Carbon Capture and Storage Quantifying Geological Storage

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SPE International

Presenter

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Role and Experience

- GaffneyCline Technical Director (Reservoir Engineer)
- 36 years of experience with mining and petroleum companies, research and consulting
- Geoscience and reservoir engineering background with worldwide experience
- Current focus on integrated studies, Resources reporting and CCUS projects
- Has been involved in ~15 CCUS projects worldwide

Professional Involvement

- Member of SPE, SPEE, IOM3 (Institute of Materials, Minerals & Mining) and SAMOG (The South African Code for the Reporting of Oil and Gas Resources)
- Fellow of the Energy Institute
- Previously board member of SPEE (2020 – 2023)
- Member of SPEE Reserves Definitions Committee
- United Kingdom Chartered Scientist

Education

- PhD. Applied Mathematics, University of Cape Town, South Africa
- MSc. Solar Terrestrial Physics, University of Natal, South Africa
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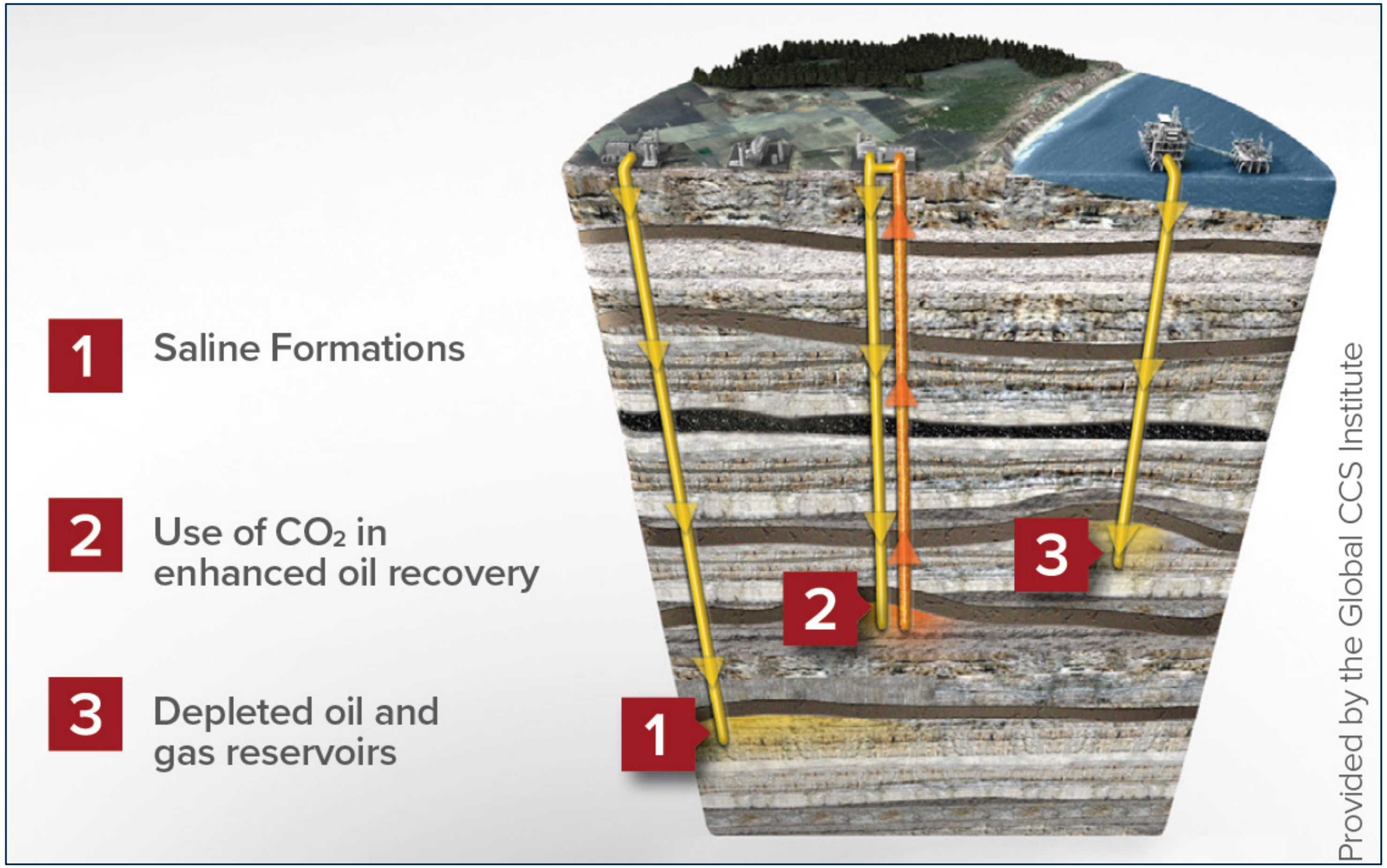
Simplified Schematic of Geological Storage



"CCS is the process of capturing and storing CO_2 before it is released into the atmosphere"

London School of Economics

Geological storage is the placement of CO_2 in deep geological formations where it remains safely isolated from the atmosphere.

The three principles of geological storage:

A. **Quantity - how much CO_2 can be stored?**
B. Injectivity - how easily can CO_2 be injected?
C. Containment - how safely can CO_2 be stored?

This presentations focusses on estimation of storable quantities in saline aquifers and depleted gas reservoirs.

Source of diagram: **https://www.globalccsinstitute.com/wp-content/uploads/2018/12/Global-CCS-Institute-Fact-Sheet_Geological-Storage-of-CO2.pdf**

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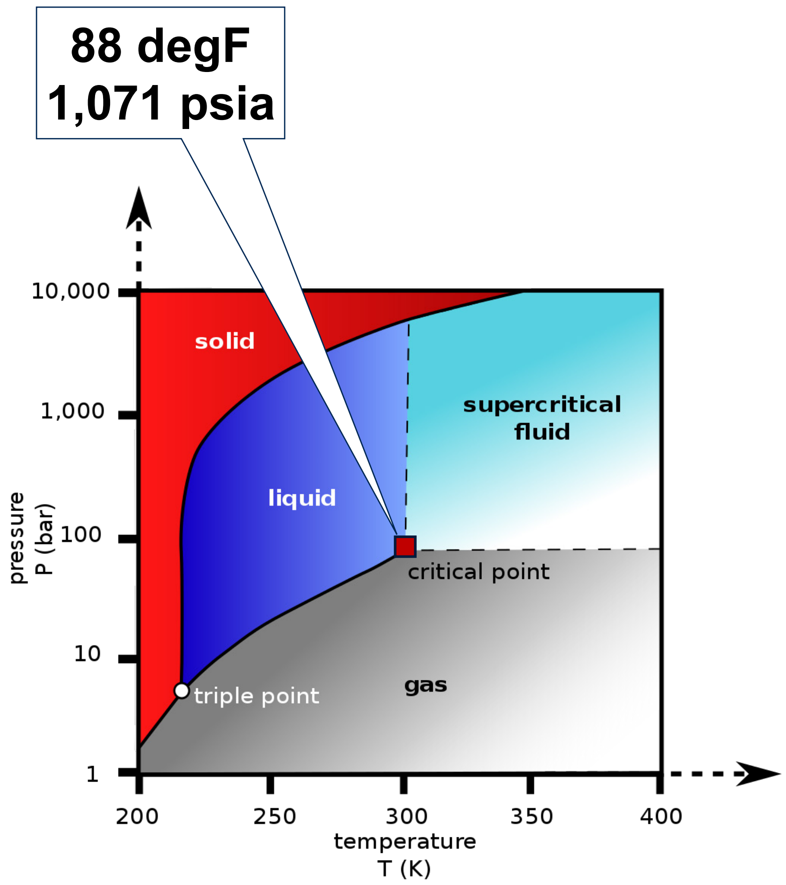
Physical Properties of CO_2

CO_2 Phase Behaviour for Reference



Item	Temperature	Pressure
Triple Point	-56.7 degC	5.1 atm
	-70 degF	75 psia
Critical Point	31 degC	72.9 atm
	88 degF	**1,071 psia**

CO_2 storage quantities are usually quoted as follows:

Storable quantities ("capacity"):

- **Mt**: Mega tonnes, or millions (10^6) of metric tonnes
- **Gt**: Giga tonnes, or billions (10^9) of metric tonnes

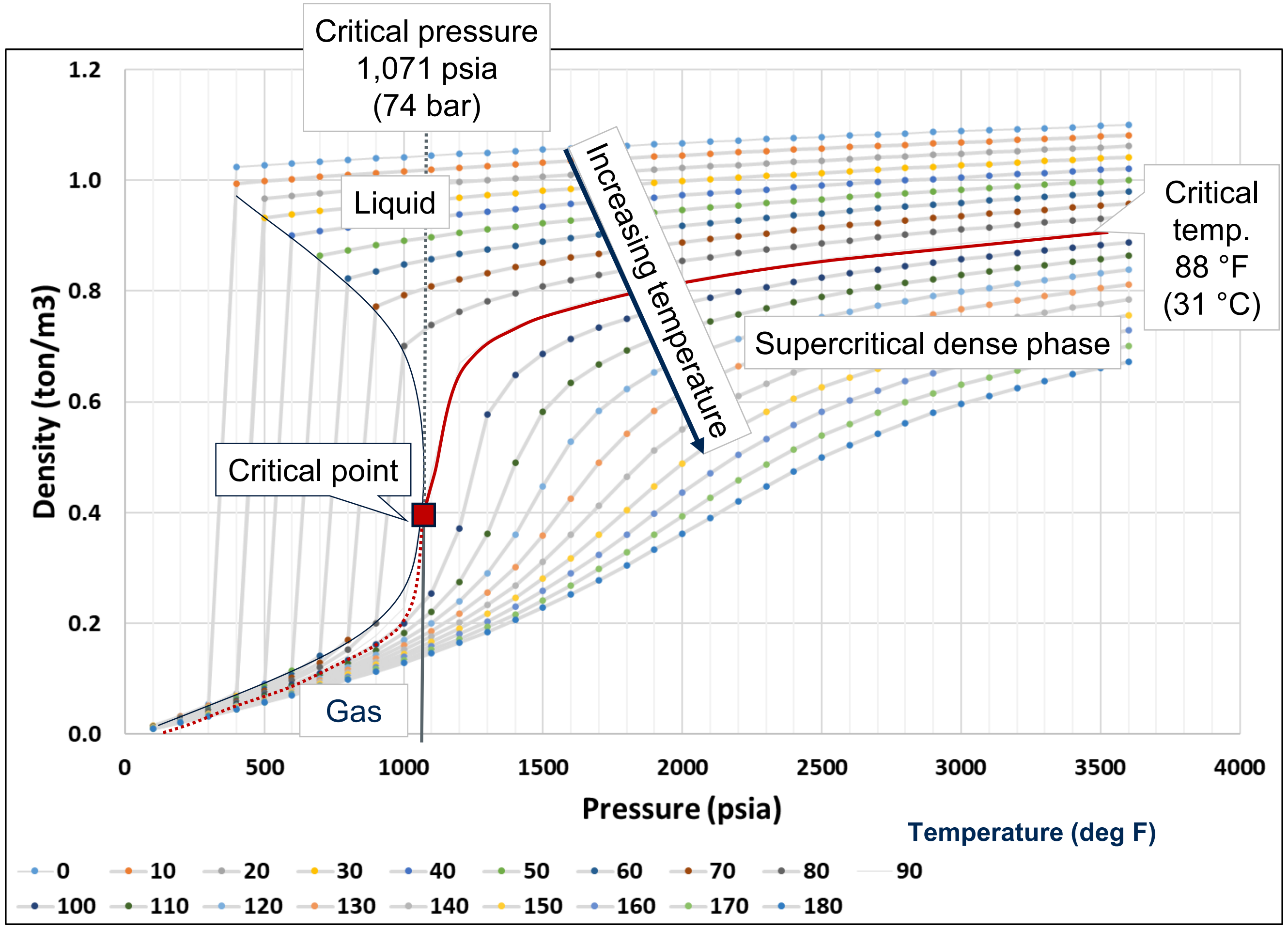
Injection rates:

- **Mtpa**: Mega tonnes per annum, or millions of tonnes per annum.

t = tonne ("metric ton") = 1,000 kg

Phase diagram source: **By Ben FinneyMark Jacobs - Commons, https://commons.wikimedia.org/w/index.php?curid=4315735**

CO_2 Density, Temperature and Pressure



Important points:

1) Density increases sharply with pressure above the critical point but is less sensitive at high pressure.

2) Density decreases with increasing temperature and is sensitive over a wide range of pressure.

CO_2 density is very important in any CCS project because it determines the efficiency of use of the storage pore space.

The higher the density, the more molecules we can fit into a given pore space

Useful website: https://webbook.nist.gov/chemistry/fluid/ which uses CO_2 properties from: **Span, R.; Wagner, W. (1996).**

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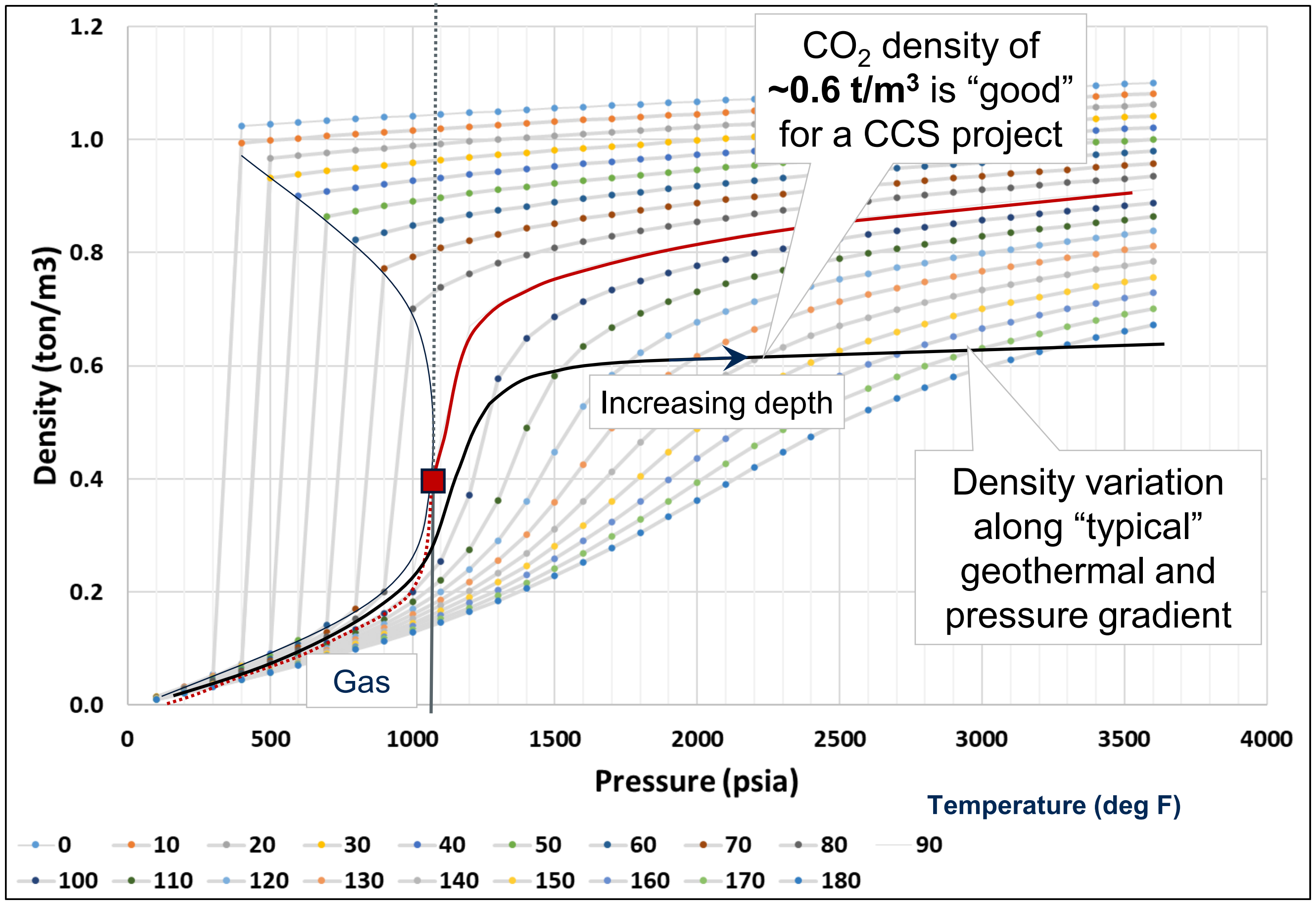
Data from: **Practical Aspects of CO2 Flooding. SPE Monograph v. 32.**

CO_2 Density, Temperature and Pressure



What happens as we penetrate the subsurface:

- Pressure increases: CO_2 becomes more dense
- Temperature increases: CO_2 becomes less dense
- T and P effects act against each other
- Therefore, storage at increasing depth has diminishing benefit.
- Most efficient utilization of storage volume:
  - Pressure range **~1,200 psia to ~2,000 psia (~840 m to ~1,400 m)** in "normal" temperature gradient environment (min ~760 m).
  - Density close to that of a liquid and viscosity close to that of gas.
- **Be aware that small variations in temperature can have a big impact on CO_2 density**

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Data from: **Practical Aspects of CO2 Flooding. SPE Monograph v. 32.**

CO_2 Phases and Density- Some Observations

- Conversion from mass (Mt) to volume ($10^6 m^3$) at standard conditions is easy:

$$\boxed{Vol = \frac{Mass}{0.00187}}$$

- CO_2 density at STP of **60 degF and 14.7 psia** is **0.00187 t/m^3**. or **1.87 kg/m^3**
- With density as the starting point, the gas expansion factor can easily be computed:

$$\boxed{E = \frac{\rho_{reservoir}}{\rho_{surface}}}$$

- CO_2 can have a high expansion factor, often higher than natural gas.
- In a depleted gas reservoir, you can theoretically store a larger volumes of CO_2 (expressed at surface conditions) than the volume of HC gas (also expressed at surface conditions) that was extracted.
- In a recent study, the natural gas had an expansion factor of **250 svol/rvol** with CO_2 at **350 svol/rvol**, so it was possible to replace natural gas at a ratio of **1.4 : 1.0**.

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CO_2/CH_4 Expansion Factor Ratio as a Function of Depth

Assumptions:

Surface temperature:

- 10 degC (50 degF).

Temperature gradient:

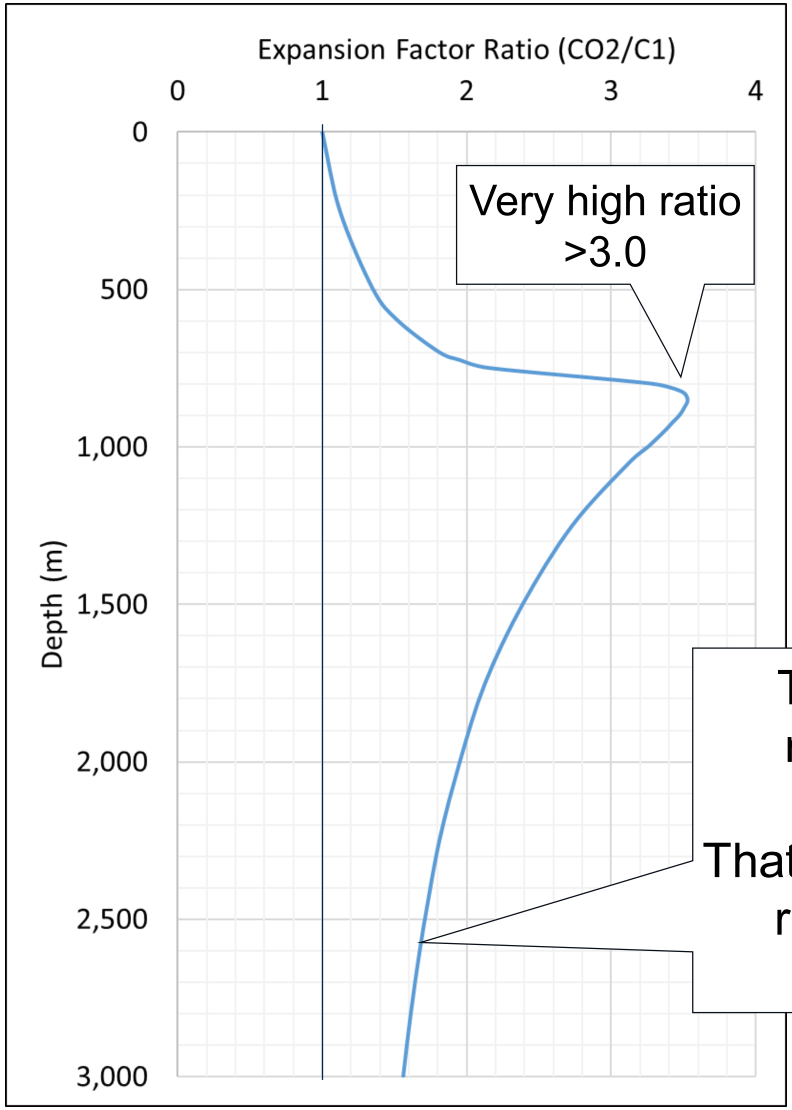
- 30 degC/km (54 degF/km).

Pressure gradient:

- 0.433 psi/ft.

Results are affected by:

- Actual composition of HC gas
- Contamination of injection stream
- Anomalous temperature gradient



The expansion factor of CO_2 remains greater than that of methane.
That is why we can store more CO_2 relative to CH_4 (expressed in surface volumes)

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CO_2 Storage in Aquifers

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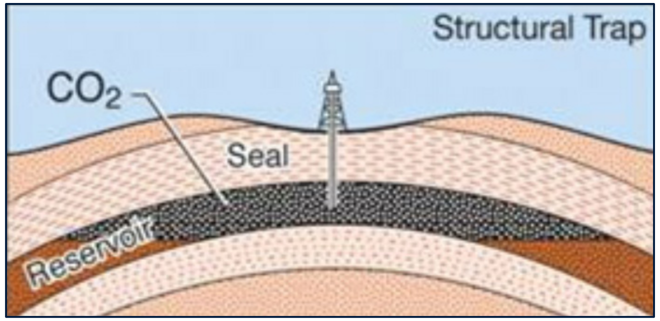
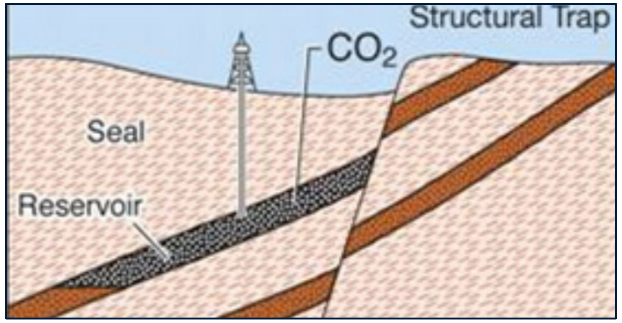
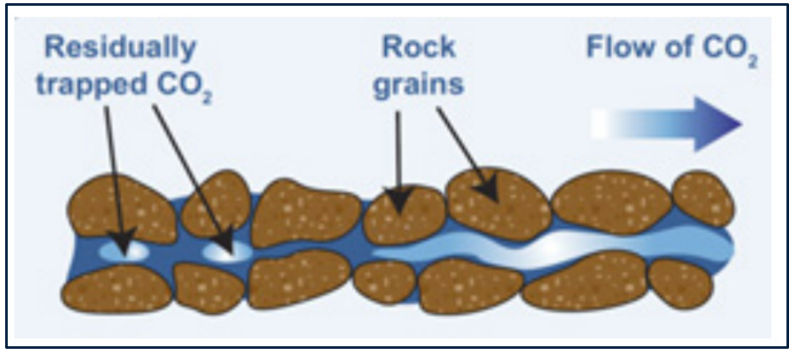
Aquifer Trapping and Immobilisation

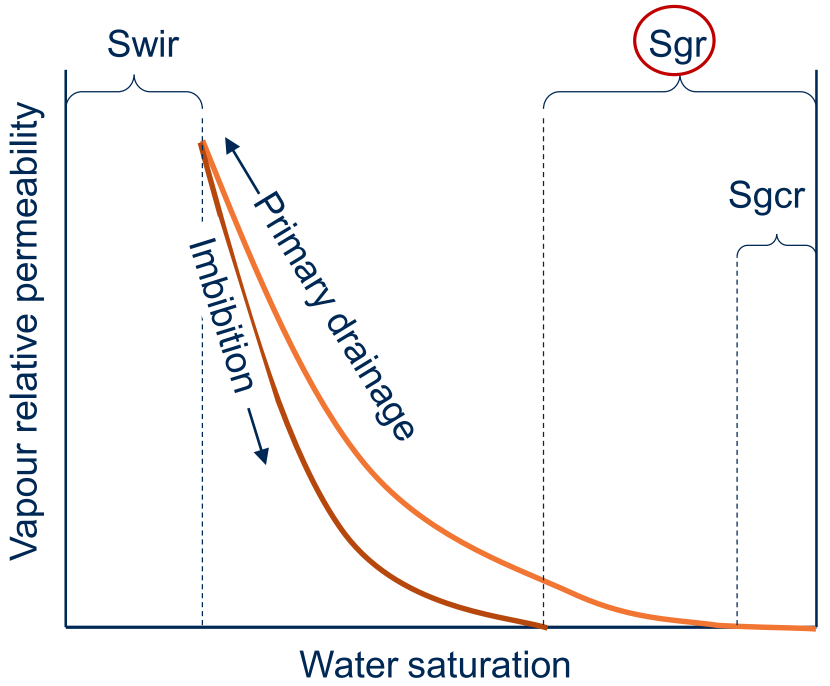
1. **Geologic trapping** (structural and stratigraphic)
   - High concentration of CO_2 in suitable structures.
   - CO_2 stored as "free phase".
   - Seal risk.





2. **Residual trapping**
   - Occurs when CO_2 migrates over long distances, displacing brine.
   - Brine imbibes into the CO_2 plume until the free phase CO_2 is immobilised at its residual saturation (Sgr).
   - The more contact with rock the better.





Aquifer Trapping and Immobilisation

3. Solubility trapping

- CO_2 progressively dissolves in brine and becomes immobilized
- The more contact with water the better.
- Solubility is greatest at:
  - Low salinity
  - High pressure
  - Low temperature

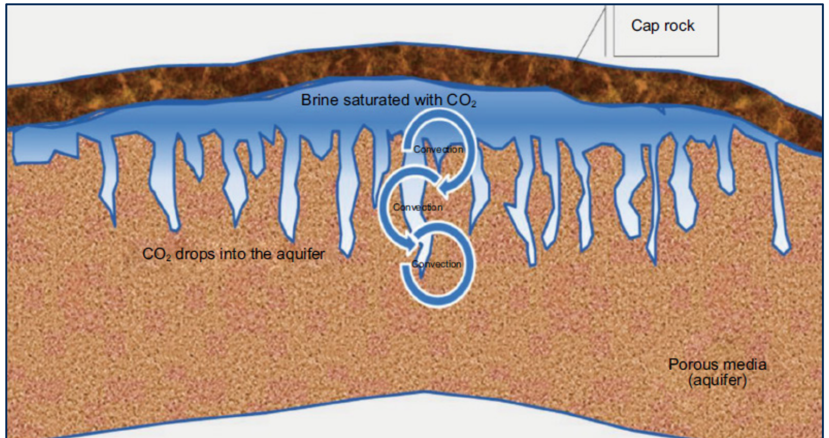
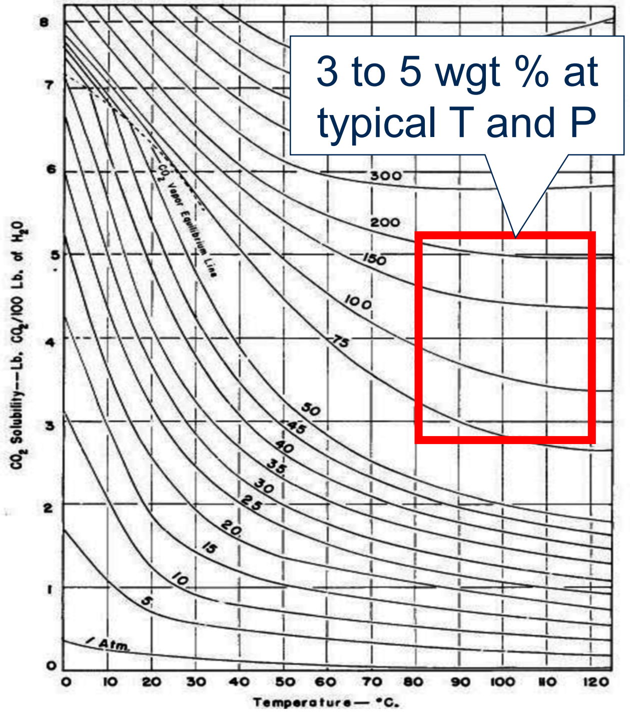
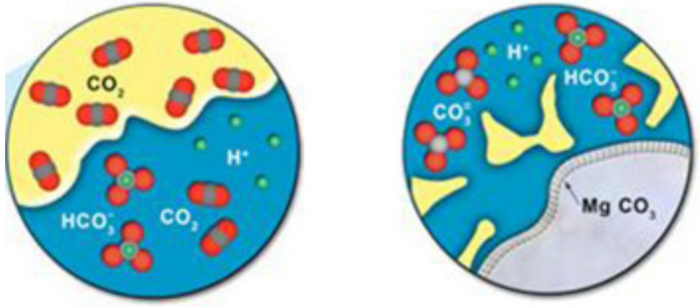


Diagram from: **Ajayi et al 2019**



4. Mineral trapping

- CO_2 dissolves in brine and alters chemistry, leading to dissolution of some minerals and precipitation of new minerals
- Very slow and mostly ignored, but very secure



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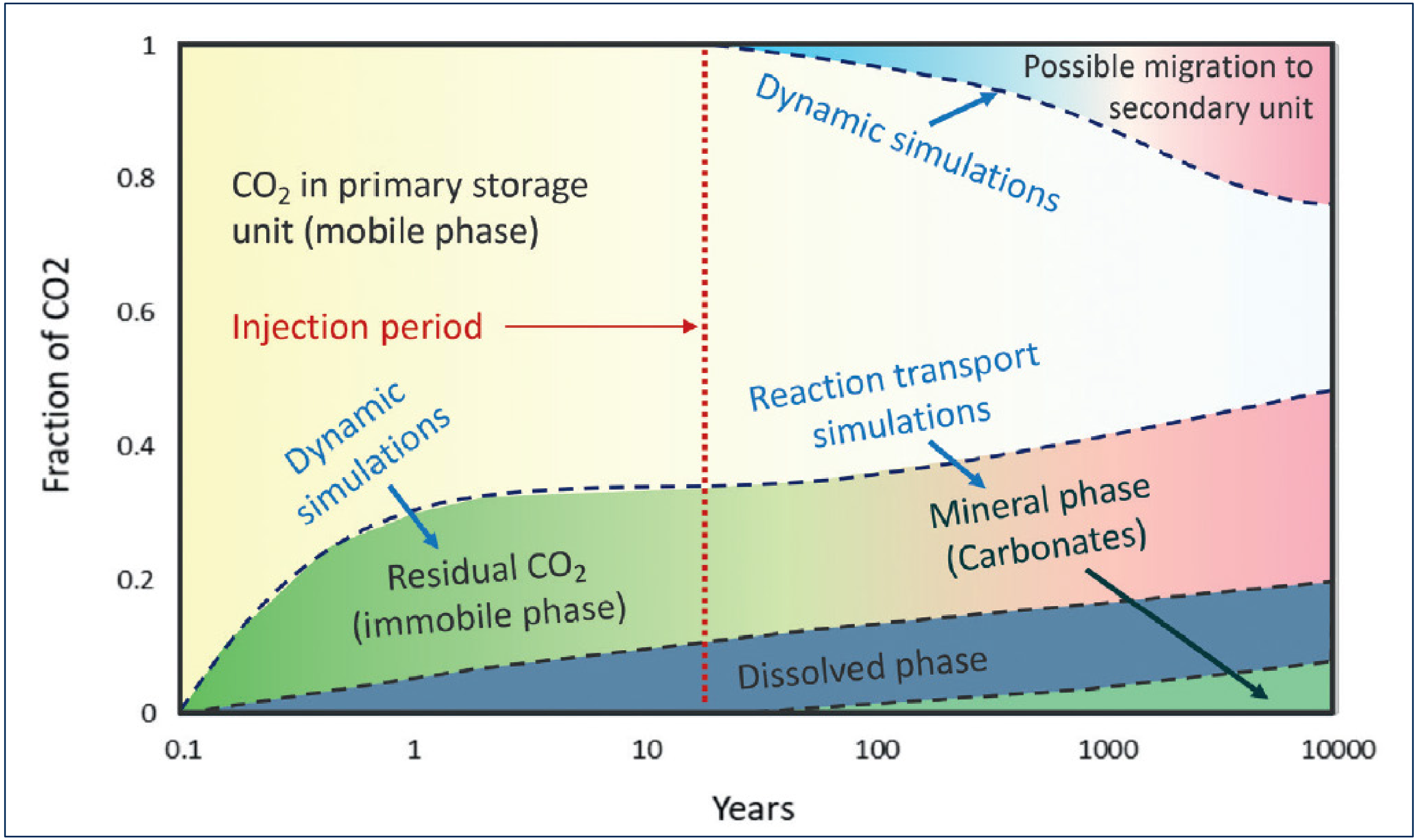
CO_2 Immobilisation over Time



- Different CO_2 immobilisation mechanisms work to increase storage security over time
- Several mechanisms continue to operate long after the end of the injection period.
- **What is the fate of free phase CO_2 in an open aquifer?**

Good dynamic modelling is important:

- Sensitivity analysis
- Alternative scenarios and realisations

Diagram source: **Ringrose, 2022, "Why CCS is not like reverse gas engineering"**

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Aquifers – The Volumetric Equation

The storable quantity of CO_2 in an aquifer "container" can be estimated with the following volumetric equation:

$$\boxed{CO2Msto = PV * EF * \rho CO2sto}$$

Where:

$CO2Msto$	mass of CO_2 that can be stored at the final storage pressure of the container [metric tonnes].
PV	pore volume of the storage container [m^3].
EF	efficiency factor - defined here as the ratio of the volume of CO_2 injected into an aquifer, to the net pore volume of the aquifer at the final storage pressure. (Think of it as the saturation of CO_2).
$\rho CO2sto$	density of CO_2 at the final storage pressure of the container [tonnes/m^3].

Two important considerations:

1. Mechanism for trapping and immobilisation of CO_2.
2. Nature of the container.

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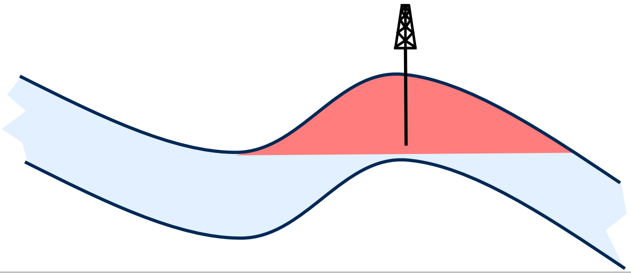
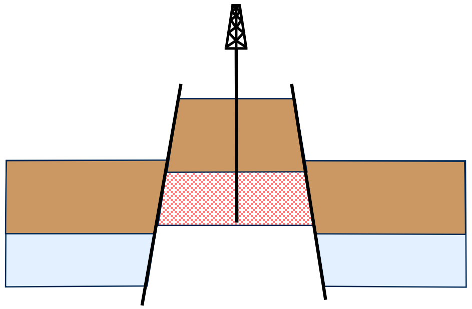
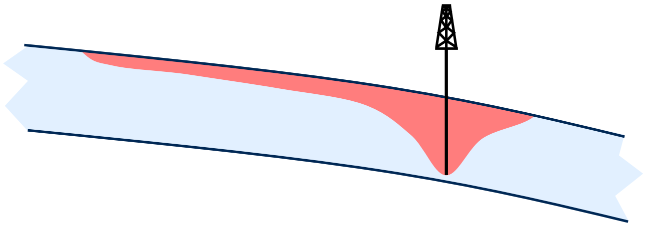
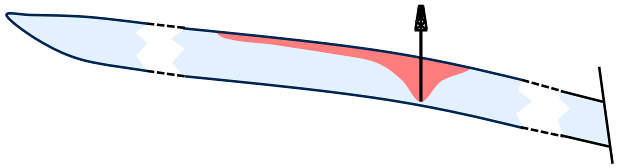
Types of Aquifer Storage

		Open Aquifer	Confined Aquifer		
$EF = (1 - Swir)$ (max) Expect EF ~ **30 to 40%** of structure PV. Increase by spilling out.	**Geologic trapping**	CO_2 displaces water and is physically trapped in mobile state. Pressure dissipates. 	CO_2 is physically trapped in mobile state. Pressure increases. 	**Geologic trapping**	$EF = C_t * \Delta P$ Expect EF ~ **0.5%** Increases with dissolution. Increases with depth Increase with brine extraction.
No simple expression for EF. Reported EF ranges typically **0.5% to 7%, (or more).** Definition of container determined by development plan.	**Solubility & residual**	CO_2 forms a plume, becoming immobilised. Pressure dissipates. 	CO_2 forms a plume, becoming immobilised. Pressure increases. 	**Solubility & residual**	Similar to adjacent case but pressure increases.
		Open Aquifer	Confined Aquifer		

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Adapted from: **SRMS Application Guidelines**

Efficiency Factor in Open Aquifer – Analytical Estimates

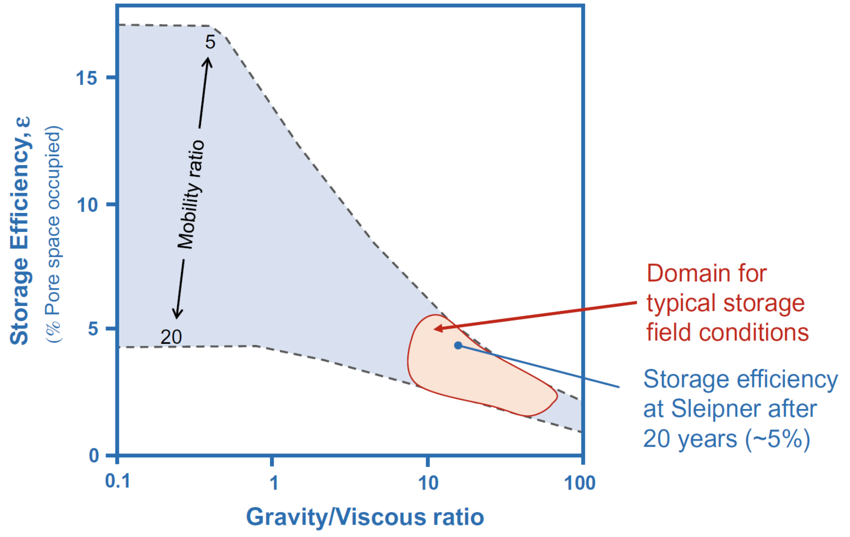


Fig. 2.22 Storage efficiency, ε, as a function of mobility ratio, λ_r, and gravity factor, Γ from Okwen et al. 2010)

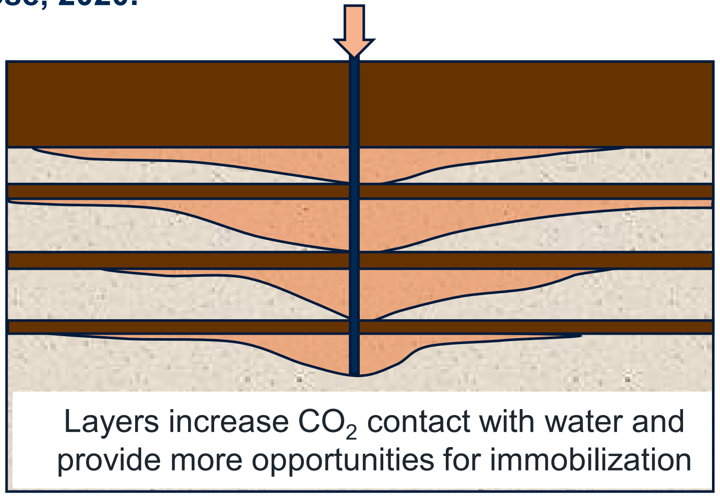
Diagram from: **Ringrose, 2020.**

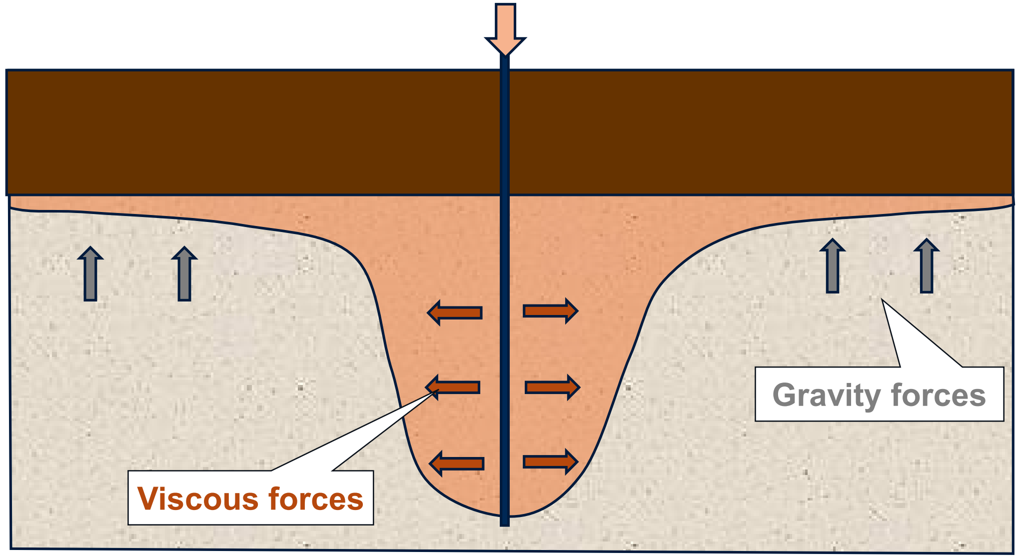
Gravity/Viscous ratio: $\boxed{\Gamma \propto \frac{\Delta\rho . k}{q_{well}}}$

Mobility ratio: $\boxed{M = \frac{k_{rCO_2} . \mu_w}{k_{rw} . \mu_{CO_2}}}$

<u>Qualitatively:</u>

- High mobility ratio (low CO_2 viscosity) leads to low EF.
- In most aquifers gravity forces will ultimately prevail over viscous forces.
- High gravity forces (low CO_2 density) cause CO_2 to override water and lead to lower EF.





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Efficiency Factors - What Does it Mean?

From SRMS (2017):

Storage Efficiency: Fraction of the Storage Capacity, Storage Resource, total pore volume, effective pore volume, bulk volume, and/or storable quantity expected to be used for storage by a specific project. May be based on actual injection, planned project, or a regional assessment. The basis for the storage efficiency must be clearly identified and documented.

Six possible interpretations!

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Worked examples

- Regional evaluation in GCC - efficiency factors
- Case study in UAE - simulation

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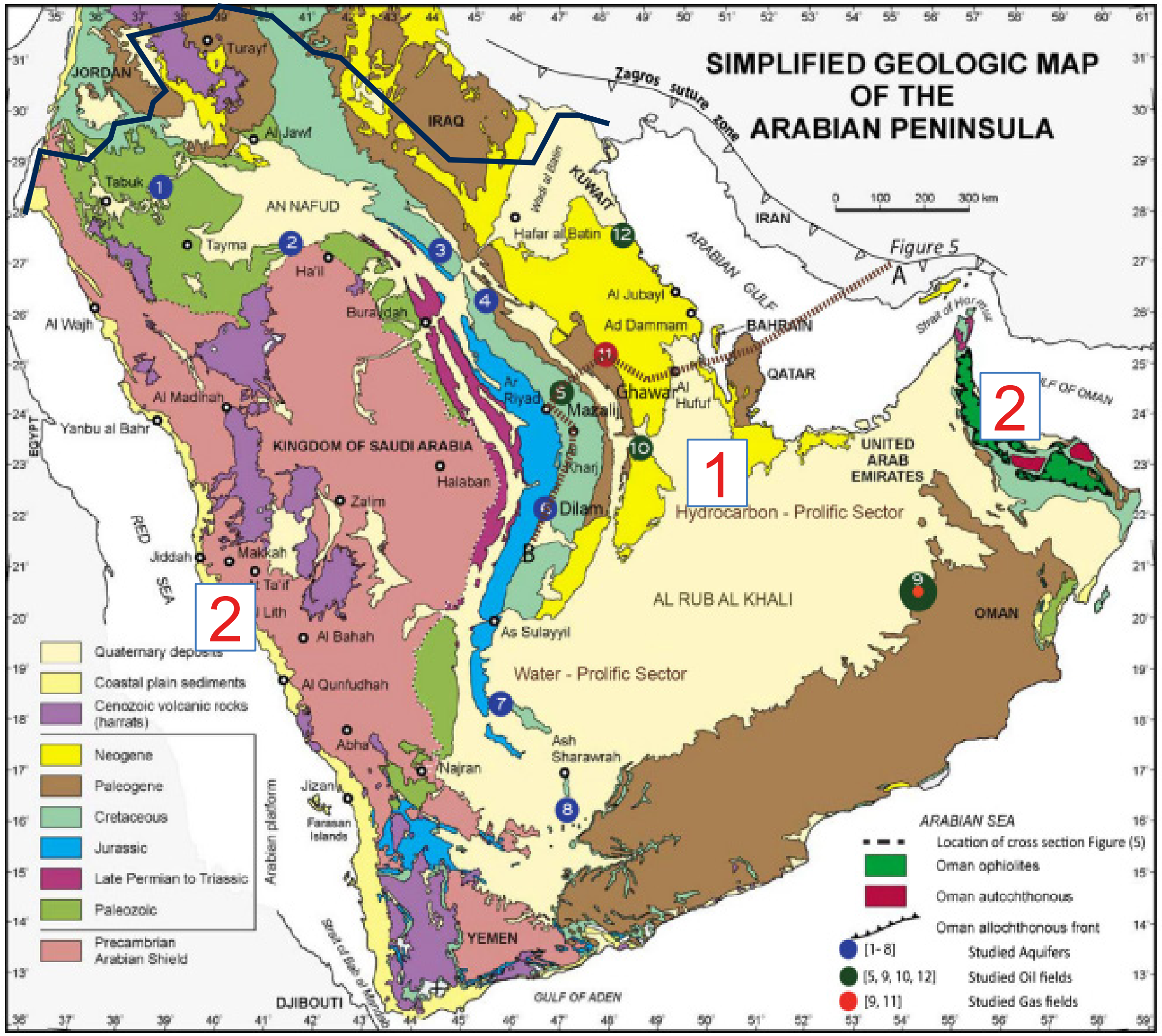
GCC Study Area and Definitions

Potential carbon sinks of two types in saline aquifers.

1. **Rub'al-Khali Basin:** Large, long-lived sedimentary basin on the northeastern flank of the Arabian Platform, in part forming the foredeep of the Zagros and Oman Mountains

2. "Geological storage" sequestration by **direct mineral reaction** with the rocks that comprise the Oman **ophiolite**. Obducted oceanic crust on the Oman continental margin.



"***CCUS deployment challenges and opportunities for the GCC***" (Gulf Cooperative Council: Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates), January 2022.

A report prepared for the OGCI by AFRY and GaffneyCline

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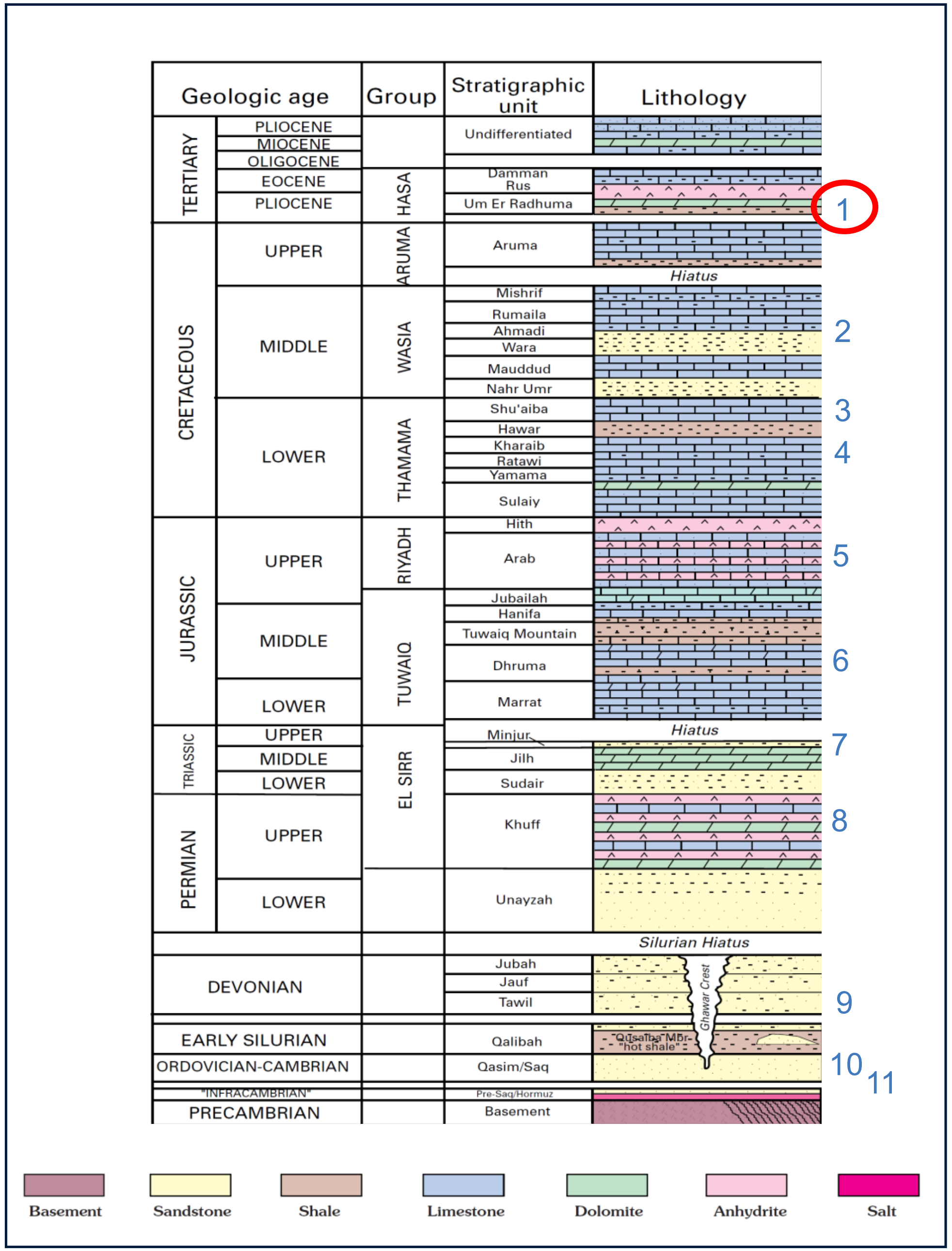
Stratigraphic Column & Storage Plays

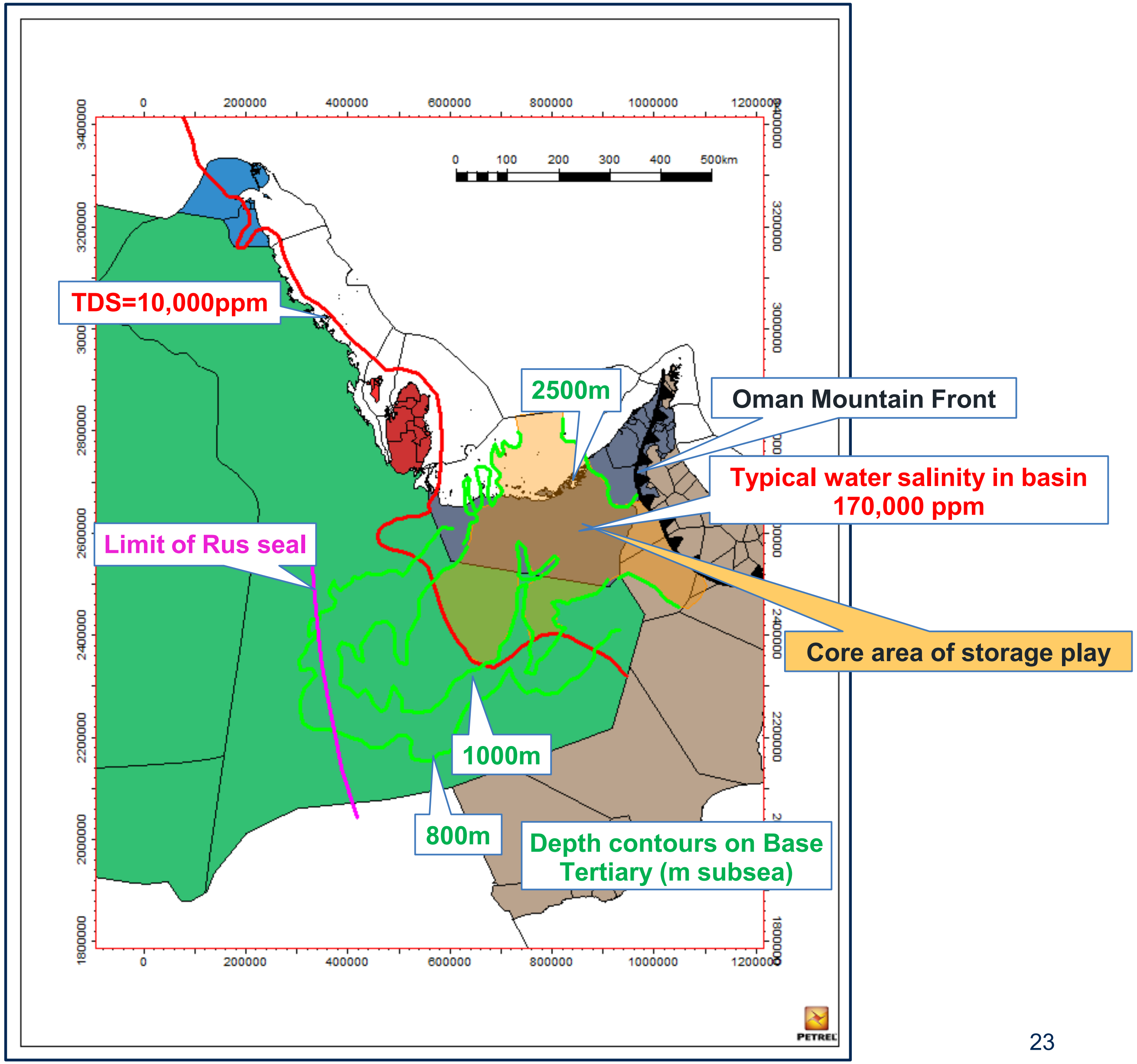
- Overall setting is widespread, long-lived passive margin platform, with extensive reservoir and seal units.
- Potential storage complexes are numbered 1 to 11 (Example 1 is discussed here).
- Each is identified by a prominent reservoir and seal.
- They may be the basis of a recognised petroleum play, or recognised potable aquifer system.



From: Vahrenkamp et al., 2021

Umm er Radhuma (UER): Storage Play Fairway Map (Example 1)

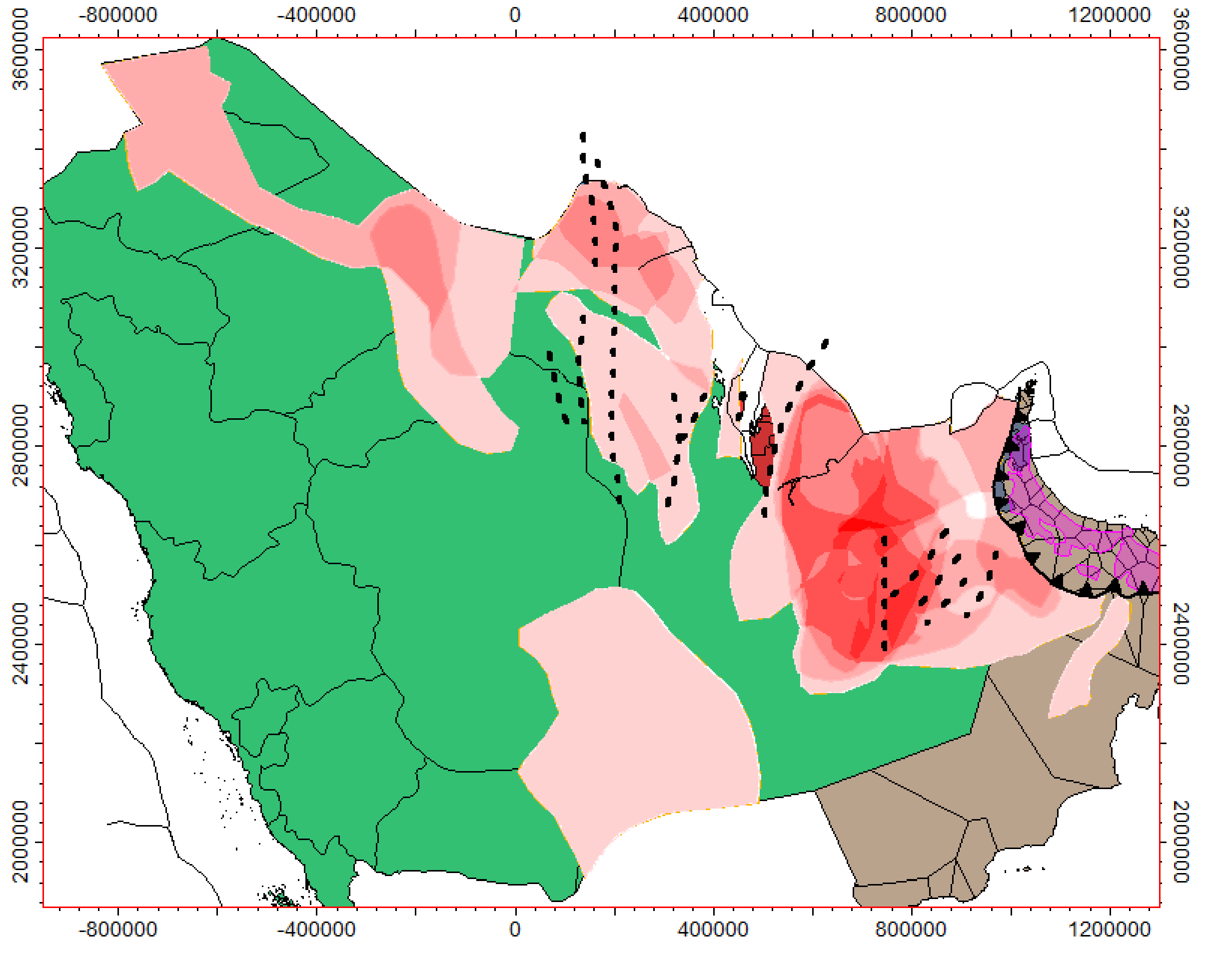
- Shallow play in part in key 1,000-2,500m burial zone
- Limit of Rus seal not a critical controlling factor
- No lithological controls recognised
- Widespread potable aquifer, so minimum salinity recognised as key control
- Storage play fairway in centre of Rub'al-Khali Basin in UAE, Saudi Arabia and Oman



From: **OGCI Report: CCUS deployment challenges and opportunities for the GCC**

Conclusions: Density of Storage Play Fairways

- Up to 6 storage plays are present in one location
- Map is colour-coded, depending on play diversity
- Highest density in onshore UAE in axis of Rub’al-Khali Basin
- Significant “hot spots” also in western Oman, Kuwait and northwestern Saudi Arabia
- Note that this does not take into account:
  - varying storage play risk
  - the storage volume potential



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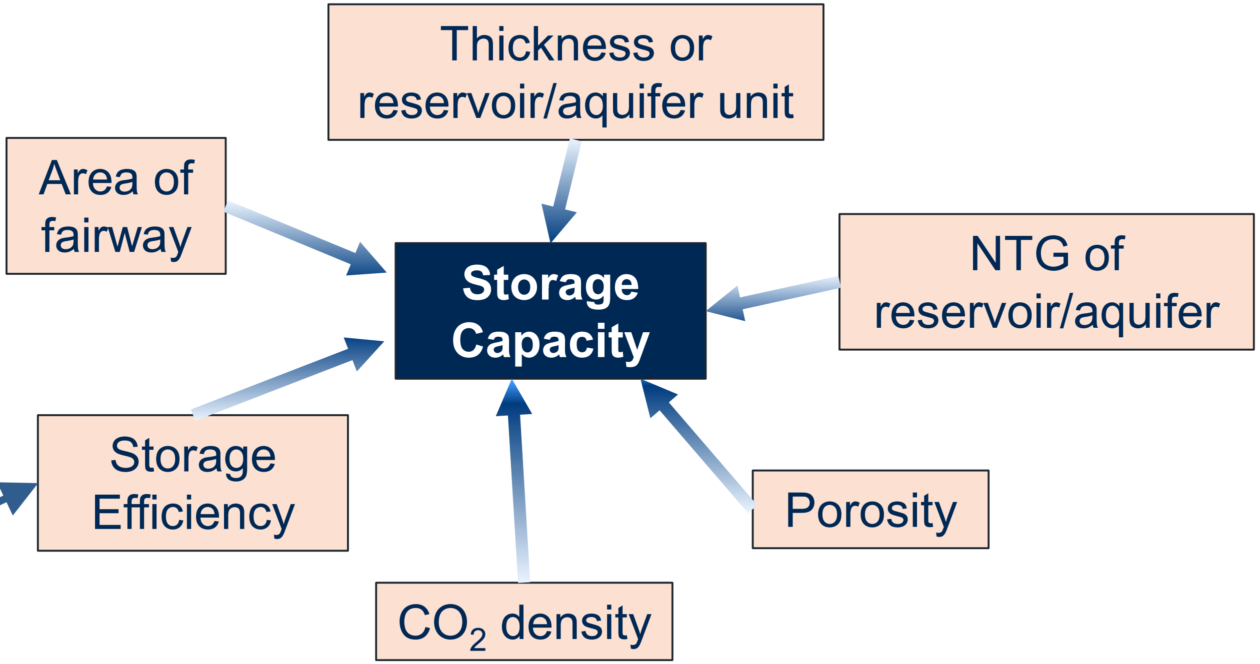
From: **OGCI Report: CCUS deployment challenges and opportunities for the GCC**

Estimation of Storable Quantities



Saline aquifers

- Volumes estimated stochastically from ranges of 6 input parameters
- Totals provide indicative range of total storage potential within saline aquifers
- Key uncertainty is storage efficiency that can be achieved (assumed range **1% to 6%**)

Ophiolites

- As estimate of **8.2 Gt** was made for the ophiolites

Saline Aquifers Total storage potential (Gt CO_2)		
Low	**Best**	**High**
40	**119**	**317**

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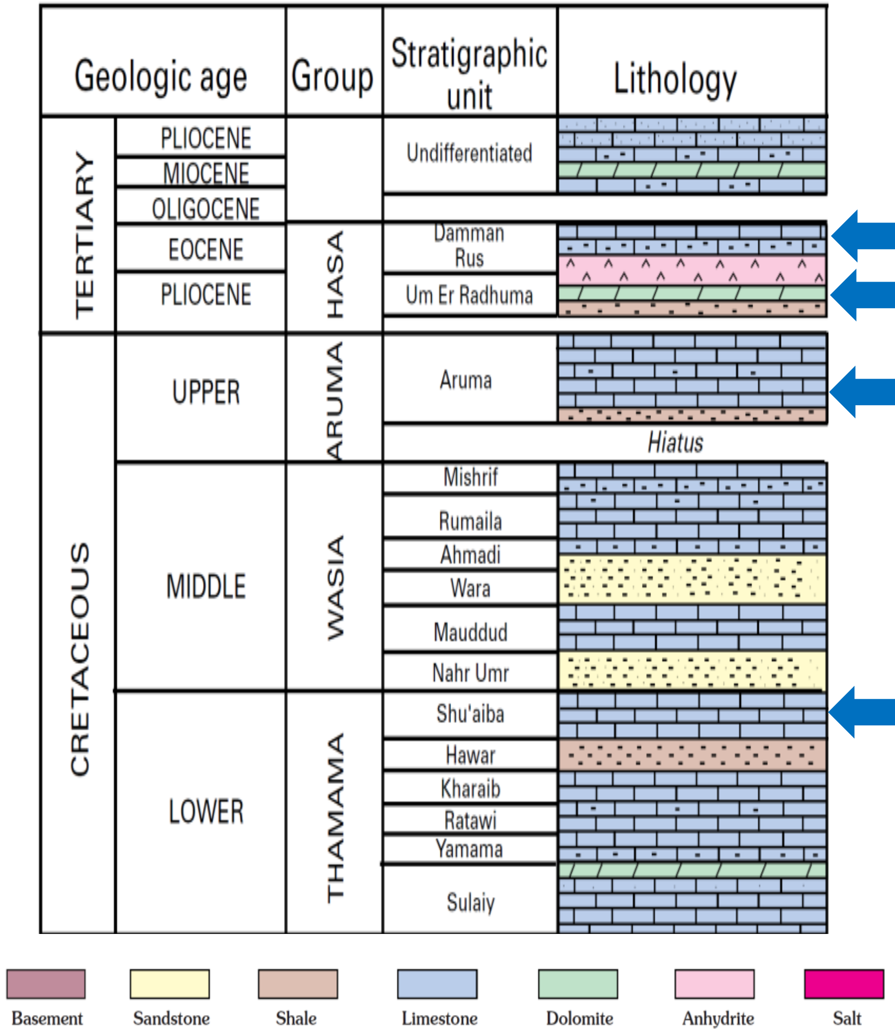
From: **OGCI Report: CCUS deployment challenges and opportunities for the GCC**

Case Study in UAE – Dynamic Modelling



Dammam

Umm Er Radhuma (UER)

Simsima

Shuaiba

All carbonate aquifers

From: **Ajayi et. al. 2019 (B)**

Case Study – Location Maps Onshore Abu Dhabi

The aquifers are in a syncline, meaning that there is not much chance of structural trapping and reliance must be placed on immobilisation.

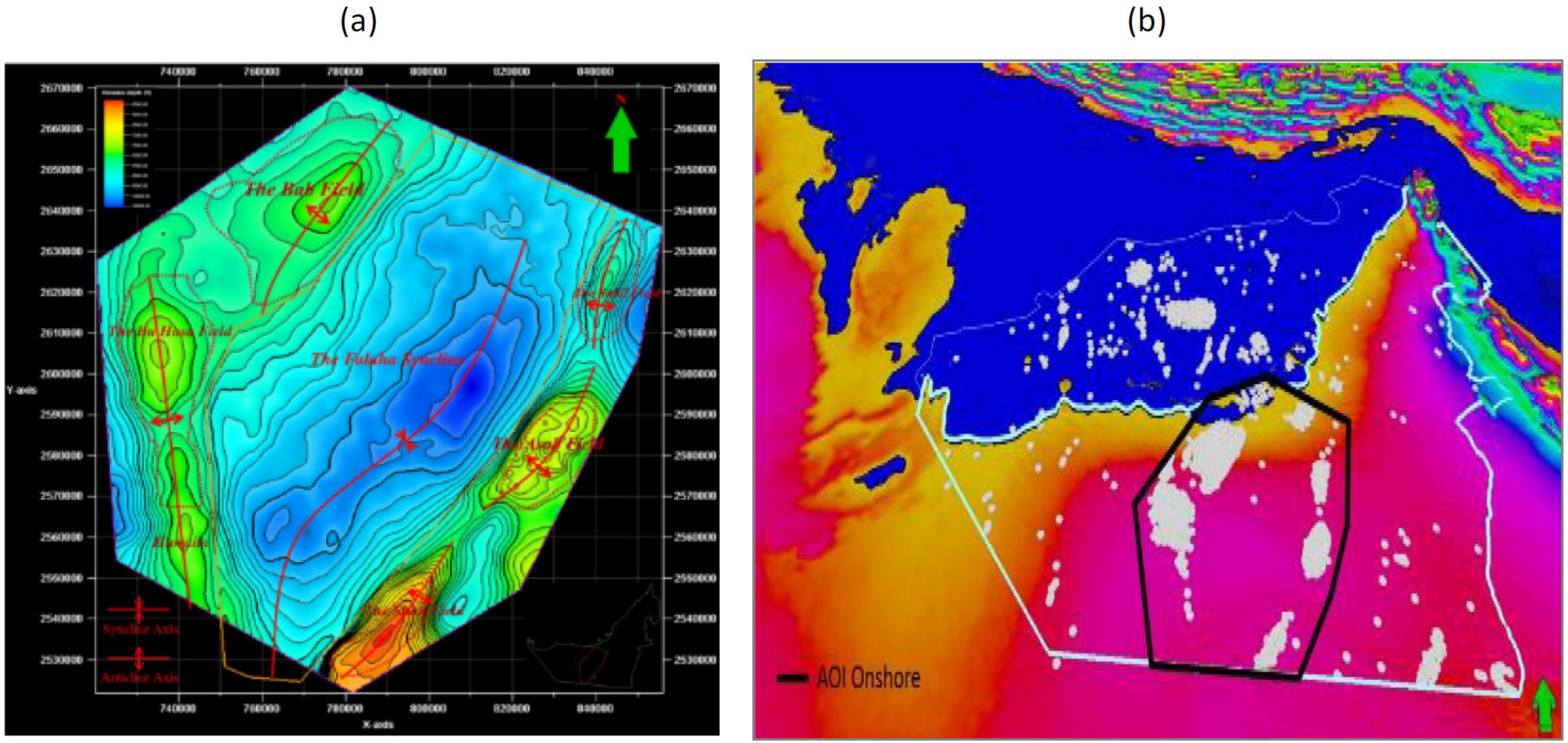


Fig. 2. (a) Top Shuaiba structure map in the Falaha syncline (orange line with converging arrows) and surrounding anticline structures (producing fields) (b) Area of interest of this study covering the main onshore oilfields UAE.

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From: **Ajayi et. al. 2019 (B)**

Case Study – Aquifer Properties

Table 1
Base Input Parameters for numerical simulations.

Parameter	Units	Simsima	Dammam	UER	Shuaiba
Average Porosity	fraction	0.2167	0.2516	0.2808	0.11
Average Permeability	*md*	66.06	87.49	161.9	4
Temperature	*F*	200	200	200	200
Injection duration	*years*	100	100	100	100
Salinity	*ppm*	100,000	100,000	100,000	100,000
Rock Compressibility	psi^{-1}	1×10^{-6}	1×10^{-6}	1×10^{-6}	1×10^{-6}
Initial Reservoir Pressure	*psi*	3000	900	2000	5000
Maximum Injection Pressure	*psi*	3900	1200	2500	6500

- Shuaiba would rank low, due to low porosity, low permeability and very high pressure (costly wells)
- UER would rank high, due to high porosity, high permeability and ideal pressure
- Dammam has initial pressure below critical.
- Study focused on the deeper reservoirs, **(Simsima and the Shuaiba),** because of their lower potential impact on surrounding fields

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From: **Ajayi et. al. 2019 (B)**

Case Study – Workflow

The study used CMG's GEM software. The priorities for estimating storable quantities are:

1. **Where will the plume go?** (free phase CO_2)
   - Run simulations with two immiscible phases.

2. **How much CO_2 will dissolve?** (free phase CO_2 and solubility)
   - Run case 1 but include solubility.

3. **What is the residual trapping component ?** (free phase CO_2 and residual trapping)
   - Run case 1 but include residual trapping (relative permeability end points).

4. **Combine all processes**

5. **How much CO_2 remains in the "free phase" and what is its long term fate?**

By running sensitivities with different components individually we get an idea of the significance and uncertainty inherent in each. By combining them into a single run we understand the interactions.

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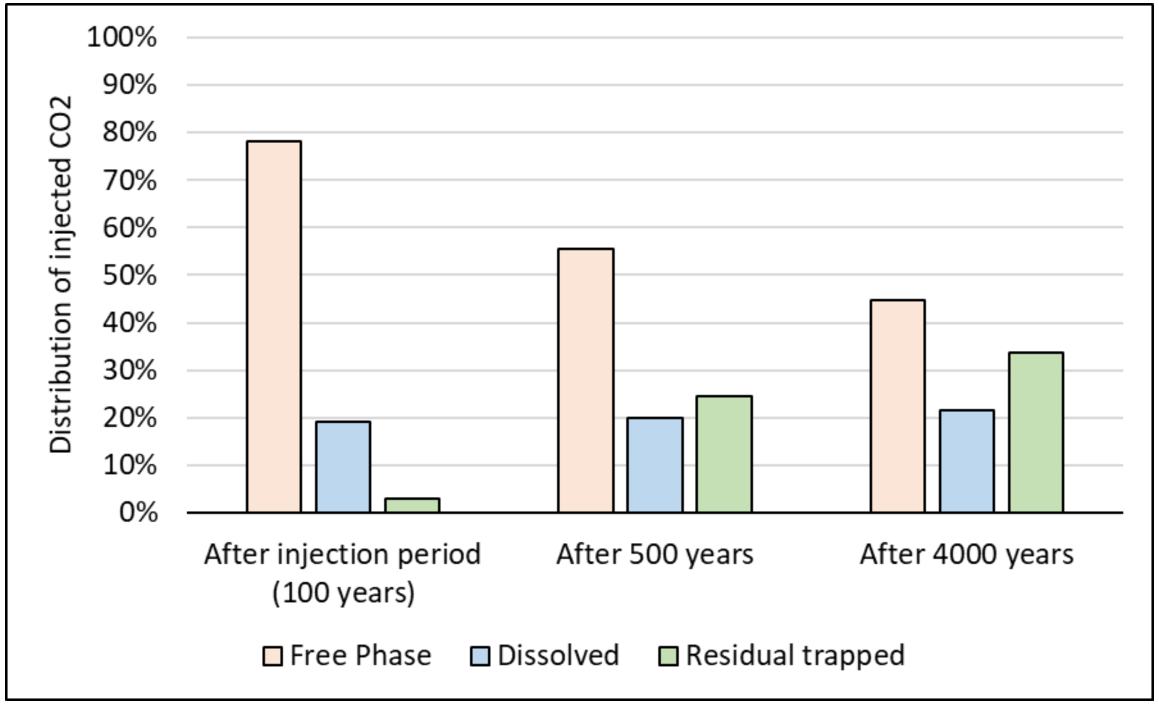
Case Study – Dynamic Modelling

Injection was into a single well completed deep in each formation.

Main Results:

- At early times, dissolution is the main immobilisation mechanism.
- As CO_2 attains its solubility limit, the amount of trapping provided by this mechanism diminishes.
- The supercritical CO_2 moves upwards via gravity segregation and is trapped by the cap rock. In this migration, brine displaces CO_2, which leads to gas trapping in the pores of the rock.
- After injection, migration of brine into the plume becomes rapid and the amount of gas trapped via residual trapping increases.

Diagram shows contribution of immobilisation processes for Shuaiba and Simsima combined



Results presented here are interpretations of published diagrams.

From: **Ajayi et. al. 2019 (B)**

Case Study – Volumetric Estimates

Table 3
Storage capacity estimates.

Formations	Storage Mass (Million Tonnes)		
	CSLF	DOE	Zhou (closed)
Dammam	1737	1895	128
UER	8455	8898	1050
Simsima	5003	5459	1140
Shuaiba	876	956	321

CSLF: Carbon Sequestration Leadership Forum

DOE : United States Department of Energy

Zhou: (see ref). Dependant on depth

Volumetric estimates of storable quantities based on published Efficiency Factors and Monte Carlo simulation:

- CSLF: 1.41% - 2.04% - 3.27%
- DOE: 0.51% - 2.00% - 5.50%
- Zhou: 0.2% to 0.8% estimated

Dynamic modelling showed the following storable quantities:

Shuaiba: **960 Mt (EF~2%)**

From: **Ajayi et. al. 2019 (B)**

CO_2 Storage in Depleted Gas Reservoirs

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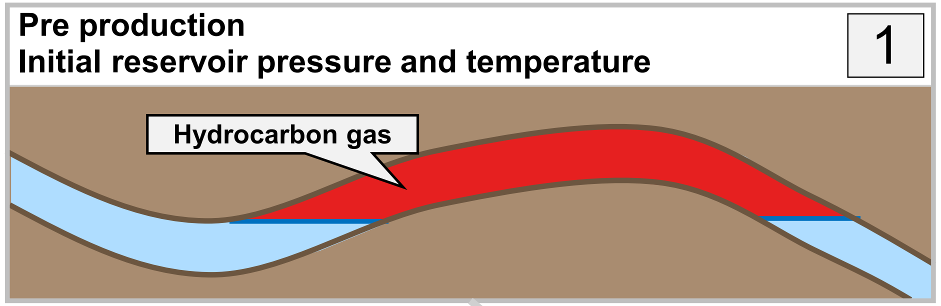
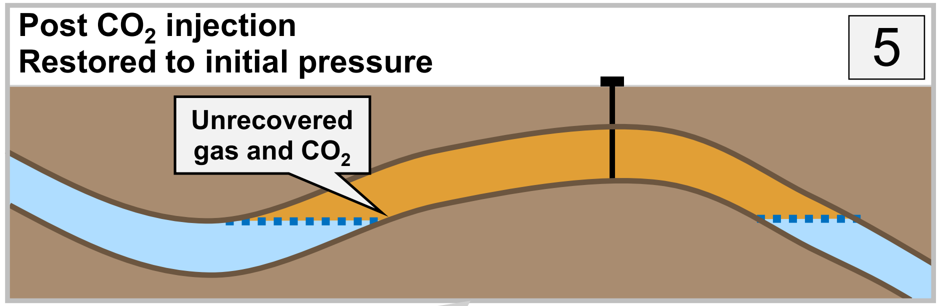
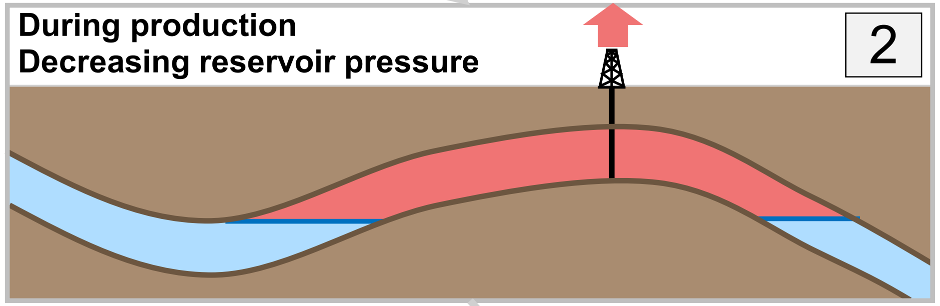
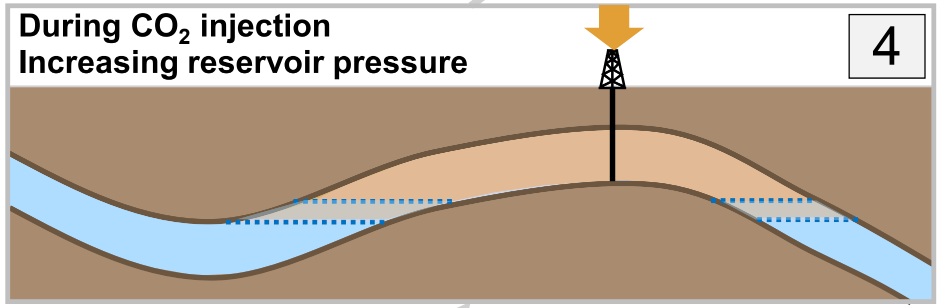
Conversion of Depleted Gas Reservoir to CO_2 Storage



CO_2 is injected into a depleted gas reservoir to restore pressure to its original level.

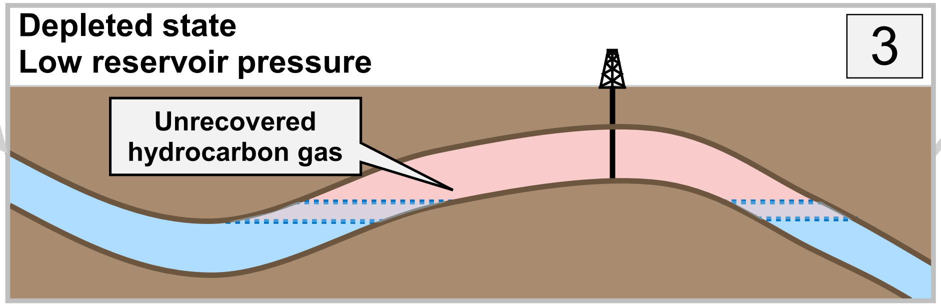






Two options:

1. Conventional geoscience estimation of pore volume.
2. Material balance.



We know how much came out so we should know how much can go back.

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Diagrams modified from: **Hattingh, S.K.F, in: OGCI Report (2022)**

Derivation of the Material Balance Equation

The material balance equation is derived by following six steps:

1. Estimate hydrocarbon pore volume at initial pressure (Pi):

   $$HCPVi = GRV * NTG * \emptyset * (1 - Swir)$$

2. Estimate GIIP:

   $$GIIP = HCPVi * Ei$$

3. Estimate volume of HC gas remaining at abandonment pressure (Pab):

   $$GIPab = GIIP - Gp$$

4. Estimate pore volume occupied by remaining HC gas at storage pressure (Psto):

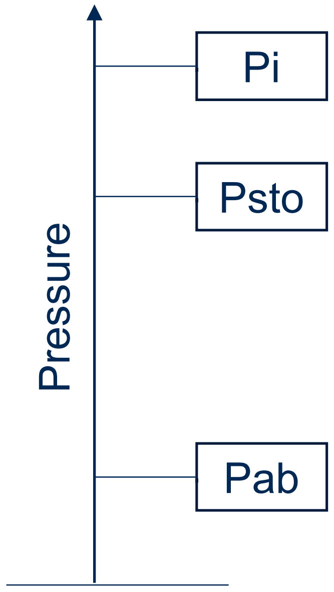
   $$HCPVsto = GIPab/Esto$$

5. Estimate pore volume available for CO_2 at storage pressure (Psto);

   $$COPVsto = HCPVi - HCPVsto$$

6. Estimate mass of CO2 that can be stored at storage pressure (Psto):

   $$CO2Msto = COPVsto * \rho CO2sto$$



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Depleted Gas Reservoirs- Material Balance

Combining the equations set out above leads to the following general material balance equation:

$$CO2Msto = \left(\left(GRV * NTG * \emptyset * (1 - Swir)\right) * \left(1 - \frac{Ei}{Esto}\right) + \frac{Gp}{Esto}\right) * \rho CO2sto$$

Where:

$CO2Msto$ mass of storable CO2 if the reservoir is returned to any pressure [metric tonnes].

$GRV, NTG, \emptyset, Swir$ gross rock volume [m^3], net-to-gross ratio [fraction], porosity [fraction] and irreducible water saturation [fraction].

$Esto$ HC gas expansion factor at storage pressure [sm^3/rm^3].

$\rho CO2sto$ density of CO2 at storage pressure [$tonnes/m^3$].

If the reservoir is restored to the original pressure by CO_2 injection, then the above equation becomes:

$$CO2Mi = \frac{Gp}{Ei} * \rho CO2i$$

Data requirements:

- Produced HC gas volume.
- HC gas PVT.
- Initial reservoir pressure.
- Initial reservoir temperature.

Where:

$CO2Mi$ mass of storable CO_2 if the reservoir is returned to its original pressure [metric tonnes].

Gp volume of HC gas that has been produced at surface temperature and pressure [m^3].

Ei initial HC gas expansion factor [sm^3/rm^3].

$\rho CO2i$ density of CO_2 at the original reservoir pressure [$tonnes/m^3$].

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Equations based on: **Hattingh, S.K.F, in: OGCI Report (2022)**

Limitations of the Basic Material Balance Equation

The material balance equations shown above do not account for:

> ❖ These points can to some extent be accounted for by expanding material balance.

Decreases

- ❖ Aquifer influx – can be very large.
- Heterogeneity – can be large.
- ❖ Condensate drop out – can be large in some cases.
- ❖ Impurities in injectant.
- ❖ Hysteresis in pore volume compressibility – expected to be small.

Increases

- Utilisation of aquifer surrounding pool – potentially large.
- ❖ Dissolution in connate water – small.

Other

- Thermal effects.
- Mixing with remaining HC gas (mixing, banking, segregation).
- Vaporization of connate water (with salt precipitation).

Dynamic simulation can be used to address most of these points.

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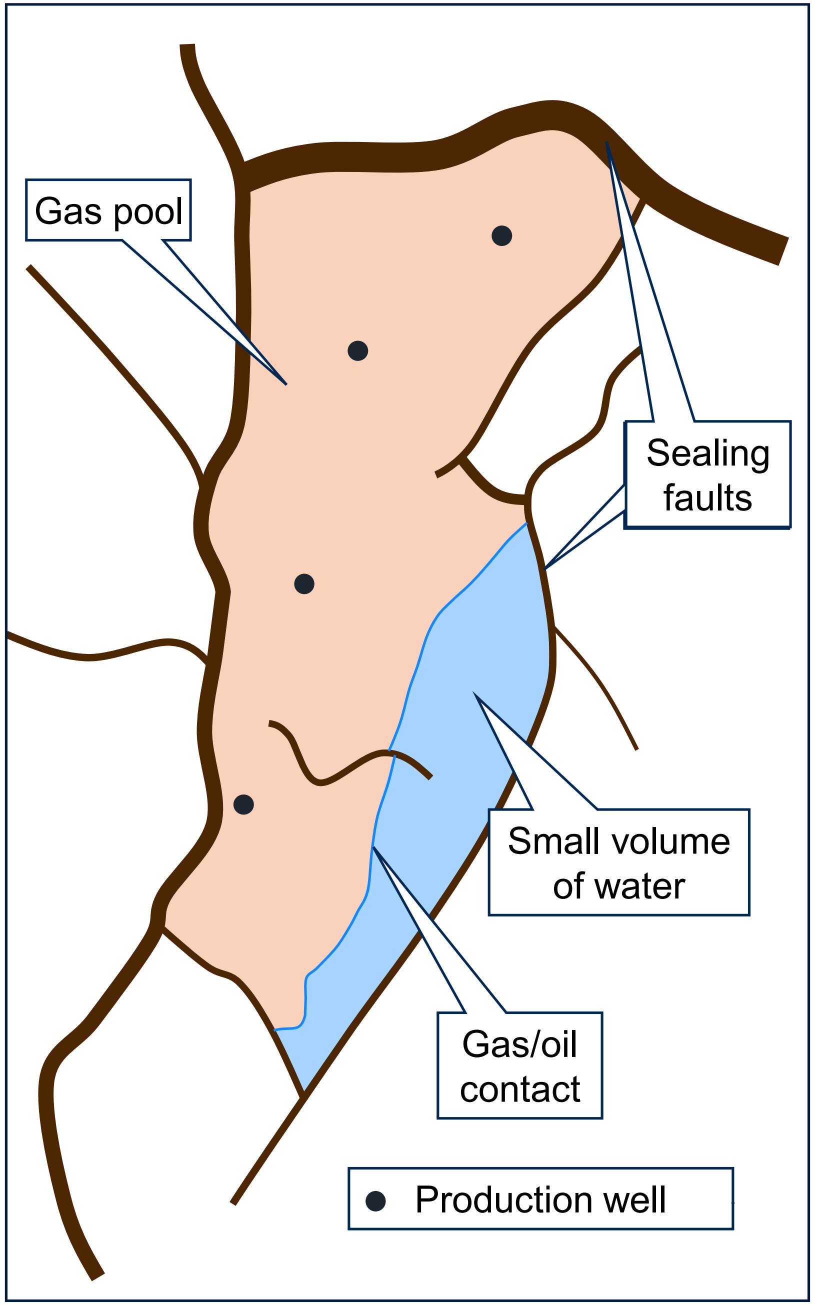
Reservoir Information

Reservoir Properties		
Parameter	**Value**	**Units**
GRV	750	mil rm3
NTG	0.85	fraction
Porosity	0.2	fraction
Water saturation	0.2	fraction
Permeability	50	mD
Reservoir depth	1,408	m
Reservoir temperature	160	degF
Reservoir pressure	2,015	psia
GIIP	**477**	**Bscf**

- Good quality sandstone
- Fault bounded on four sides
- Dry gas
- Developed with four wells
- Volumetric depletion
- Negligible aquifer



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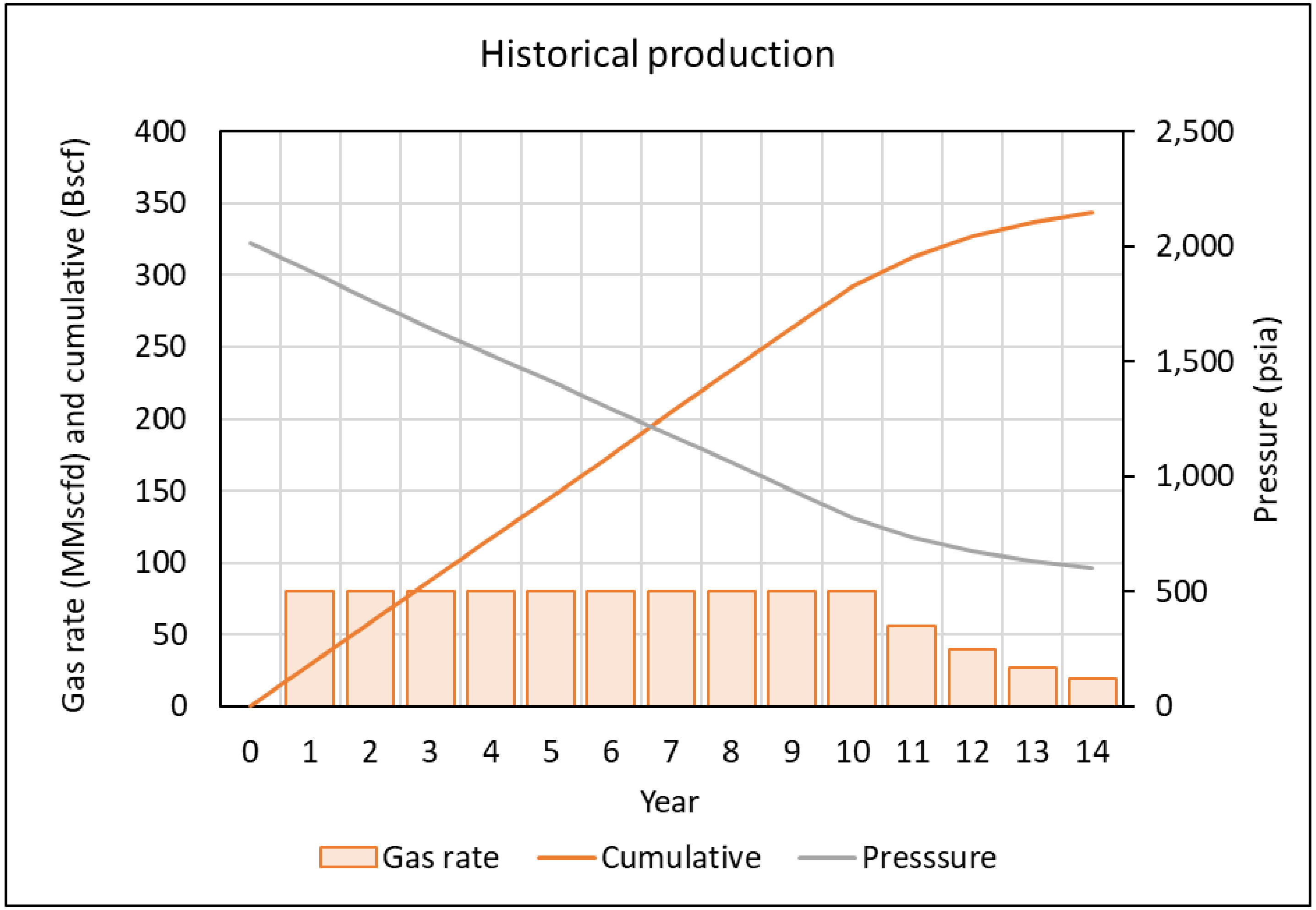
Field Performance

Plateau rate:	80 MMscfd
Minimum rate:	25 MMscfd
Plateau duration:	10 years
Field life:	14 years
Cumulative production:	344 Bscf
Recovery factor:	72%
Final pressure:	604 psia



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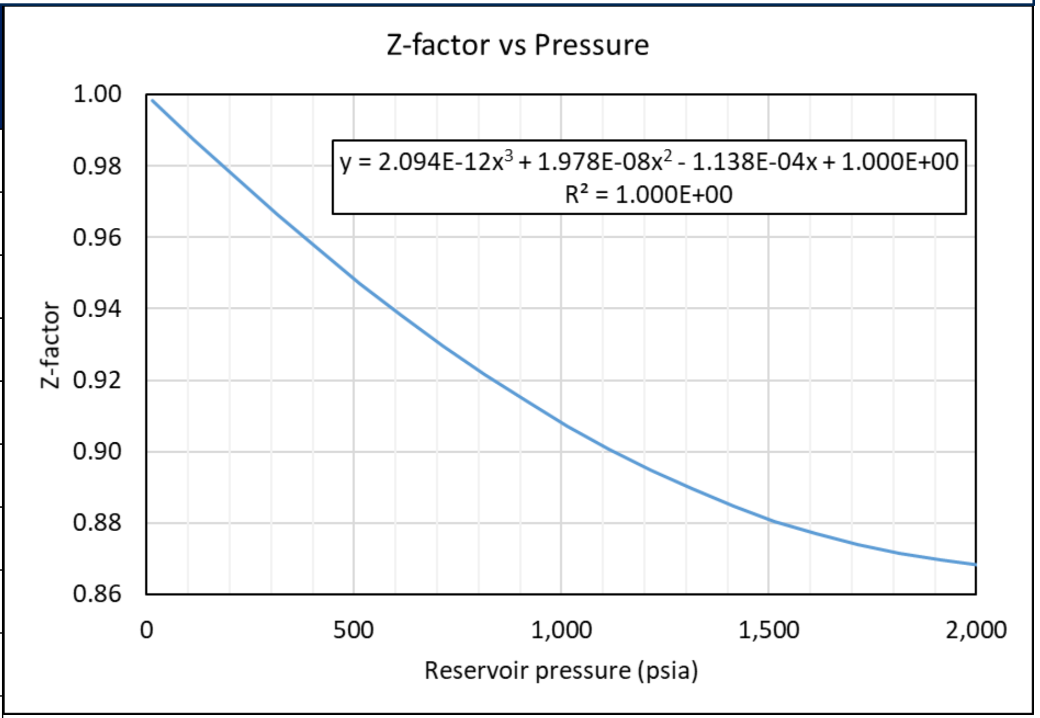
Reservoir Fluid and CO_2 Properties

Properties of Reservoir gas	
Component	**Mol %**
N2	3.48
CO2	1.31
C1	85.36
C2	5.90
C3	2.22
iC4	0.35
nC4	0.58
iC5	0.27
nC5	0.25
C6	0.28
Total	100.00



Properties of Pure CO_2		
Parameter	**Value**	**Units**
Surface Conditions		
Standard temperature	60	degF
Standard pressure	14.7	psia
Density of pure CO_2	0.001872	t/m³
	1.872	kg/m³
Reservoir Conditions		
Reservoir temperature	160	degF
Reservoir pressure	2,015	psia
Density of pure CO_2	**0.44**	t/m³
	441	kg/m³
Surface to Reservoir Conditions		
CO_2 GEF	**236**	svol/rvol

$$E = \frac{\rho_{reservoir}}{\rho_{surface}}$$

From Ti, Pi and HC gas initial Z-factor we calculate HC GEF= **132** svol/rvol

Estimating Storable Quantity to Initial Pressure

If the reservoir is restored to the original pressure by CO_2 injection, then the above equation becomes:

$$\boxed{CO2Mi = \frac{Gp}{Ei} * \rho CO2i}$$

Where:

$CO2Mi$	mass of storable CO_2 if the reservoir is returned to its original pressure [metric tonnes].
Gp	volume of HC gas that has been produced at surface temperature and pressure [m^3].
Ei	initial HC gas expansion factor [sm^3/rm^3].
$\rho CO2i$	density of CO_2 at the original reservoir pressure [$tonnes/m^3$].

<u>Assumptions</u>

- Pure CO_2
- No mixing with HC gas
- Theoretical maximum

Gp:	344	Bscf
Ei:	132	svol/rvol
$\rho CO2i$:	0.441	t/m3
$CO2Mi$:	**32.5**	Mt
	17,349	mil sm3
	613	Bscf

$$Vol = \frac{Mass}{0.00187}$$

Note that **344 Bscf** of hydrocarbon gas was produced, but the theoretical maximum storable quantity of CO_2 if the pressure is restored to the original pressure is **613 Bscf**, i.e. a ratio of **1.8**.

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Estimating Storable Quantities to Any Pressure

Initial P :	2,015	psia
Initial T :	160	degF
$\boldsymbol{Ei}$ **:**	132	svol/rvol
Storage T :	160	degF
$\boldsymbol{Gp}$ **:**	344	Bscf
Net HCPV :	102	mil rm^3

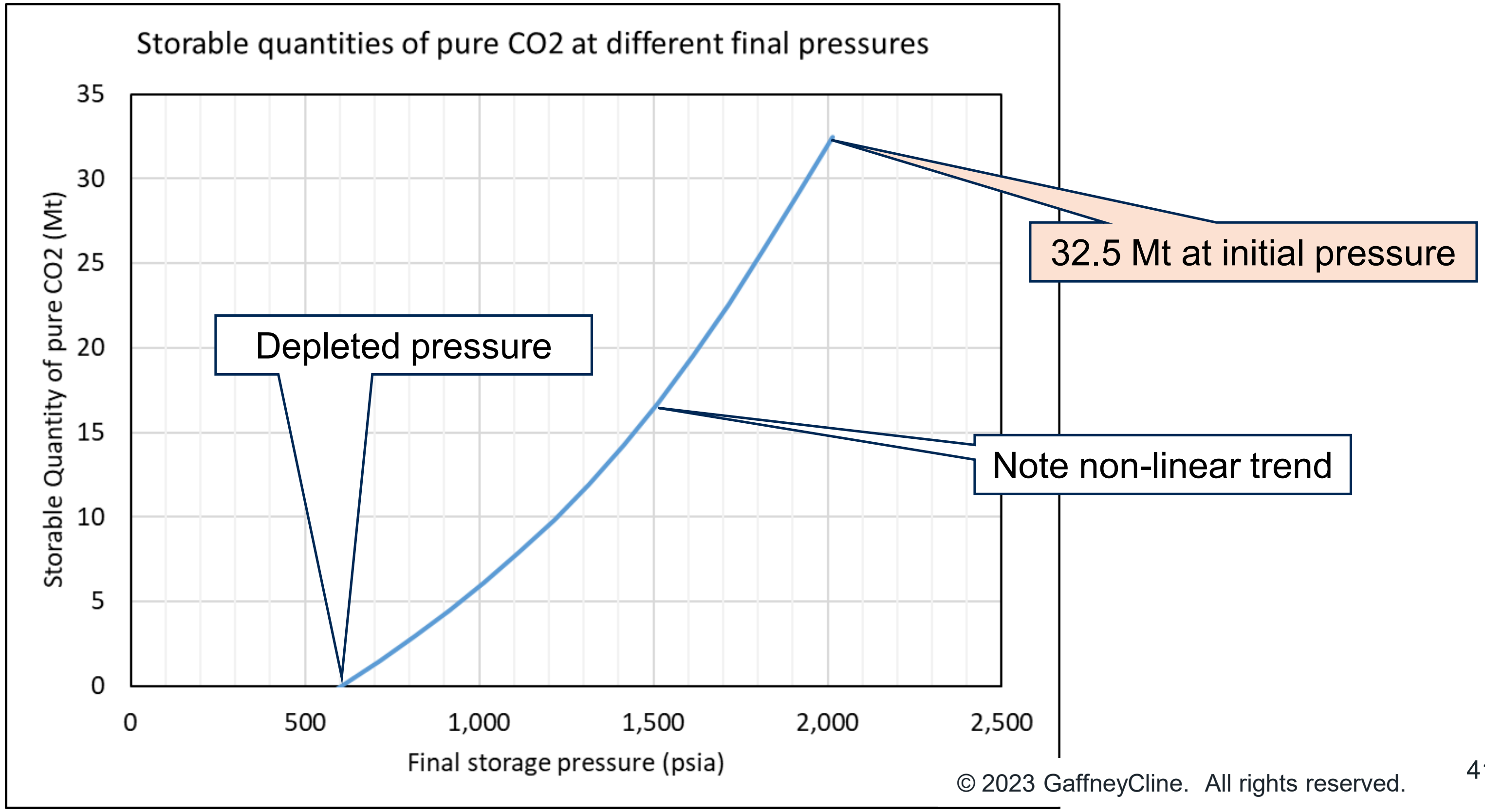
Combining the equations set out above leads to the following general material balance equation:

$$\boxed{CO2Msto = \left(\underbrace{\left(GRV * NTG * \emptyset * (1 - Swir)\right)} * \left(1 - \frac{Ei}{Esto}\right) + \frac{Gp}{Esto}\right) * \rho CO2sto}$$

Where:

$CO2Msto$	mass of storable CO2 if the reservoir is returned to any pressure [metric tonnes].
$GRV, NTG, \emptyset, Swir$	gross rock volume [m^3], net-to-gross ratio [fraction], porosity [fraction] and irreducible water saturation [fraction].
$Esto$	HC gas expansion factor at storage pressure [sm^3/rm^3].
$\rho CO2sto$	density of CO2 at storage pressure [tonnes/m^3].

$\boldsymbol{\rho CO2sto}$ and $\boldsymbol{Esto}$ are functions of final storage pressure and are obtained from PVT laboratory data or an EOS.



Assumptions

- Pure CO_2
- No mixing with HC gas
- Theoretical maximum

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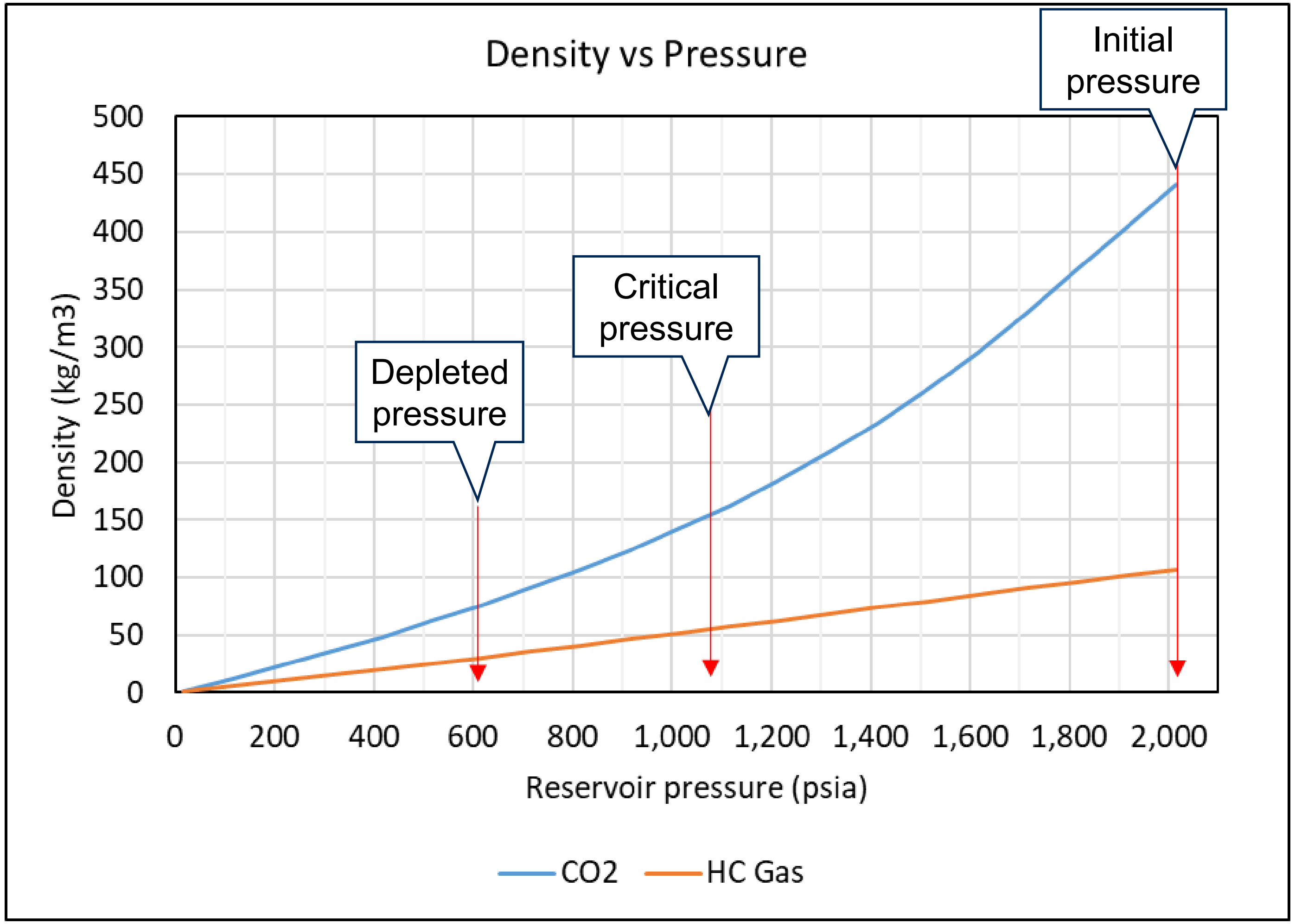
Where Does CO_2 Go When You Inject It?

- In most (all?) cases CO_2 is more dense than HC gas and will tend to sink (and mix) if injected into a gas column.
- It will accumulate at the base of the gas column, either at the gas-oil interface or at the gas-water interface.



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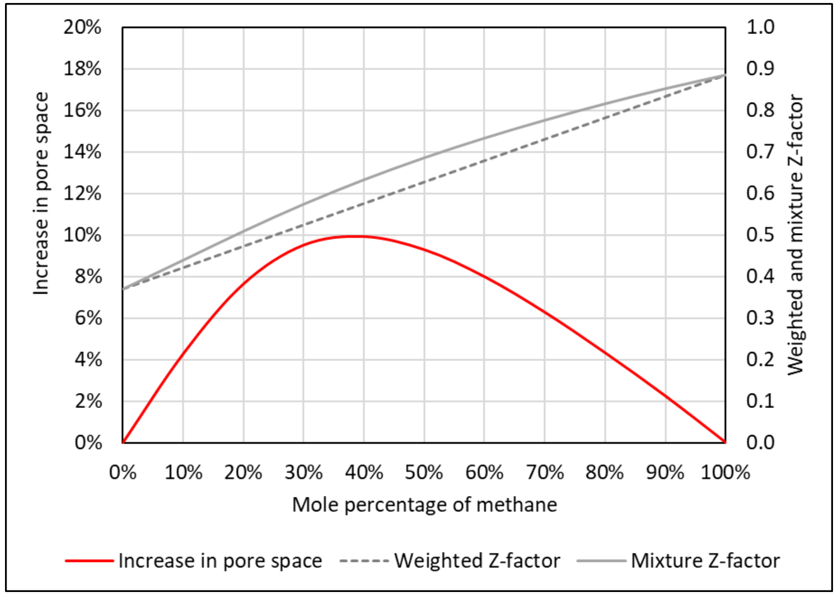
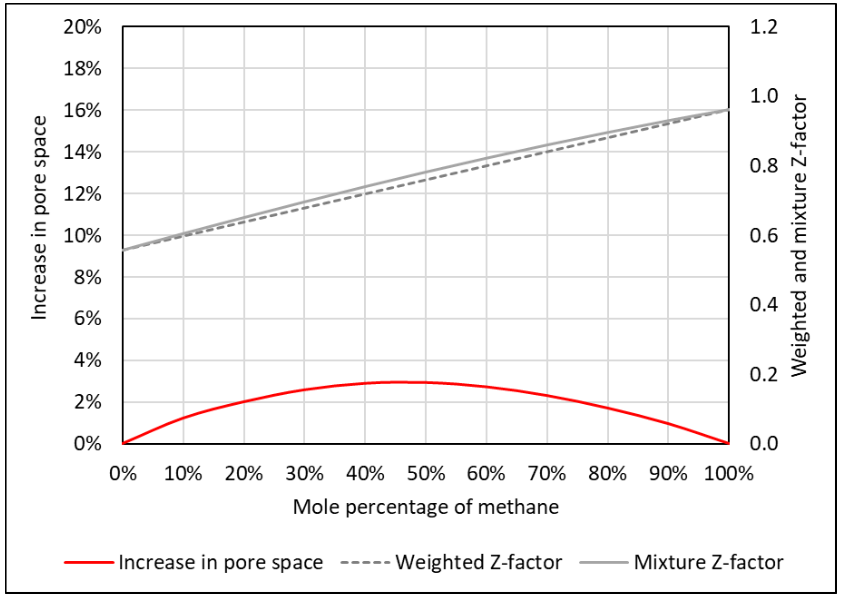
Other Aspects of Mixing - CO_2 and CH_4

Temperature: **131 degF.** Pressure: **2,160 psia**



Temperature: **185 degF**. Pressure: **3,566 psia**



Diagrams show the percentage increase in pore space needed to accommodate a given surface volume of gas if mixing occurs, compared with when no mixing occurs.

- Significant loss of storage space can occur if CO_2 mixes fully with residue hydrocarbon gas
- The effect is amplified at low temperature and low pressure
- Every situation is different and must be evaluated
- There are no reliable “rules of thumb”

In the previous example, it was shown that mixing of CO_2 with HC gas in the reservoir causes a loss of storable quantities of ~**8%**.

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Contamination of the Injected Wellstream (CO_2 with N_2)

Temperature: **131 degF.** Pressure: **2,160 psia**

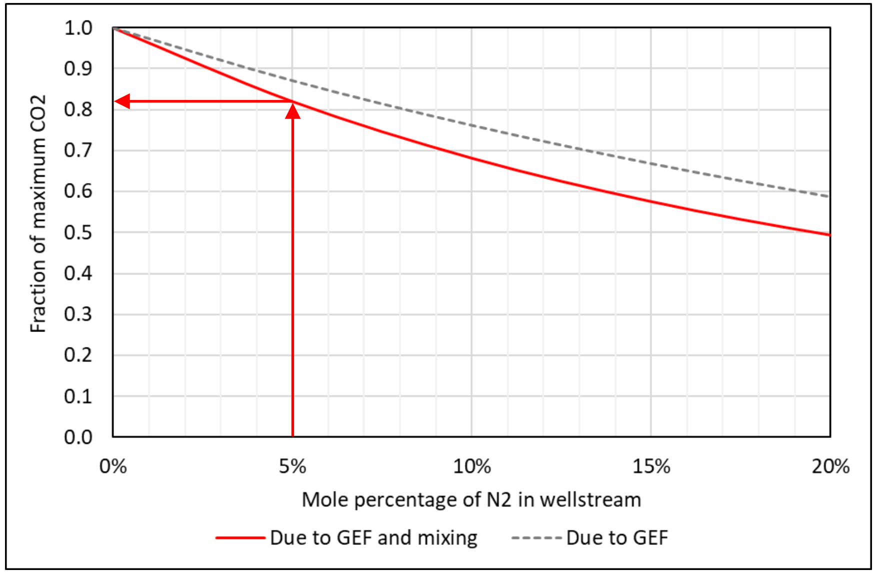

Diagram shows the quantity of CO_2 that can be stored in a given pore space when N_2 is present in the injection stream, expressed as a fraction of the quantity of pure CO_2.

- Large loss due to differences in GEF
  - GEF for CO_2: **348 svol/rvol**
  - GEF for N_2: **124 svol/rvol**
- Additional loss due to mixing

In this example, **5%** molar concentration of N_2 in the injection wellstream can reduce the storable quantity of CO_2 by **18%**.

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Some Case Studies

Dynamic Modelling in Depleted Gas – Typical Workflow

Start with a history matched dynamic model for depletion of HC gas

1. Convert to compositional formulation and re-establish the history match.
2. Run an injection forecast to initial pressure using existing production wells as injectors and pure CO_2 as injectant and compare with material balance.
3. Run scenarios with actual injectant composition, and with and without reservoir mixing (if possible) and compare with analytical calculations.
4. Run scenarios with different well configurations.
5. Set realistic maximum BHIP constraints and check tail.
6. Run parameter sensitivities and assess risks and uncertainties.
7. Optimise development based on cost effectiveness (well count vs storable quantities).
8. Evaluate long term monitoring options and build in risk mitigation strategies.
9. Run further simulations if appropriate:
    1. Geomechanical.
    2. Thermal – note that a reservoir might take decades to re-heat and this will be accompanied by pressure increases.
    3. Wellbore thermal – investigate wellbore vfp tables. Evaluate hydrate formation risk.

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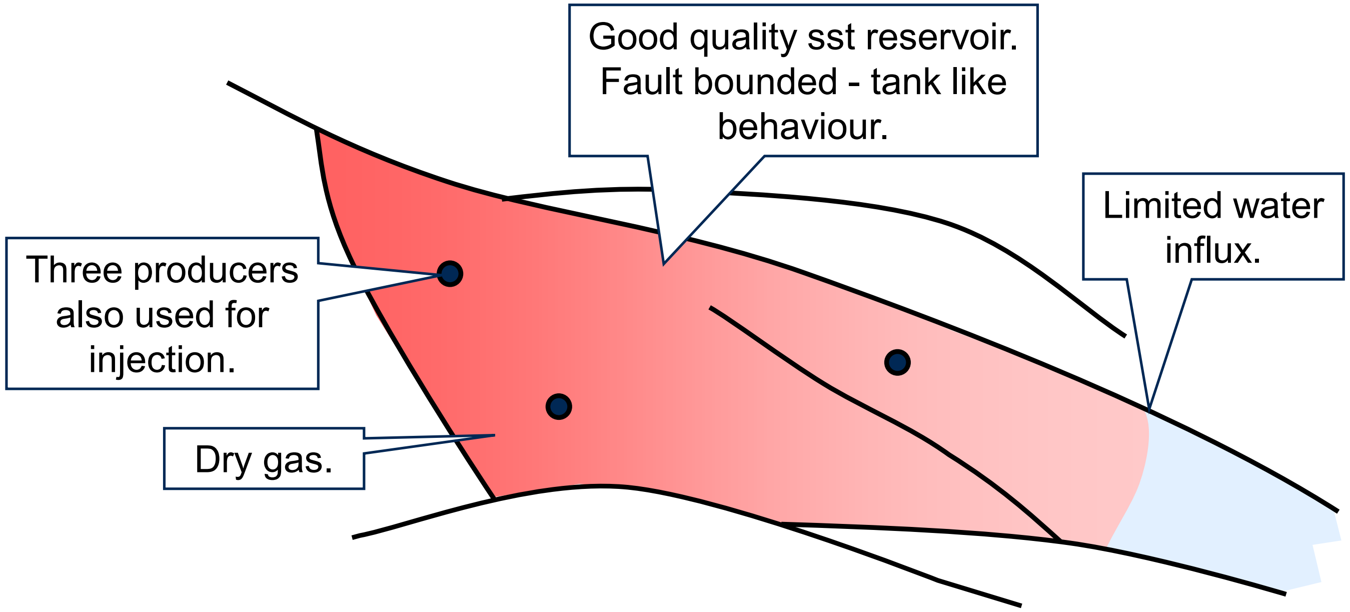
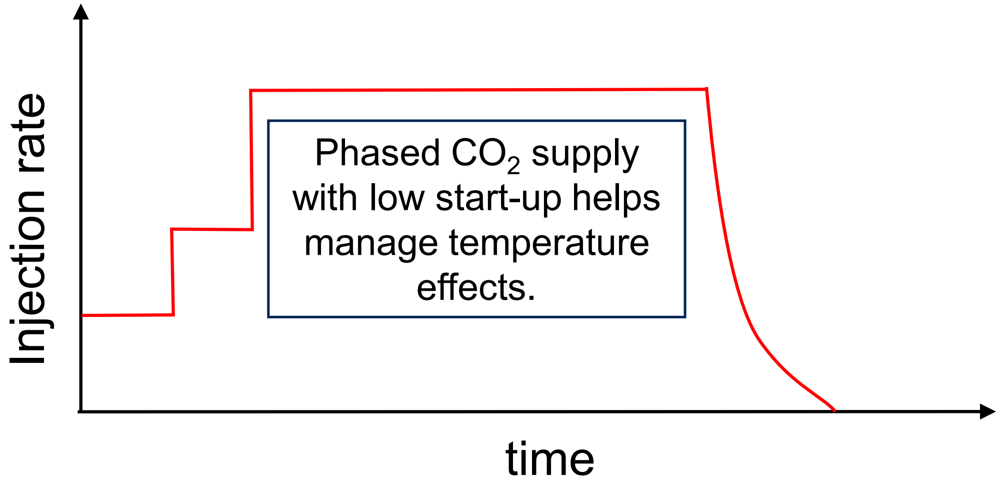
Depleted Gas Reservoirs – Example 1

Item	Quantity
Depth (m)	deep
Initial pressure (psia)	> hydrostatic
Temperature (degF)	normal
CO_2 density at initial P&T (t/m^3)	**0.65**
Depletion P (psia)	very low
Material balance CO_2 quantity (Mt)	**39.0**
Simulation CO_2 quantity (Mt)	**36.1**
Difference (%)	**-7%**



- Some water influx.
- Some mixing with remaining HC gas.
- Tiny hysteresis effect.
- Good CCS storage candidate.

<u>In reality</u>: The storable quantity will be lower because the final pressure will not be permitted to exceed hydrostatic.



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Depleted Gas Reservoirs – Example 2

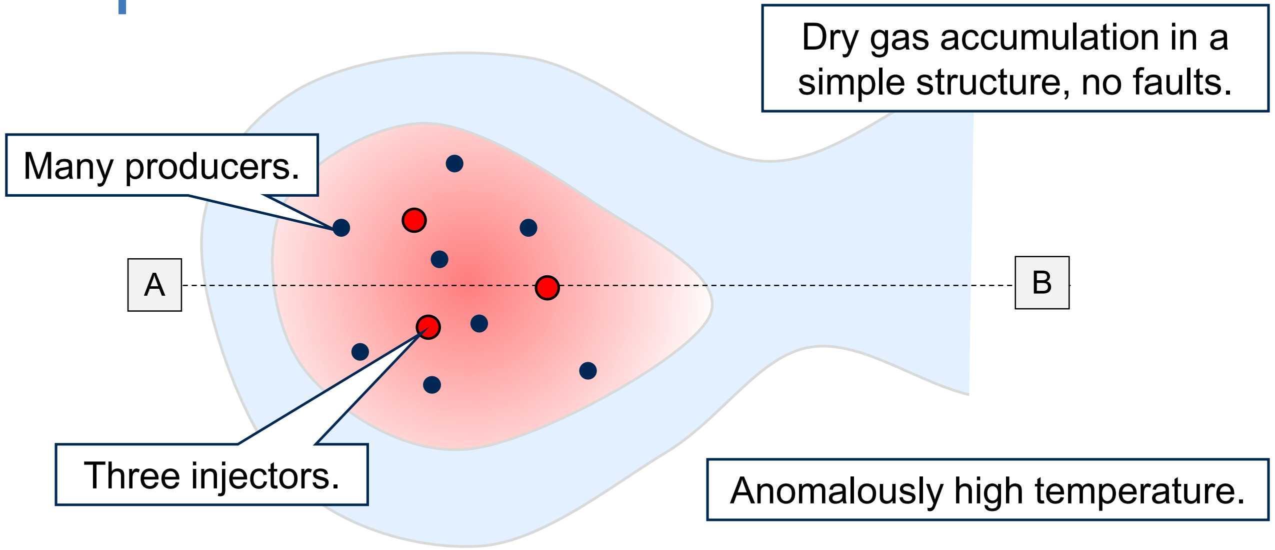
Item	Quantity
Depth (m)	moderate
Initial pressure (psia)	hydrostatic
Temperature (degF)	> normal
CO_2 density at initial P&T (t/m^3)	**0.33**
Depletion P (psia)	moderate
Material balance CO_2 quantity (Mt)	**17.4**
Simulation CO_2 quantity (Mt)	**14.8**
Difference (%)	**-15%**

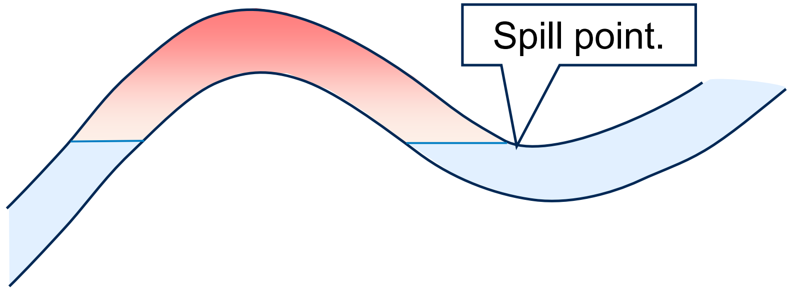
- History match for gas production is reasonable, but heterogeneity is a concern for CCS.
- Simulation sensitivities to define range of uncertainty:

11.4 : 14.8 : 17.0 Mt (low, mid, high).

-35% : -15% : -5%

<u>In reality</u>: More wells can be drilled, and storable quantities could be higher if the aquifer can be used.





- Sand-shale layers.
- Scatter in P/Z plots.
- Differential depletion in wireline pressures.
- Concerns about communication.

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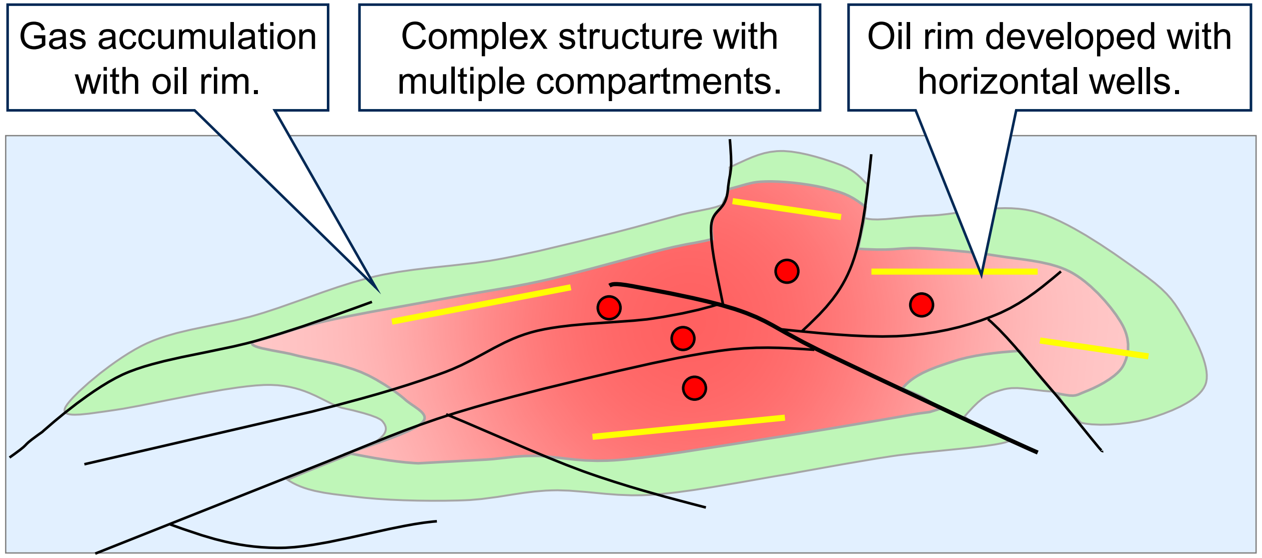
Depleted Gas Reservoirs – Example 3

Item	Quantity
Depth (m)	very shallow
Initial pressure (psia)	> hydrostatic
Temperature (degF)	> normal
CO_2 density at initial P&T (t/m^3)	**0.26**
Depletion P (psia)	moderate
Material balance CO_2 quantity (Mt)	**12.0**
Simulation CO_2 quantity (Mt)	**8.4**
Difference (%)	**-30%**

- Aquifer influx.
- Complex geology.
- Complex fluids.
- Shallow and not much scope for increasing BHIP.
- Storable quantities could be even lower.

In reality: Not an optimal CO_2 storage site!



During production:

- Water encroached into oil.
- Oil encroached into gas.
- Gas blowdown.

Dynamic modelling:

- Good black oil history match of oil, water, gas, pressures.
- Converted to compositional formulation for CCS.

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Middle East OGCI Study

$$CO2sto = UR * SF * Uplift * EF$$

$CO2sto$ = volume of CO_2

UR = ultimate recovery volume of HC gas

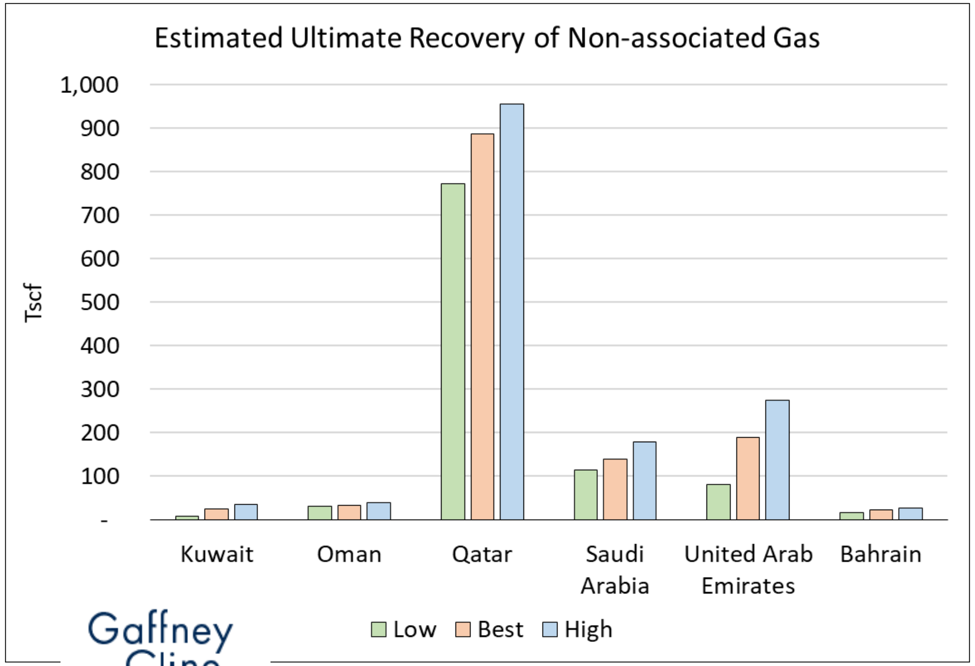
SF = suitability factor

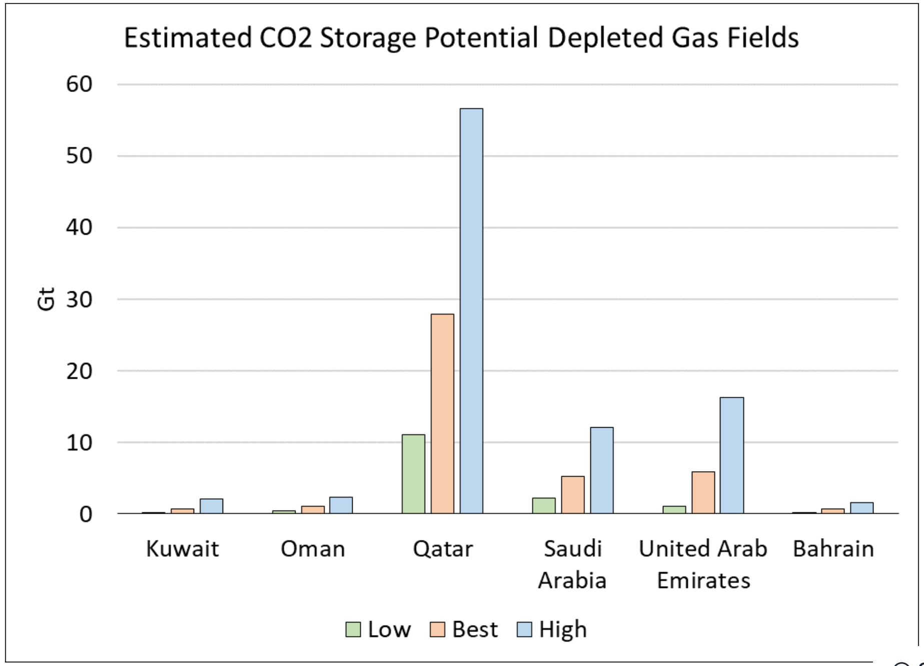
$Uplift$ = ratio of CO_2 to HC gas

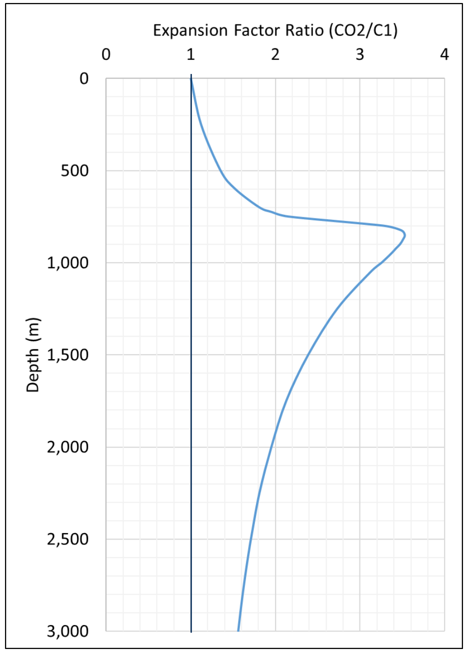
EF = efficiency factor

Country	EUR Free Gas (Tscf)			CO_2 Storage (Tscf)			CO_2 Storage (Gt)		
	Low	Best	High	Low	Best	High	Low	Best	High
Kuwait	7	24	34	2	14	38	**0.1**	**0.7**	**2.0**
Oman	31	33	39	8	20	43	**0.4**	**1.0**	**2.3**
Qatar	772	886	956	209	527	1,071	**11.0**	**27.9**	**56.7**
Saudi Arabia	114	138	178	41	99	228	**2.2**	**5.2**	**12.0**
United Arab Emirates	79	188	274	21	112	307	**1.1**	**5.9**	**16.2**
Bahrain	16	21	26	4	12	29	**0.2**	**0.7**	**1.5**
Total	**1,020**	**1,291**	**1,507**	**286**	**784**	**1,716**	**15.1**	**41.5**	**90.8**

Parameter	Low	Best	High
SF	0.3	0.5	0.7
Uplift	1.2	1.4	1.6
EF	0.75	0.85	1.00







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Summary: Depleted Reservoirs vs Aquifers

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Saline Aquifers vs. Depleted Gas Fields

	Depleted Reservoirs	Saline Aquifers
Advantages	• Well characterized by data • Confirmed trap and seal • Infrastructure	• Relatively larger storage capacity • Potential for multiple seals
Disadvantages	• Legacy wells may leak • Relatively smaller storage capacity	• Unknown seal integrity • Extensive monitoring needed

Thank you for your attention

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