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Cockrell School of Engineering

SIGNIFICANCE OF HYDRATE FORMATION DURING CO_2 STORAGE IN DEPLETED GAS STORAGE

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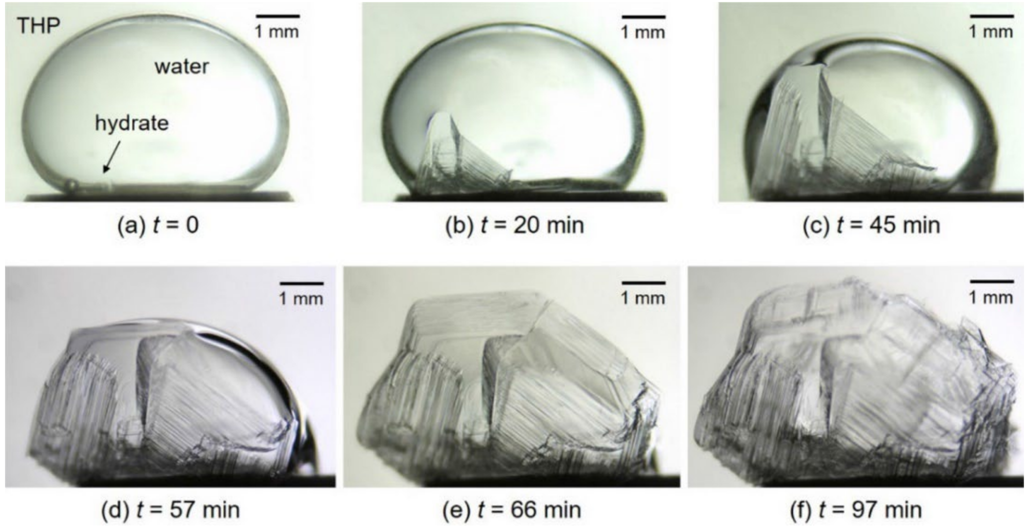
Problem Statement

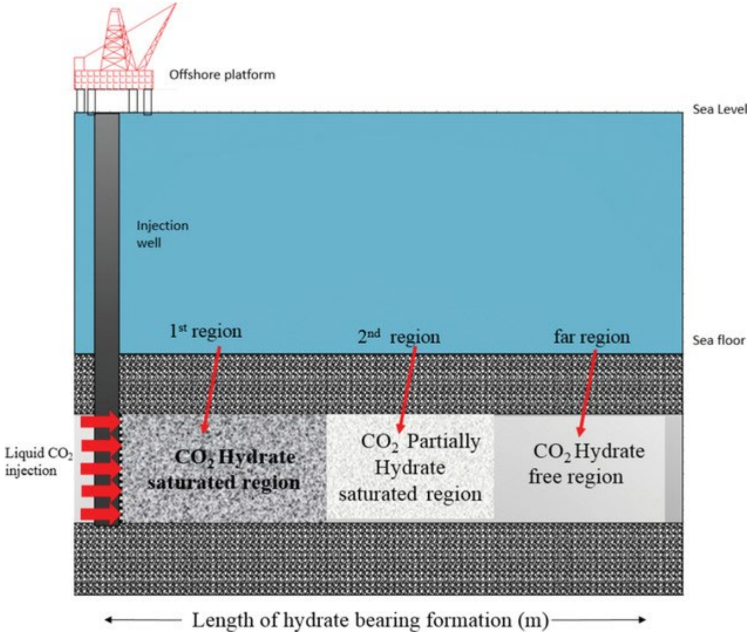
- Gas hydrates are a crystalline solid formed of water and gas.
- Injection of high-pressure cold CO_2 into porous formations can lead to the formation of hydrates.
- This effect intensifies the Joule-Thomson cooling which causes a drop in temperature, and can potentially lead to hydrate conditions.
- Hydrates can lead to severe injectivity reduction and even plugging of the reservoir areas surrounding the well.



Maruyama et al. (2021)

Hydrates in the pipelines/wellbore

Hydrates in the porous media



Ahmad et al. (2019)

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Hydrate modeling and risk assessment approaches

Phase diagram approach (qualitative):

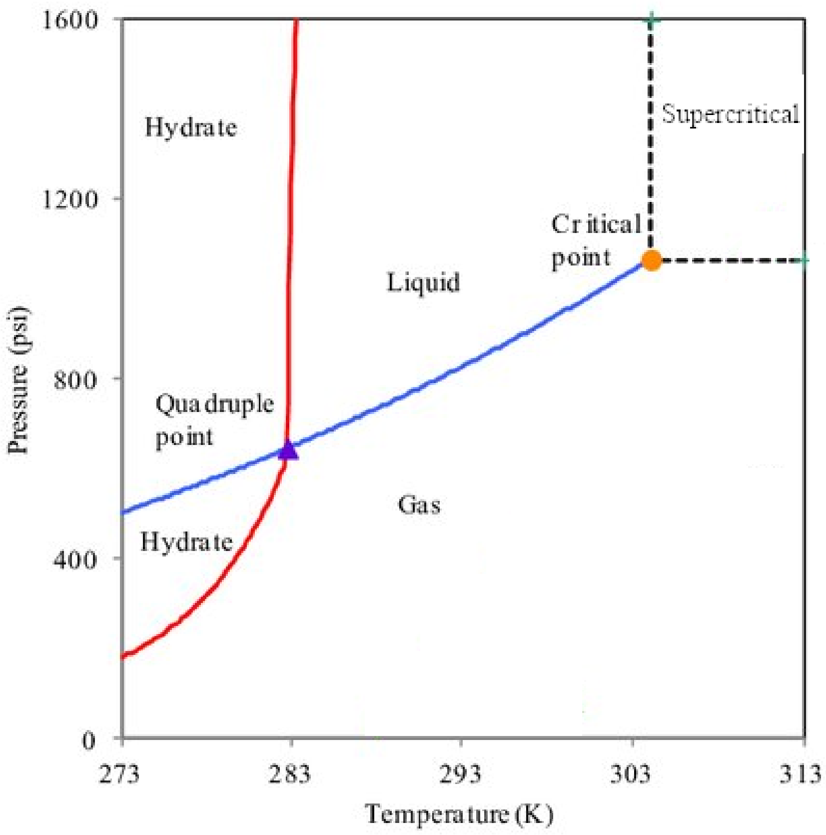
- Check reservoir conditions to determine risk of hydrates.
- Can use activity-based model to estimate phase diagram of gas mixtures and effect of inhibitors.

Flash calculation:

- Combines conventional EoS flash approach with the van der Waals and Platteeuw (1959) model.

Hydrate kinetics:

- Use kinetic models to quantify the amount of hydrate formed or dissociated over time.
- Both equilibrium and transient models are reported in the literature.



modified from Ramachandran et al. (2014)

CMG reservoir simulator capabilities

Compositional & Unconventional Simulator
GEM

- GEM features
  - Fully compositional thermal model
    - Hydrocarbon phases modeled with PR or SRK EoS
    - No mass transfer between the water phase and the HC phases
    - Water vaporization can be included with the OGW flash

Thermal & Advanced Processes Simulator
STARS

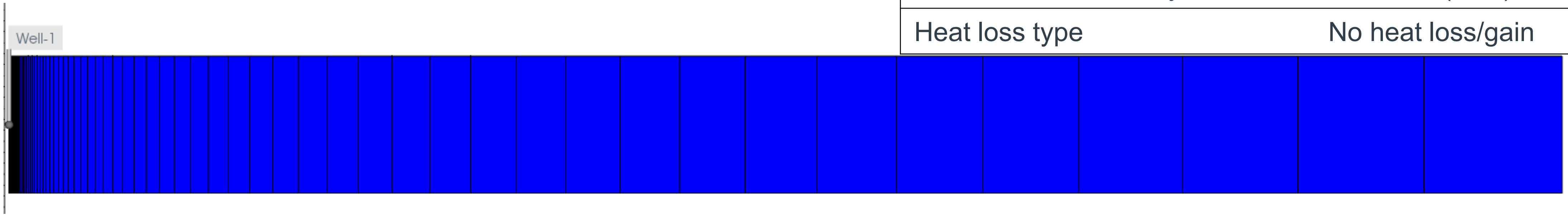
- STARS features
  - Thermal model with Joule-Thomson (Lee-Kesler model)
    - SRK EoS without binary interaction coefficients for gas phase
    - Liquid phases are modeled as slightly compressible fluids
    - K-values used for phase equilibrium (includes water-gas equilibrium for dry-out)
    - Kinetic model based on Kim et al. (1987)

VERIFICATION OF THE THERMAL MODEL WITH TOUGH2

Comparison with TOUGH2 (Open Boundary)

- Constant injection rate (3 kg/s)
- CH_4 gas reservoir and CO_2 is injected
- Initial water saturation is 0.2
- Constant diffusion coefficients
- Include heat conduction
- Data taken from:
  - "Oldenburg, C. M., Joule-Thomson cooling due to CO_2 injection into natural gas reservoirs. Energy Conversion & Management, Vol 48, pp. 1808-1815, 2007"

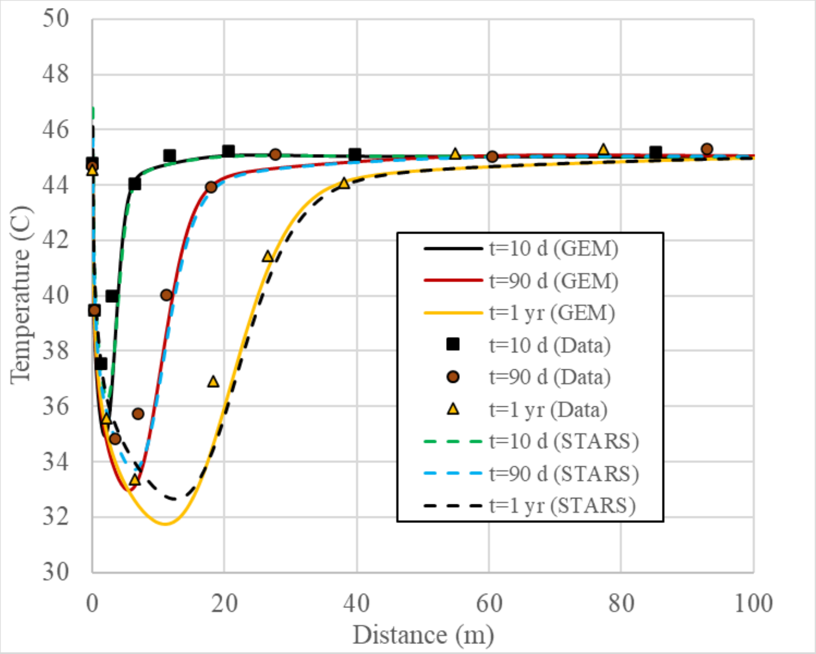
Properties	Value
Reservoir temperature	45 C
Injection temperature	45 C
Well radius	0.0097 m
Reservoir radius	1130 m
Thickness	50 m
Porosity	0.3
Permeability	5 mD
Initial pressure	5 Mpa
Injection rate	13.9527×10^4 sm^3/d (3 kg CO_2/s)
Production rate	7.1468×10^4 sm^3/d (0.56 kg CH_4/s)
Rock heat capacity	1000 J/(kg°C)
Rock heat conductivity	2.51 W/(m°C)
Heat loss type	No heat loss/gain

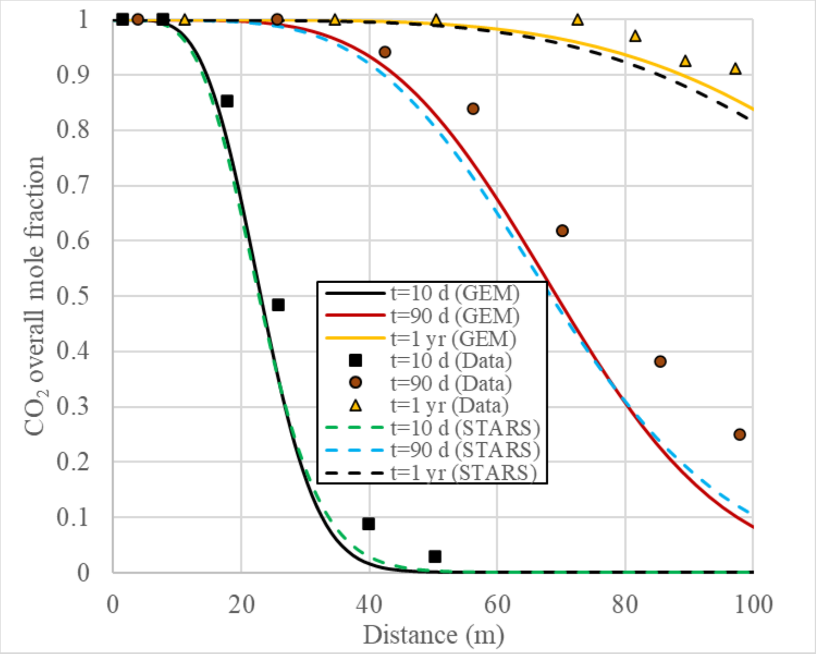


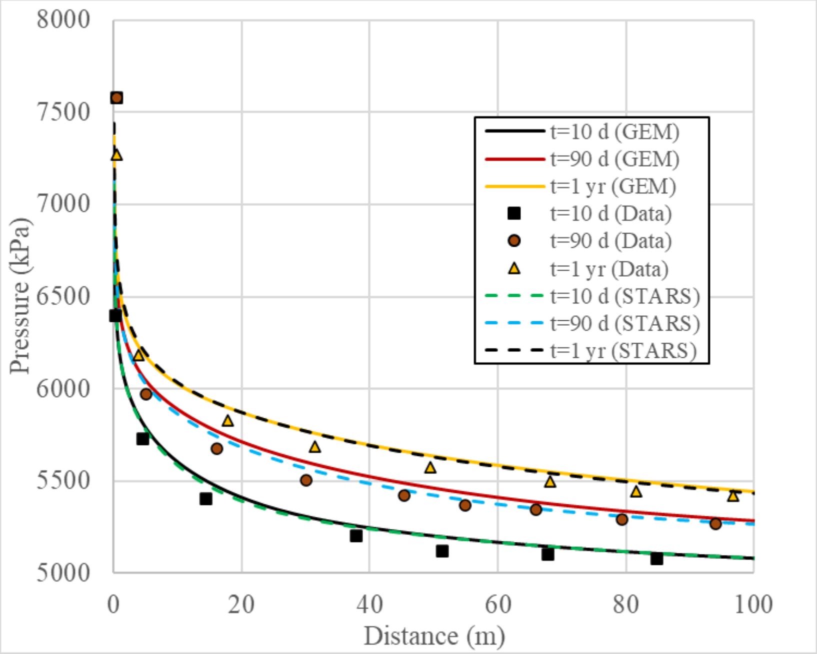
STARS and GEM vs TOUGH2 (Open Boundary)

Temperature, CO_2 Mole fraction, and Pressure profiles

*Data refers to TOUGH2







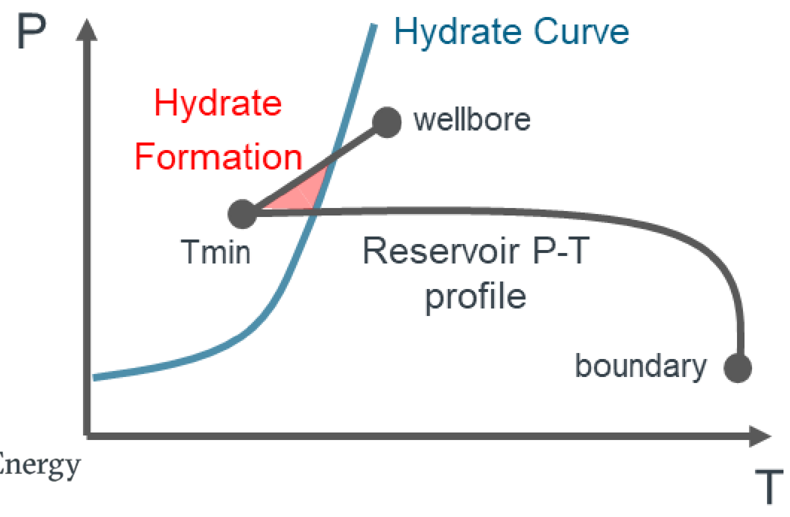
- GEM and STARS show good agreement of results.
- Discrepancies with TOUGH2 could be caused by different grid size and differences in property calculation between the simulators.

HYDRATE RISK ASSESSMENT WITH GEM

Hydrate Risk Assessment with CMG GEM (Phase diagram approach)

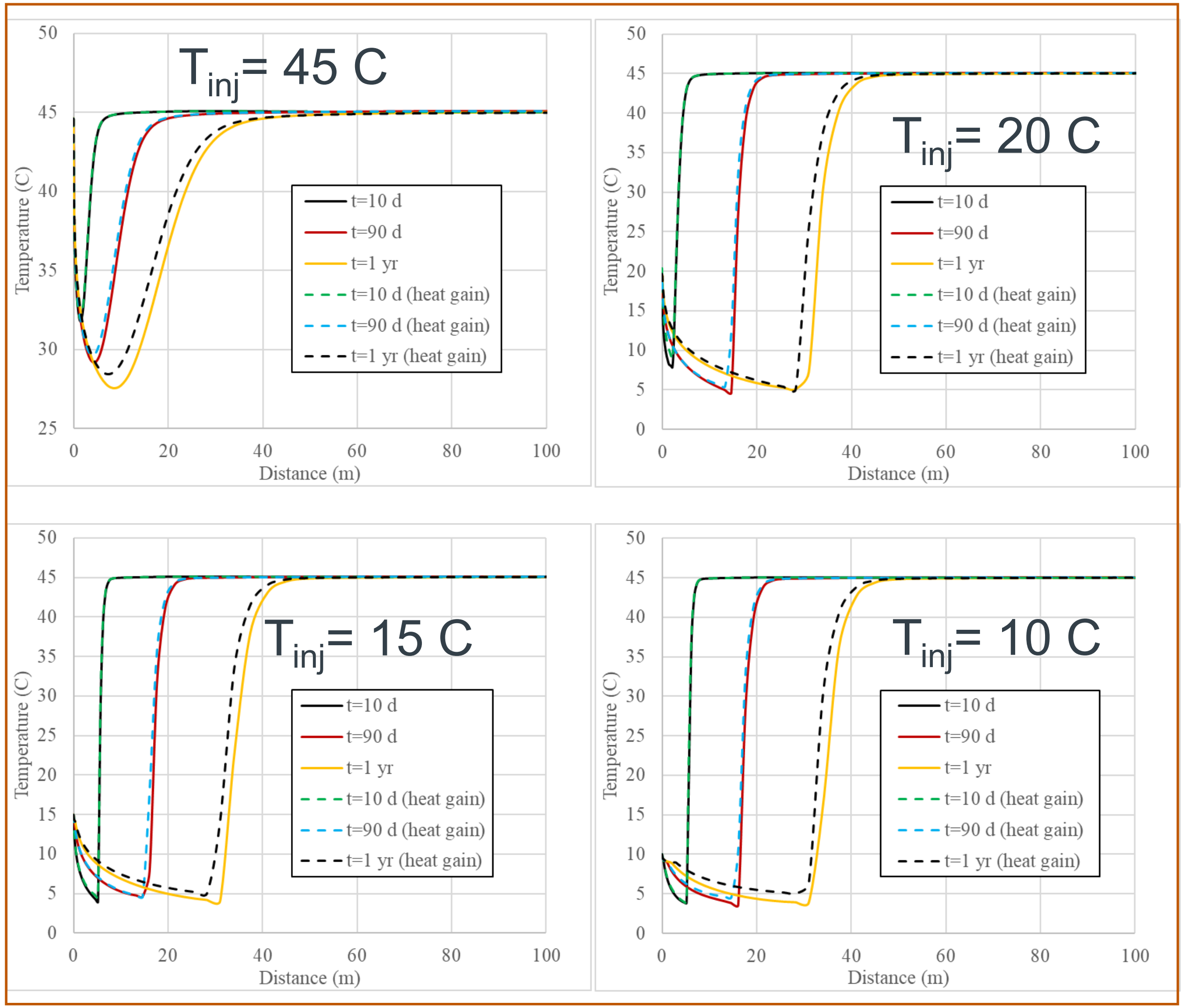
- Constant rate CO_2 injection
- Initial fluid saturations = S_w : 0.2 and CH_4
- PR EoS is used
- Model heat conduction

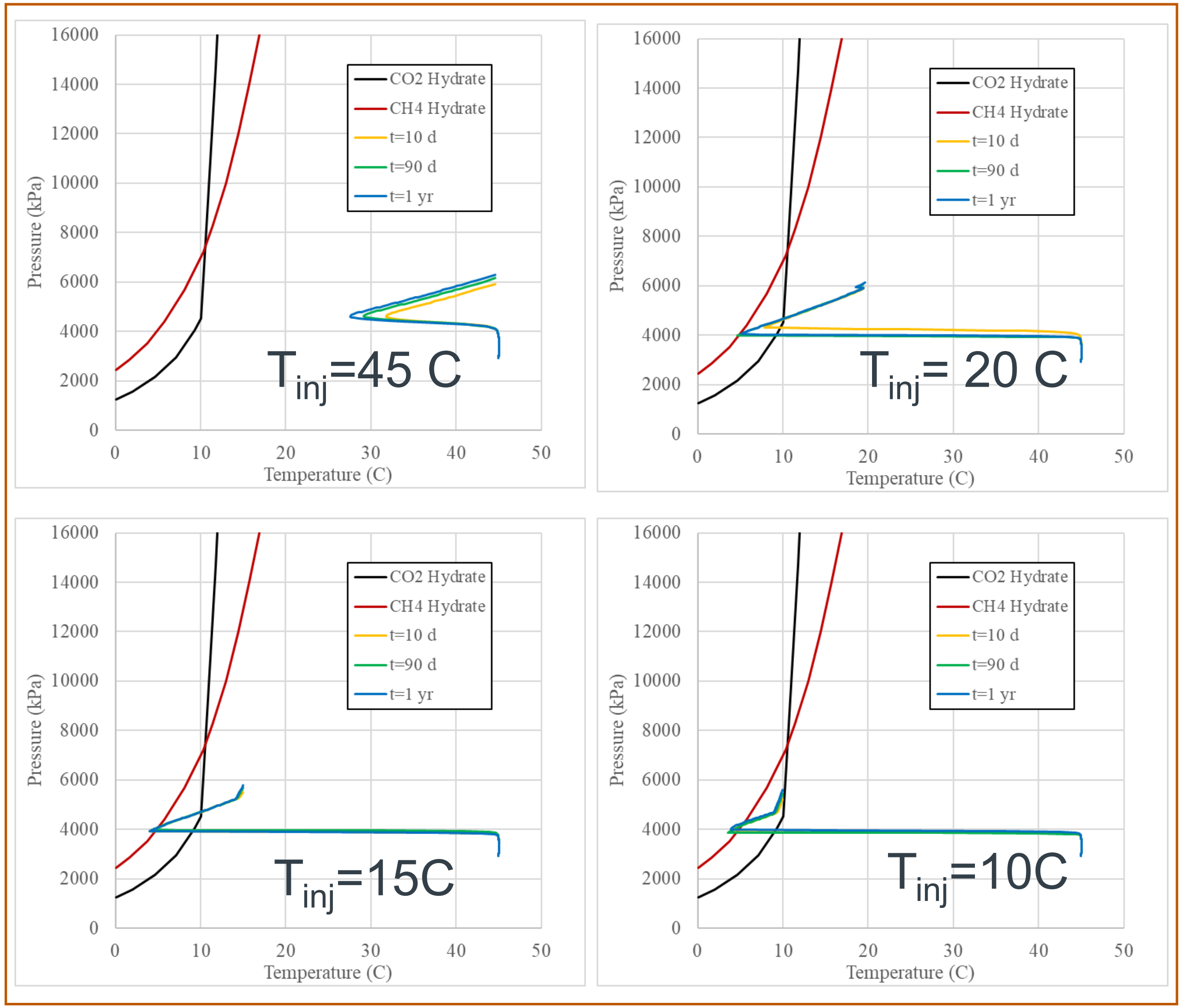
- **Liquid CO_2 was observed near the wellbore which reduces JT cooling**
- **Lower initial reservoir pressure intensifies JT cooling**



Properties	Value
Reservoir temperature	45 C
Injection temperature	**10, 15, 20, and 45 C**
Well radius	0.0097 m
Reservoir radius	1130 m
Thickness	50 m
Porosity	0.3
Permeability	5 mD
Initial pressure	**3 and 5 Mpa**
Injection rate	3 kg CO_2/s
Production rate	0.56 kg CH_4/s
Rock heat capacity	1000 J/(kg°C)
Rock heat conductivity	2.51 W/(m°C)
Heat exchange	Sensitivity
Under/overburden rock heat capacity	1000 J/(kg°C)
Under/overburden rock heat conductivity	2.51 W/(m°C)

Temperature Profile and PT diagram: T_{res} = 45°C; P_{res} = 3MPa





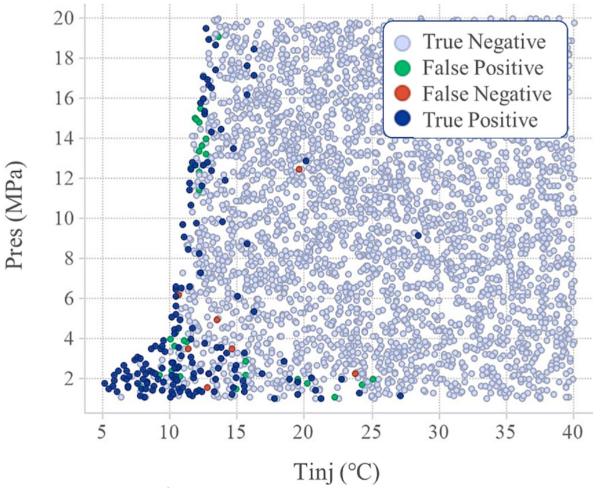
Min temperature is about 3°C even as T_{inj} is reduced

JT cooling leads to hydrate formation

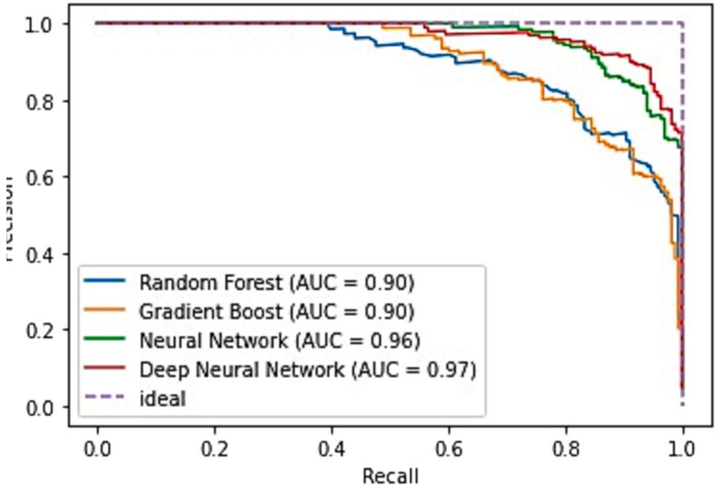
Run Simulations to train a Machine Learning tool

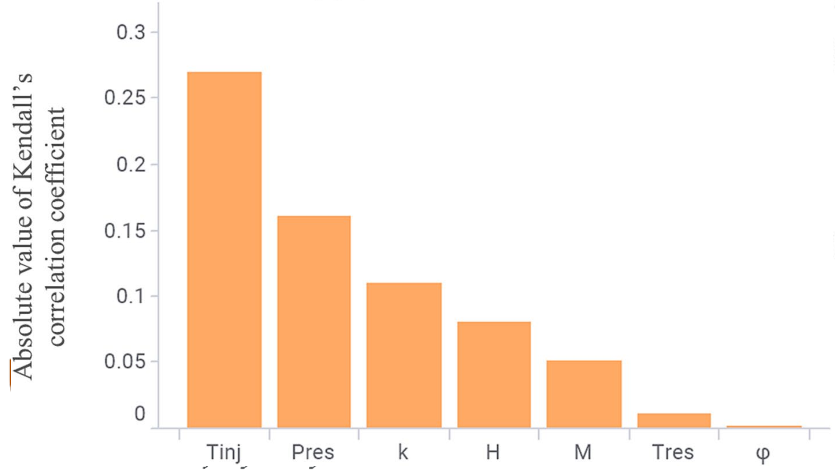
"Yamada et al., Development of a hydrate risk assessment tool based on machine learning for CO_2 storage in depleted gas reservoirs. Fuel, Vol 357, 2024"

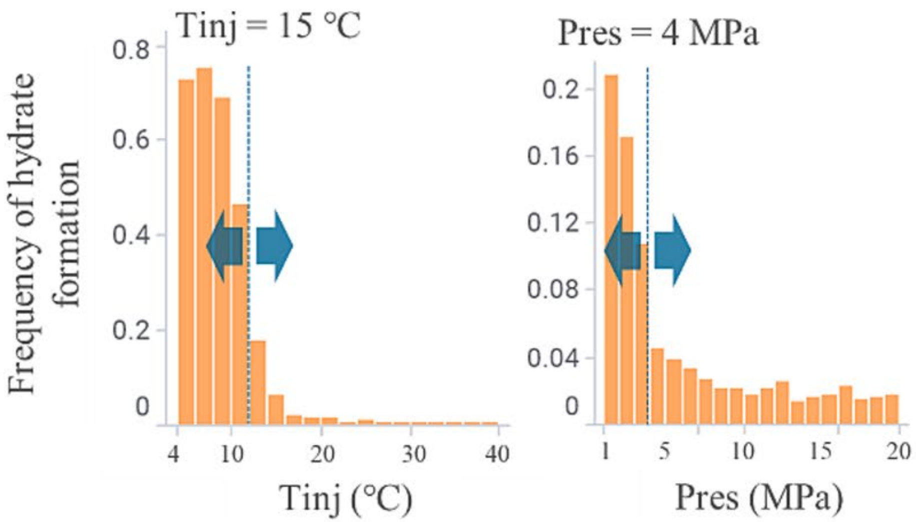
- A sensitivity analysis with **18,532 scenarios** was performed with CMG-GEM.
- ML models tested: random forest, gradient boosting, neural network, deep neural network.



		Predicted	
		Negative (limited hydrate risk)	Positive (potential hydrate risk)
Actual	Negative (limited hydrate risk)	3325	30
	Positive (potential hydrate risk)	8	160



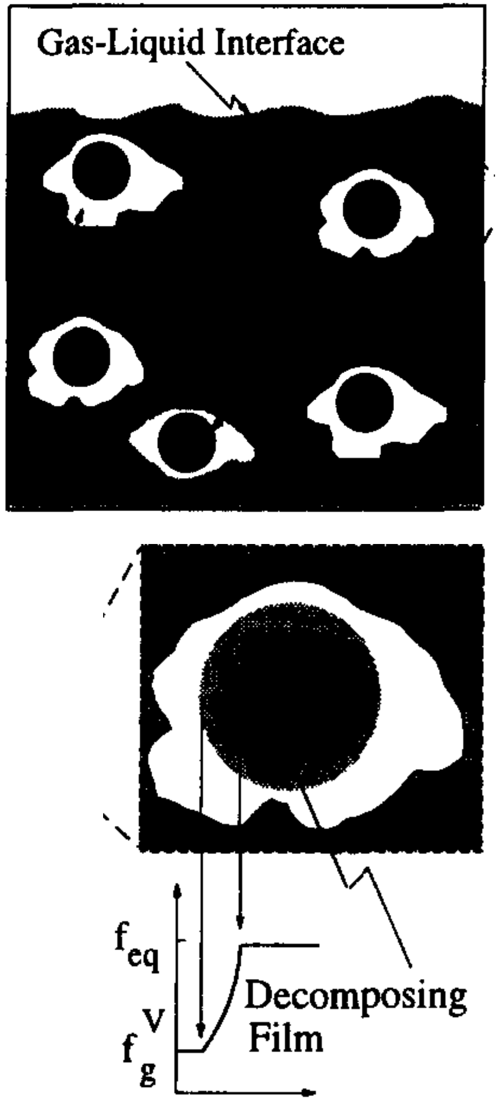




HYDRATE MODELING WITH STARS

Hydrate kinetic model

- Use Kozeny-Carman equation to calculate permeability changes as a function of porosity.
- Reactions to model hydrate formation and dissociation.



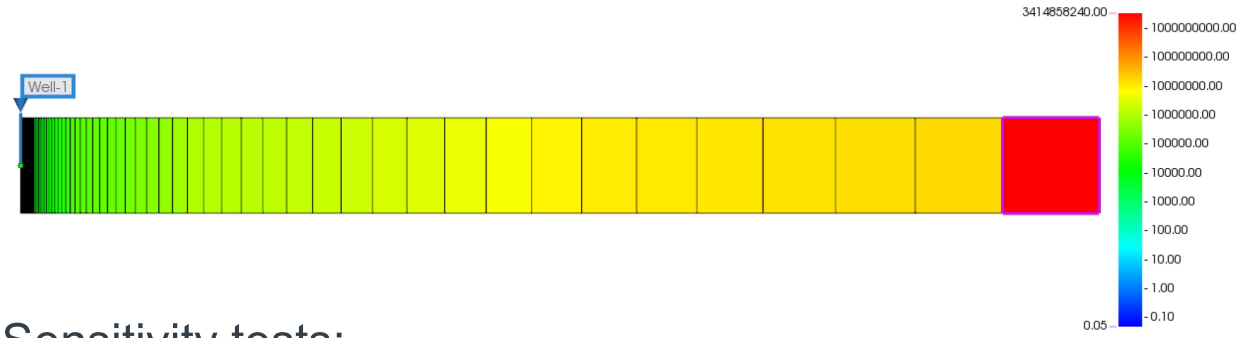
Bishnoi and Natarajan (1996)

Methane hydrate formation:	$5.75H_2O + CH_{4(g)} \rightarrow CH_4 - Hyd$
Methane hydrate dissolution:	$CH_4 - Hyd + H_2O \rightarrow 6.75H_2O + CH_{4(g)}$
CO_2 hydrate formation:	$7.7H_2O + CO_{2(g)} \rightarrow CO_2 - Hyd$
CO_2 hydrate dissolution:	$CO_2 - Hyd + H_2O \rightarrow 8.7H_2O + CO_{2(g)}$

Demonstration case

"Indina et al., On The Significance of Hydrate Formation/Dissociation during CO_2 Injection in Depleted Gas Reservoirs. 2024 Oman Petroleum & Energy Show (OPES), SPE-218550-MS."

- 100x1x1 grid with grid refinement
- Porosity changes may result in permeability change
- Model heat conduction
- Infinite reservoir is modeled



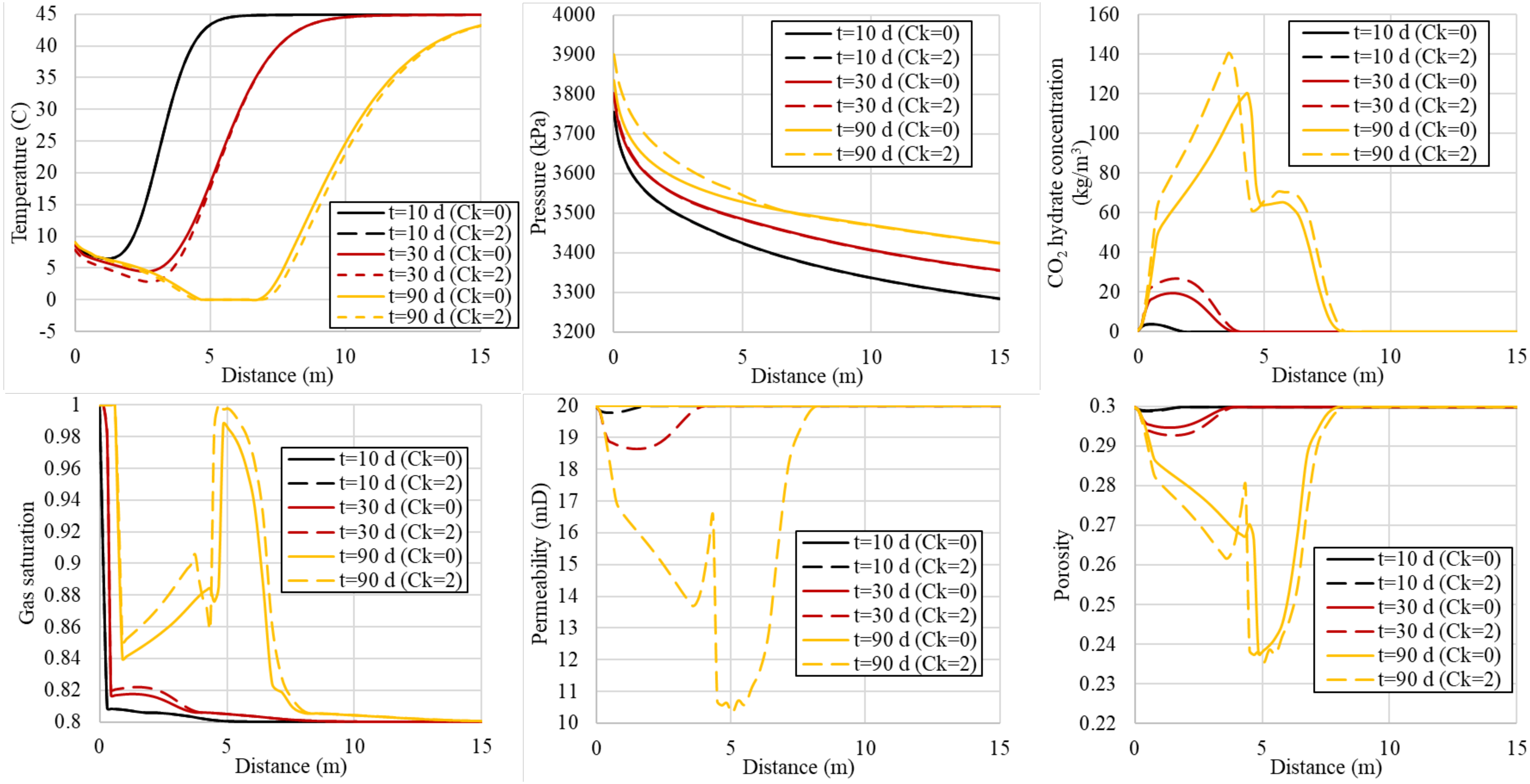
Sensitivity tests:
- Heat exchange with over and underburden formations
- Permeability reduction
- Grid geometry

	Value
Reservoir temperature	45 C
Initial water saturation	0.2
Initial hydrocarbon composition	100% CH4
Injection temperature	10 C
Well radius	0.0097 m
Porosity	0.3
Permeability	20 mD
Initial pressure	3 Mpa
Injection rate	3 kg CO_2/s
Rock heat capacity	1000 J/(kg^{o}C)
Rock heat conductivity	2.51
Base/Cap rock heat capacity	1000 J/(kg^{o}C)
Base/Cap rock heat conductivity	2.51 W/(m^{o}C)

Perm. reduction due to hydrate formation (1 year)

— No perm reduction

– – Perm reduction



Perm reduction leads to higher pressure drawdown and more JT cooling

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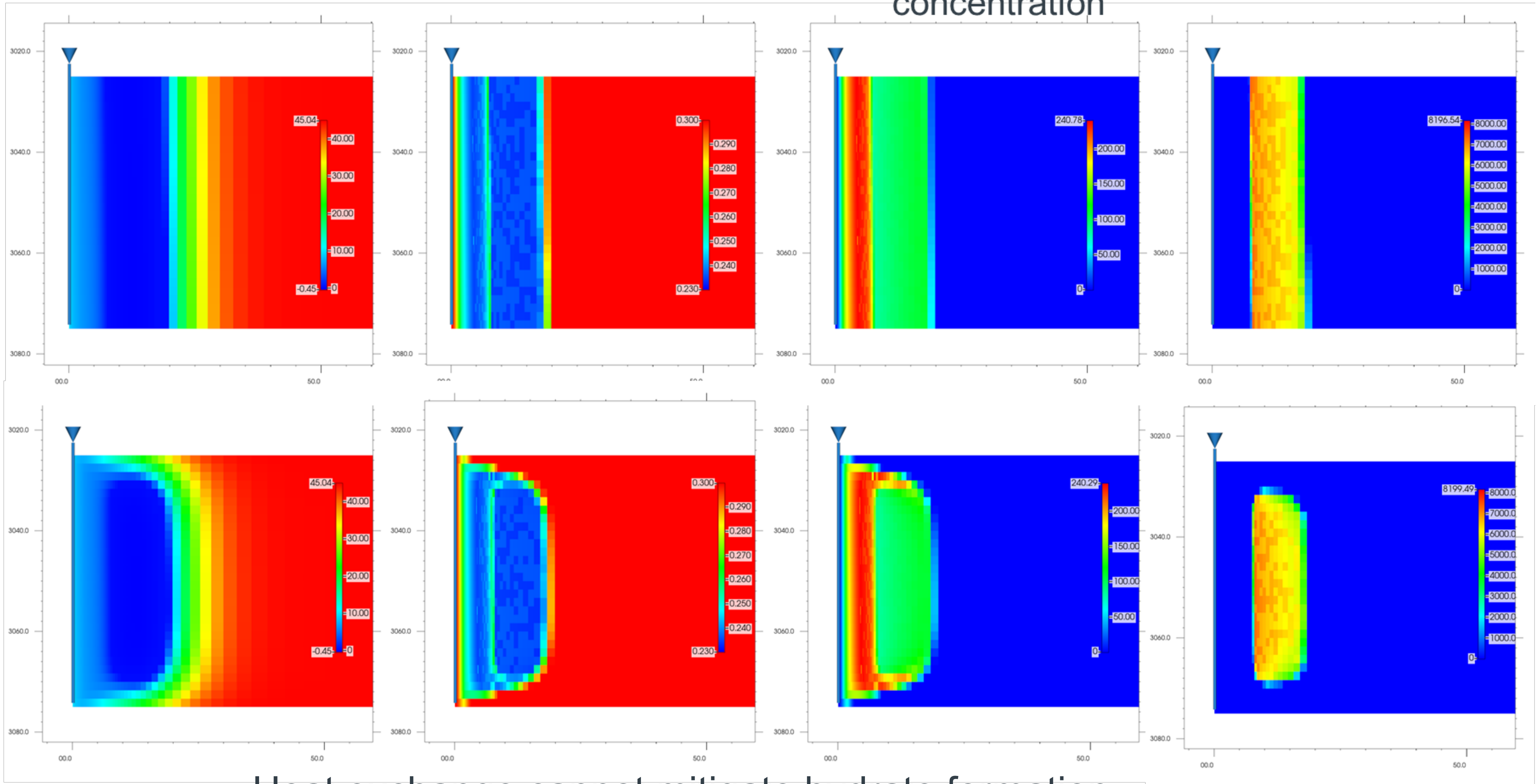
Impact of heat exchange for 3D case (1 year)

Temperature | Porosity | CO_2 hydrate concentration | Ice concentration

No heat exchange

With heat exchange



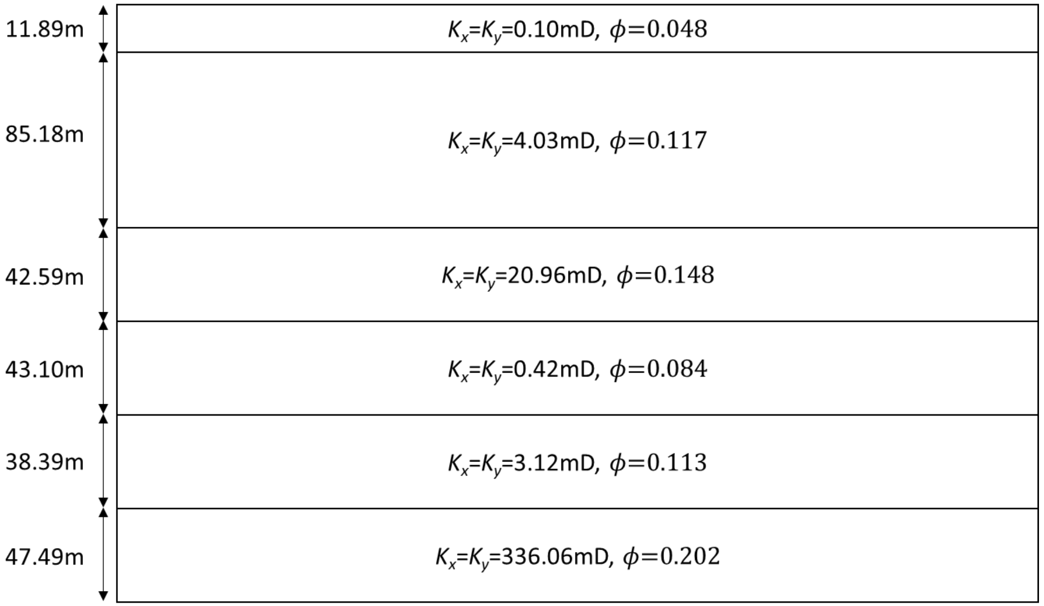
Heat exchange cannot mitigate hydrate formation

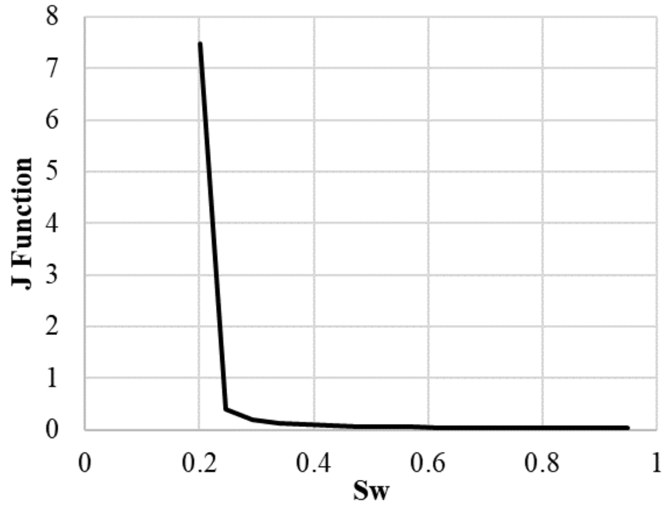
Multilayered Reservoir

"Indina et al., On The Significance of Hydrate Formation/Dissociation during CO_2 Injection in Depleted Gas Reservoirs. 2024 Oman Petroleum & Energy Show (OPES), SPE-218550-MS."

- 100x1x6 radial grid with refinement
- Each layer has different porosity and permeability
- Reservoir initially filled with water and methane
- Initial reservoir temperature: 135°C

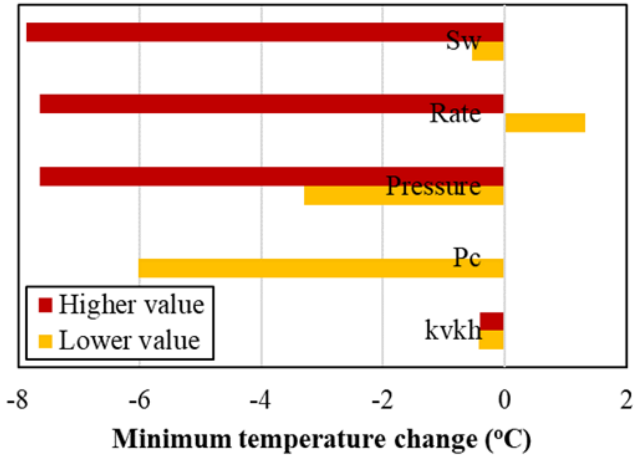
Properties	Value	Sensitivity
Initial water saturation	0.2	0.15 and 0.3
Injection temperature	10 °C	-
Initial pressure	2.5 MPa	1 and 4 Mpa
Injection rate	1 MMTA	0.5 and 2 MMTA
Kv/Kh	0.1	0.5 and 1
Capillary pressure	Not considered	J-function

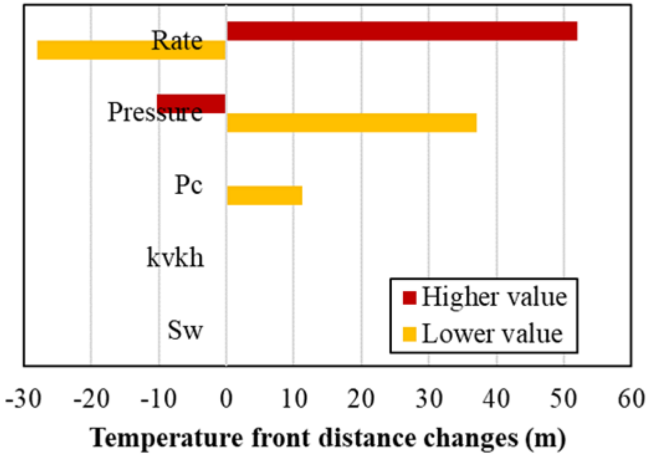


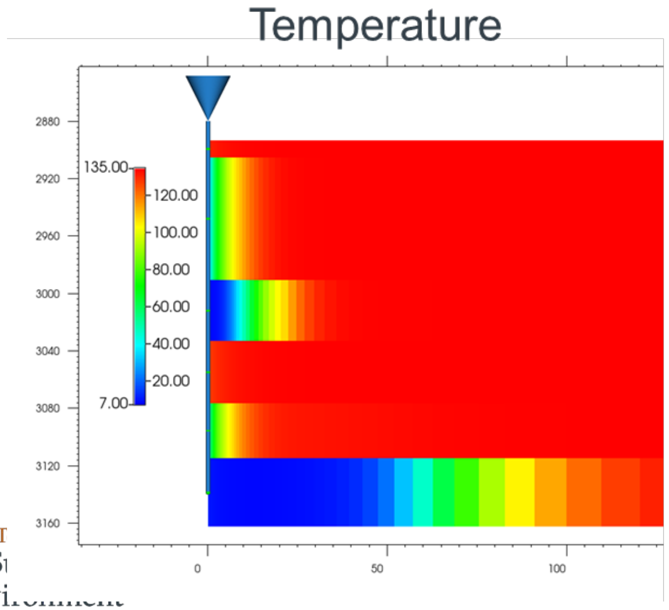


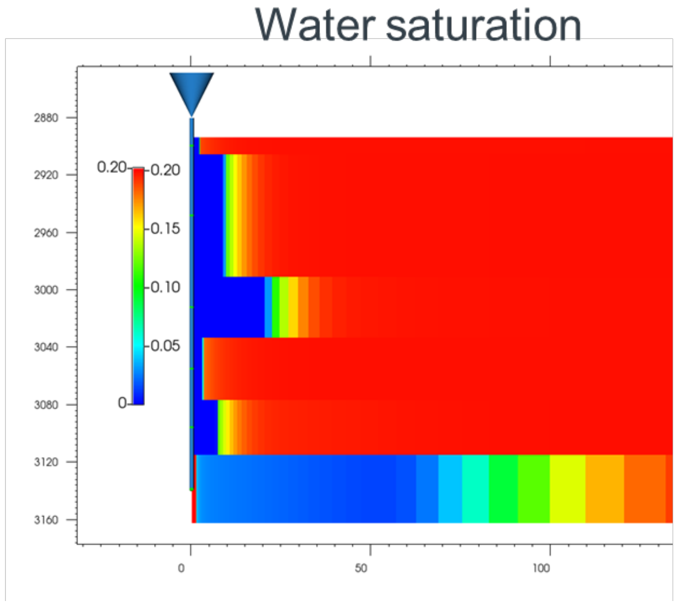
Results after 1 year of simulation

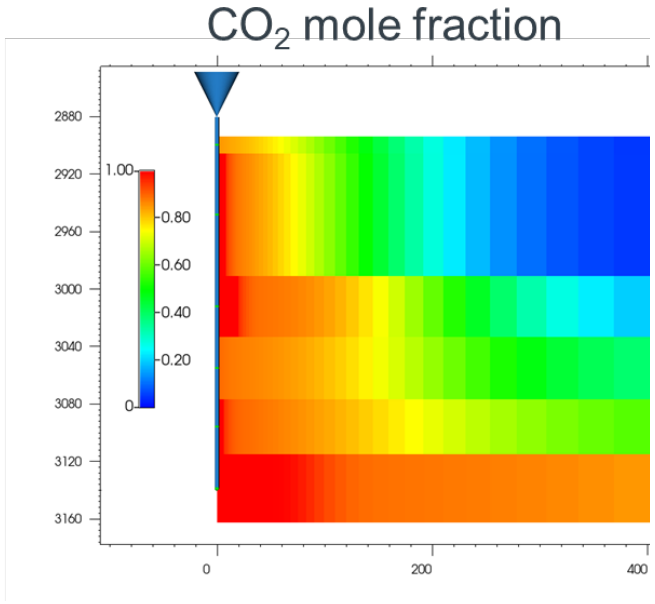
- Higher saturation = More hydrates and higher cooling
- Increase in rate = Increase pressure drawdown
- Lower initial pressure = Higher JT cooling
- Higher initial pressure = Higher hydrate equilibrium temperature











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Summary and Conclusions

- Just like in wellbore and pipeline, hydrate formation is also a risk in porous media.
- The Joule-Thomson effect can cool CO_2 to hydrate and freezing conditions even in high-temperature reservoirs.
- The heat gain from surrounding formation, heat of hydrate formation, and water dry-out did not prevent hydrate formation.
- Permeability, injection rate, initial reservoir pressure, and injection temperature all play a critical role in the formation of hydrate.

Acknowledgement

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Questions?