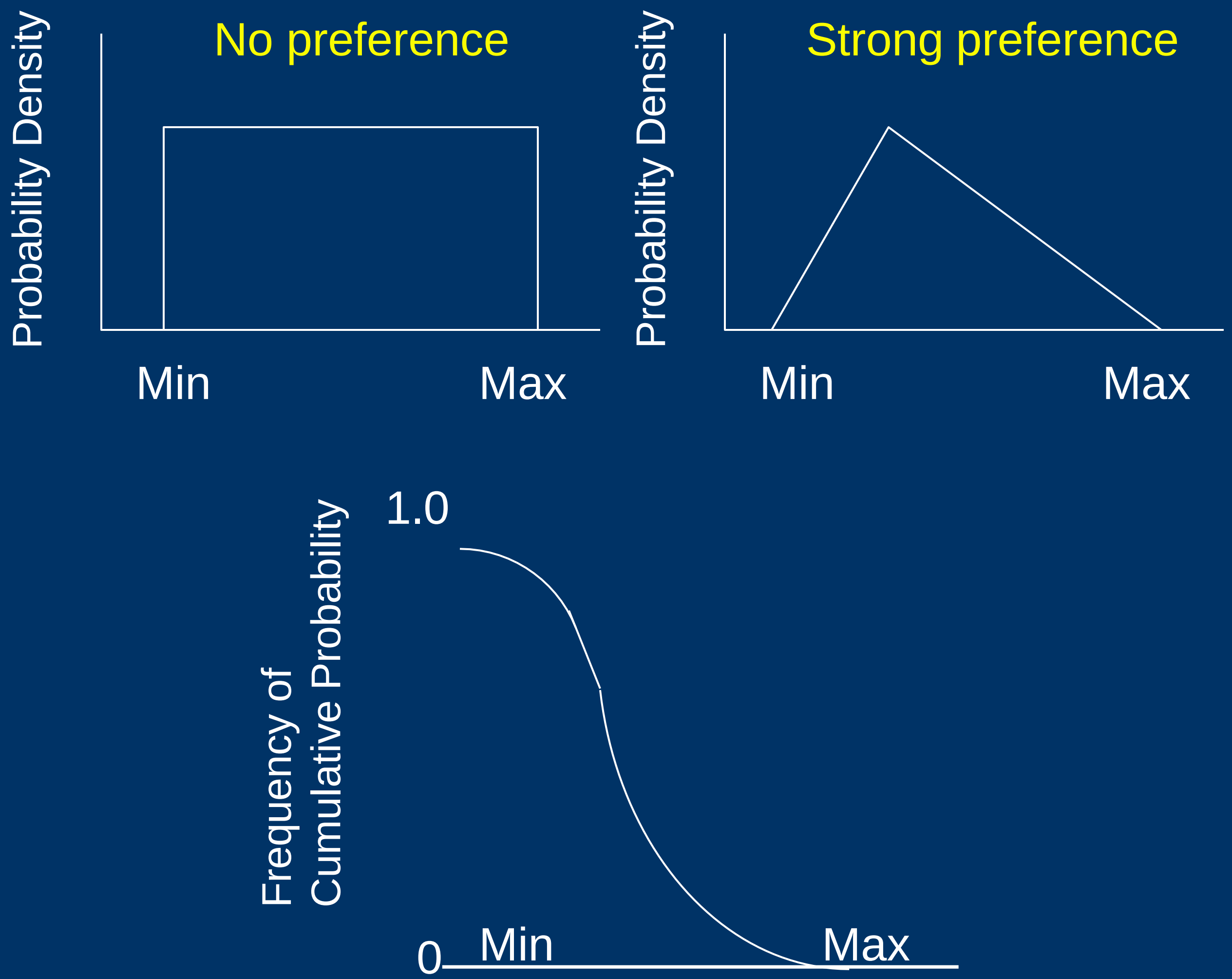
  A: 300m x 500m h: 200m ϕ: 20%

  S_w: 25% B_o: 1.35

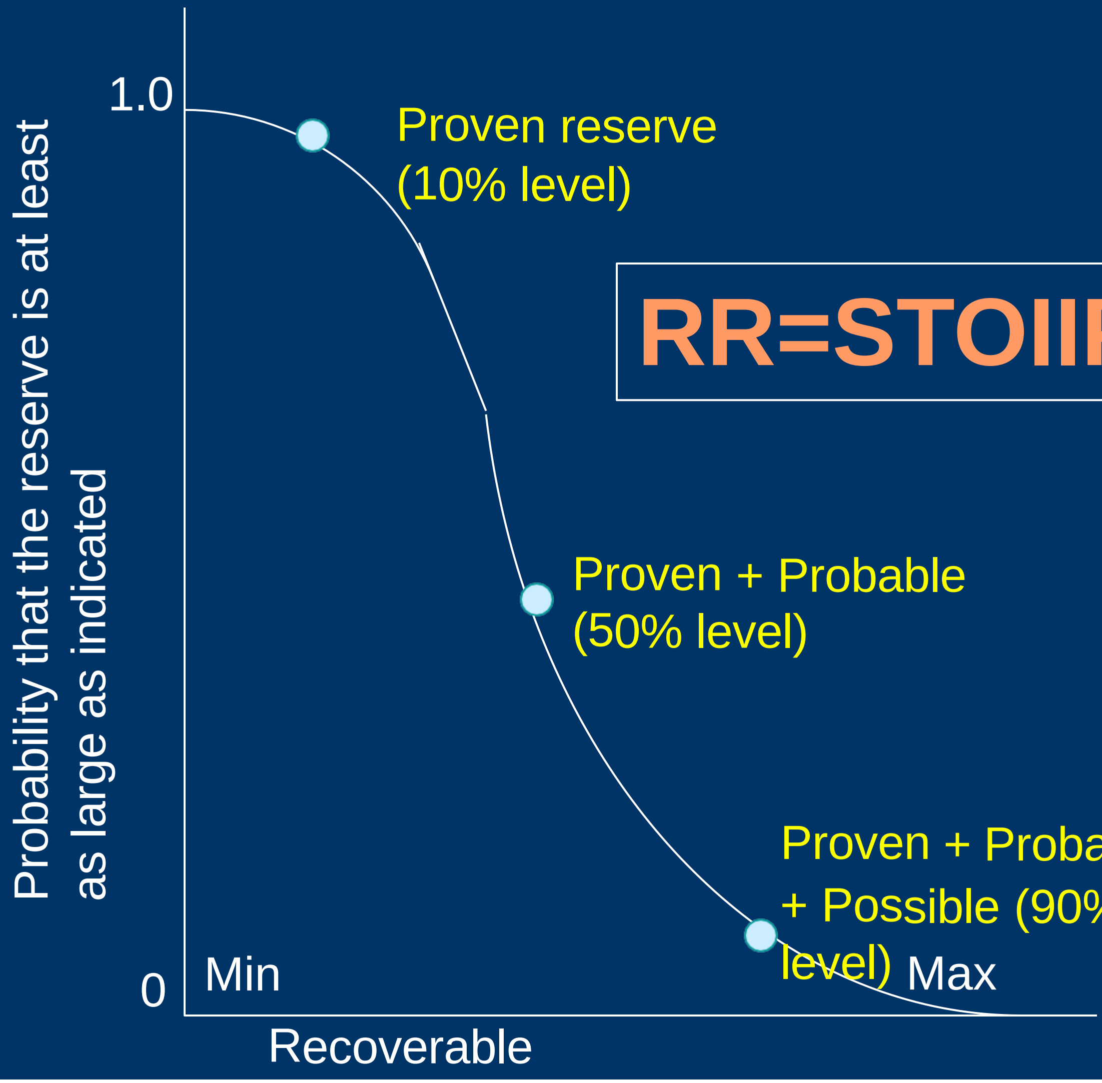
  $1m^3 = 6.289$bbls

- If ultimate RF of this reservoir is 30% and oil price is $20/bbl, how much is the total revenue? Assume there is no market for the gas in this case.

Probabilistic Estimation
Monte Carlo Approach



Recoverable Reserve
Probabilistic Representation



RR=STOIIP x RF

Reservoir Drive Mechanism

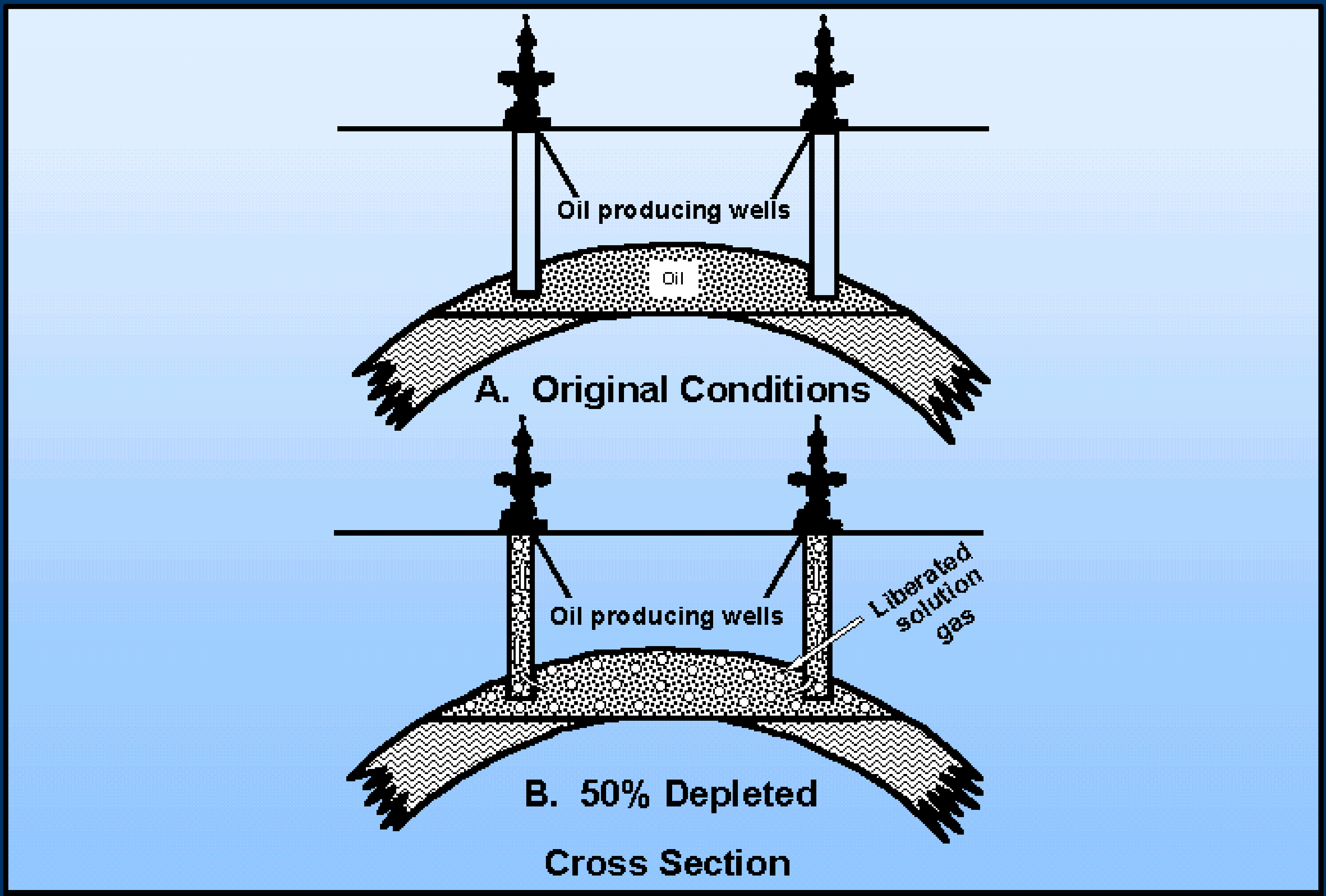
Oil Reservoir Drive Mechanisms

- Solution-gas drive
- Gas-cap drive
- Water drive
- Combination drive
- Gravity-drainage drive

Reservoir Energy Sources

- Liberation, expansion of solution gas
- Influx of aquifer water
- Expansion of reservoir rock and compression of pore volume
- Expansion of original reservoir fluids
  - Free gas
  - Interstitial water
  - Oil, if present
- Gravitational forces

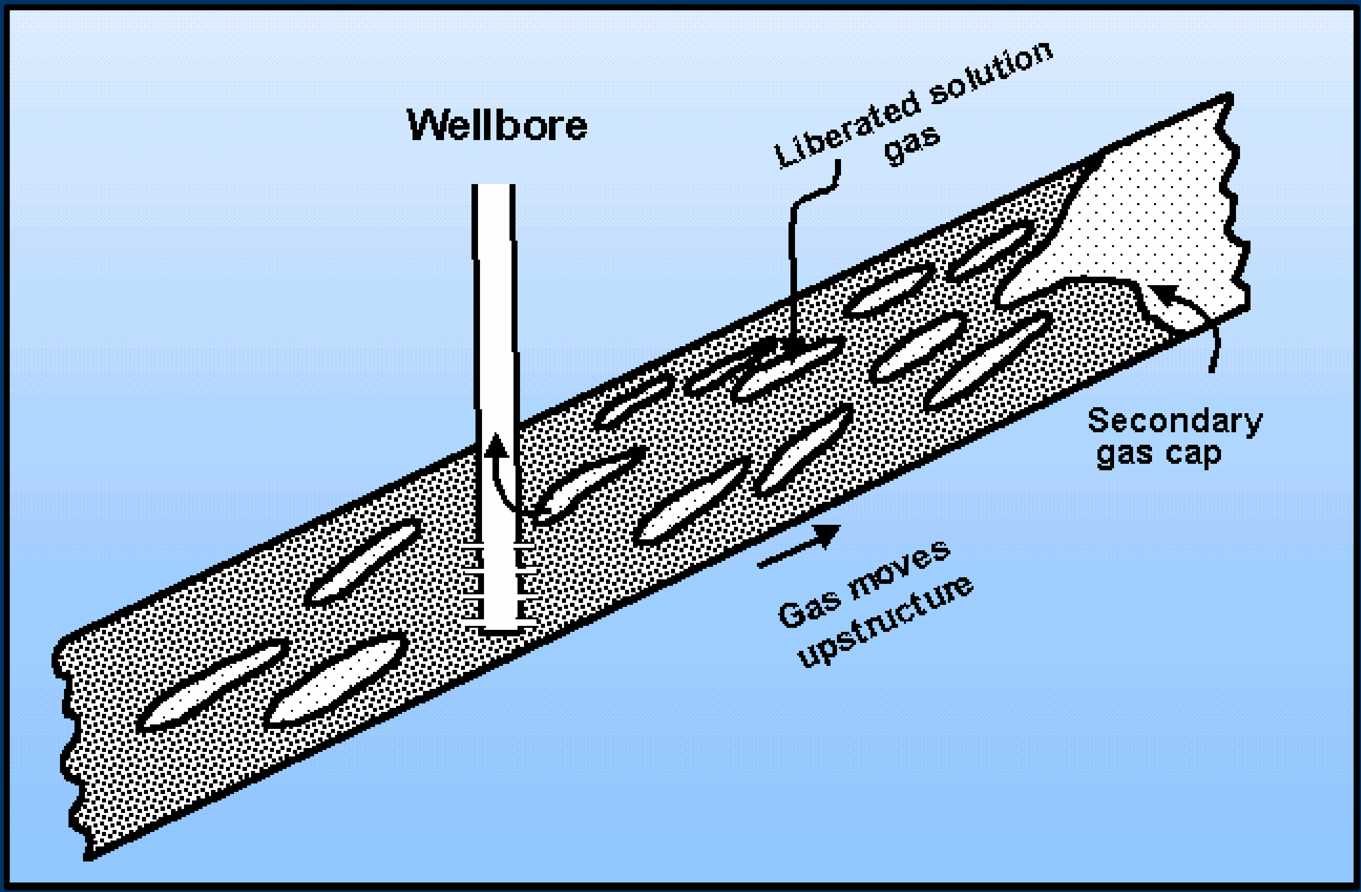
Solution Gas Drive in Oil Reservoirs



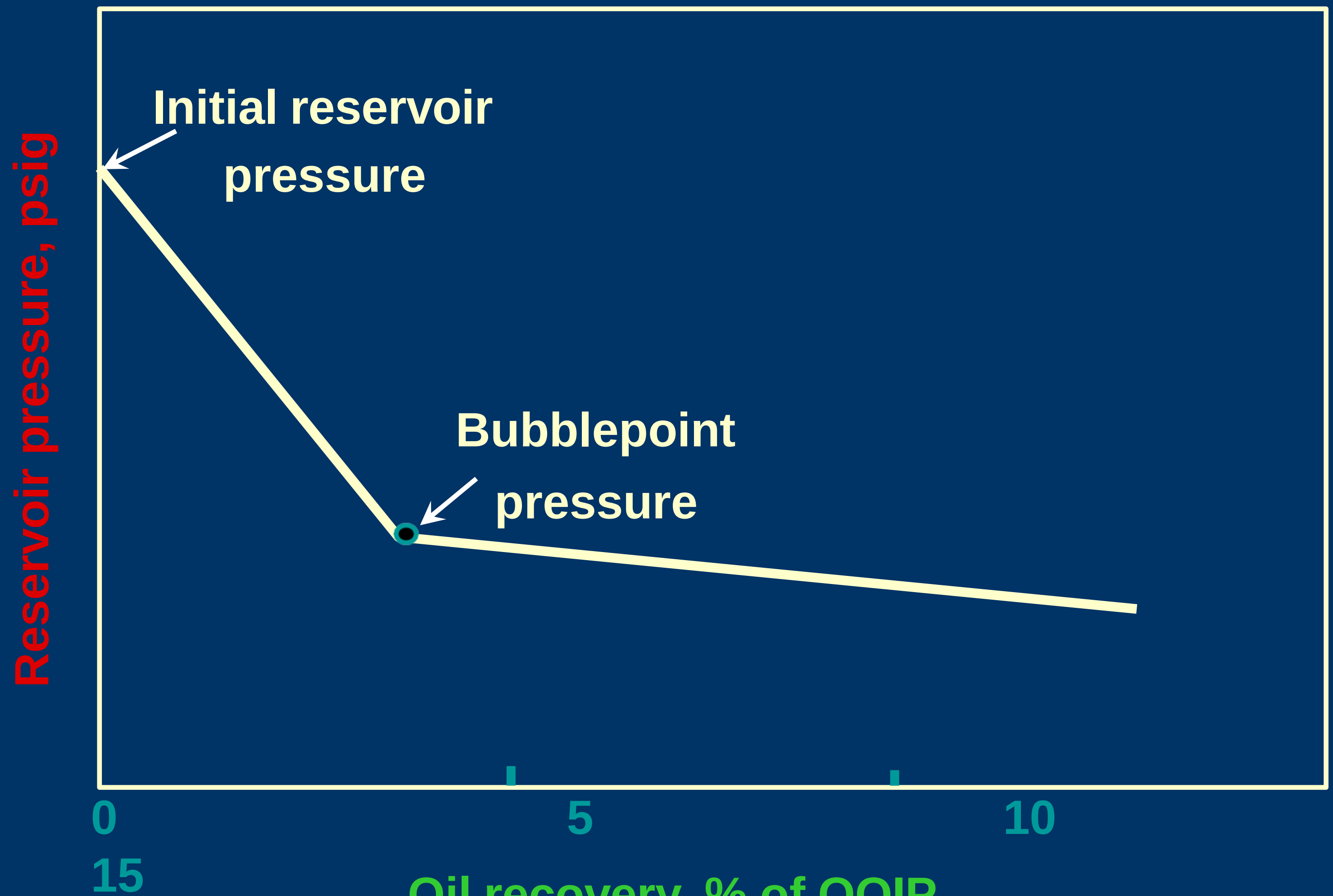
Solution Gas Drive in Oil Reservoirs

- No original gas cap or aquifer
- Main source(s) of reservoir energy
  - liberation and expansion of dissolved gas
- Possible secondary gas cap
  - liberated free gas can migrate up-structure
- Typical production characteristics
  - Rapid GOR increase after P_b

Solution Gas Drive in Oil Reservoirs
Formation of Secondary Gas Cap

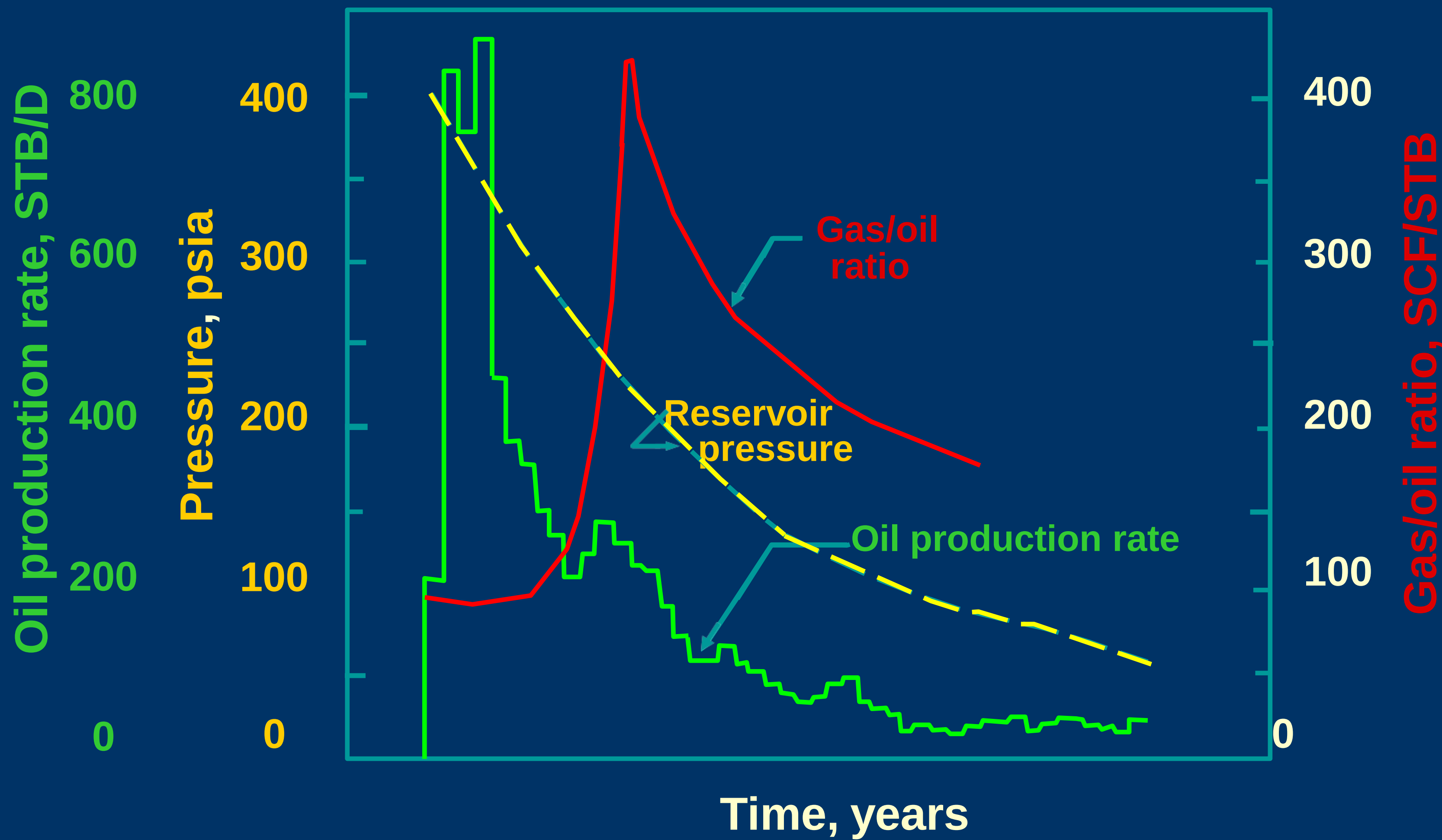


Solution Gas Drive in Oil Reservoirs
Typical Production Characteristics



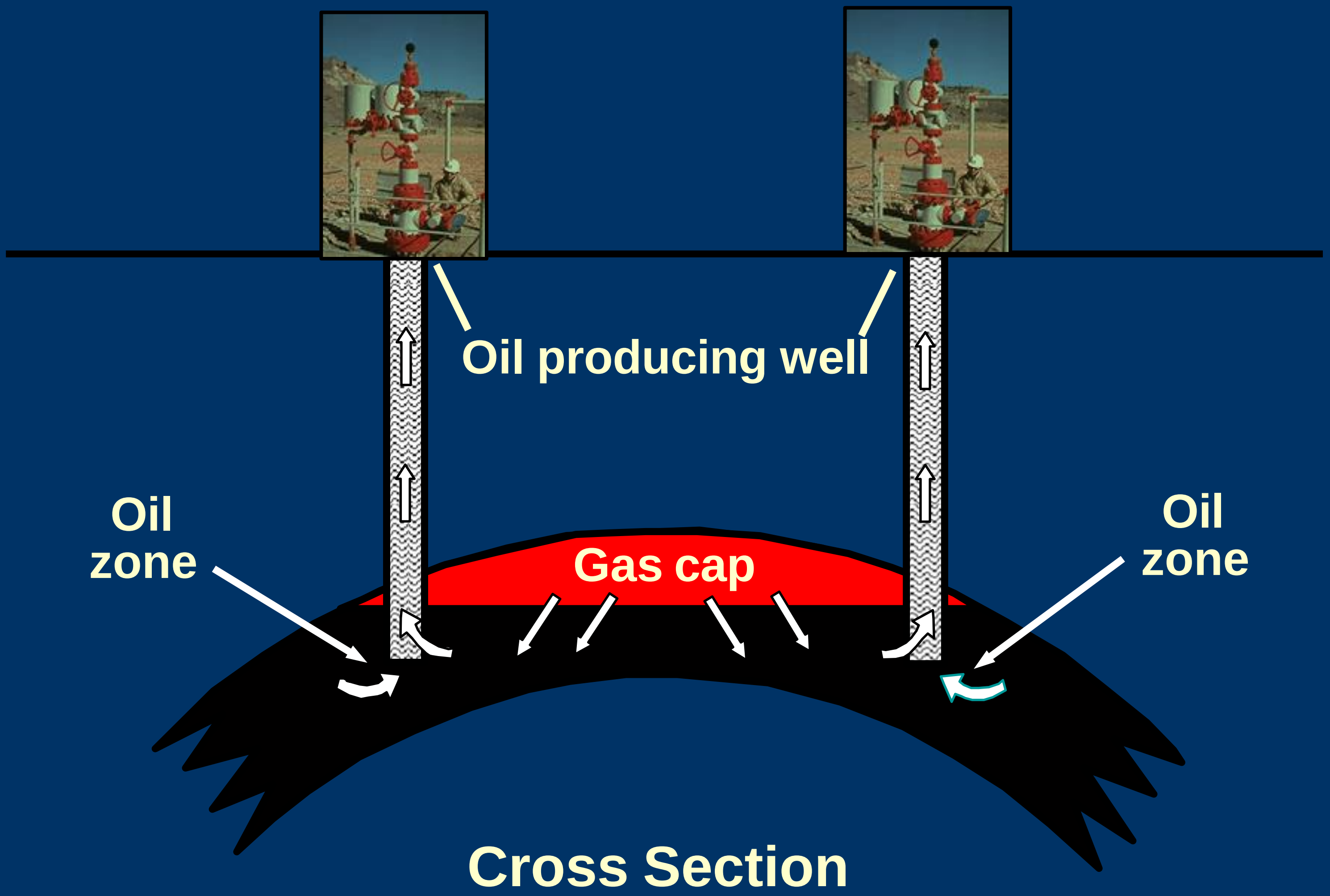
Reservoir pressure behavior

Solution Gas Drive in Oil Reservoirs
Typical Production Characteristics



Production data

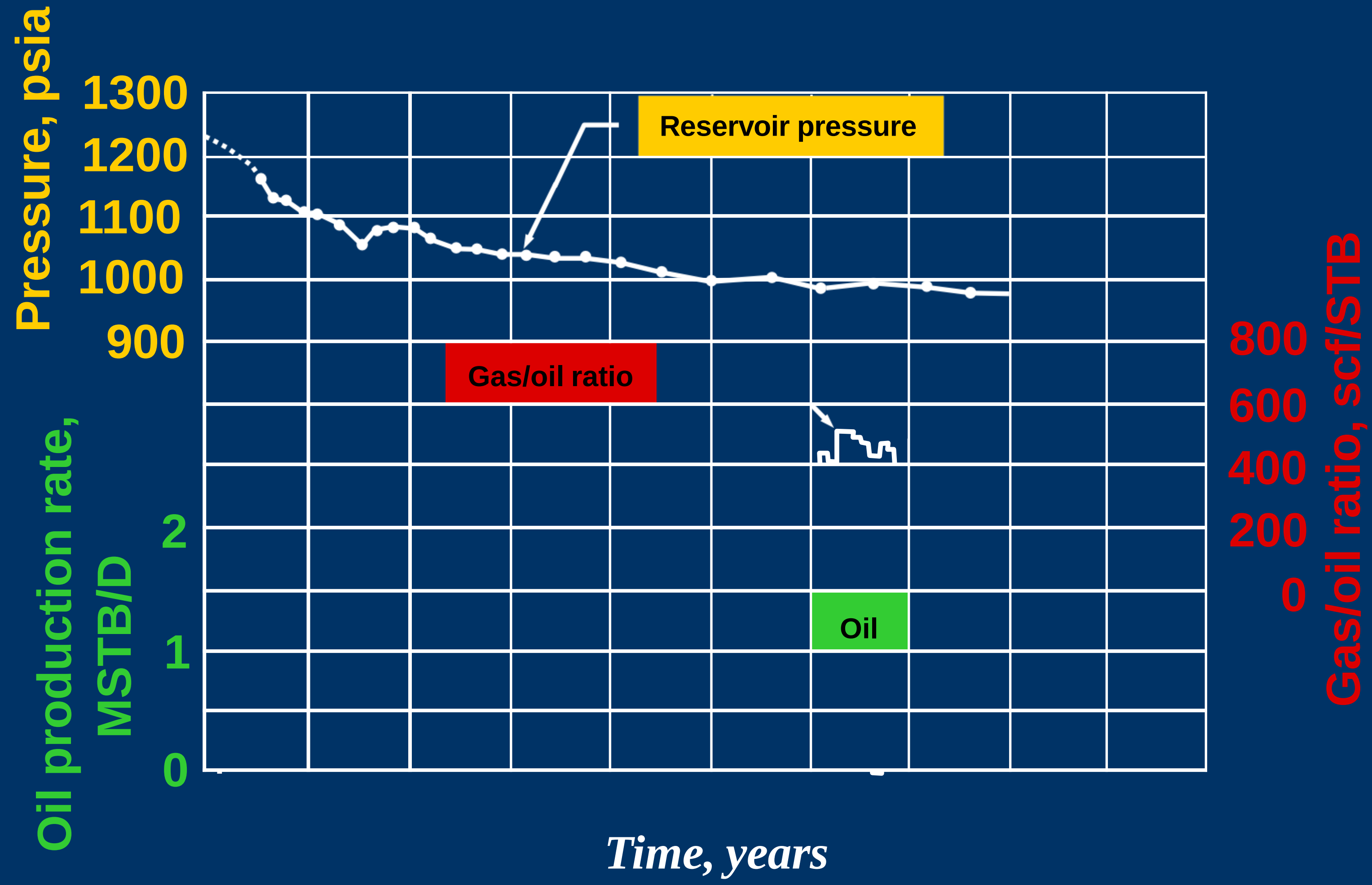
Gas Cap Drive



Gas Cap Drive

- Free gas phase exists as an original gas cap
- Pure gas-cap drive reservoir has no aquifer
- Main source(s) of reservoir energy
  - Expansion of gas cap and liberation and expansion of solution gas in the oil zone
- Gas cap expands pushing GOC down and maintaining higher pressure
- Good sweep
- Typical production characteristics
  - dramatic GOR increase when gas breakthrough

Gas Cap Drive
Typical Production Characteristics

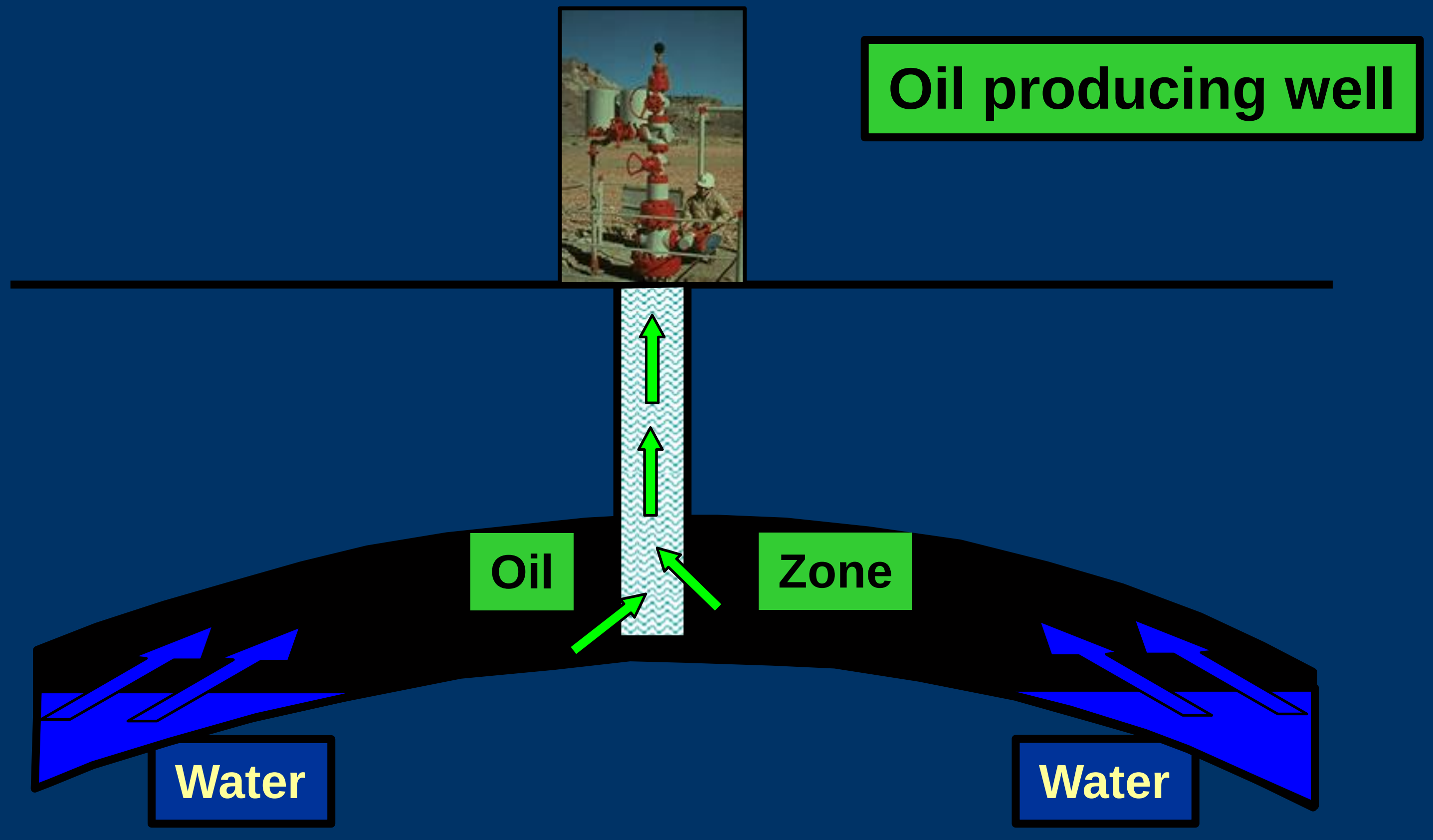


Production data

Water Drive in Oil Reservoirs

- Oil zone in communication with acquifer
- Main source(s) of reservoir energy
  - influx of acquifer water - edge-water drive, bottom-water drive
- Pressure decline relatively slow
- GOR kept relatively low and stable
- Water production increases steadily
- Oil production declines when water breakthrough
- Reasonable sweep - depends on mobility ratio

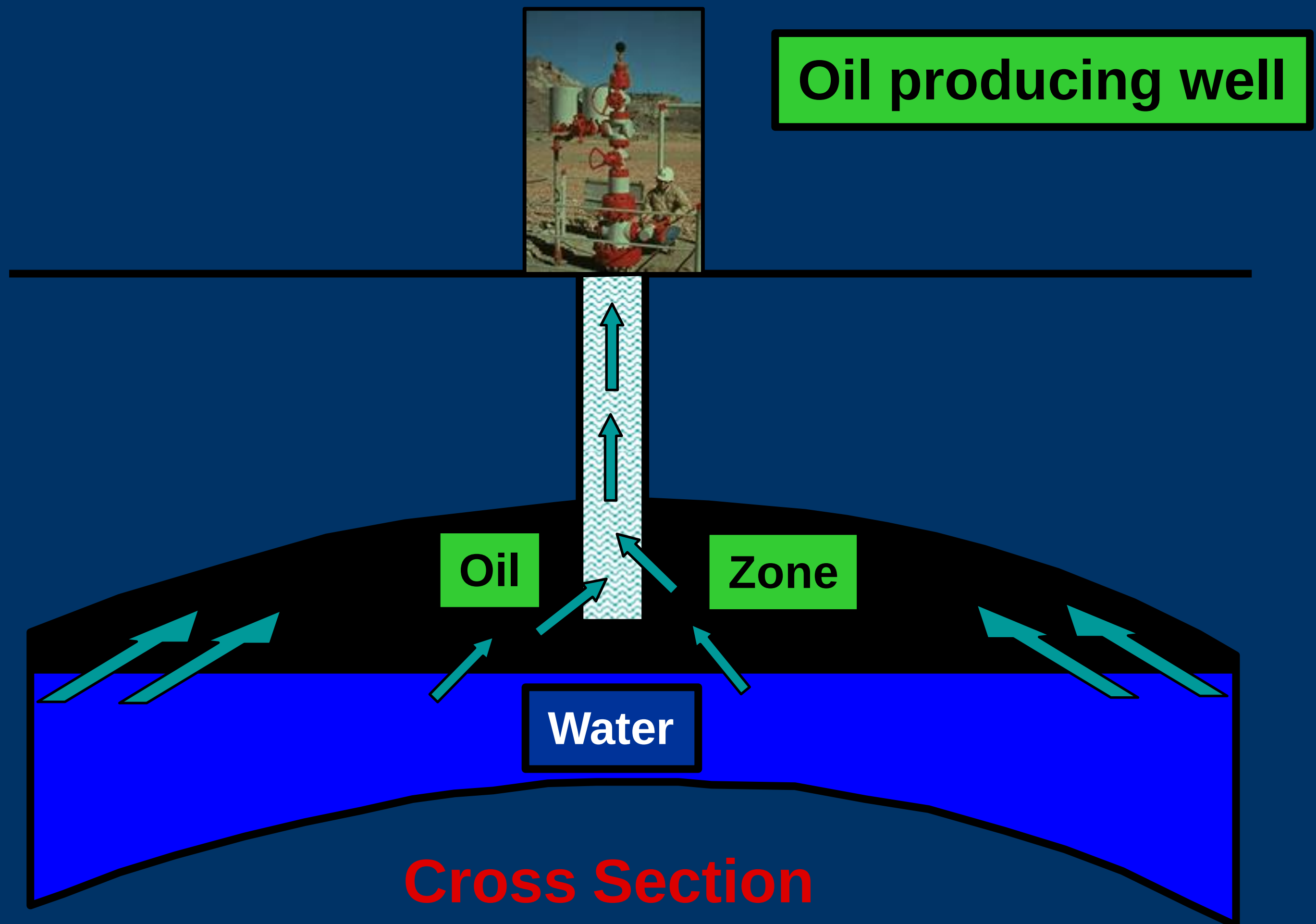
Water Drive in Oil Reservoirs
Edge-Water Drive



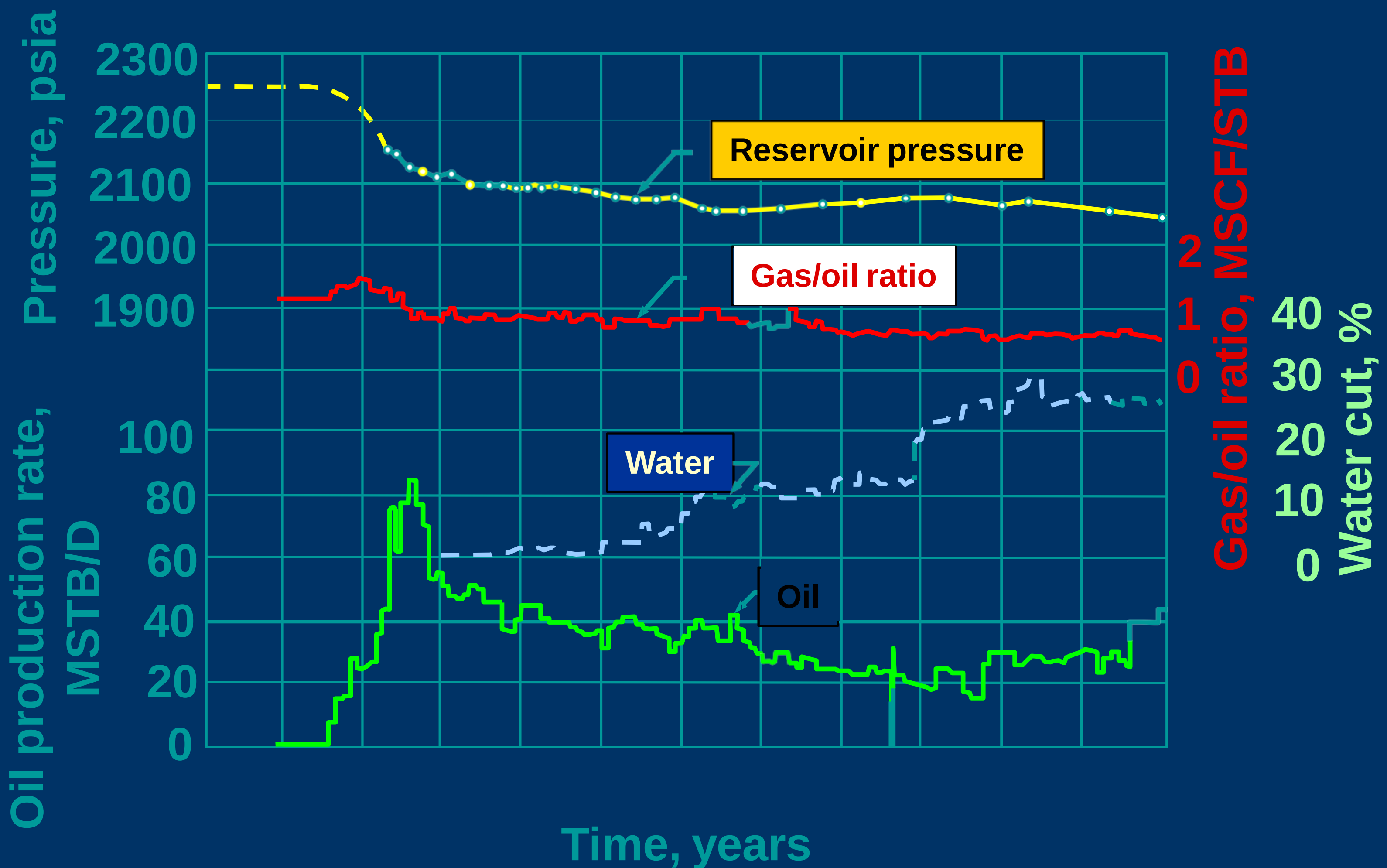
Cross Section

Water Drive in Oil Reservoirs

Bottom-Water Drive

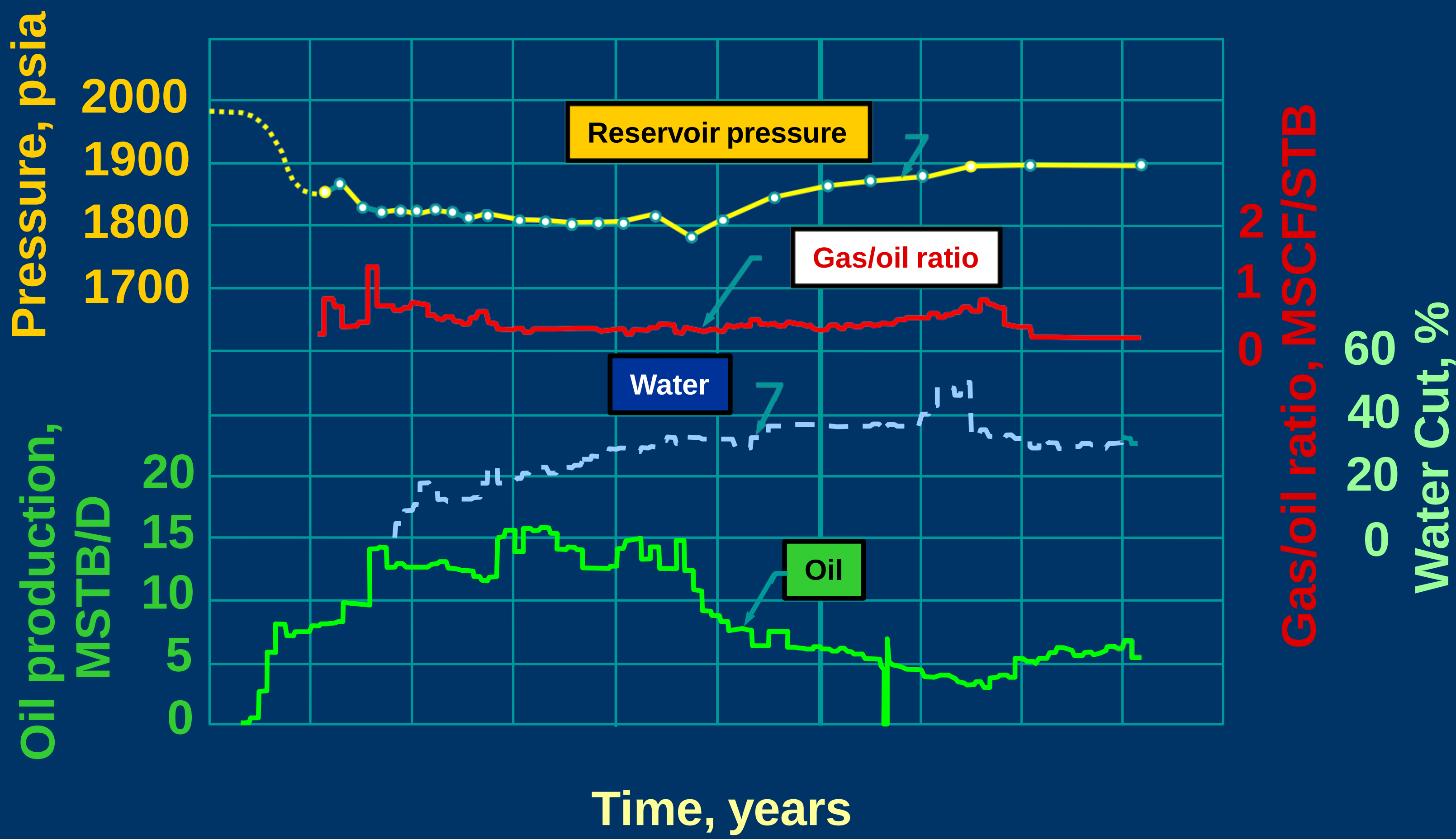


Water Drive in Oil Reservoirs
Typical Production Characteristics



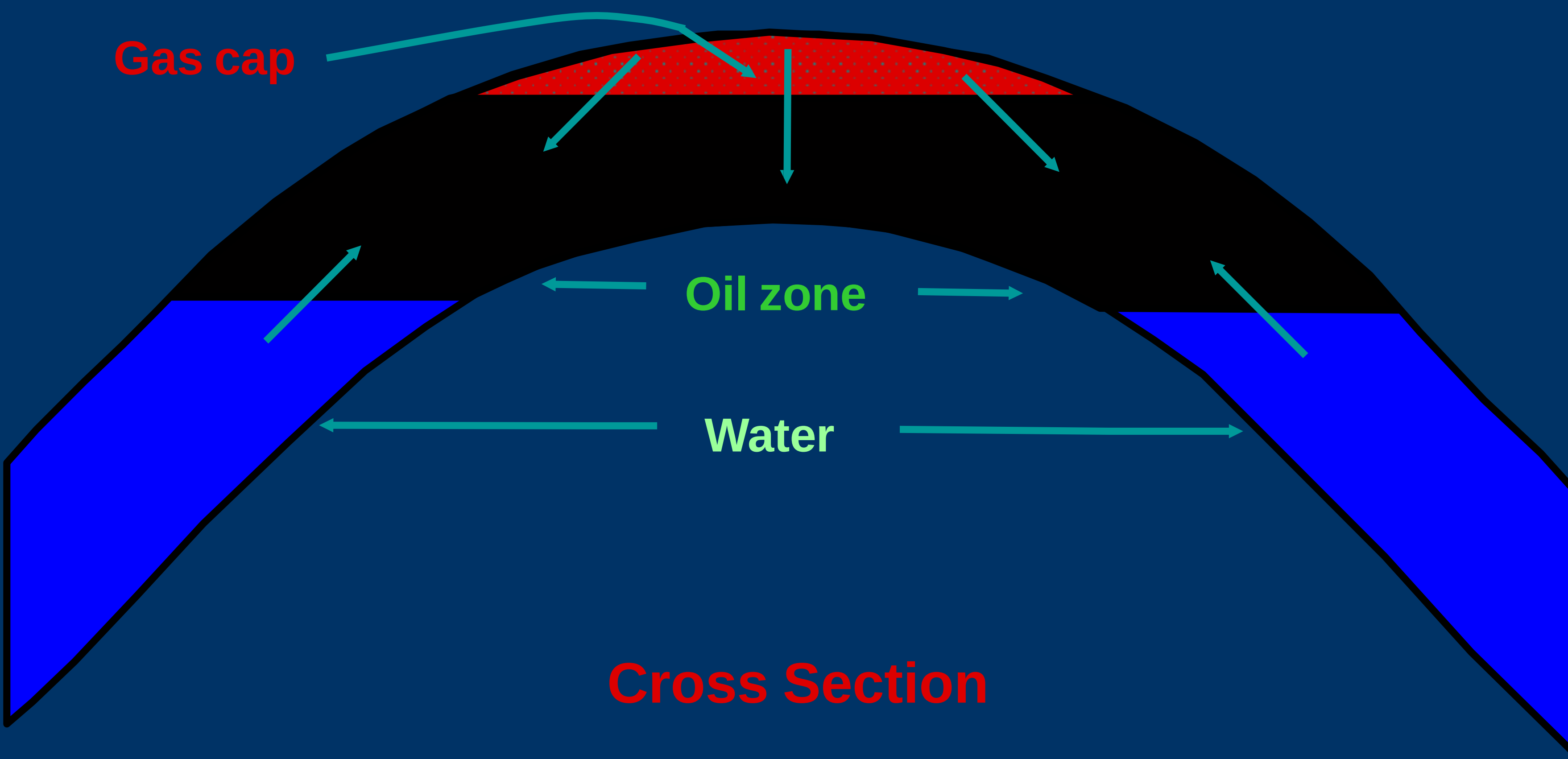
Production data

Water Drive in Oil Reservoirs
Effect of Production Rate on Pressure



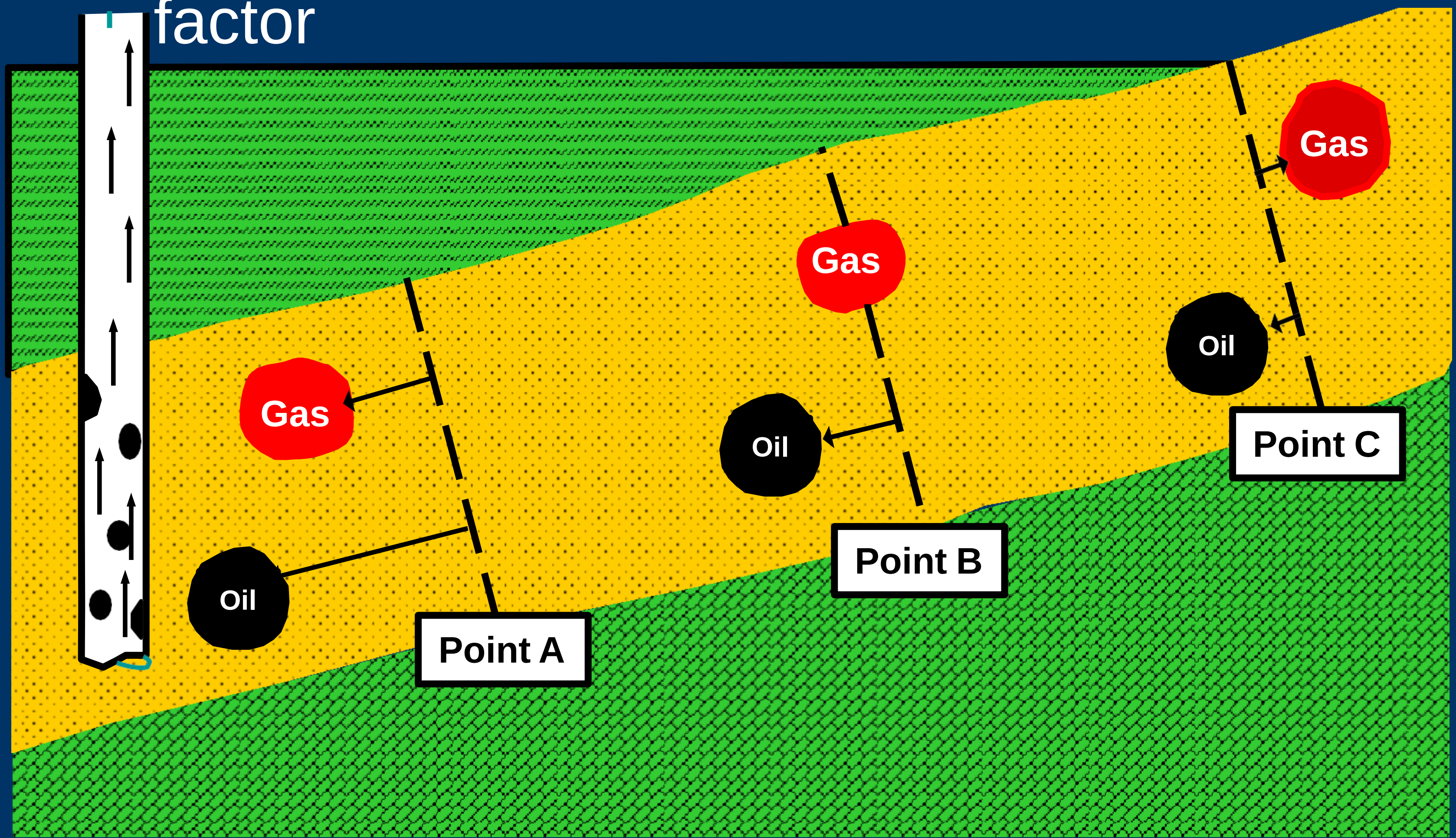
Production data - lower oil production rate

Combination Drive in Oil Reservoirs

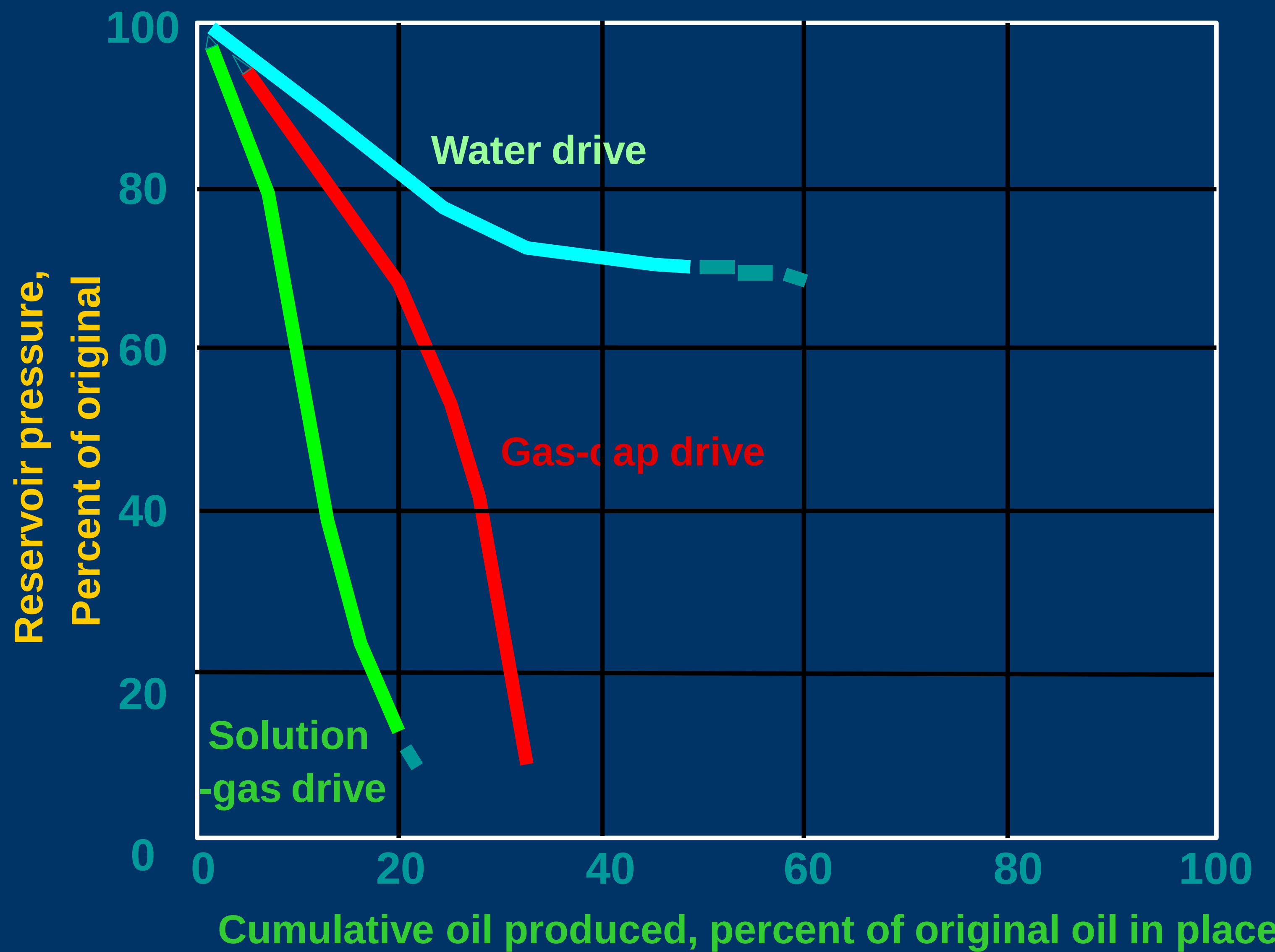


Gravity Drainage in Oil Reservoirs

- Main energy - gravitational force
- Good drainage efficiency and recovery factor

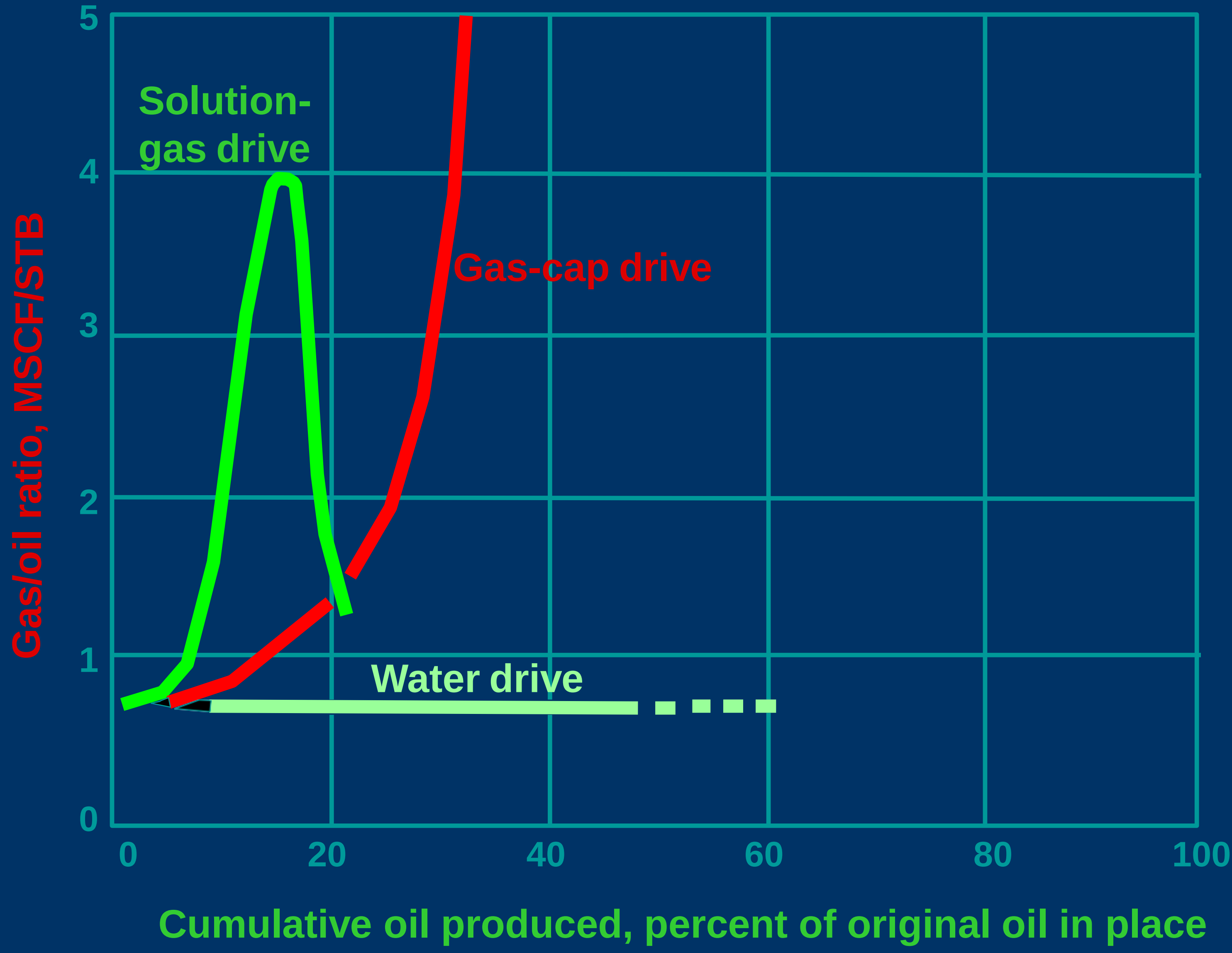


Pressure Trend



Reservoir pressure trends

GOR Trend



Gas/oil ratio trends

Gas Reservoir Drive Mechanisms

- Volumetric reservoir (gas expansion drive)
- Water drive

Volumetric Gas Reservoirs

- Gas reservoir with no acquifer
- Main source(s) of reservoir energy
  - expansion of gas
- Pressure decline slowly and continuously
- No water production
- Flowing life can be increased by reducing surface back-pressure through installing compression

Water Drive in Gas Reservoirs

- Gas reservoir with acquifer
- Main source(s) of reservoir energy
  - expansion of gas and water influx
- Pressure decline slower than volumetric gas reservoir
- Water production may start early and increases with time
- Flowing life can be increased by installing continuous or intermittent water removal equipment

Oil Reservoir Drive Mechanisms (summary)

- Solution-gas drive
- Gas-cap drive
- Water drive
- Combination drive
- Gravity-drainage drive

Gas Reservoir Drive Mechanisms (summary)

- Volumetric reservoir (gas expansion drive)
- Water drive

Exercise

- What is the drive mechanism of your reservoir?
- What are the characteristics of pressure, GOR, water production evolution?

Average Recovery Factors
Oil Reservoirs

Drive Mechanism	Average Oil Recovery Factors, % of OOIP	
	Range	Average
Solution-gas drive	5 - 30	15
Gas-cap drive	15 - 50	30
Water drive	30 - 60	40
Gravity-drainage drive	16 - 85	50

Average Recovery Factors
Gas Reservoirs

Drive Mechanism	Average Gas Recovery Factors, % of OGIP	
	Range	Average
Volumetric reservoir (Gas expansion drive)	70 - 90	80
Water drive	35 - 65	50

Properties Favorable for Oil Recovery

- Solution-gas drive oil reservoirs
  - Low oil density
  - Low oil viscosity
  - High oil bubblepoint pressure
- Gas-cap drive oil reservoirs
  - Favorable oil properties
  - Relatively large ratio of gas cap to oil zone
  - High reservoir dip angle
  - Thick oil column

Properties Favorable for Oil Recovery

- Water drive oil reservoirs
  - Large aquifer
  - Low oil viscosity
  - High relative oil permeability
  - Little reservoir heterogeneity and stratification
- Gravity drainage oil reservoirs
  - High reservoir dip angle
  - Favorable permeability distribution
  - Large fluid density difference
  - Large segregation area
  - Low withdrawal

Properties Favorable for Gas Recovery

- Volumetric gas reservoir (gas expansion drive)
  - Low abandonment pressure
- Water-drive gas reservoir
  - Large aquifer
  - Small degree of reservoir heterogeneity and stratification

Estimation of Oil Recovery Factors

- Solution-gas drive - API study
- E_R: in %

$$E_R = 41.8\left[\left(\frac{\phi(1-S_{wi})}{B_{ob}}\right)^{0.1611}\left(\frac{k}{\mu_{ob}}\right)^{0.0979}(S_{wi})^{0.3722}\left(\frac{p_b}{p_a}\right)^{0.1741}\right]$$

Estimation of Oil Recovery Factors

- Water drive - API study

$$E_R = 54.9 \left[\left(\frac{\phi (1 - S_{wi})}{B_{oi}} \right)^{0.0422} \left(\frac{k \mu_w}{\mu_{oi}} \right)^{0.0770} (S_{wi})^{-0.1903} \left(\frac{p_i}{p_a} \right)^{-0.2159} \right]$$

Estimation of Oil Recovery Factors

- Water drive : Guthrie-Greenberger study

$$E_R = 0.272 \log k + 0.256\, S_{wi} - 0.136 \log \mu_o - 1.538\, \phi - 0.0003\, h + 0.114$$

Exercise

- Estimate recovery factor of your field
- Comments/observations?

Summary

- Typical production characteristics
- Average recovery factors
- Favorable reservoir properties
- Estimating oil recovery factors

Other Important Concepts

Productivity Index (PI or IP)

$$PI = \frac{q}{\overline{p} - p_{wf}}$$

Productivity Index (PI or IP)

$$PI = \frac{q}{\overline{p} - p_{wf}}$$

$$\Rightarrow \frac{k \times h}{141.2 \times \mu \times B_0 \times \left[\ln\left({r_e}/{r_w} \right) - \frac{3}{4} + S \right]}$$

Productivity Index (PI or IP)

Changes (decrease) with time:

•Decrease in the permeability to oil due to presence of free gas near the wellbore

•Increase of oil viscosity with $P_r < P_b$

•Reduction in perm. Due to formation compressibility.

Flow Efficiency

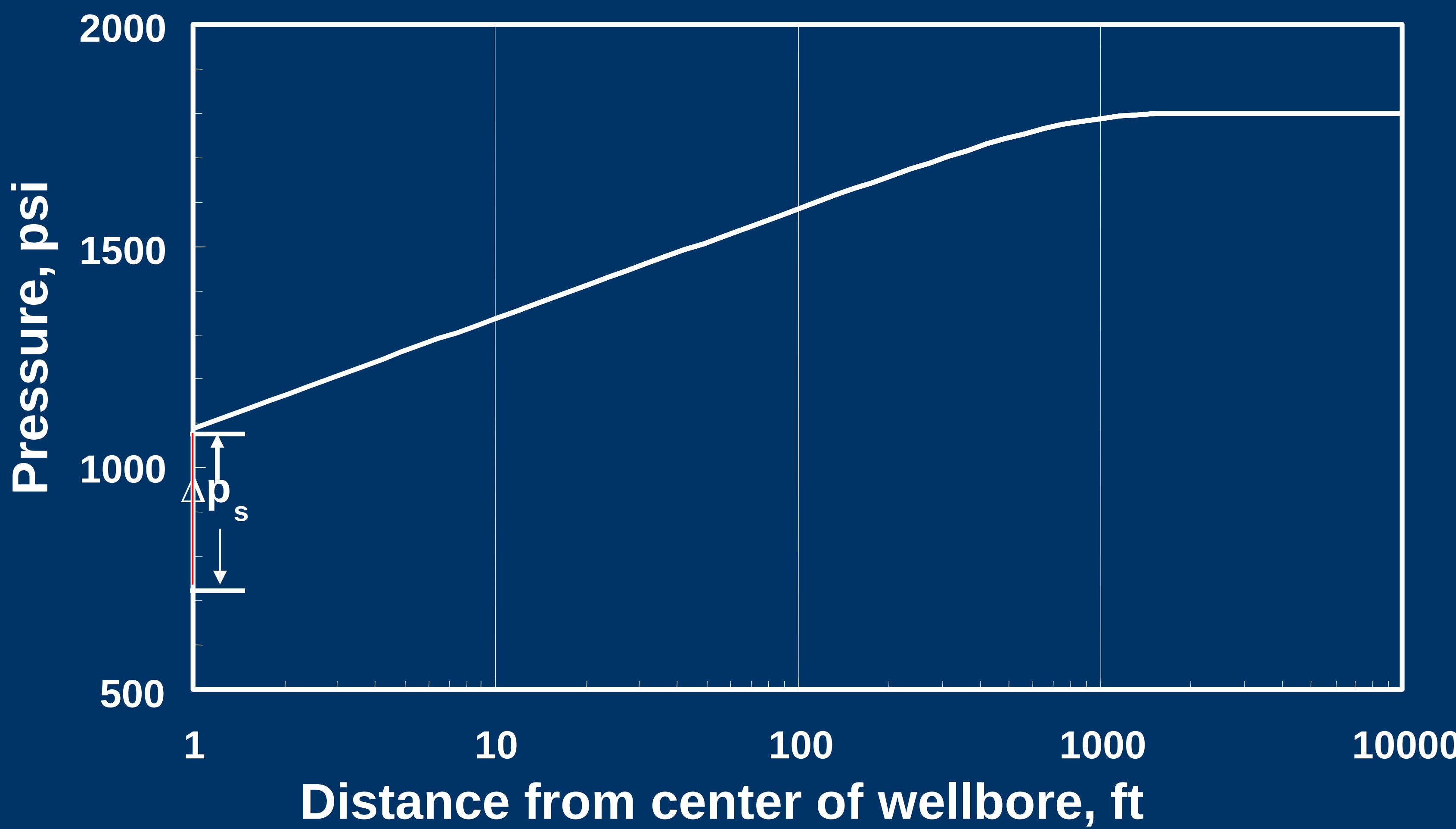
$$E_f = \frac{PI_{actual}}{PI_{ideal}} = \frac{\bar{p} - p_{wf} - \Delta p_s}{\bar{p} - p_{wf}}$$

Rule of Thumb

$$\Pr odRatio = \frac{8}{8 + Skin}$$

Skin Concept:

Introduced in 1953 by Van Everdingen and Hurst for differences in observed and calculated bottomhole pressure



Skin Concept:

Introduced in 1953 by Van Everdingen and Hurst for differences in observed and calculated bottomhole pressure

Steady State with flow at Re

(as per "Darcy")

$$P_e - P_{wf} = 141.2 \times \frac{q \mu B_0}{Kh} \times \ln\left(\frac{r_e}{r_w}\right)$$

Skin Concept:

Introduced in 1953 by Van Everdingen and Hurst for differences in observed and calculated bottomhole pressure

Steady State with flow at Re ("Real Life")

$$P_e - P_{sf} - \Delta P_s = 141.2 \times \frac{q\mu B_0}{Kh} \times \ln\left(\frac{r_e}{r_w}\right) - 141.2 \times \frac{q\mu B_0}{Kh} \times S$$

Skin Concept:

Introduced in 1953 by Van Everdingen and Hurst for differences in observed and calculated bottomhole pressure

$$\Delta p_s = \frac{141.2 qB\mu}{kh} s$$

S = Skin Factor as per Van Everdingen and Hurst

S = Adimentional number. Not related to any physical phenomena

Extra pressure drop “at the wellbore”

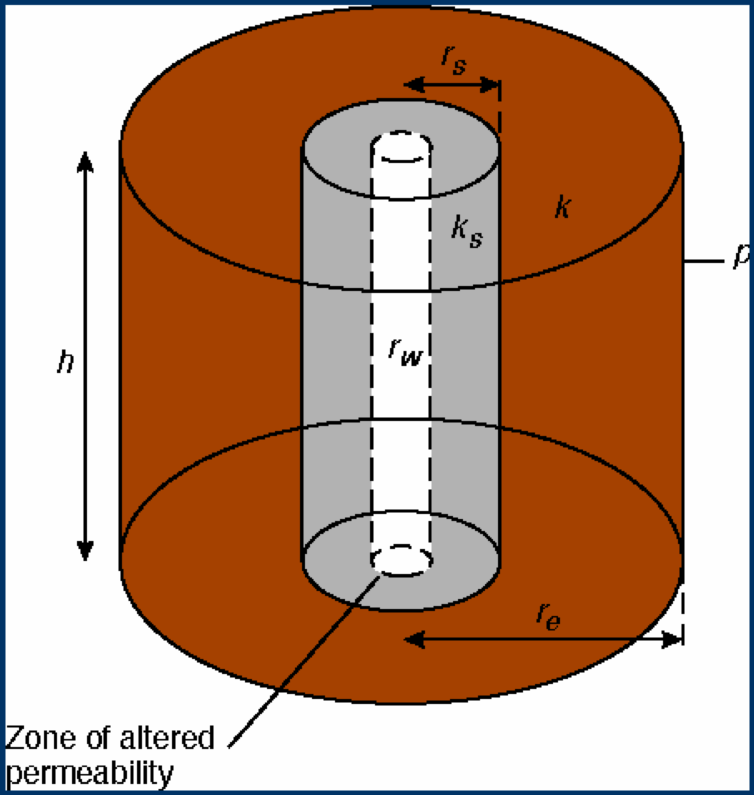
Zero thickness ==> Skin

Skin Concept:

In 1956 Hawkins introduces the concept of "Thick Skin"

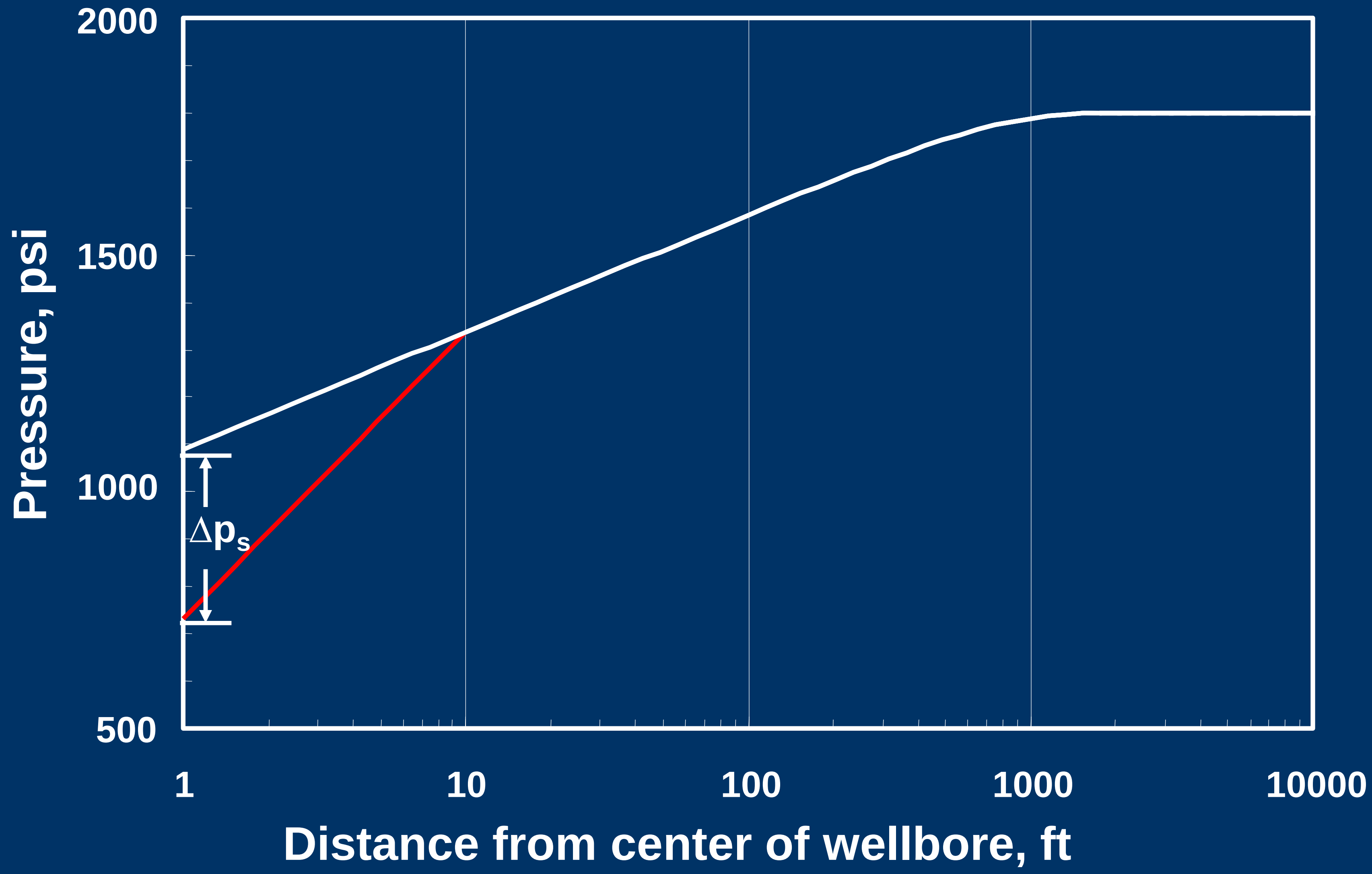
- Zone of altered permeability around the Wellbore (ra / Ka)

-Extra Pressure drops occurs not in the "Skin"of the wellbore but in a "Thick Zone".



Skin Concept:

In 1956 Hawkins introduces the concept of "Thick Skin"



Skin Concept:

In 1956 Hawkins introduces the concept of "Thick Skin"

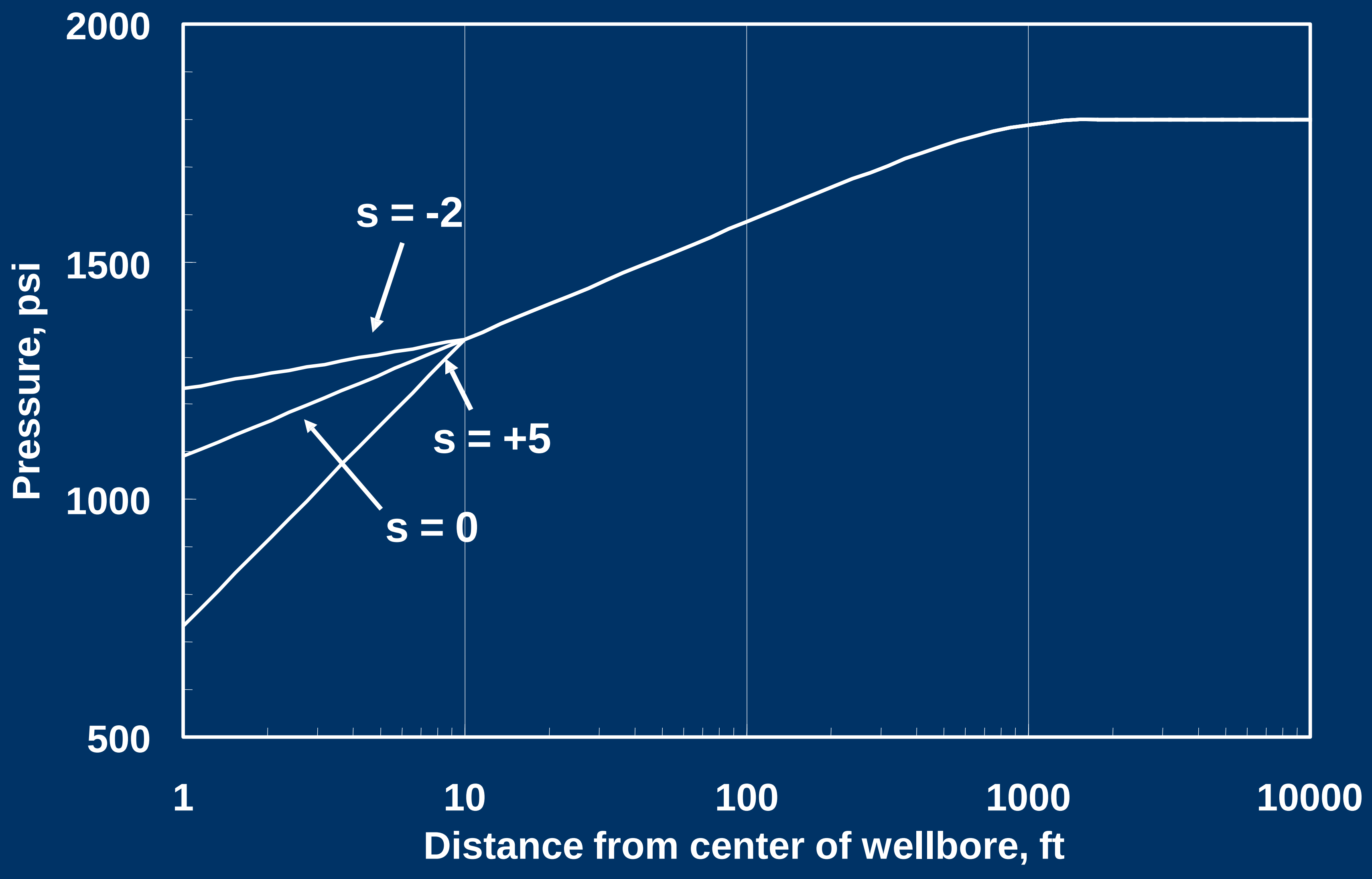
$$\Delta P_a = 141.2 \times \frac{q\mu B_0}{K_a h} \times \ln\left(\frac{r_a}{r_w}\right) - 141.2 \times \frac{q\mu B_0}{K_e h} \times \ln\left(\frac{r_a}{r_w}\right)$$

$$\Rightarrow 141.2 \times \frac{q\mu B_0}{K_e h}\left[\frac{K_e - K_a}{K_a} \times \ln\left(\frac{r_a}{r_w}\right)\right]$$

$$\Rightarrow S = \left[\frac{K_e - K_a}{K_a} \times \ln\left(\frac{r_a}{r_w}\right)\right]$$

Could be related to a physical phenomena (Invasion)

Reservoir Pressure Profile



<u>Skin Concept:</u>

So ==> Skin is **<u>CHANGE IN PRESSURE DROP</u>** that exists near the wellbore in “real wells” compared to a “Darcy-model” of the well

What can cause this change in pressure drop near the wellbore??:

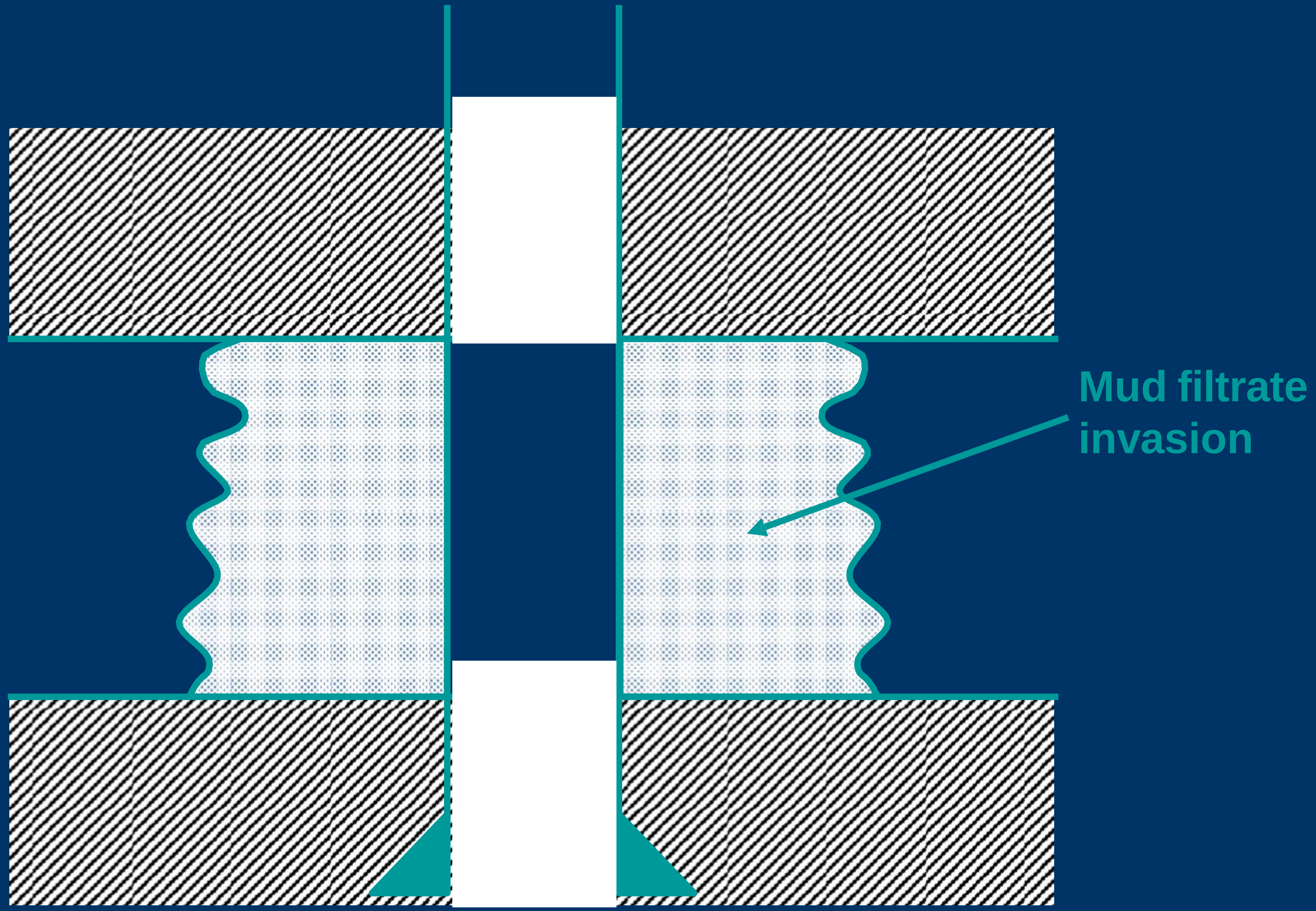
- Geometrical factors:
    - Inclined Well (S<0)
    - Spherical flow (Partial completion / Penetration)
    - Perforations (phase, density)

Skin Concept:

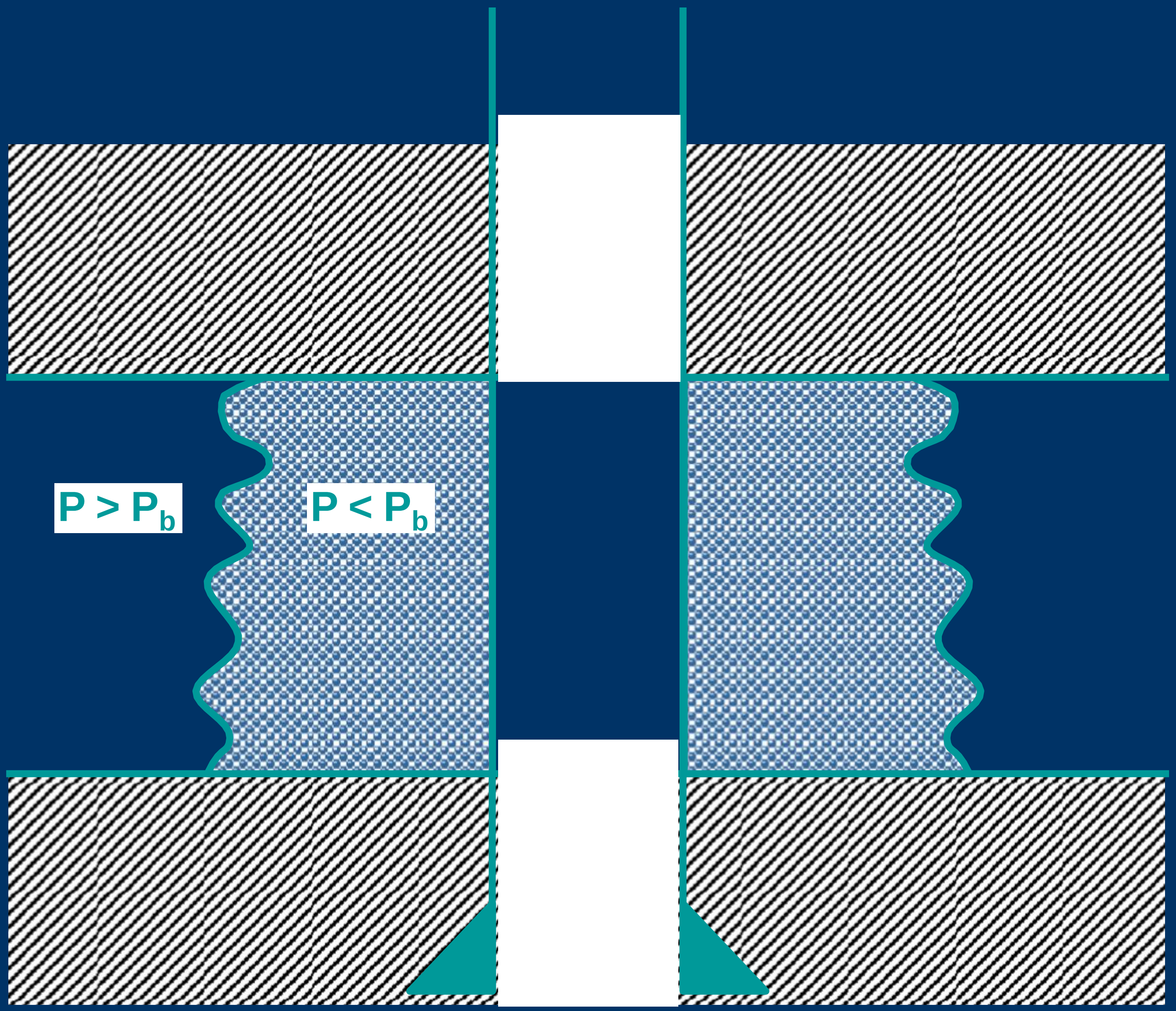
Mechanical Skin "Damage":

- Zone of altered permeability around the wellbore
  - Change in stress distribution
  - Drilling completion damage
  - Perforations ==> Crushed zone
- Others
  - Gas liberated from solution near the wellbore
  - Gravel Packs completions
  - Fracture / Stimulations

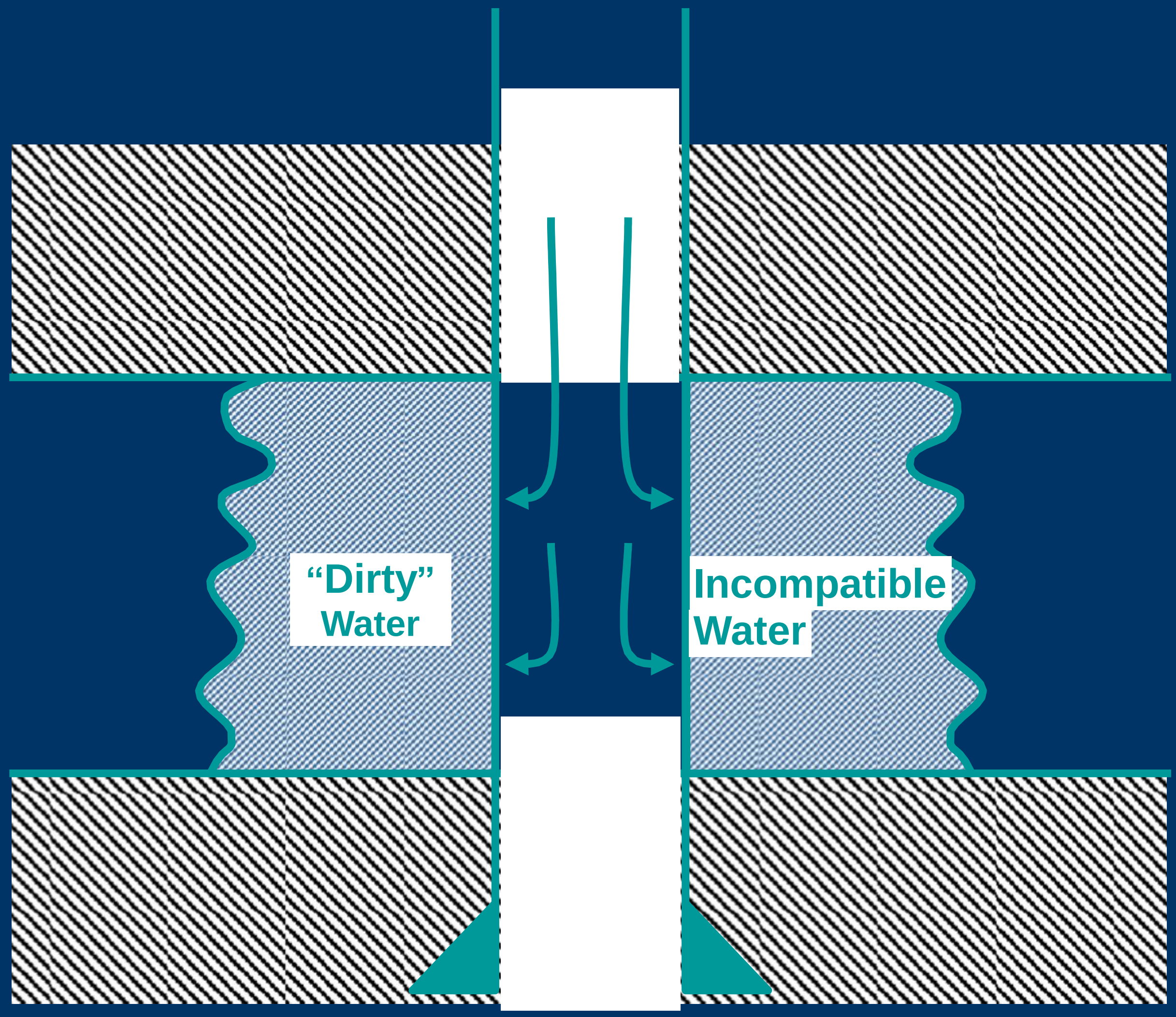
Damage Caused by Drilling Fluid



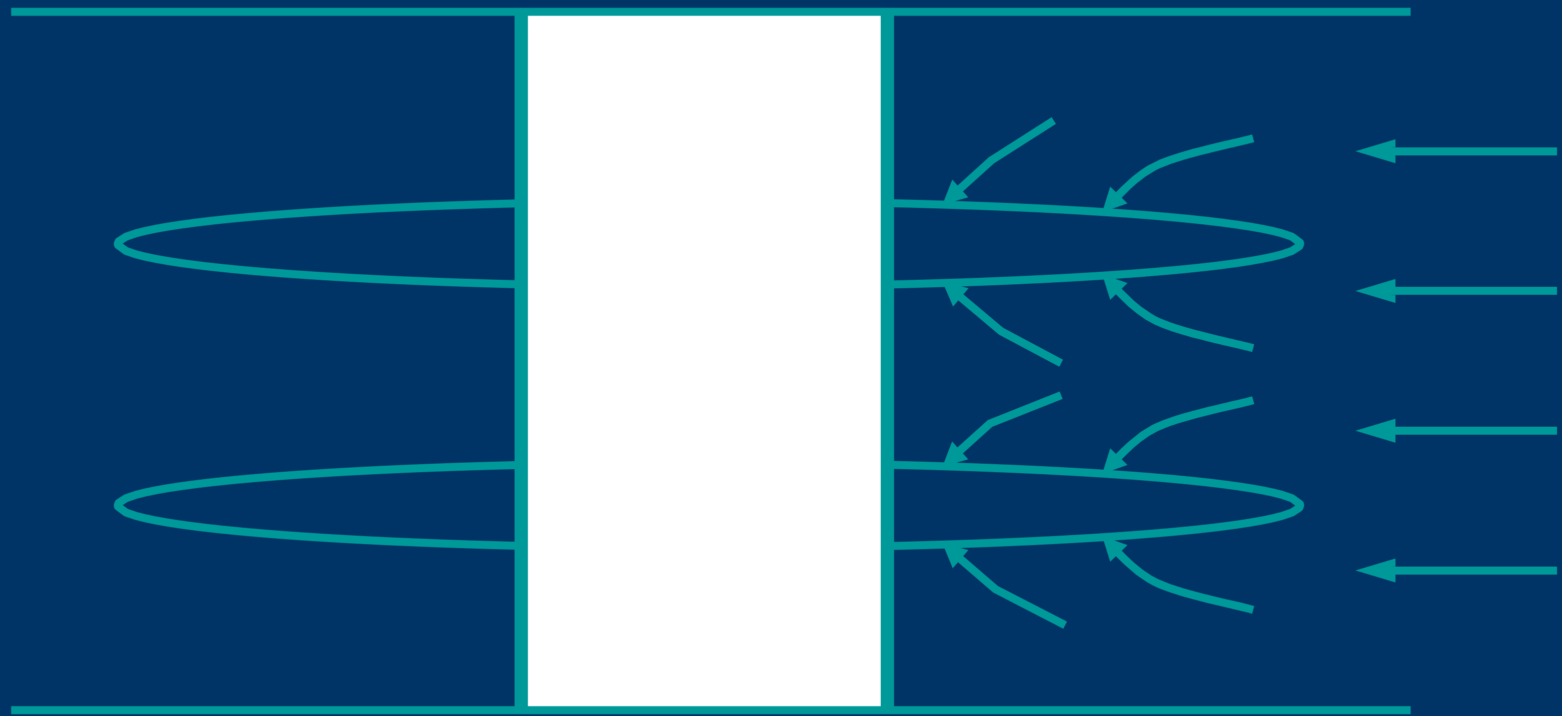
Damage Caused by Production



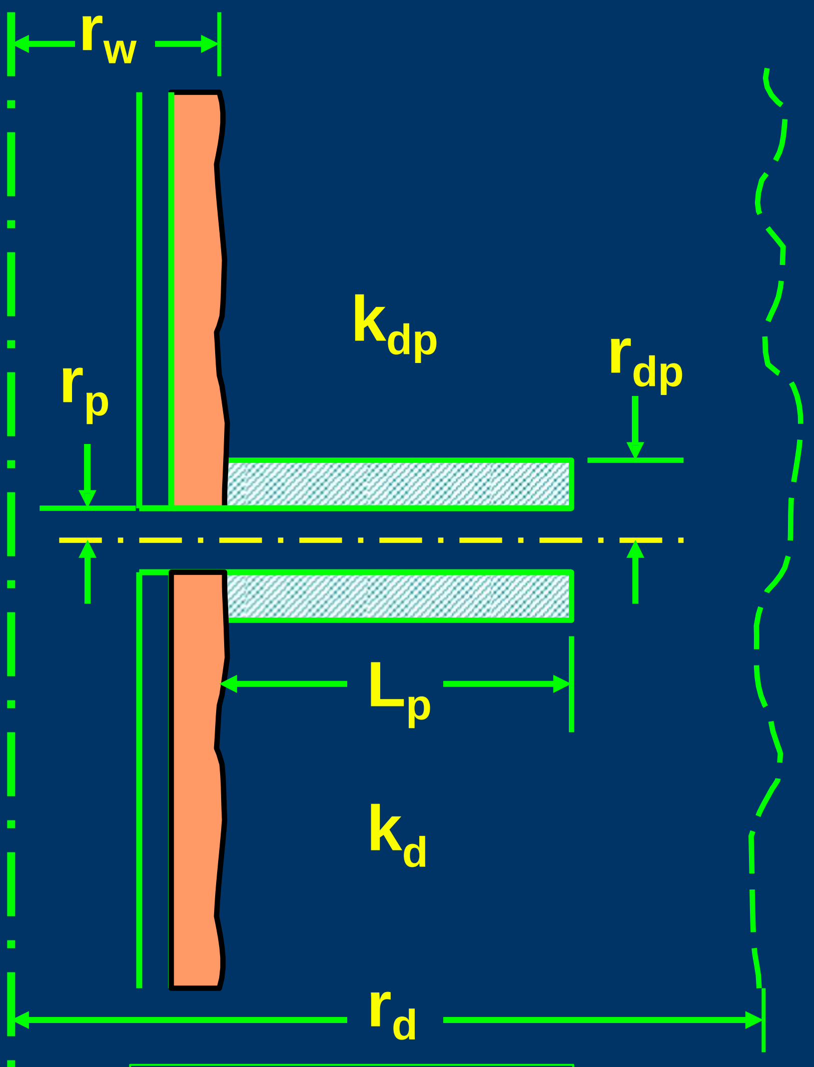
Damage Caused by Injection



Geometric Skin - Converging Flow to Perforations



Completion Skin

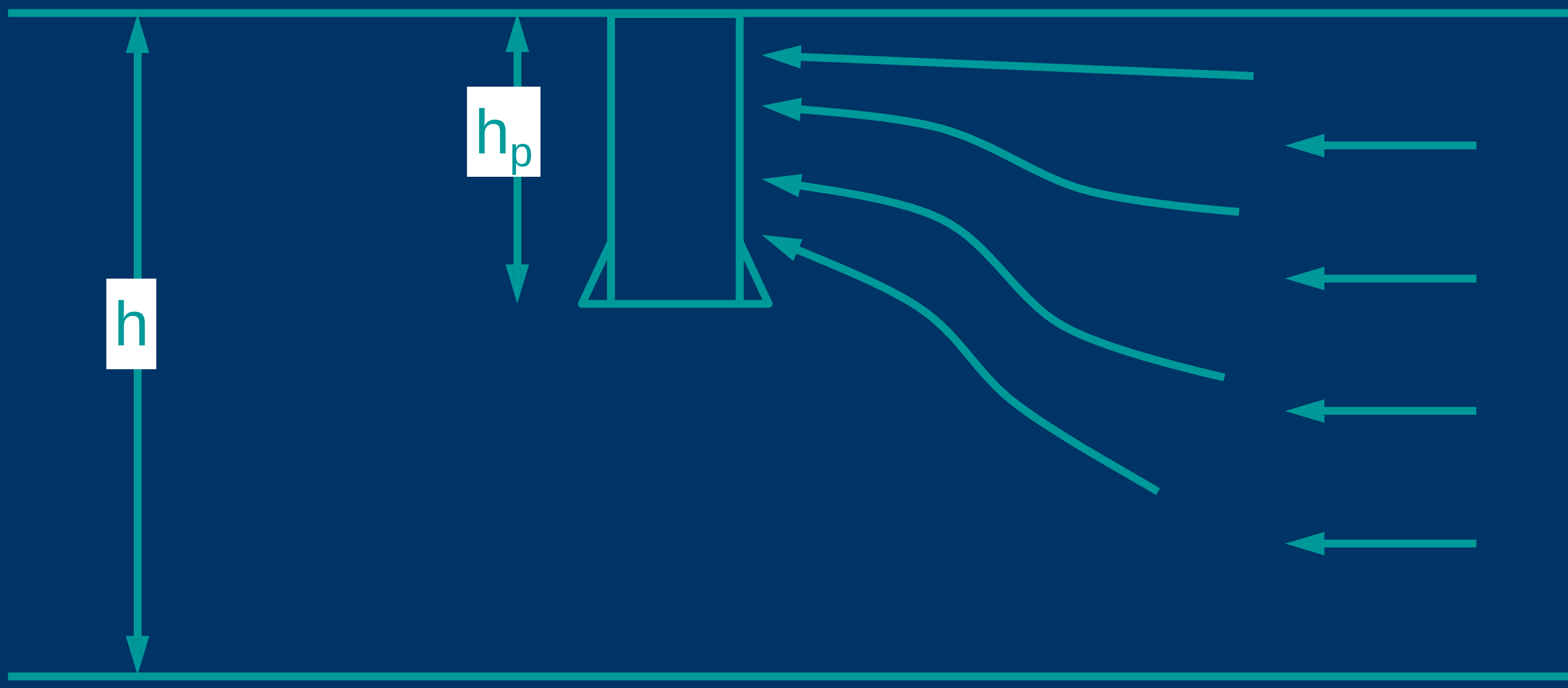


$$s = s_p + s_d + s_{dp}$$

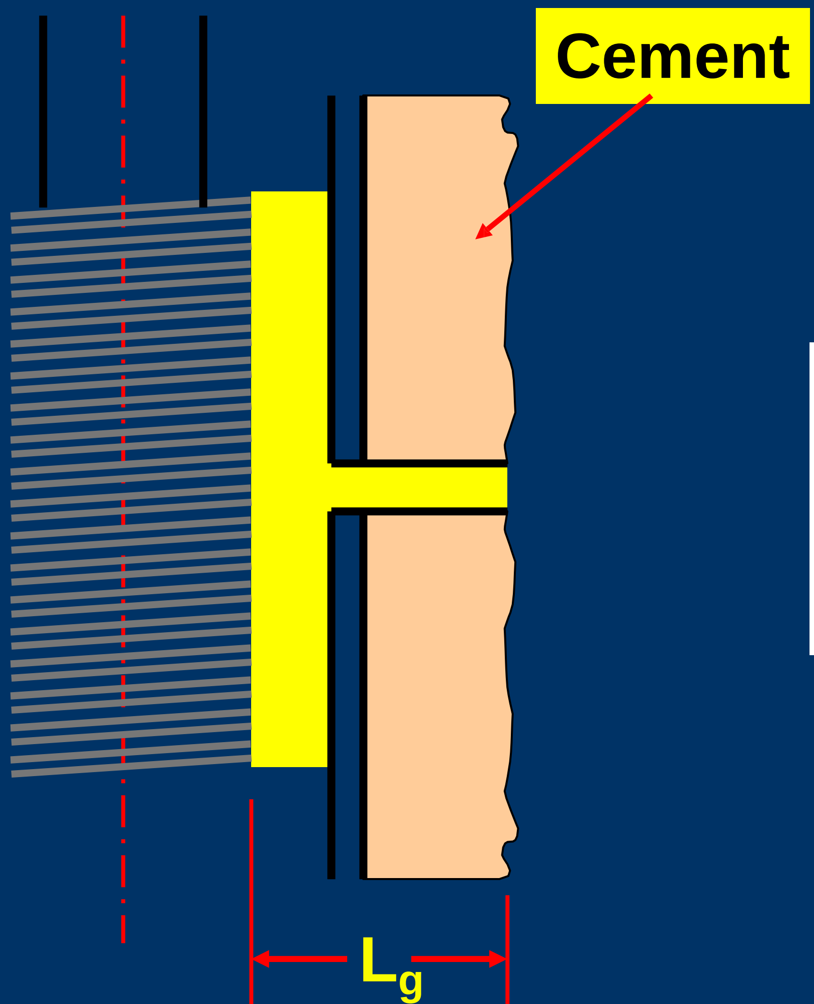
$$s_{dp} = \left(\frac{h}{L_p n}\right)\left(\ln \frac{r_{dp}}{r_p}\right)\left(\frac{k_R}{k_{dp}} - \frac{k_R}{k_d}\right)$$

After McLeod, JPT (Jan. 1983) p. 32.

Geometric Skin - Partial Penetration

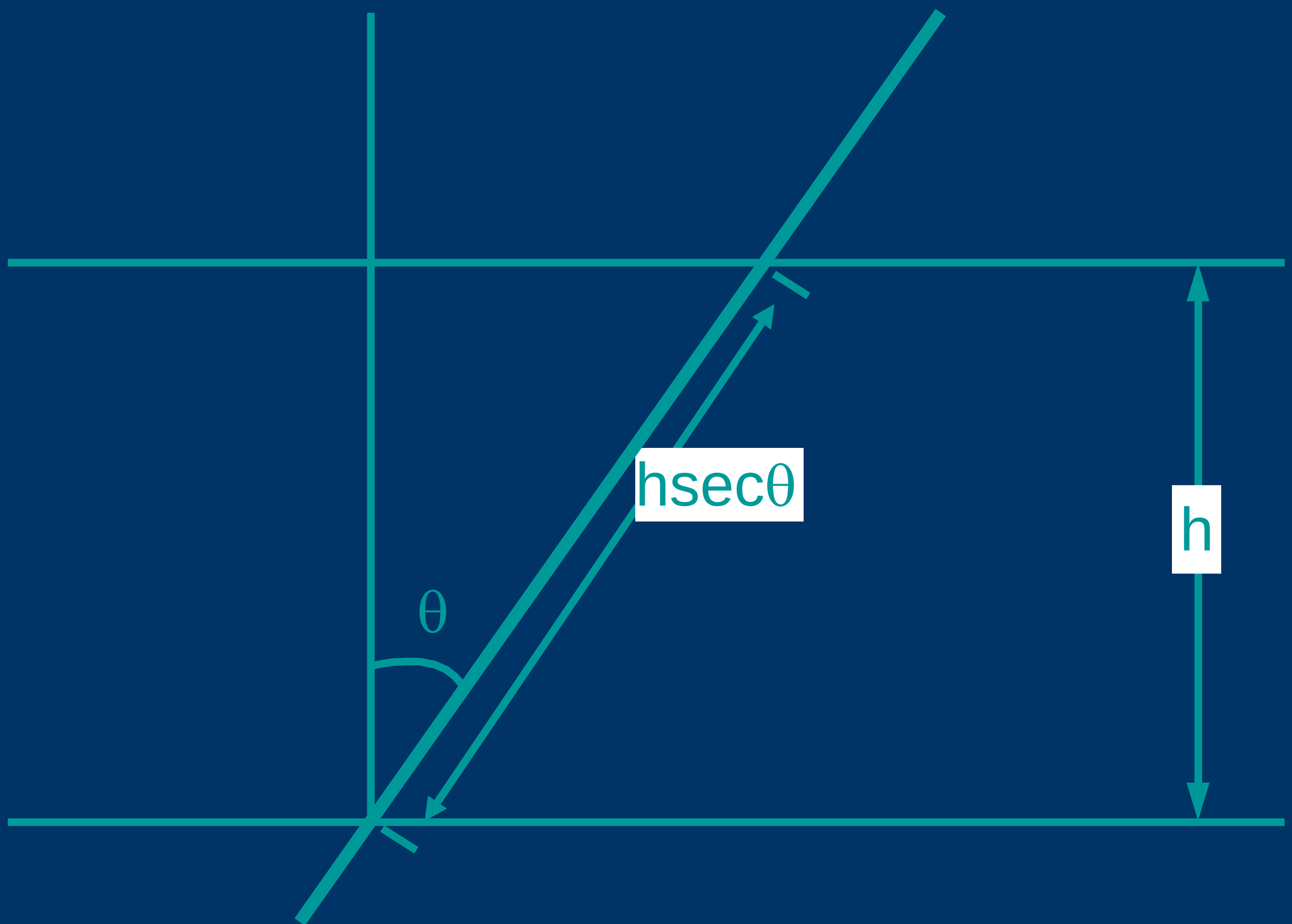


Gravel Pack Skin

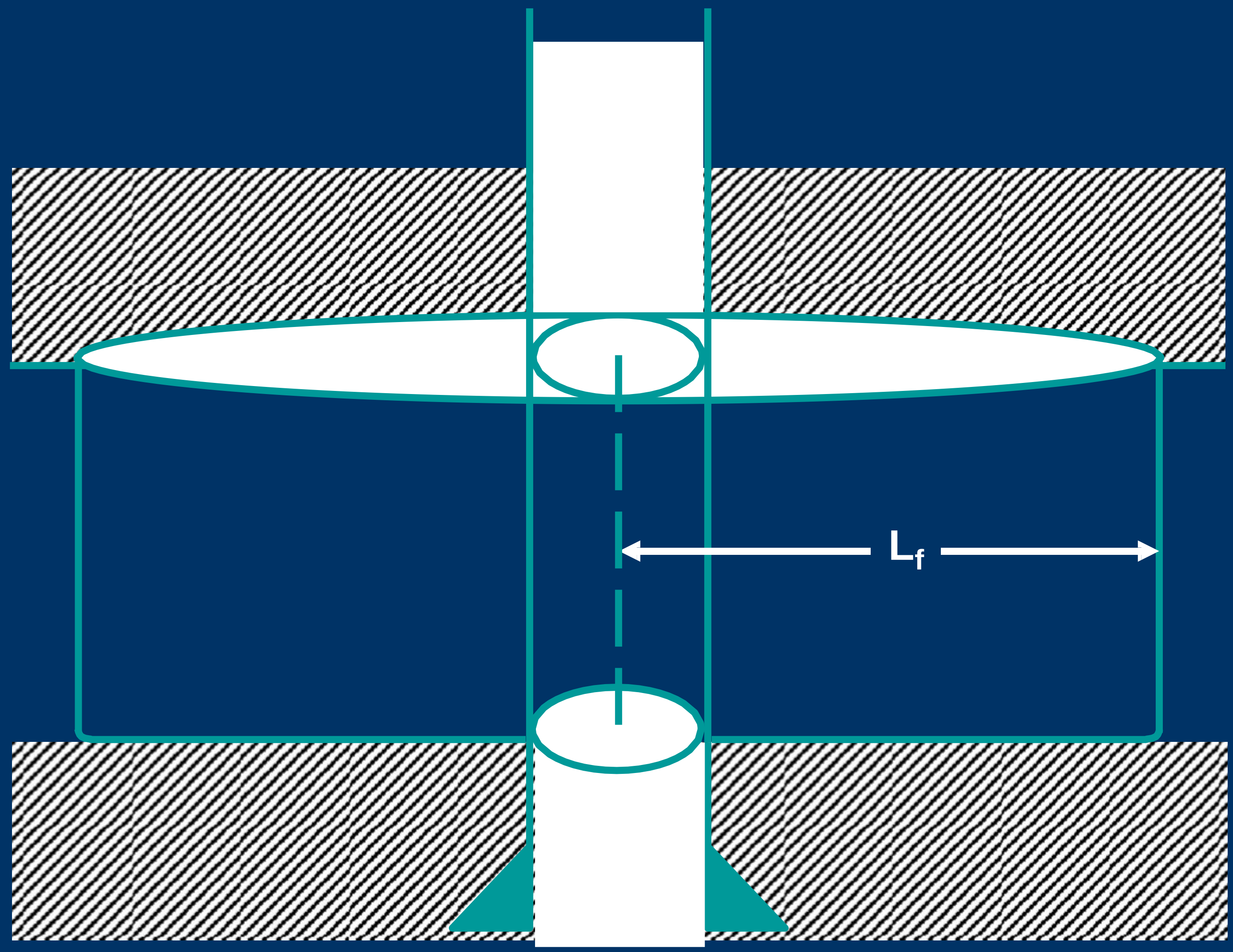


$$s_{gp} = \frac{k_R h L_g}{2 n k_{gp} r_p^2}$$

Geometric Skin - Deviated Wellbore



Geometric Skin - Well With Hydraulic Fracture



Skin Concept:

Pressure Build ups measures TOTAL Skin

Individual components of Skin can NOT be simply added

WE NEED TO KNOW WHAT PART OF THE SKIN CAN BE REMOVED.

Skin Concept:

Example:

Partial completion and damage (after Saidikowski 1979)

$$s_t = \frac{h_t}{h_p} \times s_d + s_p$$

$$s_p = \left(\frac{h_t}{h_p} - 1 \right) \times \left[\ln \left(\frac{h_t}{r_w} \times \sqrt{\frac{k_h}{k_v}} \right) - 2 \right]$$

St = Total Skin , Sd = Mechanical Skin, Sp=Partial Comp Skin

ht = Total Net Thickness, hp = Perforated thickness

Kh = Horiz Perm, Kv = Vert. Perm.

Skin Concept:

Example:

Partial completion and damage (after Saidikowski 1979)

Given:

h_t= 50 ft , h_p = 10ft, K_h=100md, Anisotropic ratio=10

B_s = 8.5 in

We perform a BU and we obtain a S = 11

Should we stimulate?

Skin Concept:

Example:

Partial completion and damage (after Saidikowski 1979)

NO

Ei-Function Solution

- Exponential integral solution
- Diffusivity equation solved in case of infinite acting reservoir from a line-source at constant rate

$$p = p_i + 70.6 \frac{qB\mu}{kh} Ei\left(-\frac{948\phi\mu c_t r^2}{kt} \right)$$

Exercise

- There is a oil producing well and pressure observation well in one field. What is the pressure at the observation well on the following case?

- P_i=5000psi, q=2000bopd, B_o=1.2
  k=100mD, h=100ft, ϕ=0.2
  μ=0.5cP, C_t=1E-5, r=500ft,
  h=2400hours