Dynamic Modeling of Geological Carbon Storage (GCS) in Mesozoic Deep Saline Aquifers on the Scotian Shelf.

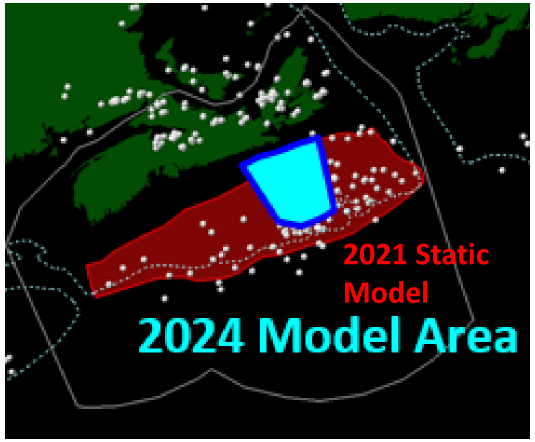
Julianne Jager, Tristan Leclerc, F.W.(Bill) Richards, and Grant Wach

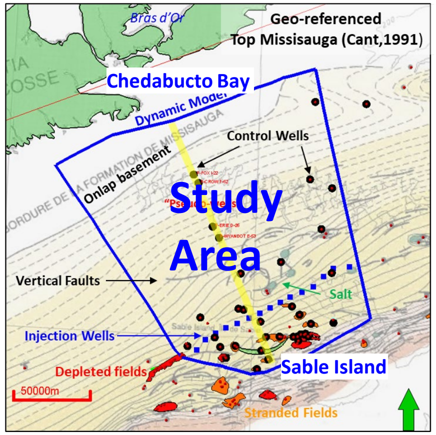
IPCC Special Report on Carbon Dioxide Capture and Storage (2005)

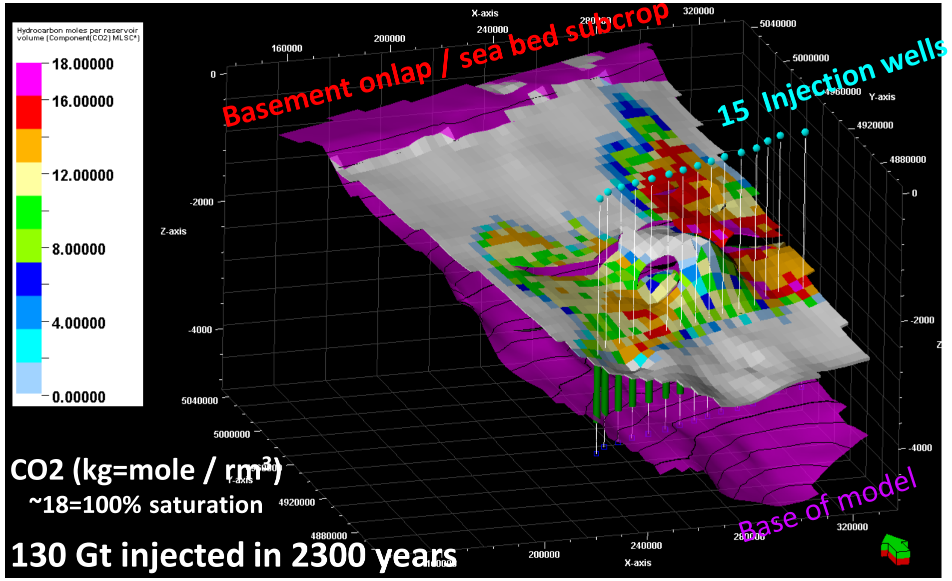
Objectives & Initial Results

OBJECTIVES

- Test hypothesis that Scotian Shelf has world-class, safe, GCS capacity
  - Highgraded area of the Sable Island Delta, updip of hydrocarbon fields
- Essentially model a 15 to 60 well "Sable GCS Project"
  - 15 wells - could represent clusters of 2 or 4 wells
- Investigate open vs closed systems – well & geologic variables







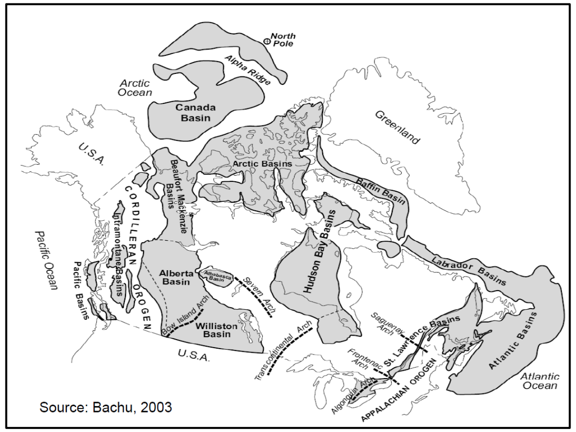
INITIAL RESULTS

- Need extreme injection for CO_2 to reach seabed subcrops
- Need to model long duration , high injection rates to assess connectivity
- Key issue is staying below topseal fracture closure pressure
- Further question is the effects of connate water expulsion

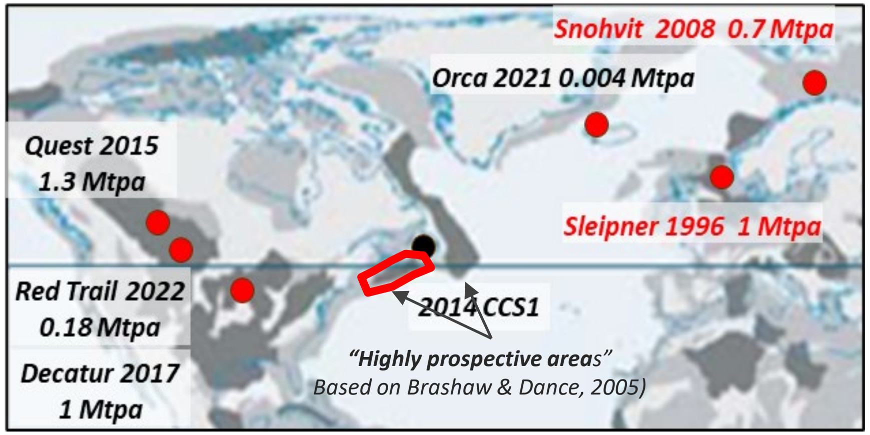
Background: GCS in N.S. (2003-14) - Qualititative

- 2003: Bachu "Screening and ranking of sedimentary basins"
- 2005: IPCC "Special Report". "Highly Prospective"
- 2007-2015: USA & Canada Carbon Storage Atlas – 5 editions
- 2008 May: Henry "Geological Storage of Carbon Dioxide in Nova Scotia" R & D Forum, Antigonish
- 2009 - 2015 Carbon Capture and Storage Research Consortium of Nova Scotia (CCS Nova Scotia)
- <u>2010: Wach et al. "Assessment of Prospective Sites for the Geological Storage of CO2 Nova Scotia"</u>
- 2011: Sydney Sub-Basin Storage Feasibility Project Study
- 2014: Unsuccessful CCS1 well in Cape Breton (tight)

Bachu, 2003 Screening
(from Henry, 2008 pre-NS CCS Consortium)



IPCC, 2005. CCS Propectivity. Operational Facilities (GCSSI, 2022)

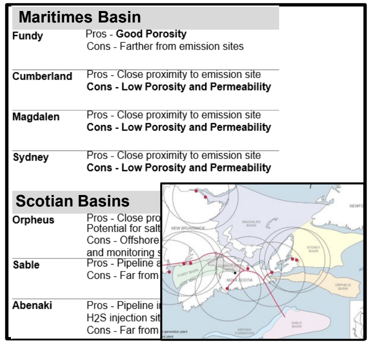


North American CCS Atlases

- **5 editions 2007- 2015**

Wach et al, 2010

- **Reservoir-seal. Proximity**



CCS Simulation, 2011

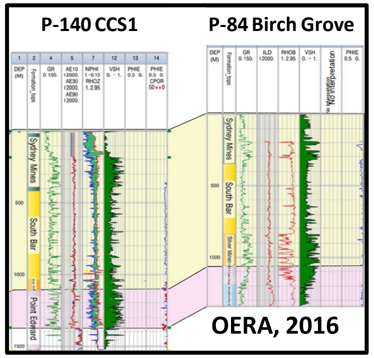
- **V. low capacity**

Sydney Sub-Basin CO2 Storage Feasibility Project (Schlumberger)

One well has sufficient capacity to sustain 100 tonnes/day) in the first injection scenario. However, it is unlikely to reach the higher rate level (5,500 tonnes/day) in the second scenario. This is primarily because CO2 only manages to enter the formation through isolated and very thin permeable beds.

CCS1 Well, 2014

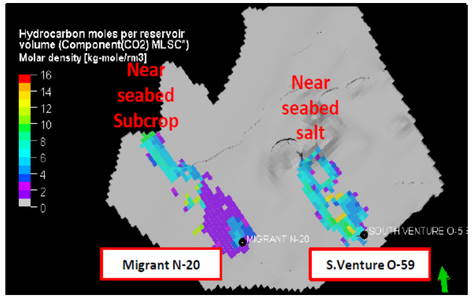
- **(No useable PHI-K)**



Background: GCS in N.S. (2019-24) - Quantitative

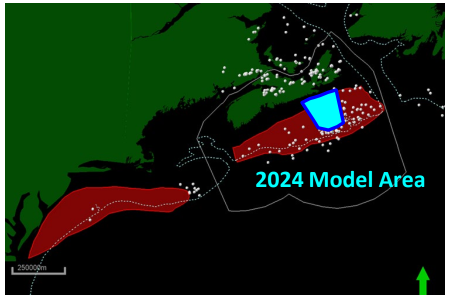
- 2019: O'Connor et al. E3 Energy Conference Halifax – "Dynamic Modeling of Buoyant Fluids Sable Subbasin"
- 2019: US DOE "Mid-Atlantic U.S. Offshore Carbon Storage Resource Assessment Project"
- 2020: Schmelz et al. "Total cost of carbon capture and storage implemented at a regional scale: NE & MW USA"
- 2022: Chakraborty et al. "Minus CO2 Challenge 2021/2022 – Student teams evaluate potential world-class carbon storage capacity offshore Nova Scotia, E. Canada" (First Break)
- 2023 April: Carbon Neutrality Forum at Dalhousie
- 2023: GSC "Preliminary assessment of geological carbon-storage potential of Atlantic Canada"
- **2024: Dalhousie undergraduate project - 3D dynamic modeling highgraded area of the Sable Island Delta**

O'Connor et al, 2019: simulation of thin interval in highgraded area



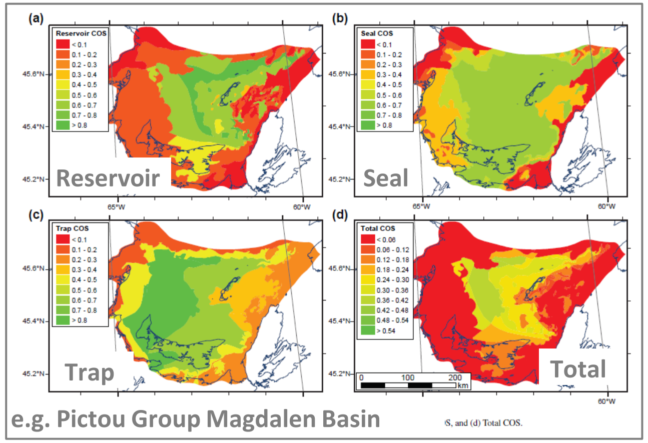
DOE, 2019 --- EAGE, Dal, DNRR 2021

- **Static model based "atlases"**



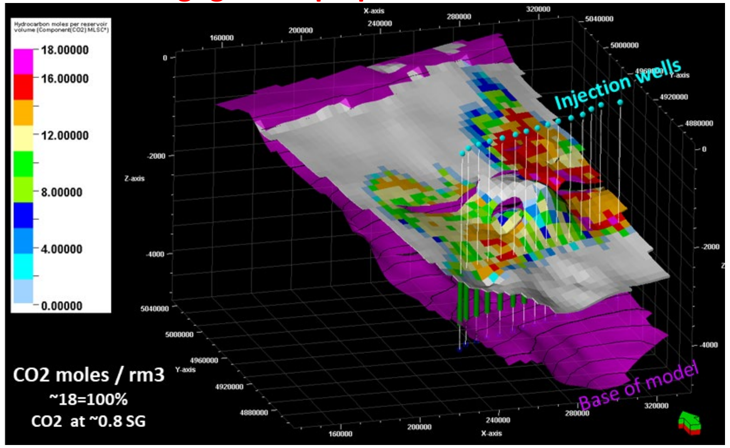
Carbon Neutrality Forum (Dalhousie. April, 2023)

GSC, 2023 - COS maps to identify promising GCS regions & formations throughout Atlantic Canada



e.g. Pictou Group Magdalen Basin

Dal., 2024 – this talk: dynamic simulation of Cretaceous section in highgaded updip area of Sable Island Delta



Current GCS Projects

Weyburn-Midale – Saskatchewan
(Whitecap Resources)

- Onshore
- EOR with CCS
- ~3.0Mtpa

Sleipner – Norway
(Equinor)

- Offshore
- LNG/Condensate + CCS
- ~ 0.9Mtpa

Snøhvit – Norway
(Equinor)

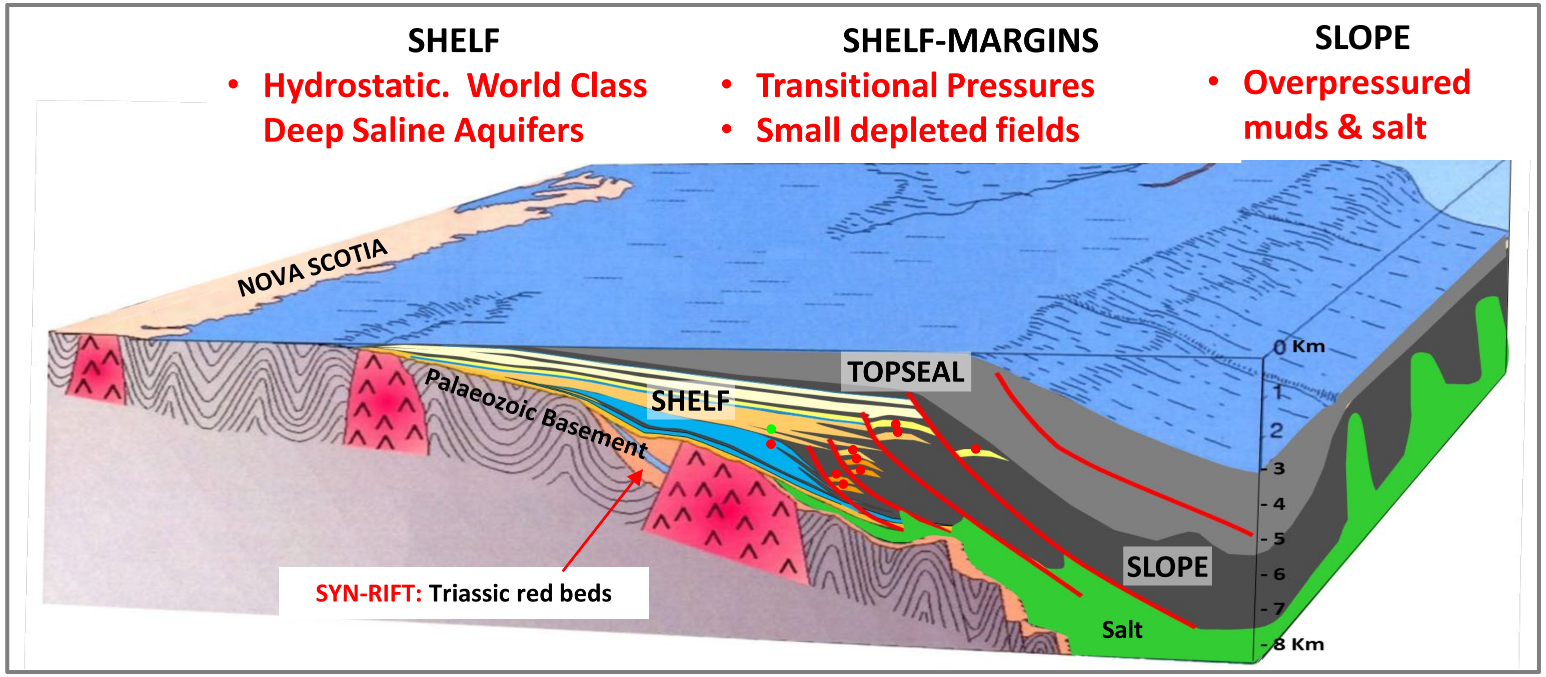
- Offshore
- LNG/Condensate + CCS
- ~ 0.7Mtpa

- Monitoring strategies
- '4D' Seismic
- Canadian example

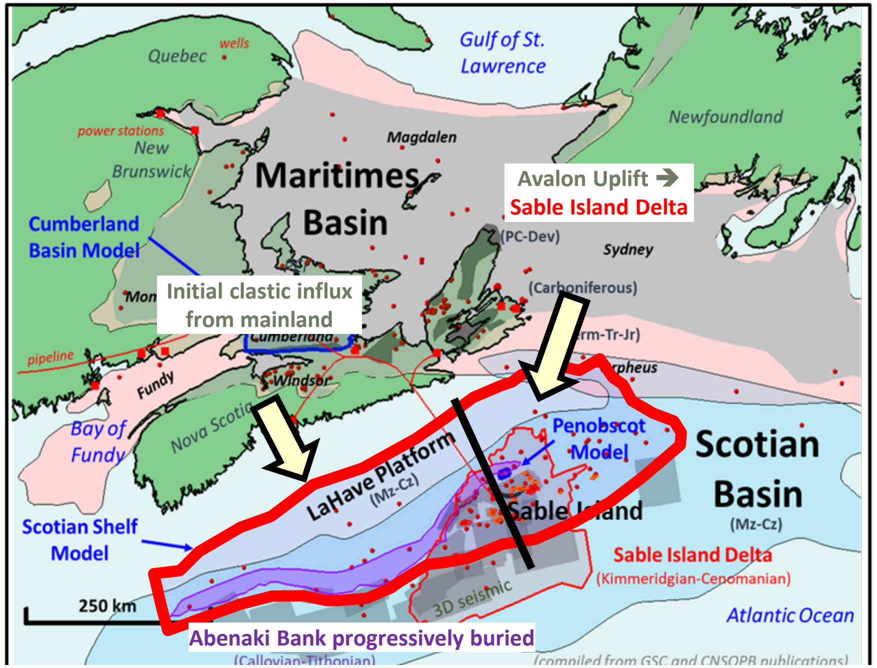
- Norwegian projects are most similar to Nova Scotian opportunities
  - Offshore
  - *Saline Aquifers*
  - Similar basin architecture

Regional Setting

- **Atlantic margin**: **Syn-rift** tight. **Post-rift** reservoirs & aquifers. **Sag** topseal. (Triassic; Jur. & Early. K.; Late. K & Cen.)
- **GCS Capacity: world-class hydrostatic aquifers ➔ small depleted fields ➔ none in overpressured muds** (poss. in salt diapirs – Brazil)
- **Pressure transition**: **SEABED** subcrop🡐 **SHELF** hydrostatic 🡐 **SHELF-MARGINS** overpressure steps 🡐 **SLOPE** overpressured



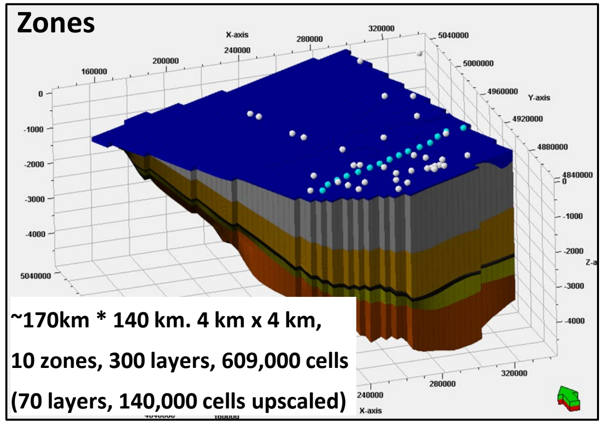
* Schematic Section – modified from OERA 2011 (after J. Wade, modified Grant, CNSOPB, 2009).

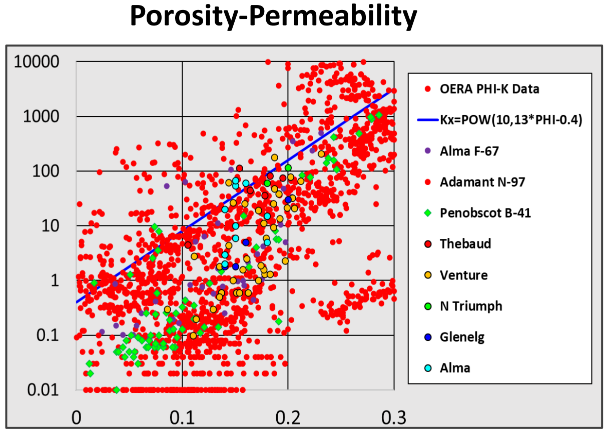


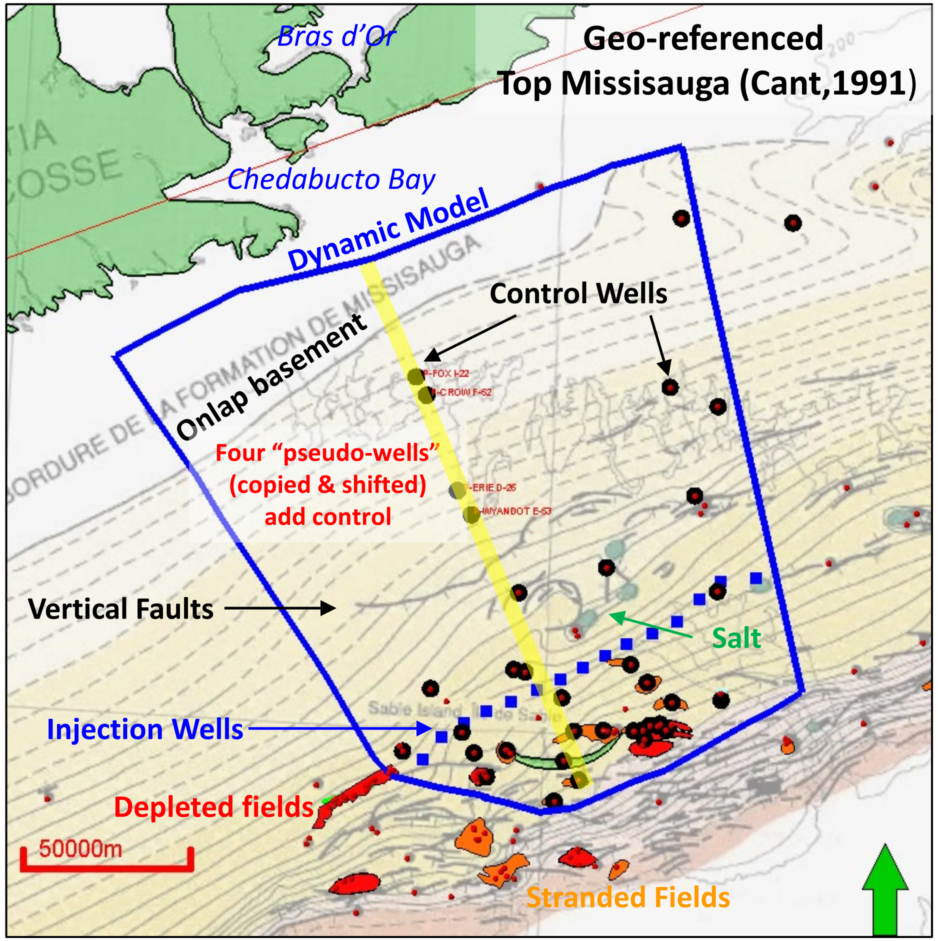
Compiled from GSC & CNSOPB publications

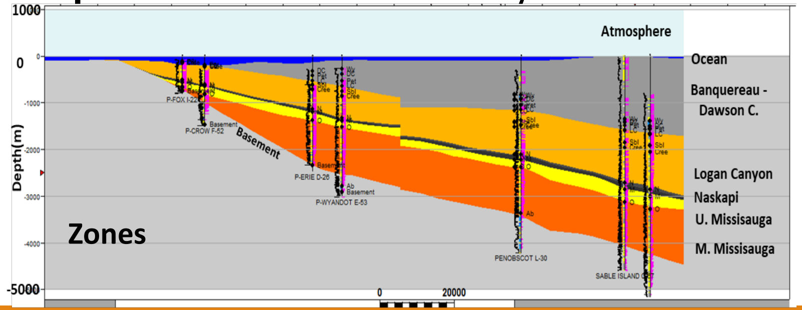
Data and Methods: Static Modeling (Petrel)

- **Petrel framework horizons** from 1991 GSC Atlas (Cant, 1991) & 2011 OERA/Beicip-Franlab PFA
  - 10 zones (4 Naskapi + ocean & atmosphere
  - 4 x 4 km grid. Vertical faults.
  - 4 "Pseudo-wells"
  - Horizons flexed to tops at 37 wells (BASIN)
- **Sonic porosities (**with Vshale cut-offs)
- **Permeabilities** from core (Kz=0.5 * Kx)
- **Upscaled** from 300 to 70 layers

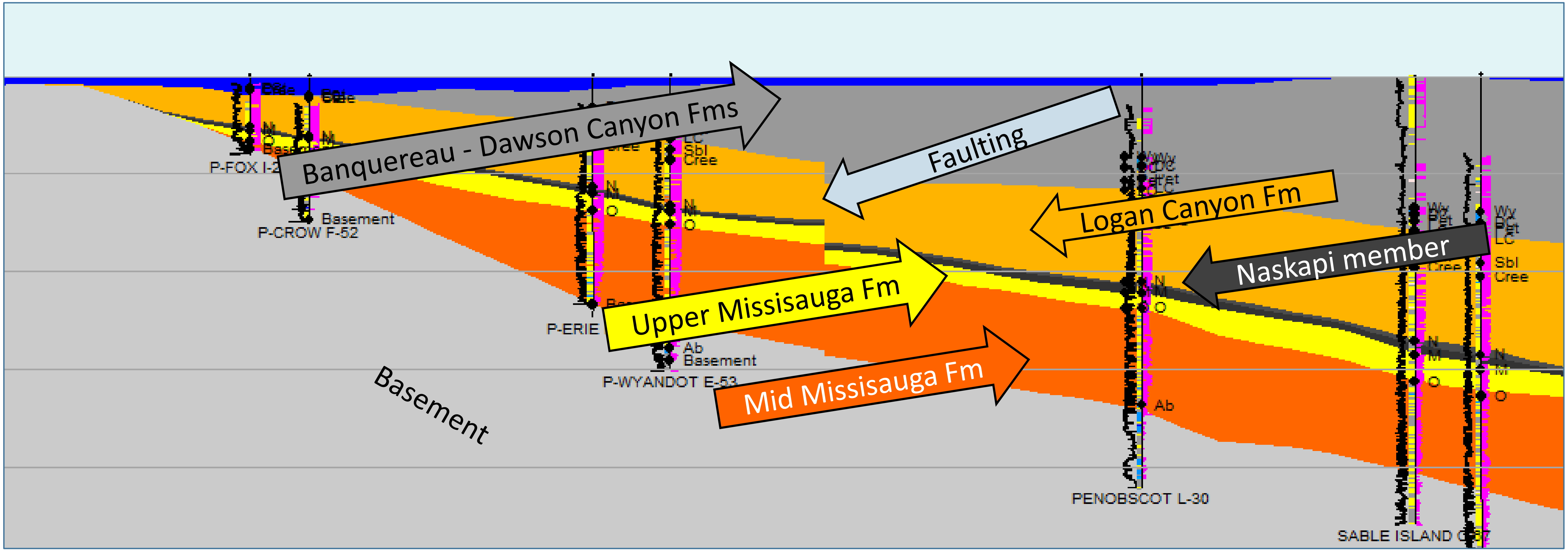






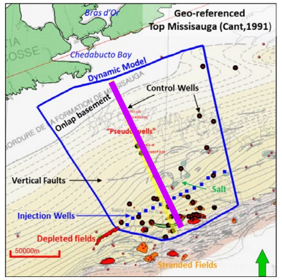


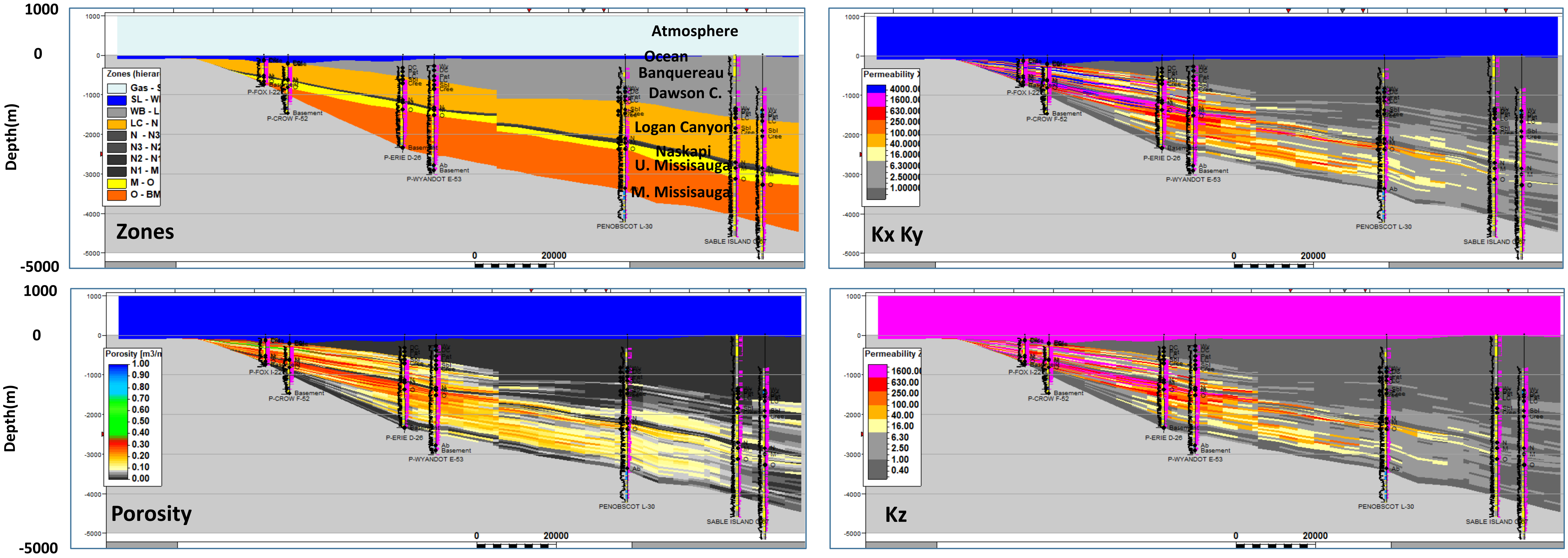
Formations and Members



Cross section of basic facies model – Facing ~NE

Static Model: 2D Traverse Images





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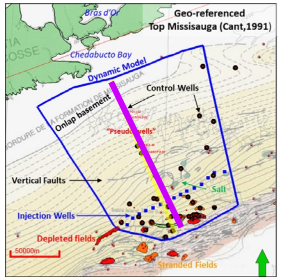
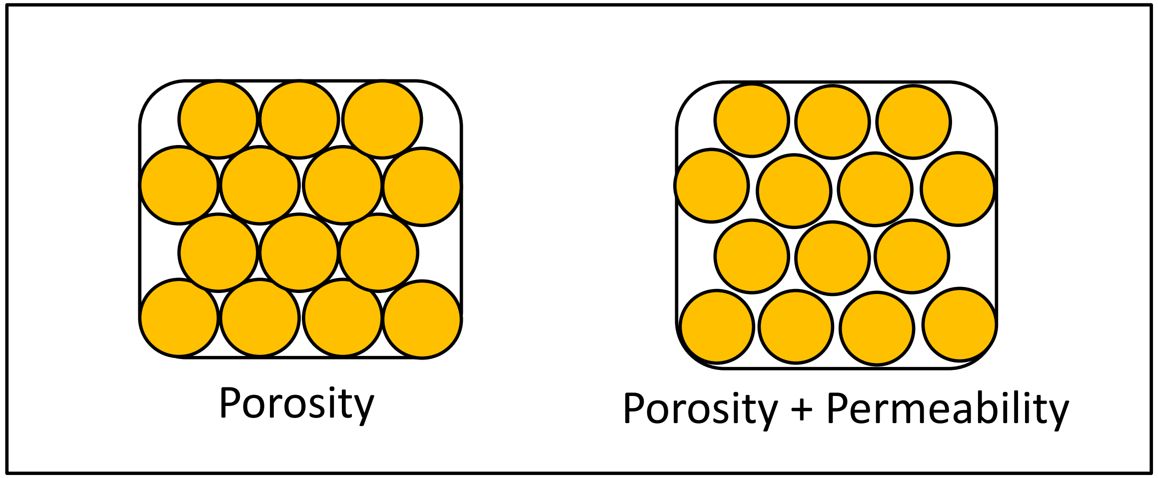
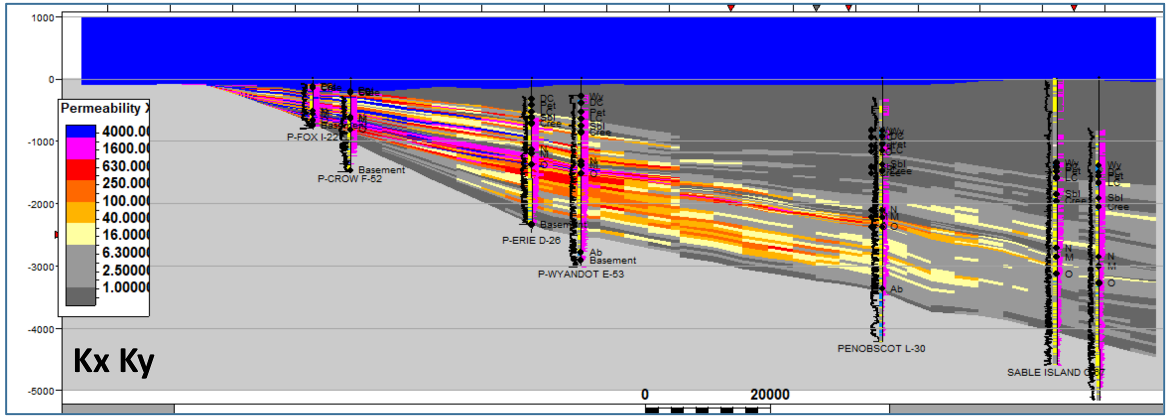
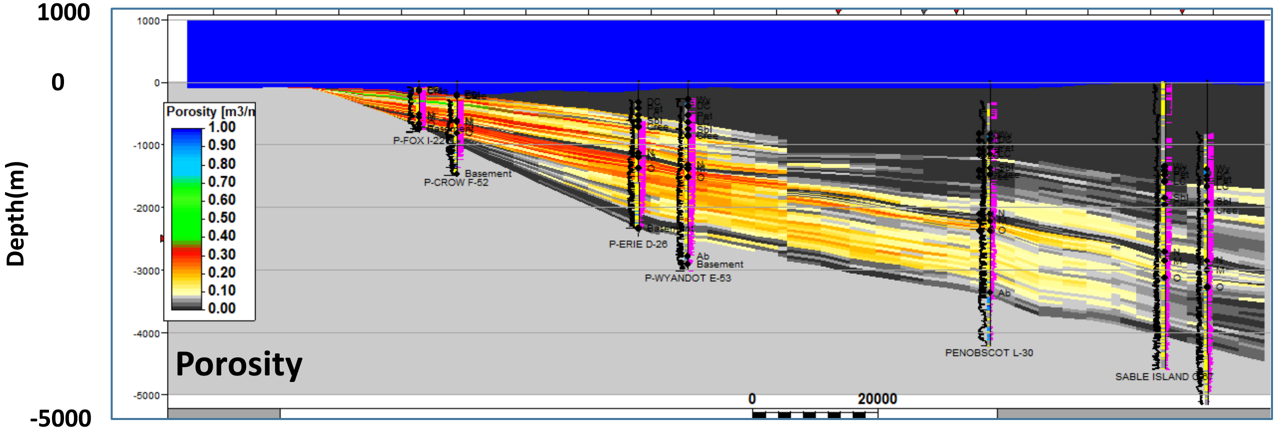
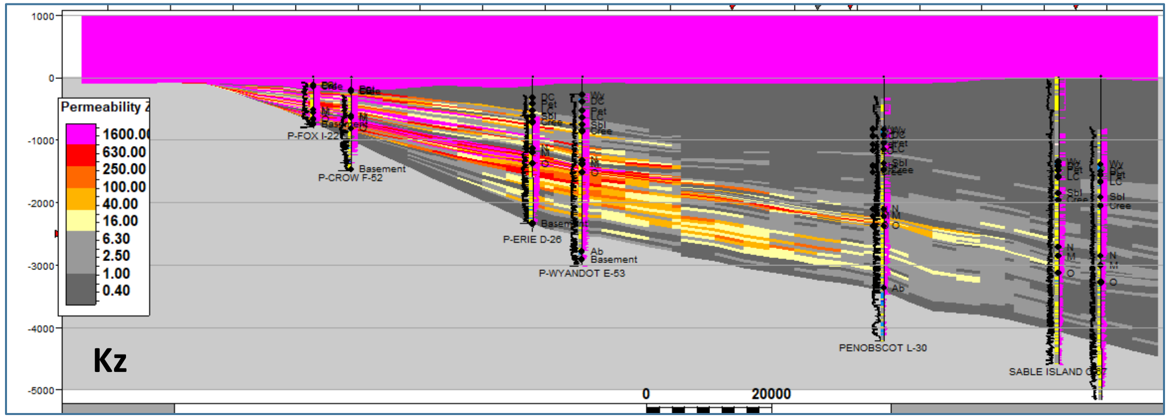


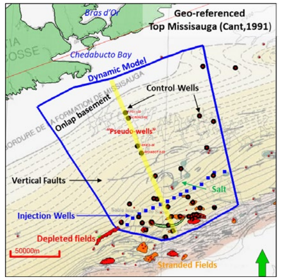




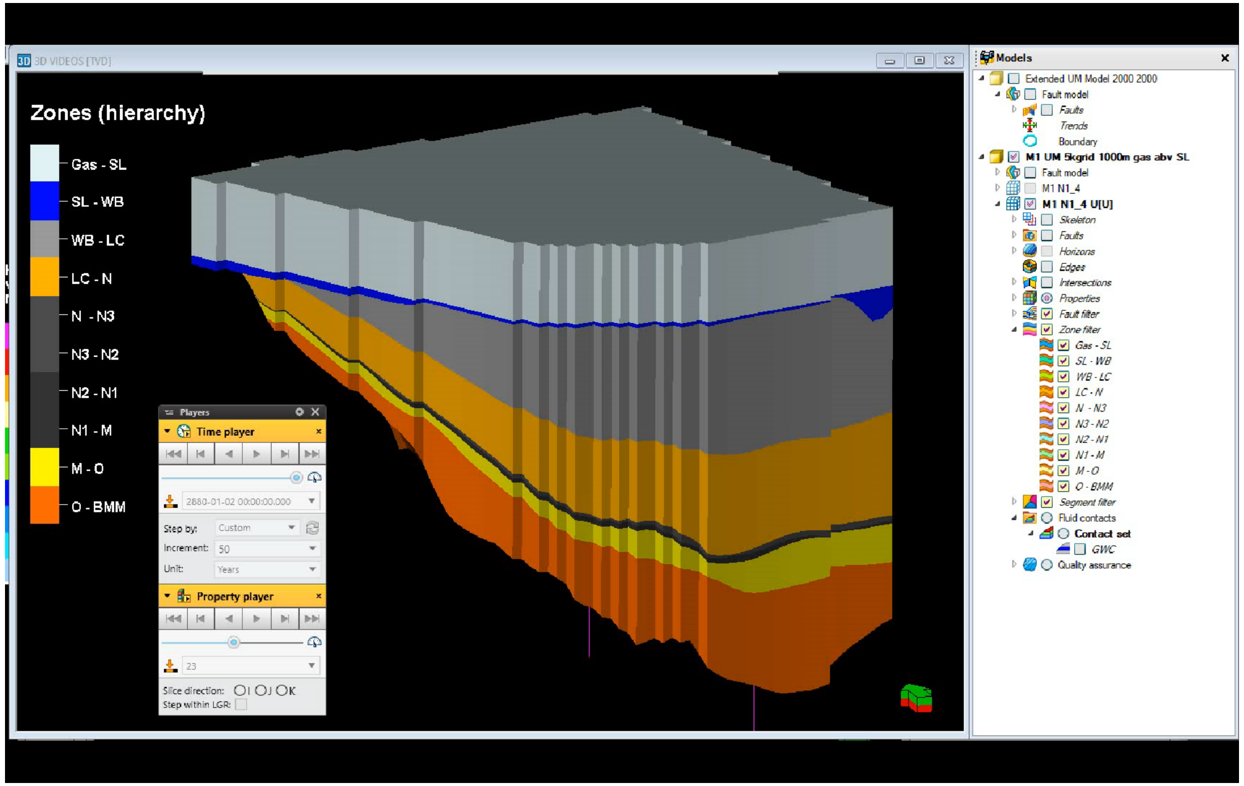




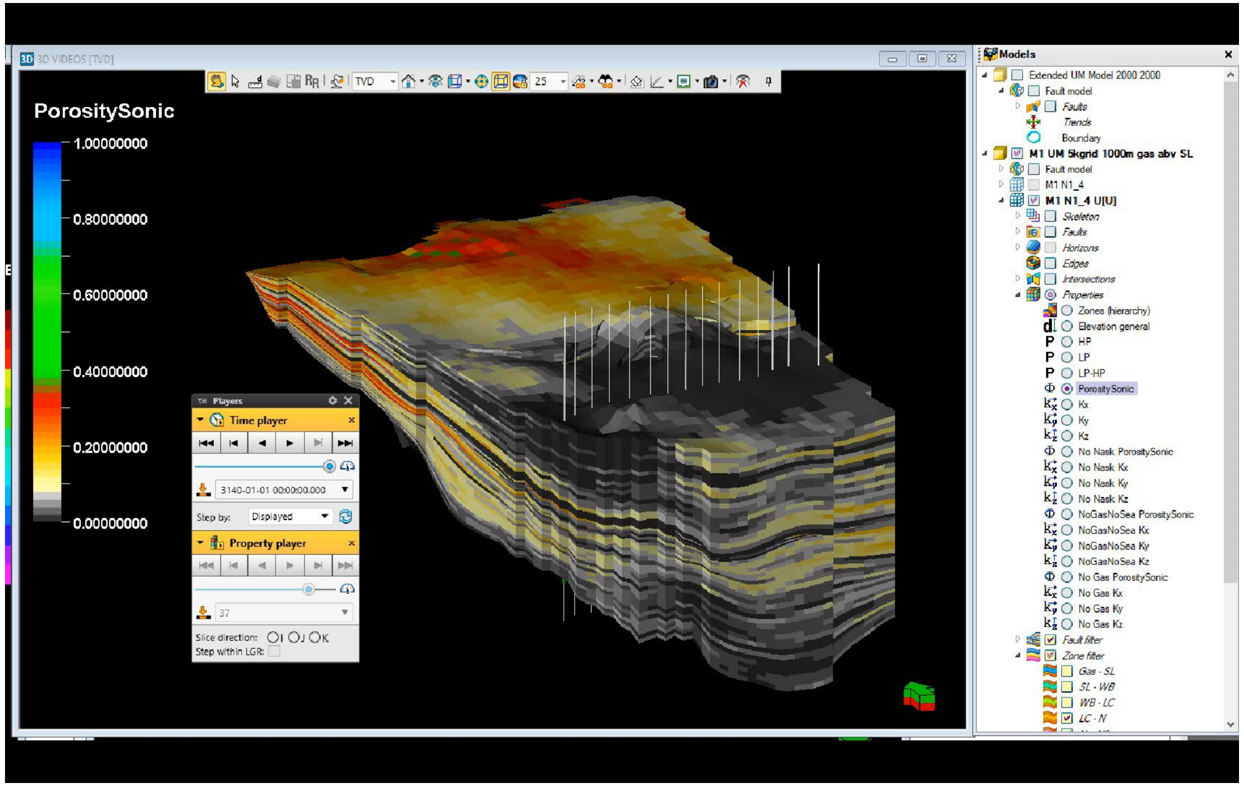
Static Model: - Videos 1 & 2



- **Zones and Layers**



- **Porosity and Permeability**



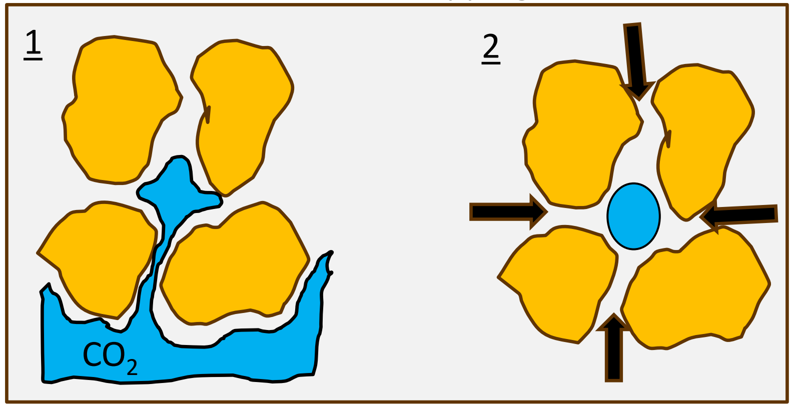
Storage Mechanisms:

Advantages of Saline Aquifer Storage

Residual/Capillary Trapping → Solubility Trapping → Mineral Trapping

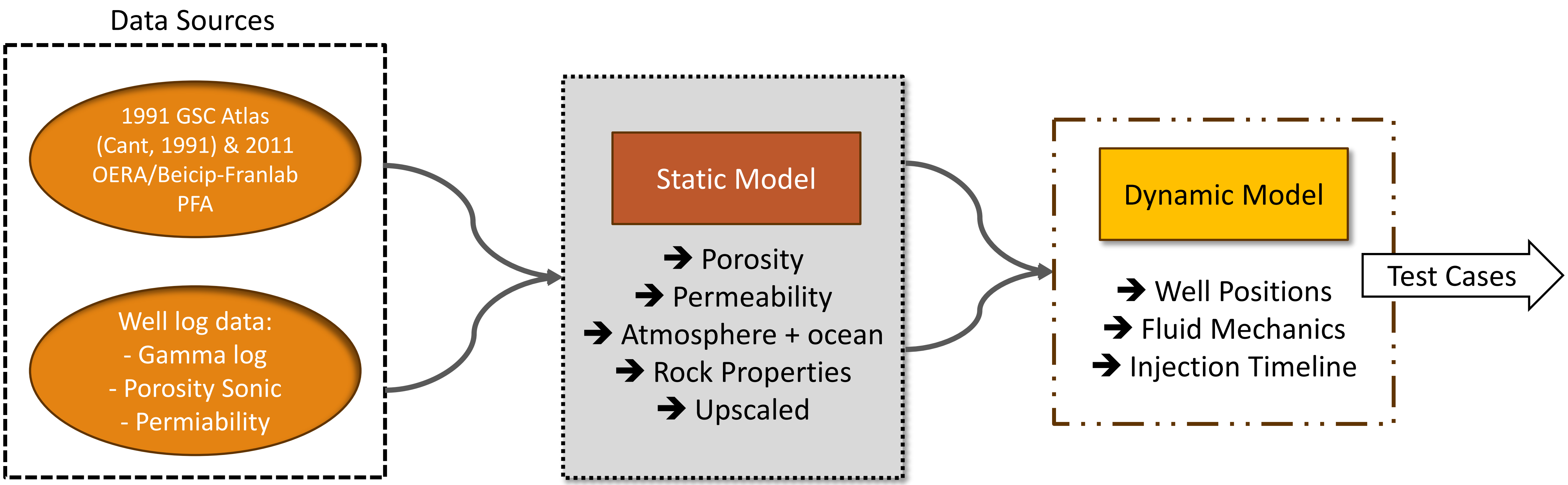
Increasing Stability With Time

Residual Trapping



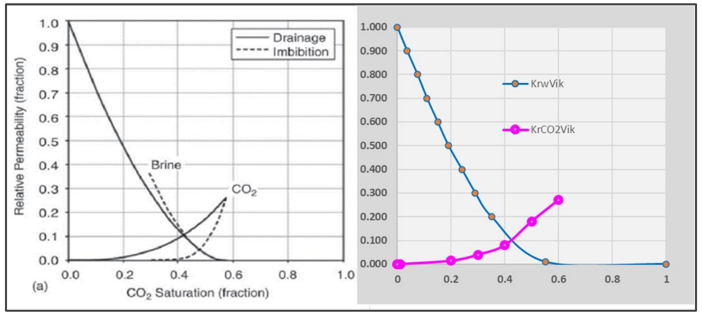
- Residual trapping can make traditional structural traps unnecessary
- Connate fluid and wall rock chemistry will determine solubility and mineral precipitation

Model Workflow



Data and Methods: Dynamic Modeling (Eclipse E300)

- **Fluid model**: Dry gas default. Injected 100% CO_2
- **1000m of CO2 atmosphere above MSL "Gas Water Contact"**
- **Rock Physics Functions:**
  - **Saturation:** default drainage relative perm. (v. similar to drainage curve from Bennion & Bachu – Viking sst, Alberta)
  - **Compaction:** Petrel consolidated sandstone default
- **Development Strategies**
  - 15 wells perforated from 2400 to 3400m in Missisauga Fm.
  - Varied bottom hole pressures 40-60 Mpa
  - Varied injection rates ~1 to 4 x 10^6 sm^3 (0.7 – 2.9 Mtpa)
  - Varied injection periods (50-2300 years) & equilibration
- **Inspected production profiles & properties using time and property players:** CO2 mole fraction, pressure & fraction



Well gas injection control (CCS0)

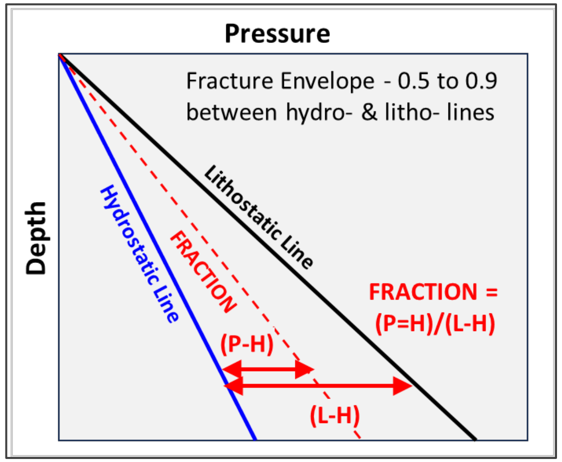
Parameter name	Unit	Parameter value
Wells		CCS0
Control mode		Surface rate
Surface rate	sm3/d	4000000
Reservoir rate	rm3/d	
Bottom hole pressure	bar	500
Tubing head pressure	bar	
Injection flow perf. table		
BHP reference depth	m	

BHP constrains surface rate

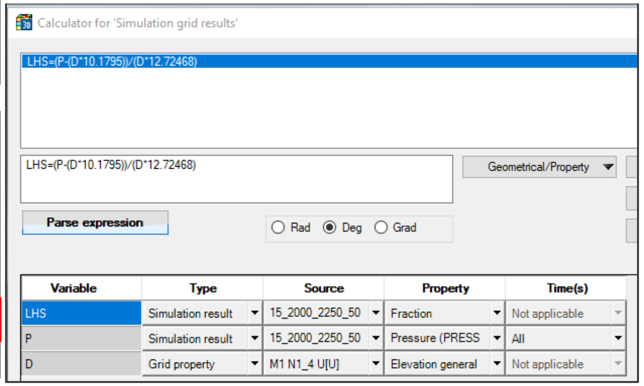
Group injection stream (Group 1)

Parameter name	Parameter value
Groups	Group 1
Source: group	
Source: well	CCS0
Source: composition	1,0,0,0,0,0,0,0
Source separator stage number	

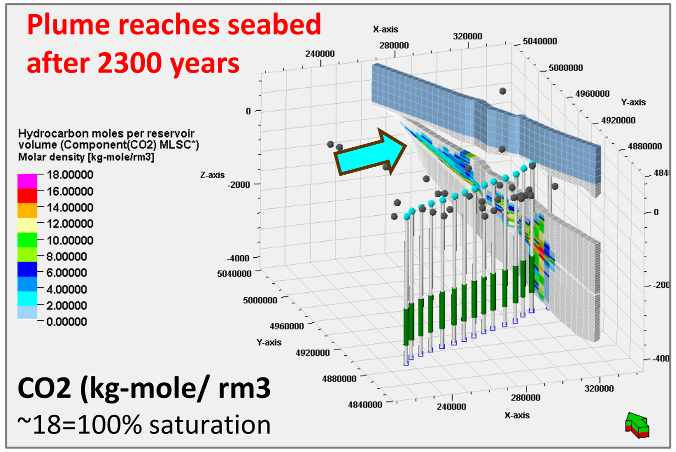
100% CO2

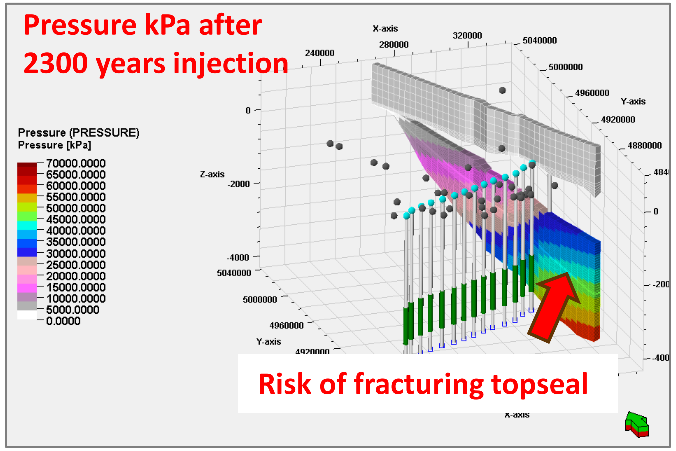


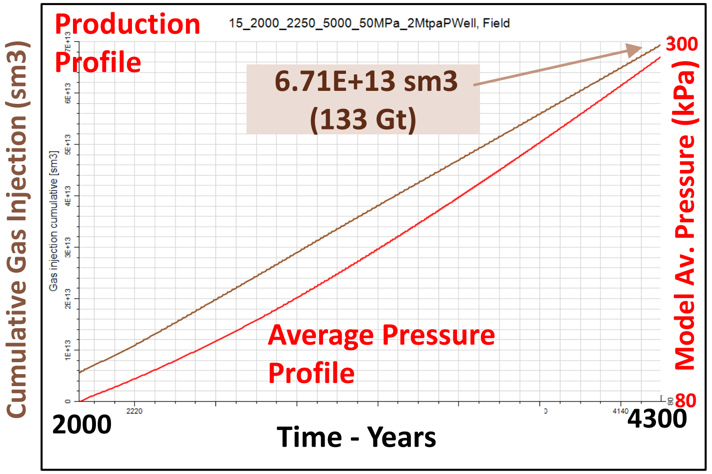
Calculation of fraction between hydrostatic and lithostatic pressure

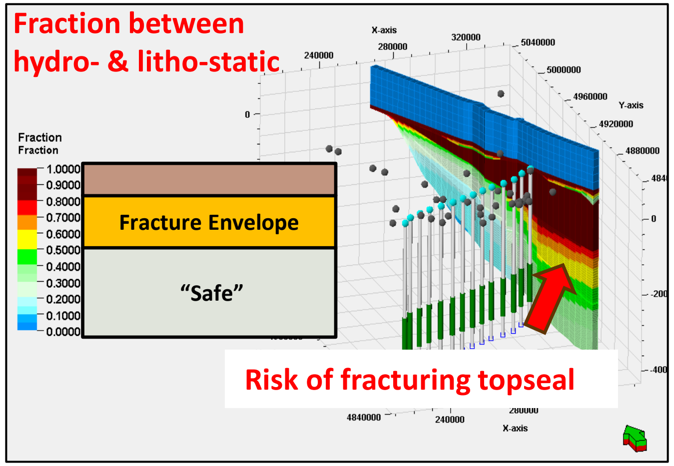


Dynamic Model: 2300 years injection (perspective views)









Model Input							
Wells	Start Inj	Stop Inj	End Model	Years	Max. MPa (BHP)	Injection sm3 /day per well	Density kg/sm3 STP
15	2000	4300	4300	2300	50	20,000,000	1.98

Model Input - Injection				
Per well Mtpa	Per well Total Mt	Project Mtpa	Project Total Gt	
14.46	33,249.00	216.84	498.74	
Model Results - Injection				**Input from model**
Per well Mtpa	Per well Total Mt	Project Mtpa	Project Total Gt	Injection sm3 TOTAL
3.85	8852.54	57.73	132.79	6.71E+13

Modeled injection constrained by bottom hole pressure

sm3 = surface meters^3
rm3= reservoir metres^3

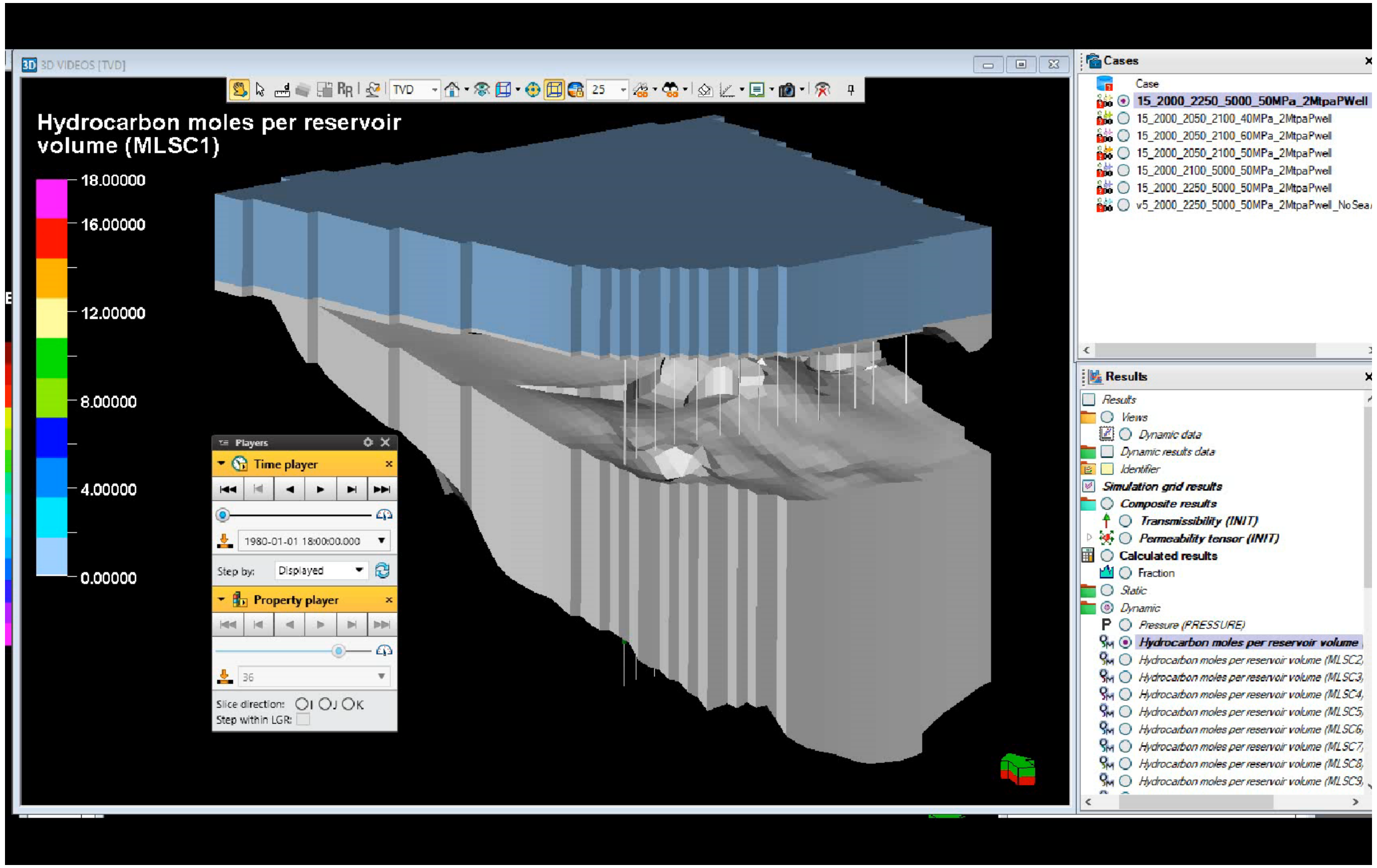
Dynamic Model: 2300 years injection - Video 3

Extreme Case – Open system

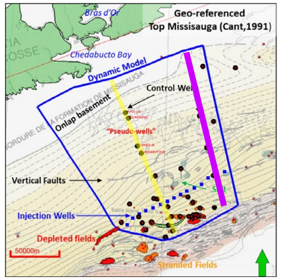
- 15 wells 2 Mtpa each
- BHP 50 MPa
- Injected 2000-4300
- Nominal injection ~500 Gt
- Modeled injection ~133 Gt
- Limited by BHP

Monitor

- Plume
- Pressure (kPa)
- Pressure Fraction



Nb: First case incorrectly named & v5 should be 15



Dynamic Model: - Sensitivities

100 years injection
- Not much difference

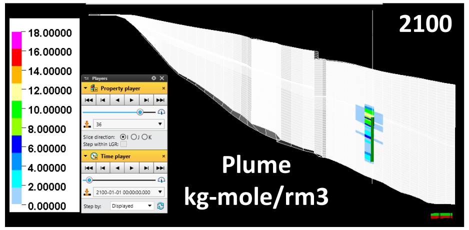
620 years injection
#2 spreads out below Naskapi
#3 reaches bottom hole pressures at perfs – contraining further storage

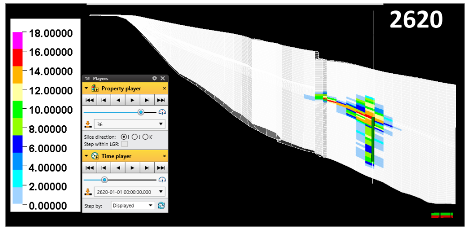
1770 years injection
#1 spreads laterally towards subcrop
#2 becomes pressure compartment-alised – local X-fault migration localises pressure release & upward plumes

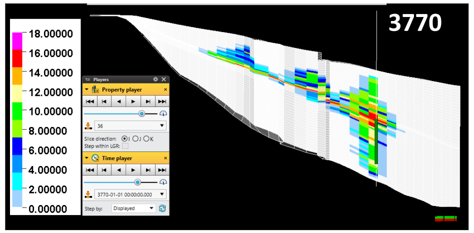
2340 years injection
#1 reaches subcrop

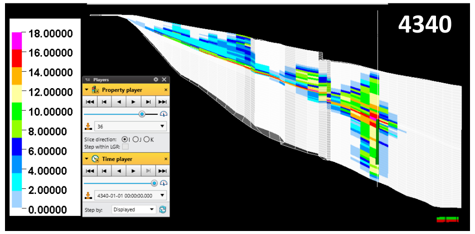
Pressure Fraction - when simulation terminated (runs very slowly approaching BHP pressure constraints)

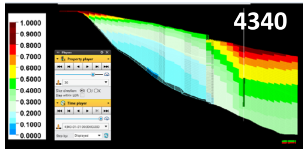
#1. Base Case Open System
(subcrop to ocean column & 1000m atmosphere)



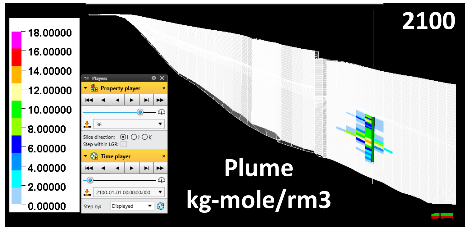


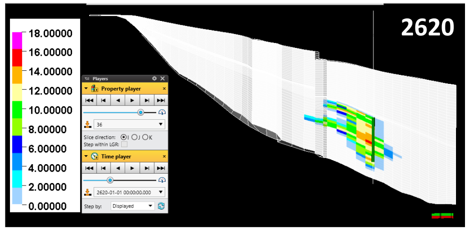


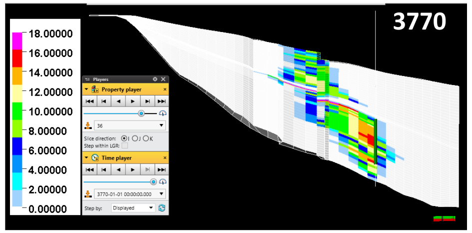


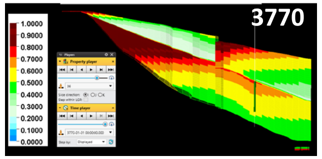


#2. Base Case Open System:
Naskapi intra-formational seal - baffle set to 0 PHI-K

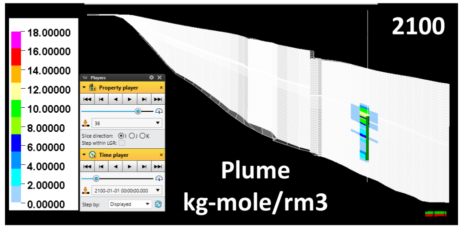


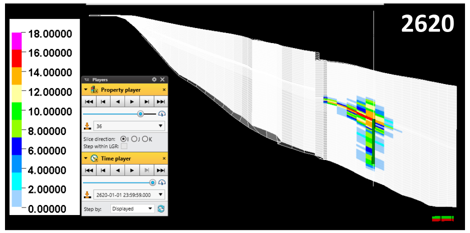


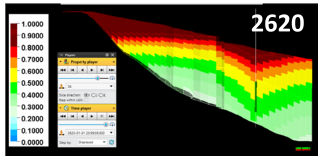




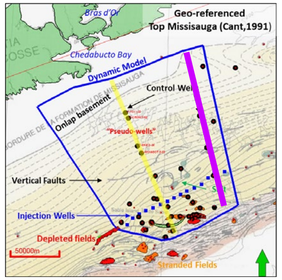
#3. Base Case Closed System
PHI-K set to zero in ocean and atmosphere







Dynamic Model: - Sensitivities



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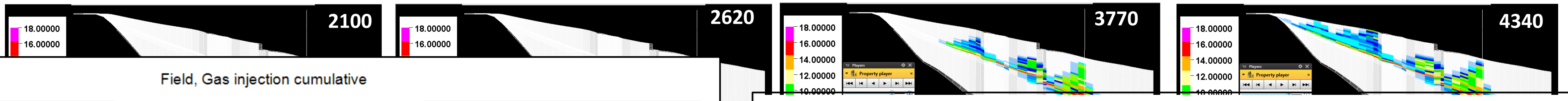
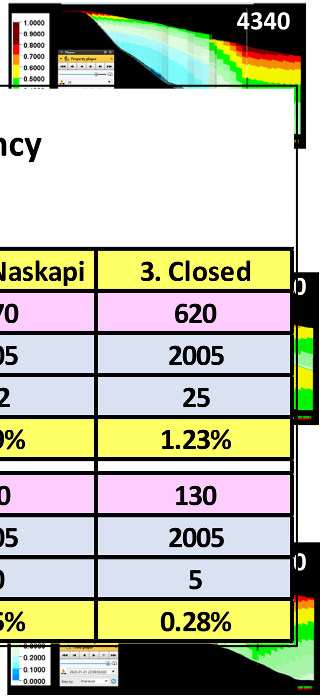
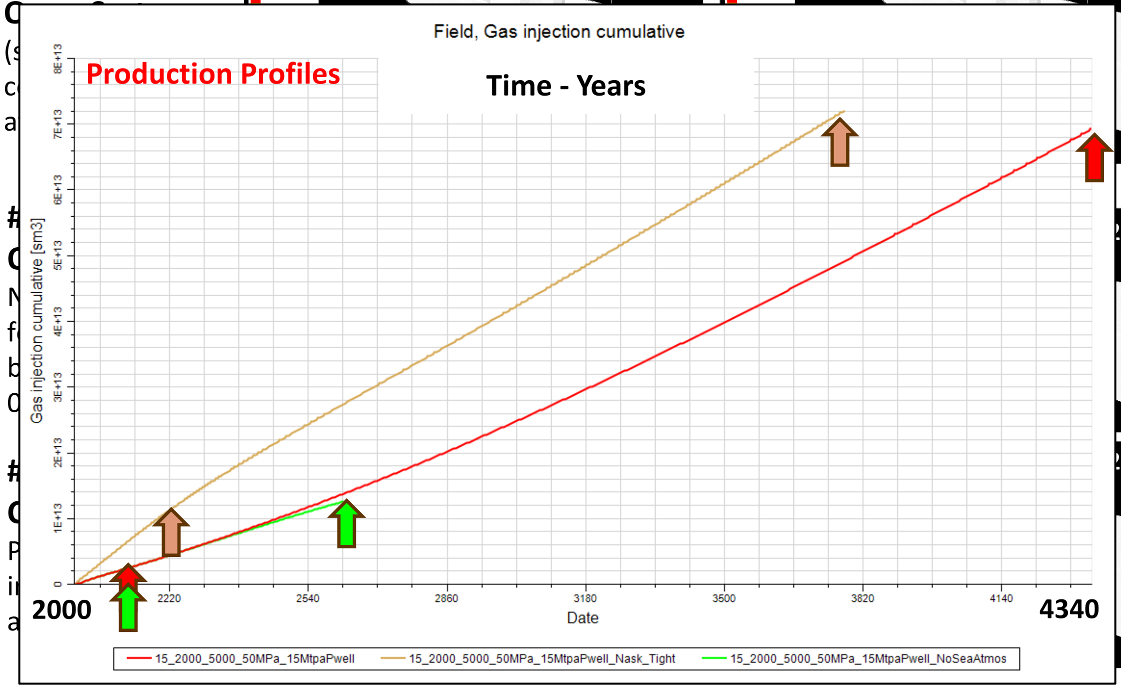
Pressure Fraction - when simulation terminated (runs very slowly approaching BHP pressure constraints)

#1. Base Case

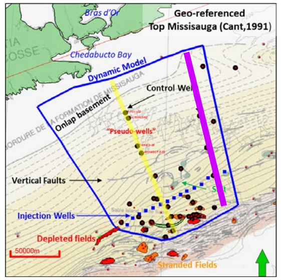






Topseal pressure constraint reduces storage efficiency ~1-8% range to ~ 0.25-1% range

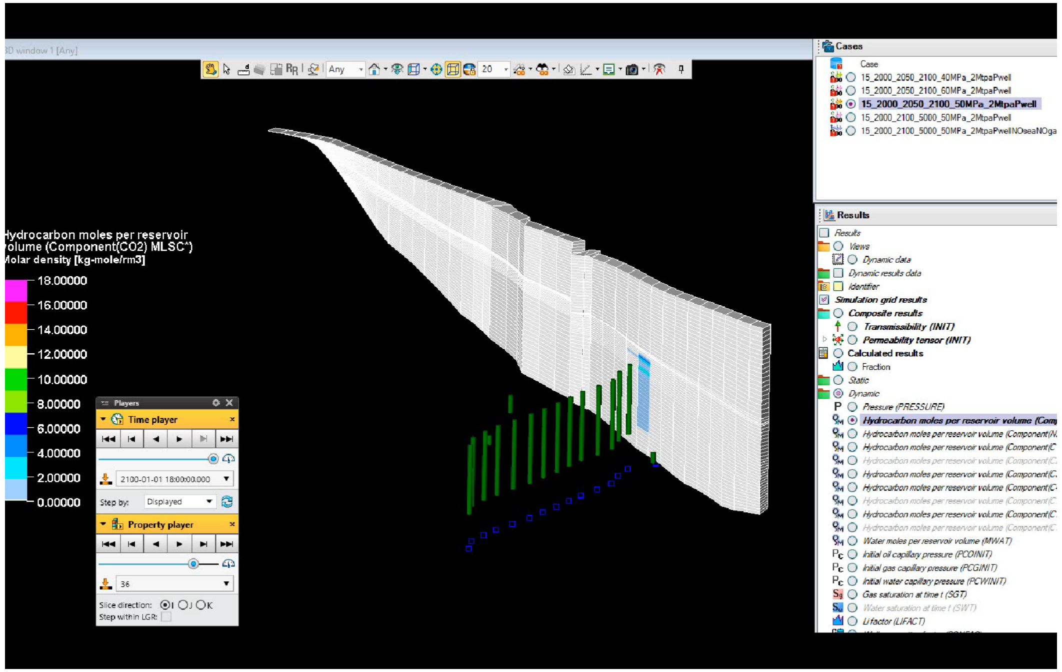
Geologic Model	1. Open	2. Tight Naskapi	3. Closed
No Topseal Constraint (Years Injection)	2340	1770	620
Theoretical Capacity (800-3400m) Gt	2005	2005	2005
CO2 Injected Gt	132	142	25
Efficiency (No topseal pressure restriction)	6.61%	7.09%	1.23%
Topseal Pressure Fraction < 0.8 (Years injection)	130	220	130
Theoretical Capacity (800-3400m) Gt	2005	2005	2005
CO2 Injected Gt	5	20	5
Efficiency (With topseal pressure restriction)	0.28%	1.05%	0.28%



Dynamic Model - Base Case : Video 4

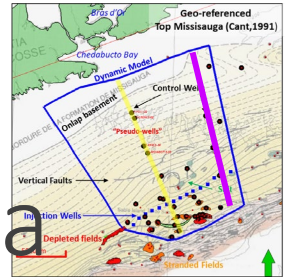
Injection 2000-2050. Equilibration 2050-2100

- 15 wells nominal 2Mtpa each (Nominal total 1.5 Gt)
- Bottom hole pressure 50 MPa
- Monitor: Plume - Pressure - Fraction

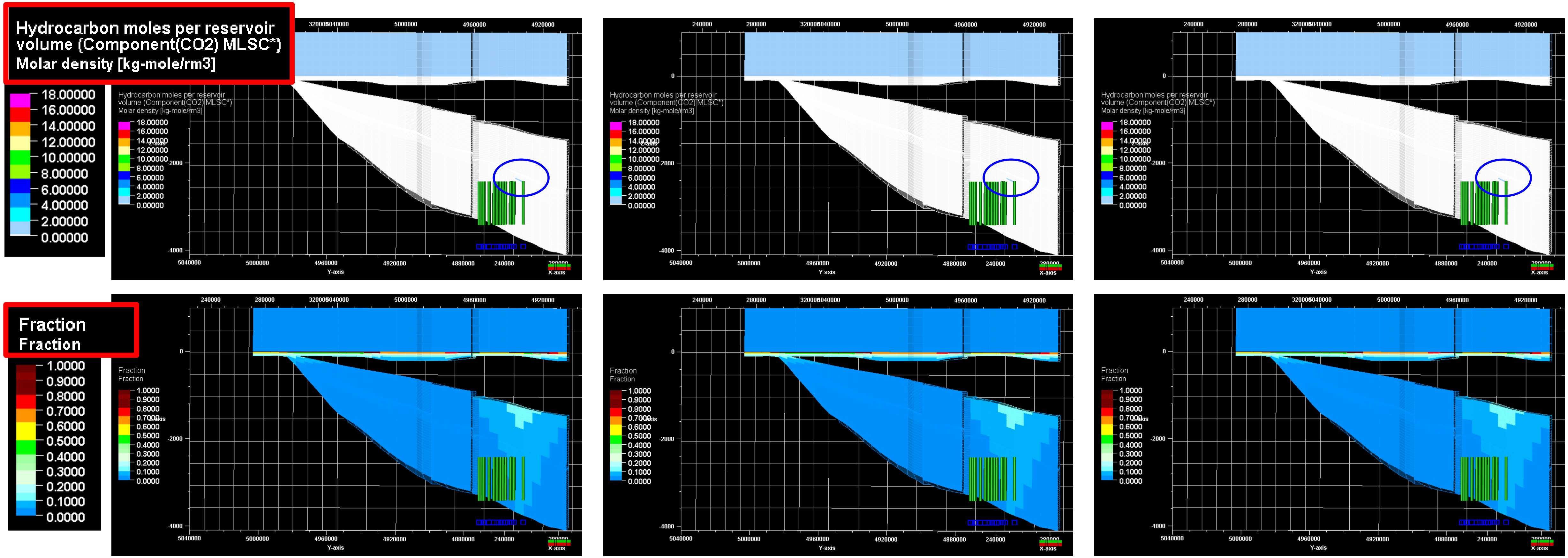


Model Input								Model Input - Injection				Model Results - Injection				From Eclipse
Wells	Start Inj	Stop Inj	End Model	Years Inj	Max. MPa (BHP)	Injection sm3 /day per well	Density kg/sm3 STP	Per well Mtpa	Per well Total Mt	Project Mtpa	Project Total Gt	Per well Mtpa	Per well Total Mt	Project Mtpa	Project Total Gt	Injection sm3 TOTAL
15	2000	2050	2100	50	40	2,767,000	1.98	2.00	100.00	30.00	1.50	1.67	83.63	25.09	1.25	6.34E+11
15	2000	2050	2100	50	50	2,767,000	1.98	2.00	100.00	30.00	1.50	1.87	93.56	28.07	1.40	7.09E+11
15	2000	2050	2100	50	60	2,767,000	1.98	2.00	100.00	30.00	1.50	1.94	97.11	29.13	1.46	7.36E+11

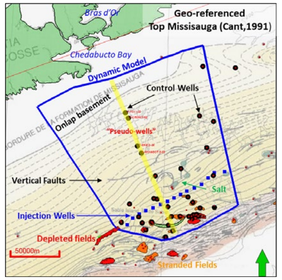
Dynamic Model – Base Case: Test BHP 40-50-60 MPa



- **Injection 2000-2050. Equilibration 2050-2100.** **40-50-60 Mpa cases. Plumes are very small & pressures (fraction) are safe**



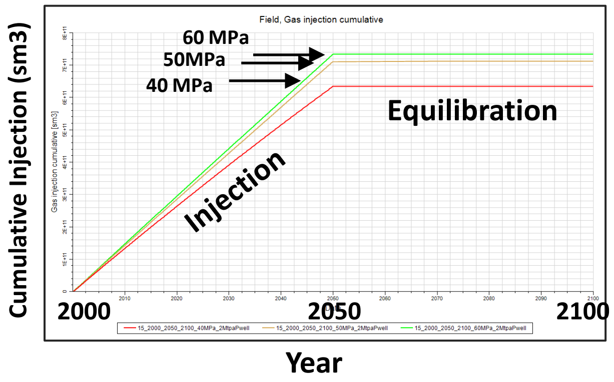
Dynamic Models - Base Case: Results



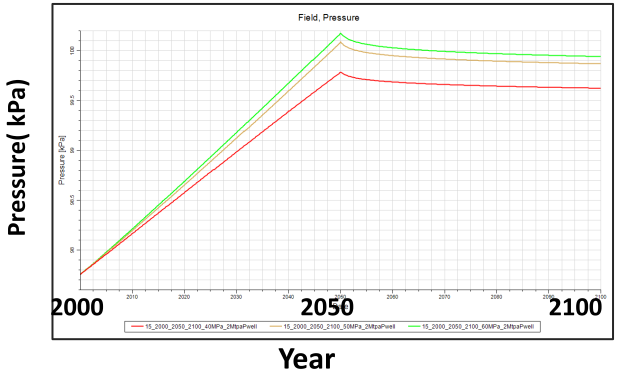
- **50 years injection, 50 years equilibration**
- **15 Wells. Each 2 Mtpa for 50 years. Could represent clusters of 2-4 wells. Cum. injection: 1.25-1.5 Gt. Yearly inj. 25-30 Mt)**

Model Input								Model Input - Injection				Model Results - Injection				From Eclipse
Wells	Start Inj	Stop Inj	End Model	Years Inj	Max. MPa (BHP)	Injection sm3 /day per well	Density kg/sm3 STP	Per well Mtpa	Per well Total Mt	Project Mtpa	Project Total Gt	Per well Mtpa	Per well Total Mt	Project Mtpa	Project Total Gt	Injection sm3 TOTAL
15	2000	2050	2100	50	40	2,767,000	1.98	2.00	100.00	30.00	1.50	1.67	83.63	25.09	1.25	6.34E+11
15	2000	2050	2100	50	50	2,767,000	1.98	2.00	100.00	30.00	1.50	1.87	93.56	28.07	1.40	7.09E+11
15	2000	2050	2100	50	60	2,767,000	1.98	2.00	100.00	30.00	1.50	1.94	97.11	29.13	1.46	7.36E+11

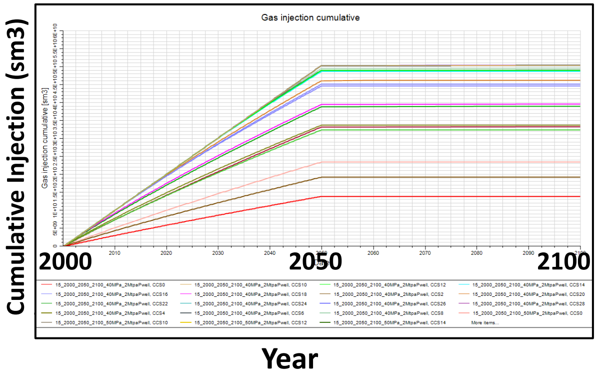
All Wells Cumulative Injection



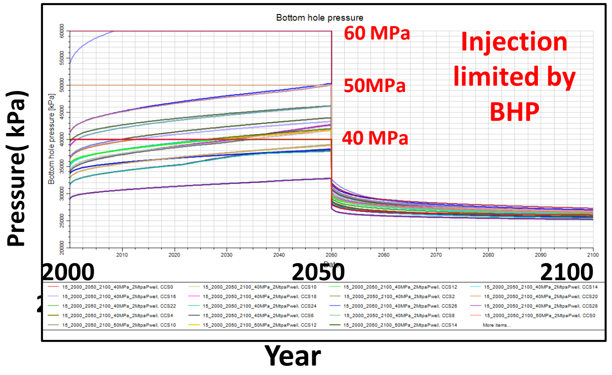
Whole Model Average Pressure



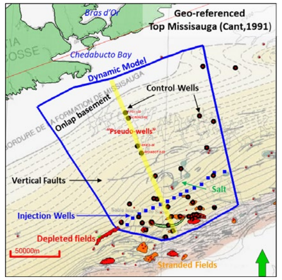
All Wells Cumulative Injection

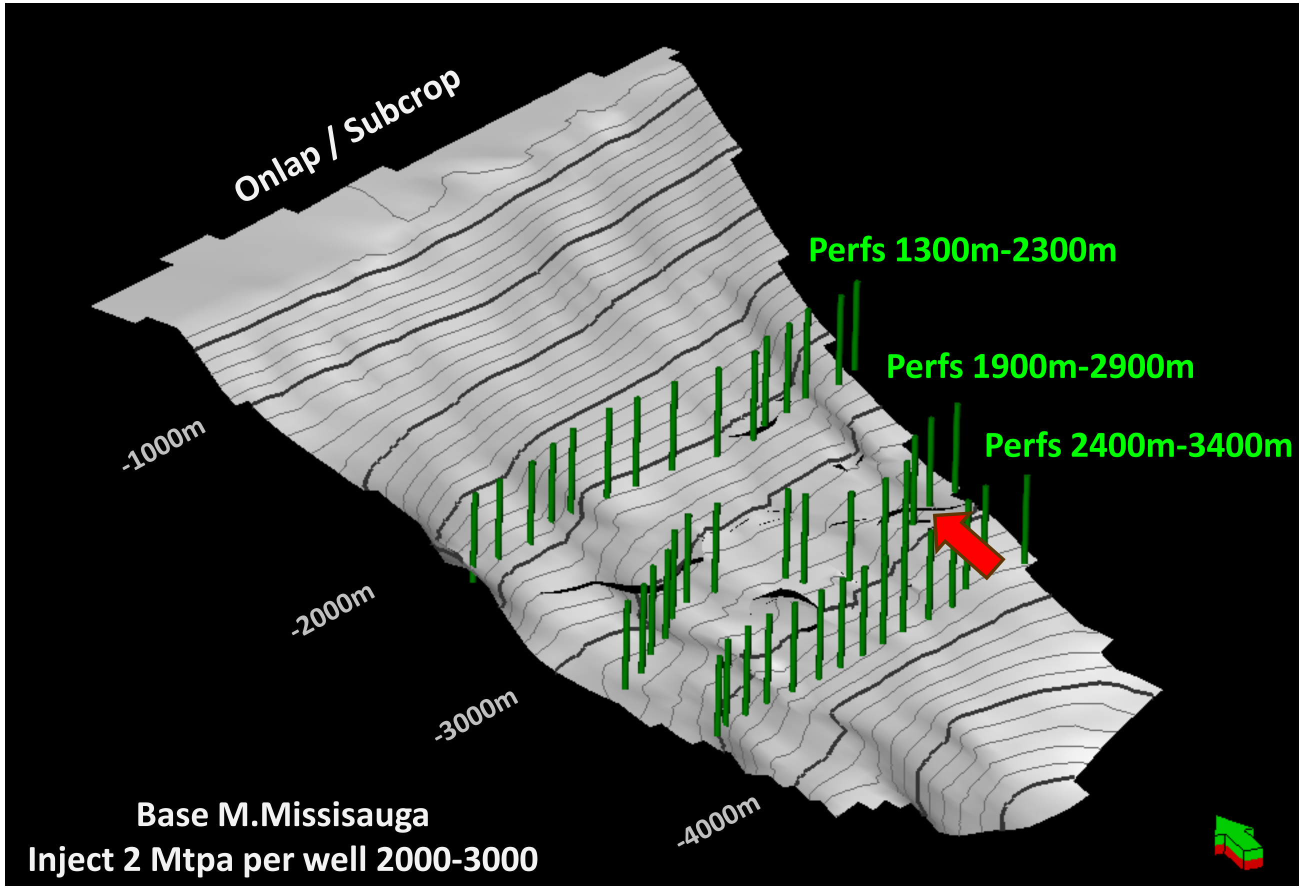


All Wells Bottom Hole pressure

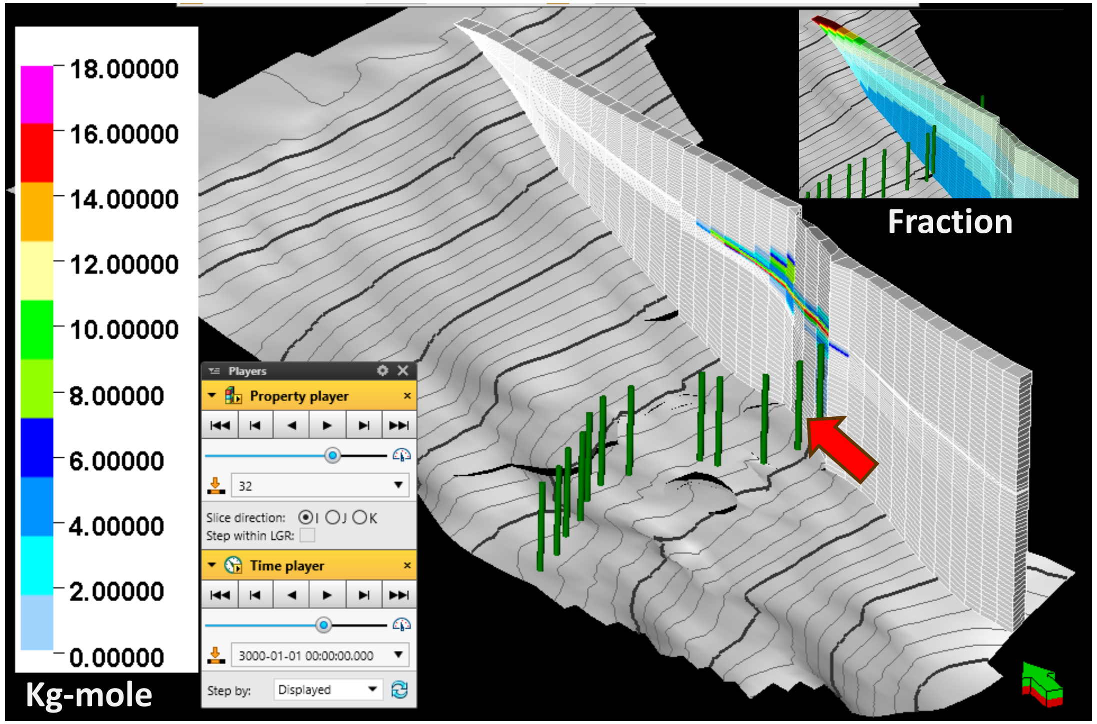


Updip Well Locations

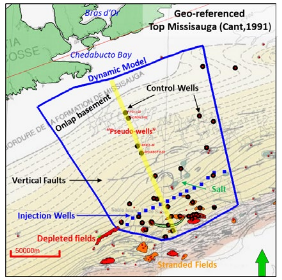


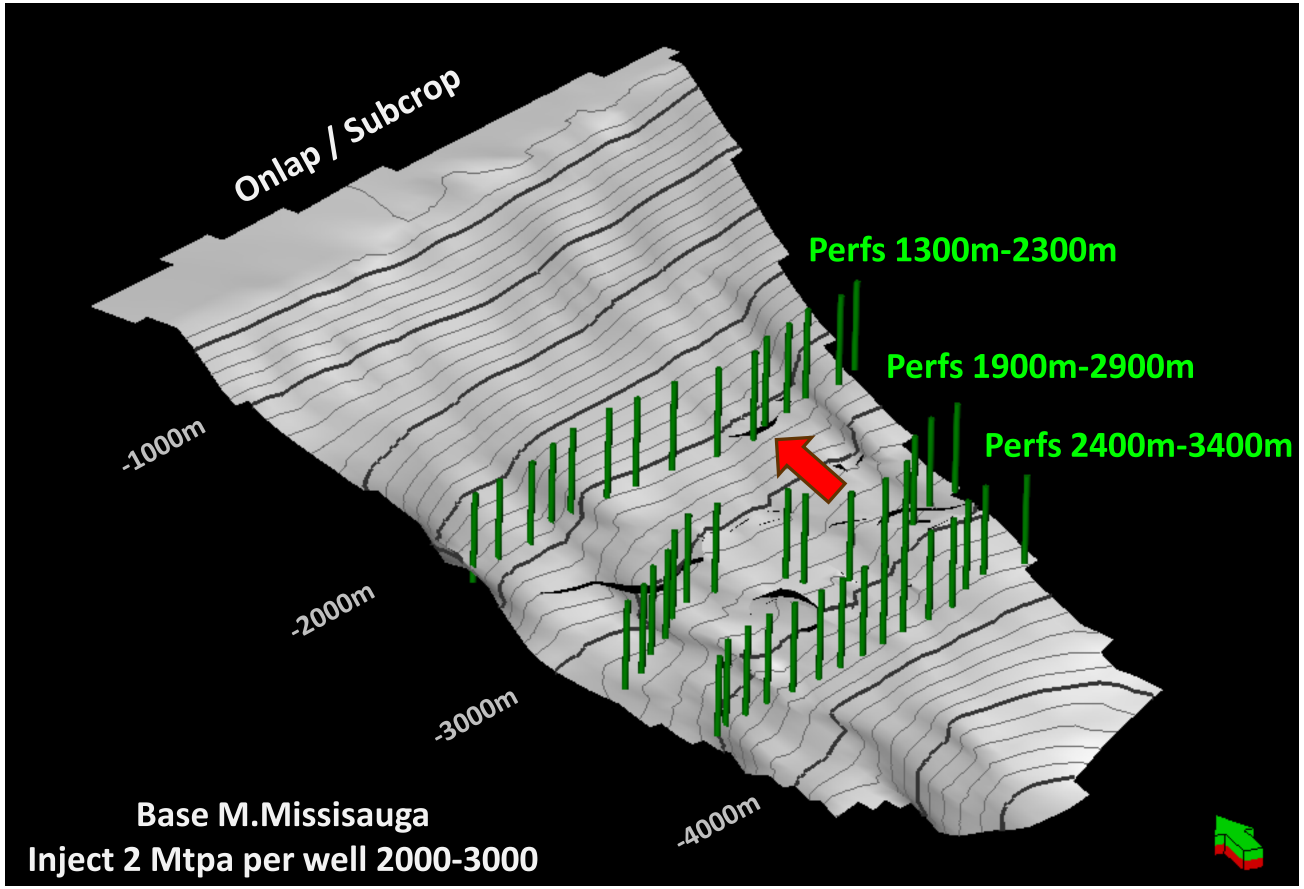


Key faulting highlighted

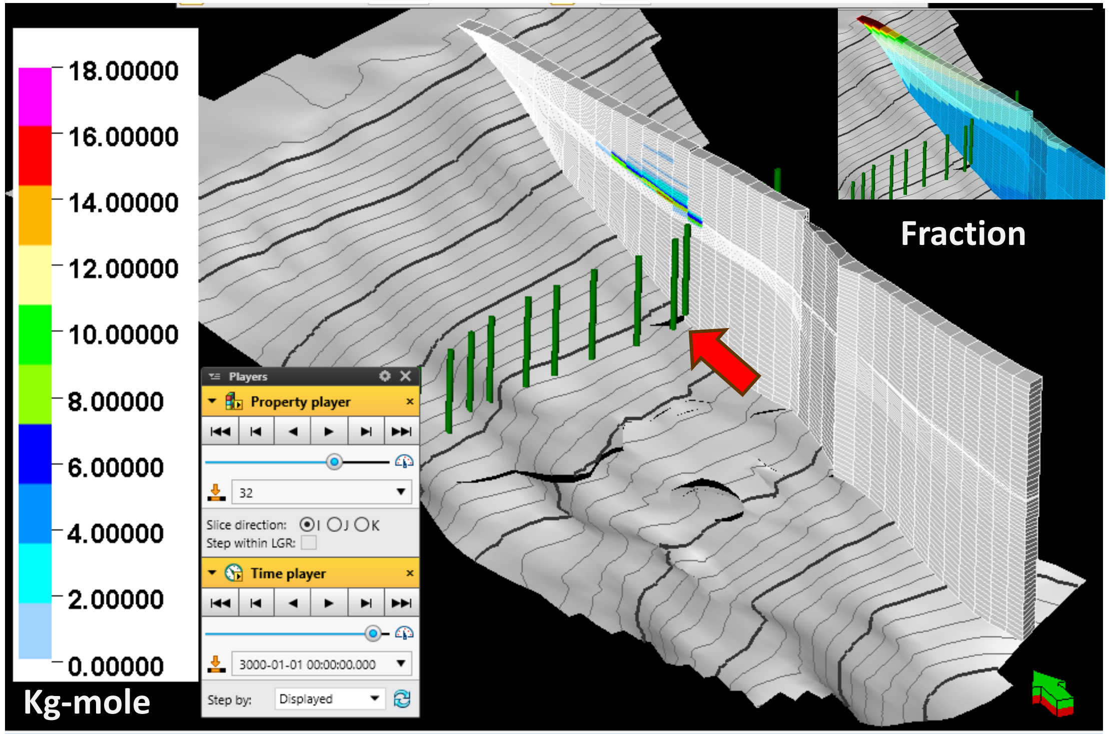


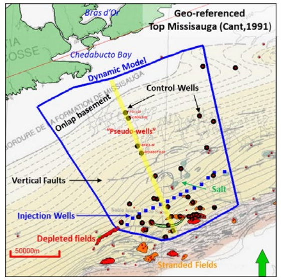
Updip Well Locations





Highlighted fault becomes important

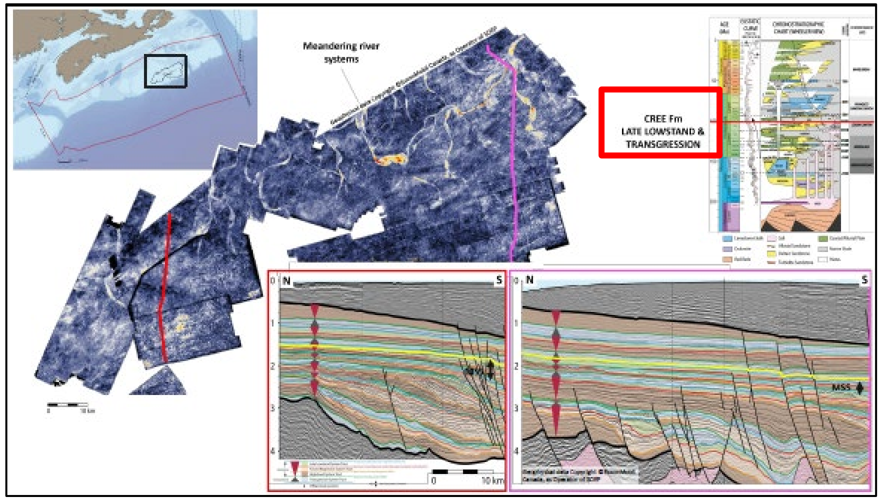


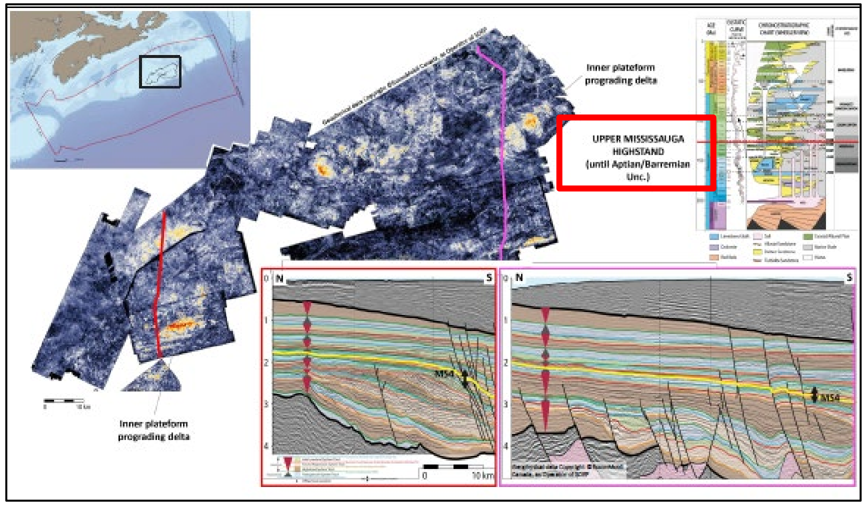


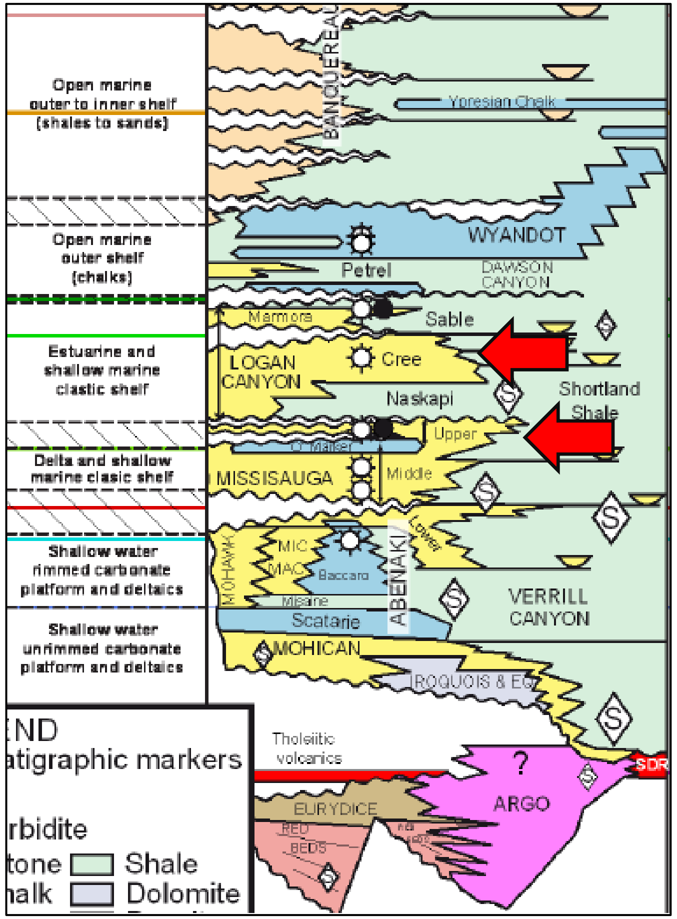
Dynamic Model – Further Cases OR Future Work

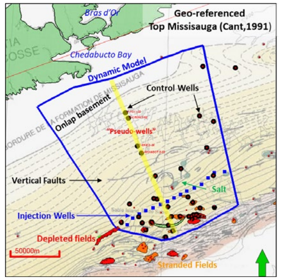
(1) Channels in Logan Canyon and Missisauga (2) Move wells updip

- Need to model Logan Canyon (fluvio-estuarine) and Missisauga (fluvio-deltaic)
- Risk of direct updip conduits to subcrop .
- Can base this on 2023 Beicip-Franlab Scotian Basin Integration Atlas (Paleoscan)









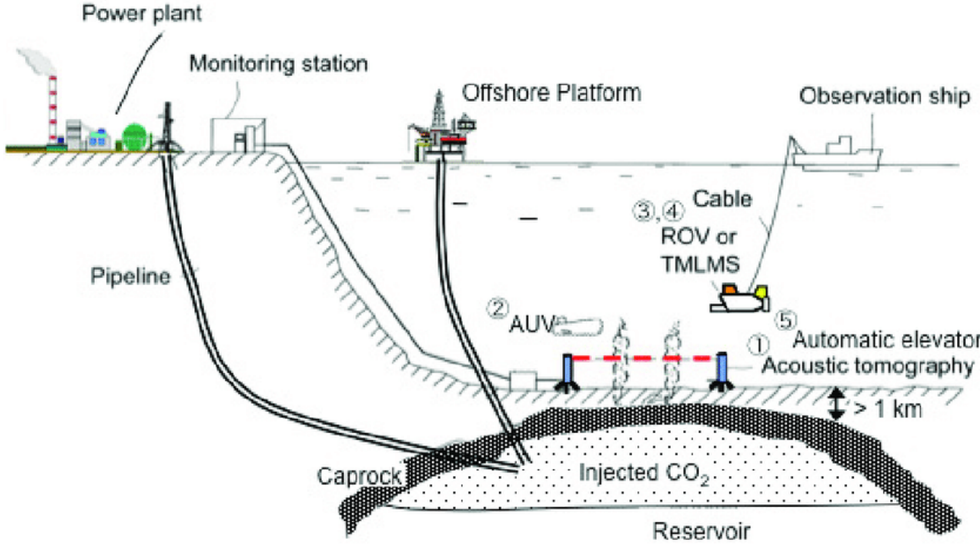
Risks and Mitigation

Environmental Implications

Risks	Mitigation
Subcrop leakage	Forward modeling + 4D plume monitoring
Displacement of **connate water**	Updip pressure release well
Disruption of **marine life**	Environmental Surveying
Pipeline leakage/failure	Good maintenance and compliance to design parameters

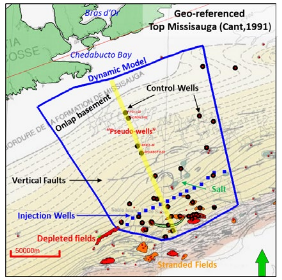
Project Chronology

- Comprehensive injection model and development plan
- Offshore test-project
- Commercialization and expansion
- Implement long term monitoring



The Project — Barriers to Implementation

- High construction cost for Nova Scotia
- Profit highly dependent on federal carbon pricing
- Regulatory impediments (e.g., London Protocol)
- Ecological conservation and NIMBY concerns



Discussion & Conclusion

Key points

1 - Effective **storage space** in deep saline aquifers on par with **North Sea projects**

2 - Constraining factor is **pressure at topseal**

3 - Storage efficiencies lower than in literature <- 0.25%-1.0%

4 - Residual trapping less risky than structural trapping