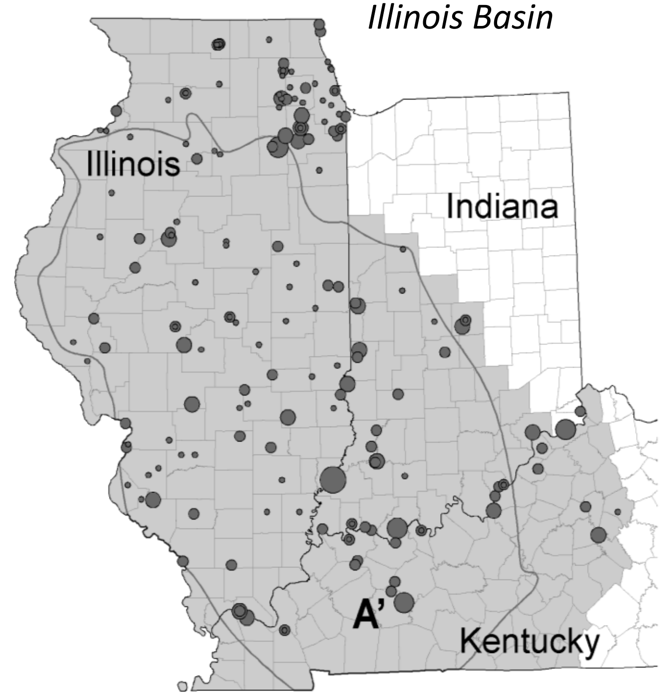
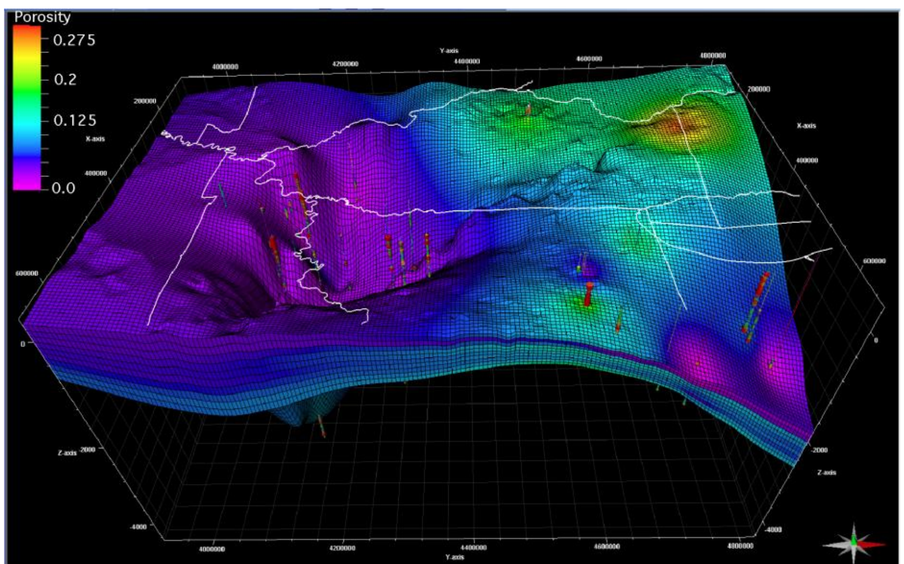
Assessing the Risk of CO_2 Leakage & Induced Seismicity Across the Illinois Basin

Mark Person & Yipeng Zhang; NM Tech
Mike Celia, Karl Bandilla, Tom Elliott; Princeton University
John Rupp, Kevin Ellet; Indiana Geological Survey
Brenda Bowen, Purdue University (University of Utah)
Carl Gable, Los Alamos National Lab



Power Plant Locations, Illinois Basin



Aquifer Porosity, Knox Formation, Illinois Basin

Goals of Study
DE-FC26-FE001161

- Develop & Test New Multi-Layer Sharp-Interface Models of Basin Scale CO_2 Sequestration

- Build 3D Hydrostratigraphic Framework model for Illinois Basin

- Represent Spatial Variations in Reservoir & confining unit Petro-physical Properties

- Test Petro-physical model by:

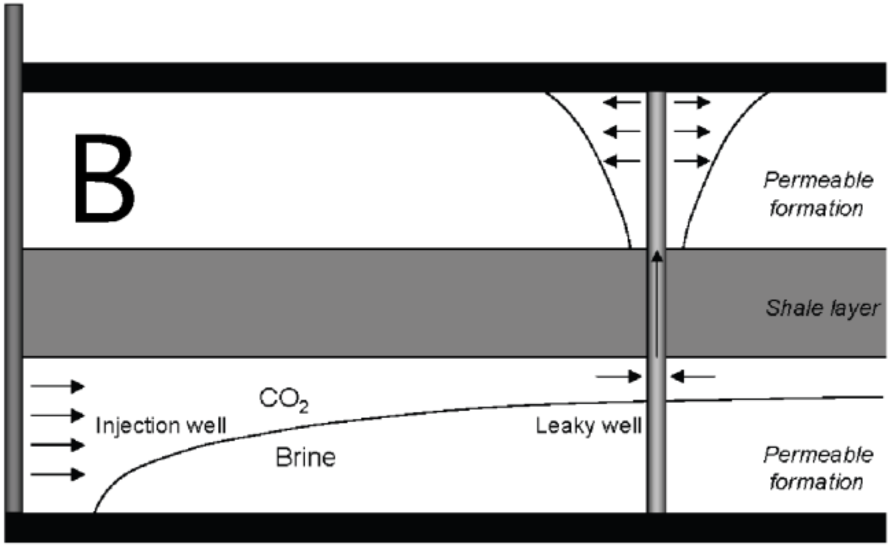
  a) Matching drawdown patterns in Cambro-Ordovician Aquifers using historical pumping data
  b) Matching regional salinity & stable Isotope patterns which have developed on geologic time scales

- Apply Model to Illinois Basin to Assess:

  a*) Potential for CO_2 Leakage through wells and fault zones due to basin wide CO2 injection*
  b) Potential for induced seismicity

Sharp-Interface Model Approach

- Multi-Layer (7-10 layers represented in Illinois Basin)
- Transmissivity Based Flow Equations, one for each fluid Phase (3D → 2D)
- Position of the Sharp-Interface are the Unknown Variables
- Leakage up Wells and Faults
- Governing Equations solved both Analytically & Numerically

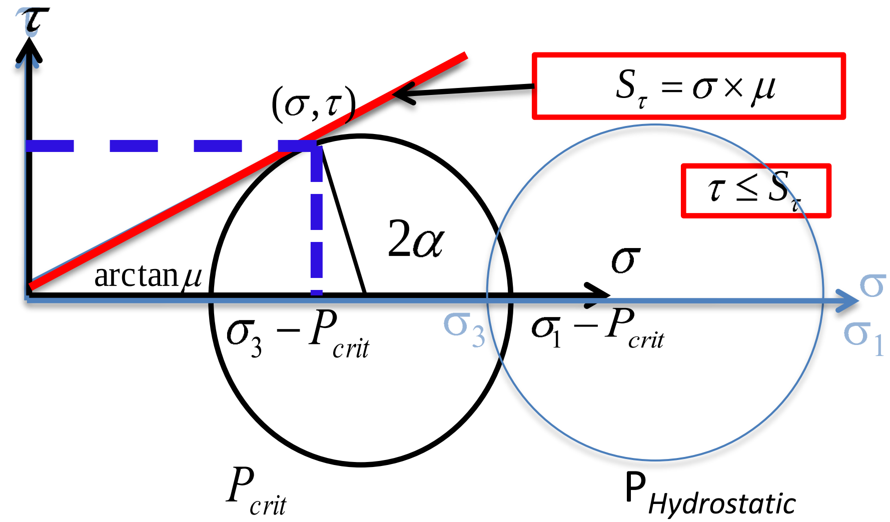


Critical Pressure (P_{crit}) & Failure Criteria (FC)

$$P_{crit} = \sigma_v (3\alpha - 1)/2$$

$$FC = (h - z)\rho g - P_{crit}$$

Nicolson & Wesson (1990)

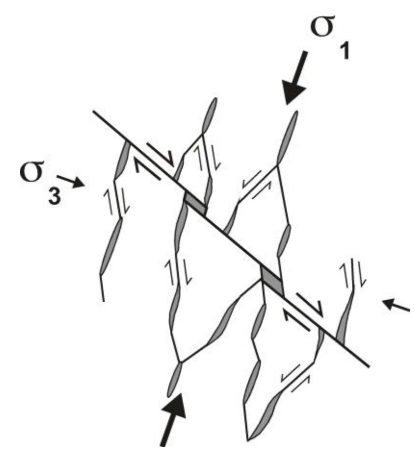


Variables:

σ_v - vertical loading, h - hydraulic head
$\alpha = \sigma_3/\sigma_1$, z - elevation,
ρ- fluid density g - gravitational acceleration
σ_1 – maximum horizontal stress
σ_3 – minimum horizontal stress

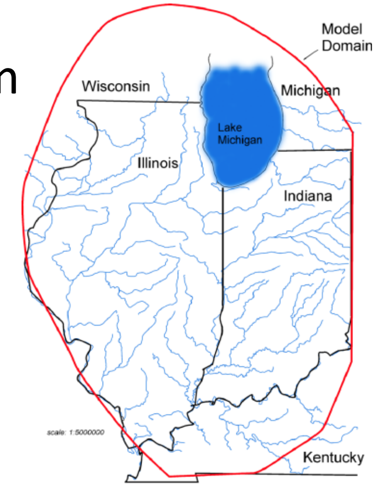
Assumptions:

Fault plane has no cohesion
Fault is critically stressed
Maximum horizontal stress(σ_1) is close to vertical loading (σ_v)
Coefficient of friction (μ) is 0.6

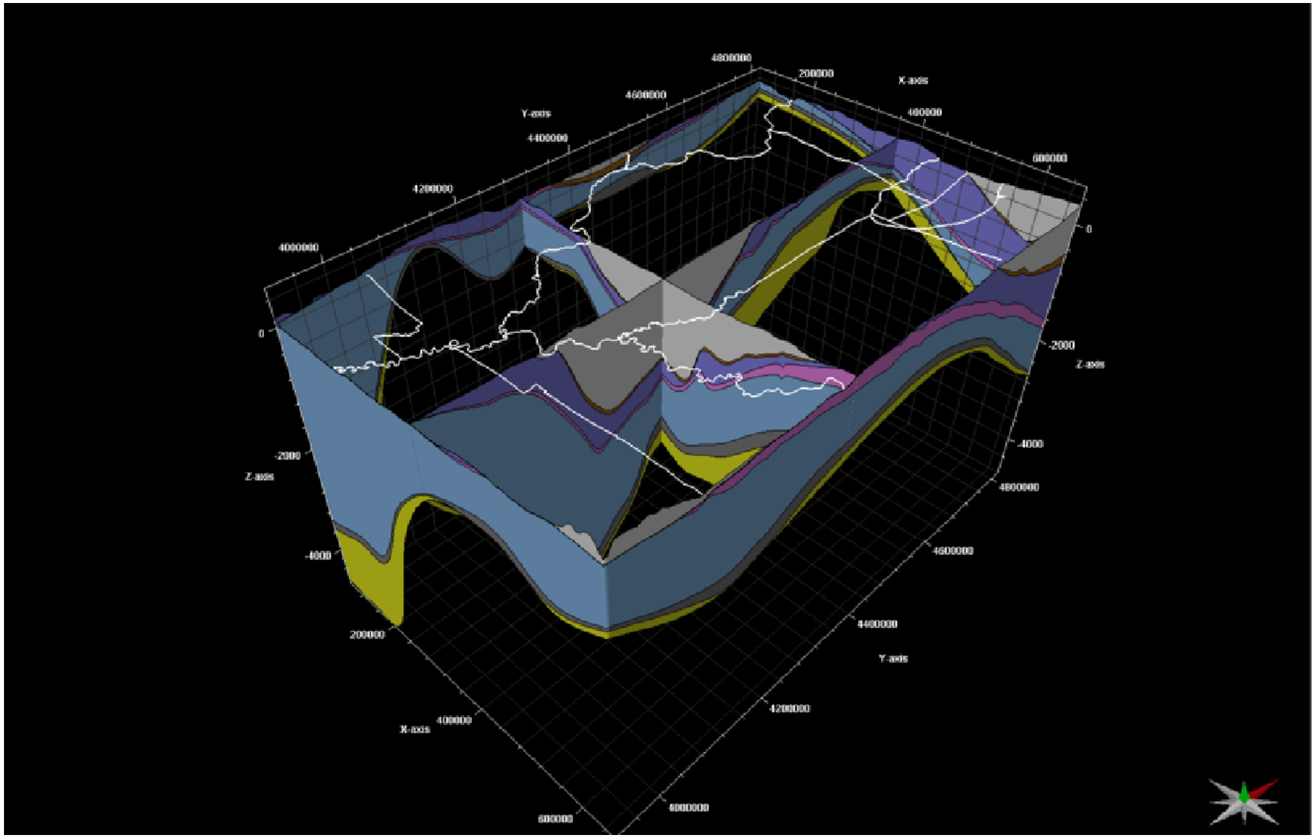


7 Layer Model of Illinois Basin Aquifer-Confining Unit System

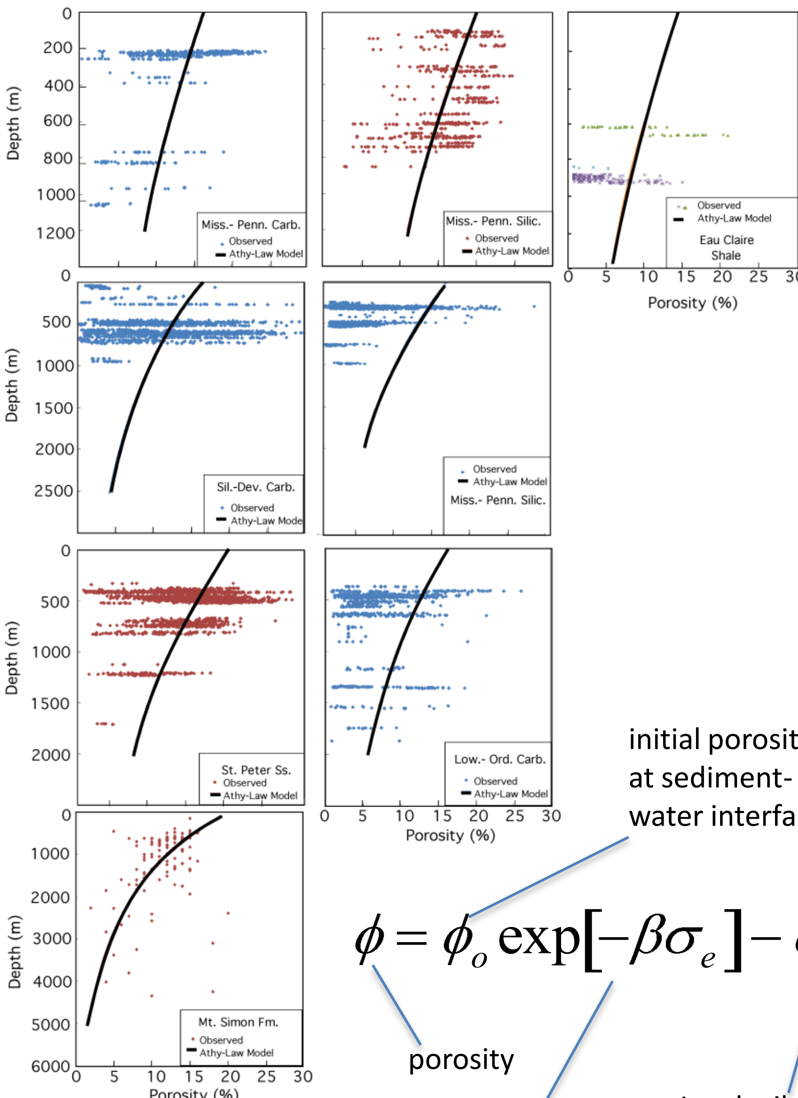
System		Hydrostratigraphic Unit (Model Layer)	Dominant Lithology
Pleistocene-Holocene		AQF4 (L7)	Glacially-derived sediments
Pennsylvania	Upper		Predominantly siliciclastics with interbedded coals
	Middle		
	Lower		
Mississippian	Upper		Interbedded carbonates and siliciclastics
	Middle		Predominantly carbonates
	Lower	AQT3 (L6)	Shale
Devonian	Upper		
	Middle	AQF3 (L5)	Predominantly carbonates with minor sandstone
	Lower		Carbonates
Silurian	Upper		
	Lower		
Ordovician	Upper	AQT2 (L4)	Shale
	Middle	AQF2 (L3)	Carbonates and sandstone
	Lower		Carbonates
Cambrian	Upper		
	Middle	AQT1 (L2)	Predominantly shale
	Lower	AQF1 (L1)	Predominantly sandstone



Indiana Geological Survey



Develop Petrophysical Models



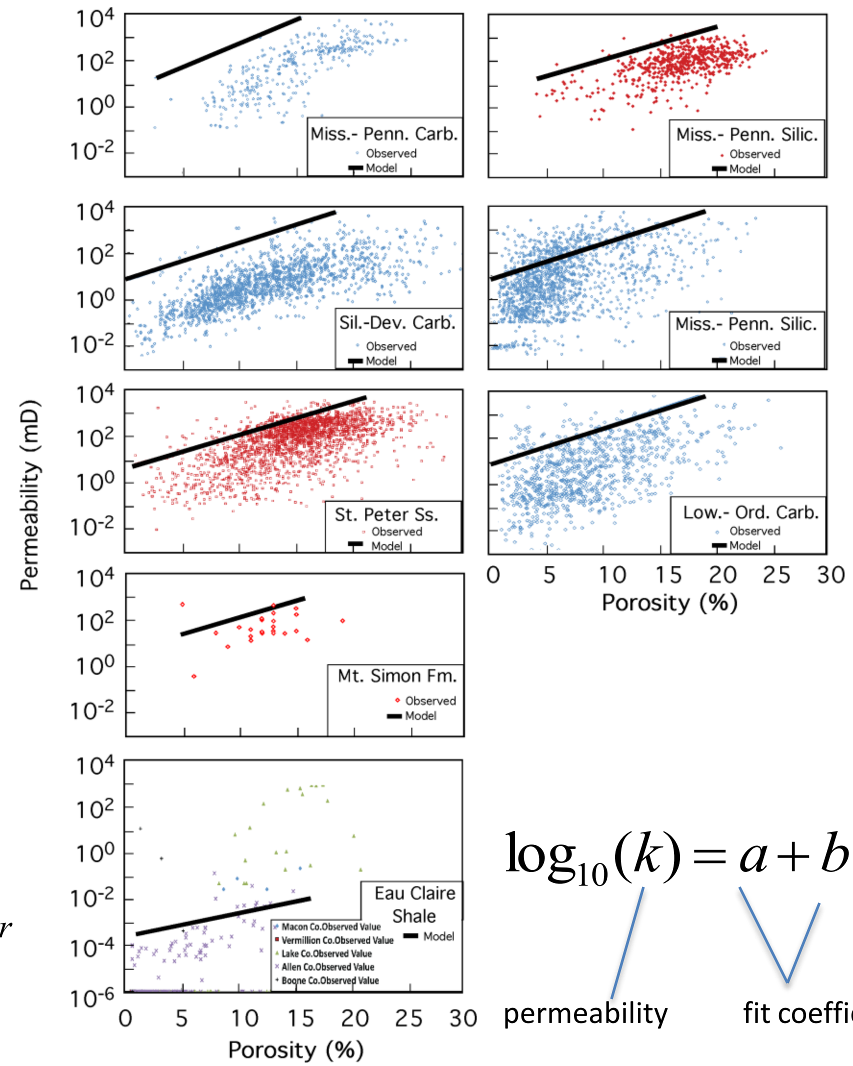
$$\phi = \phi_o \exp[-\beta\sigma_e] - \phi_{ir}$$

initial porosity at sediment-water interface

porosity

rock compressibility

Irreducible porosity



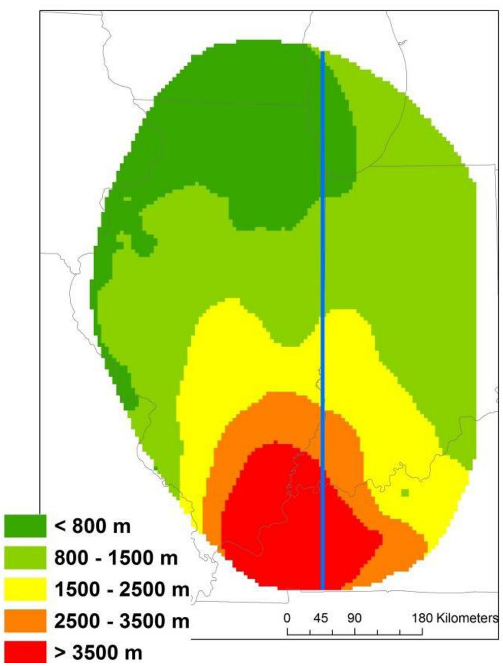
$$\log_{10}(k) = a + b\phi$$

permeability

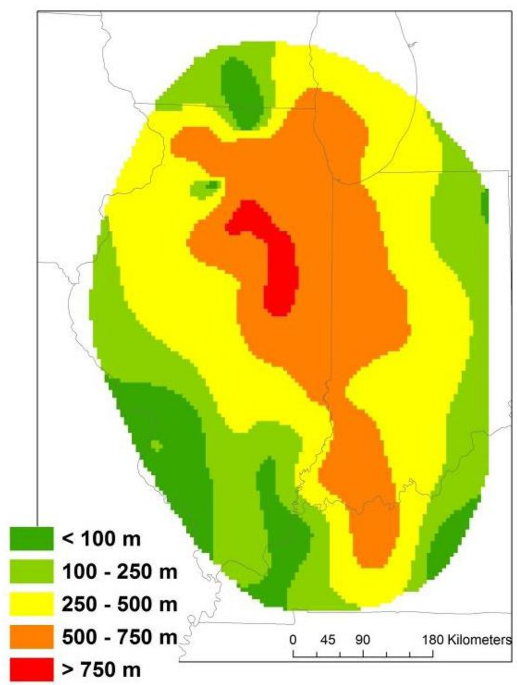
fit coefficients

Example of Heterogeneity Represented in Model: Mt. Simon (AQ1)

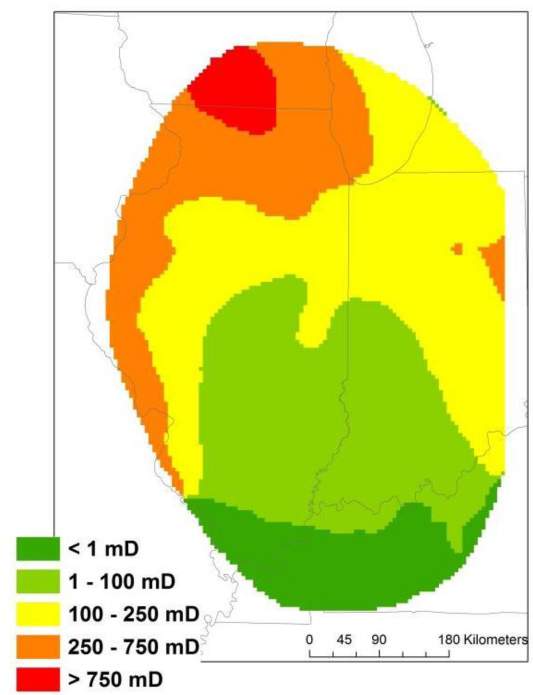
Depth (m)



Thickness (m)

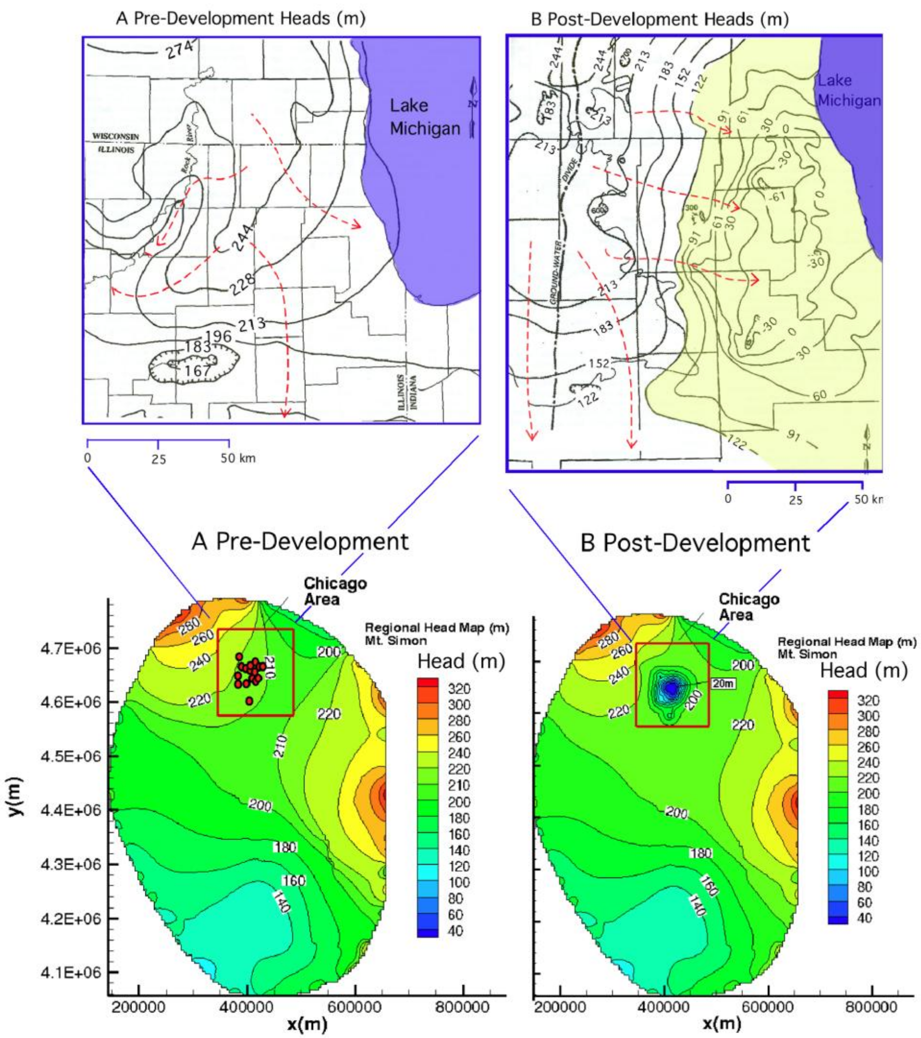


Permeability (mD)



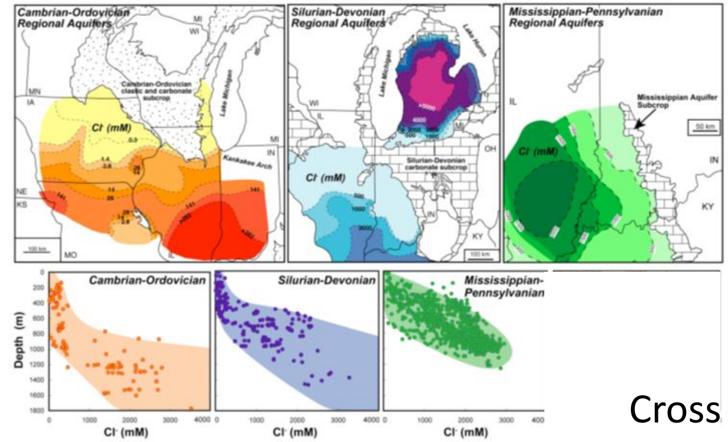
Bandilla et al (2012)

Model Calibration to Historical Pumping of Cambro-Ordovician Aquifer around Chicago

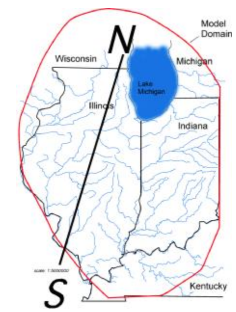


Person et al (2012)

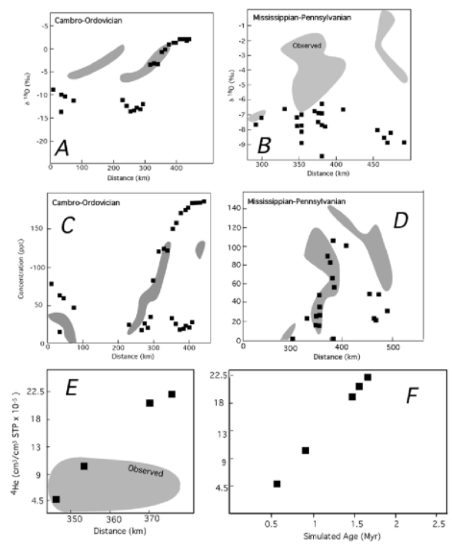
Regional Salinity Patterns



Cross Section Location

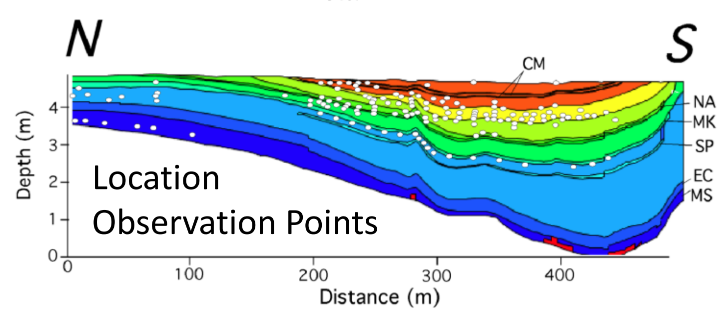


Model Calibration



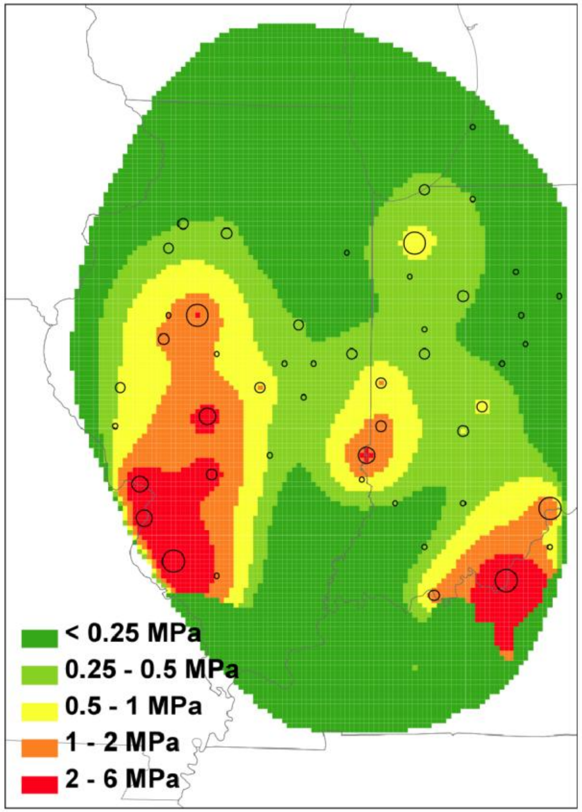
● - Model

- Observed

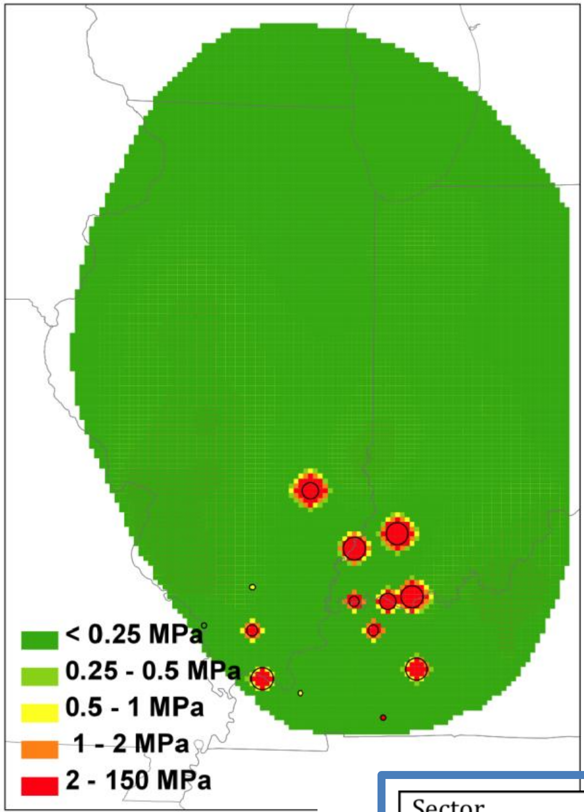


Simulated Injection Pressure

Mt. Simon Fm.



Knox Dolomite



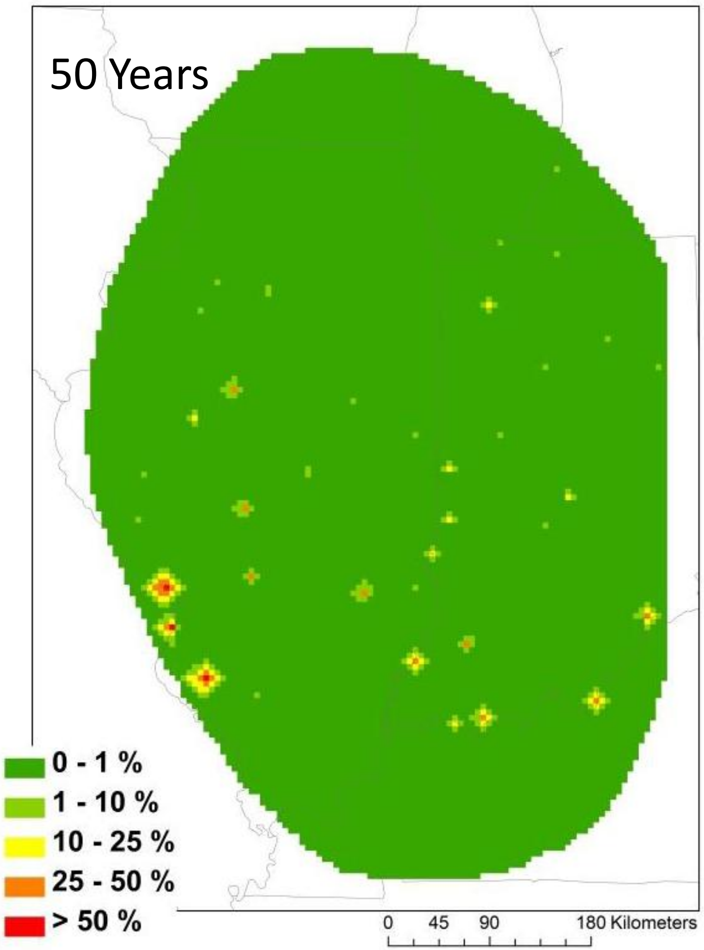
208 MT/yr CO_2 Injection after 50 Years

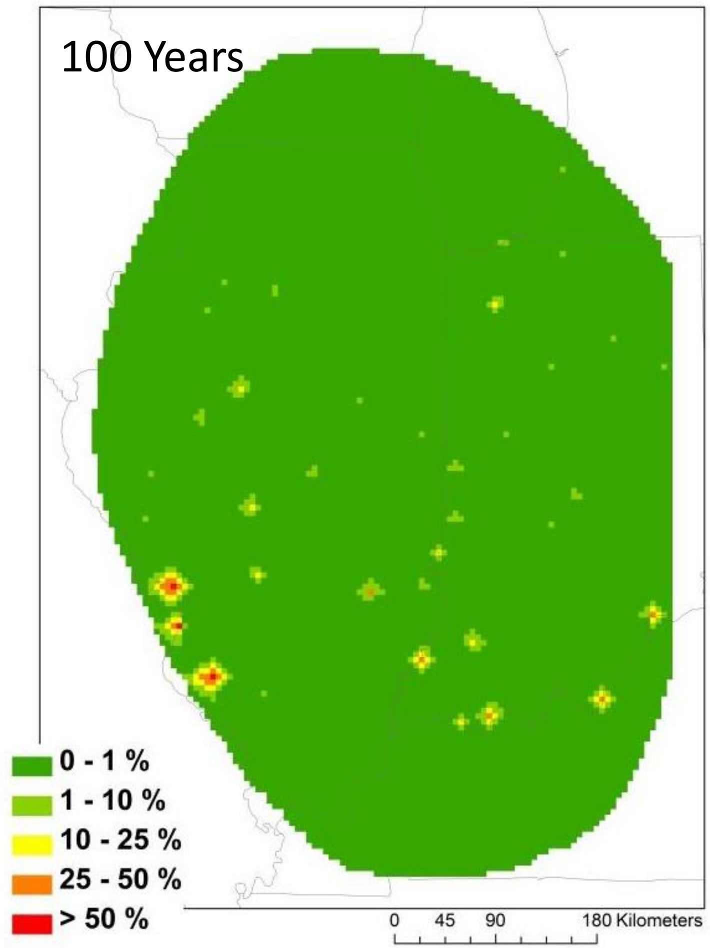
Illinois Basin CO_2 Sources

Sector	Annual Emissions		Number of sites	
	[Mt/yr]	[%]	#	[%]
Electricity	289.0	79.1	129	37.5
Ethanol	13.7	3.7	32	9.3
Industrial	38.4	10.5	106	30.8
Petroleum/Gas	1.8	0.5	43	12.5
Refineries	14.0	3.8	11	3.2
Cement	7.55	2.0	11	3.2
Agricultural	0.6	0.2	7	2.0
other	0.2	0.1	5	1.5
total	365.3	100.	344	100.0

Bandilla et al (2012)

Simulated CO_2 Footprint & Leakage Estimates





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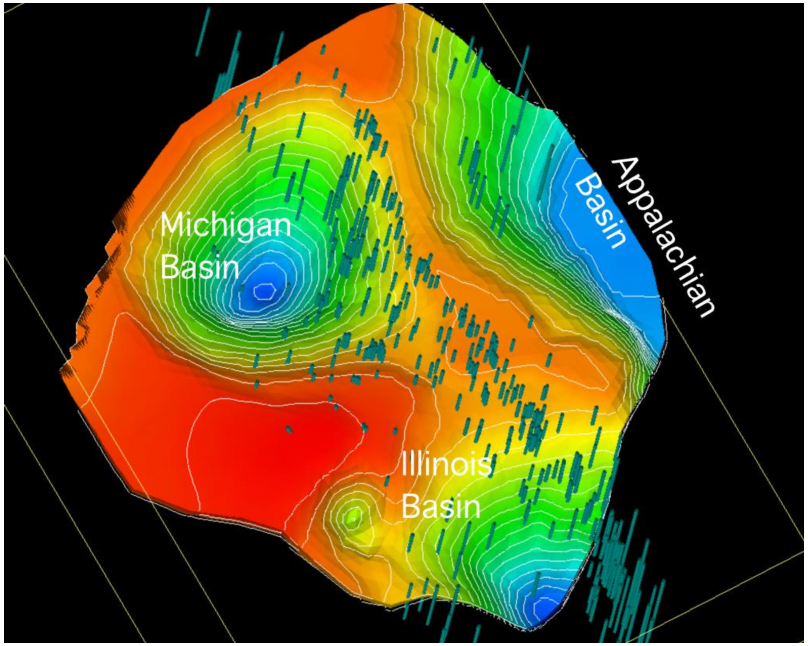
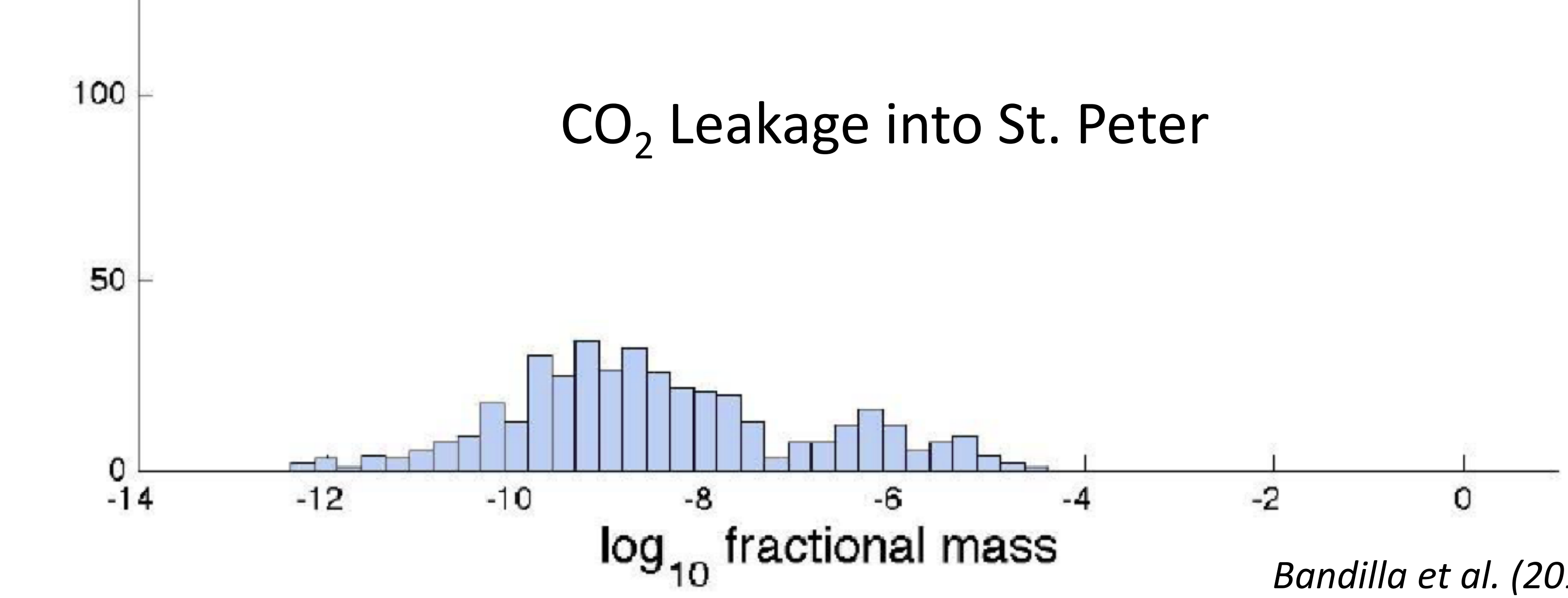
Bandilla et al. (2012)

Wells Completed in Mt. Simon



CO_2 Leakage into St. Peter



Bandilla et al. (2012)

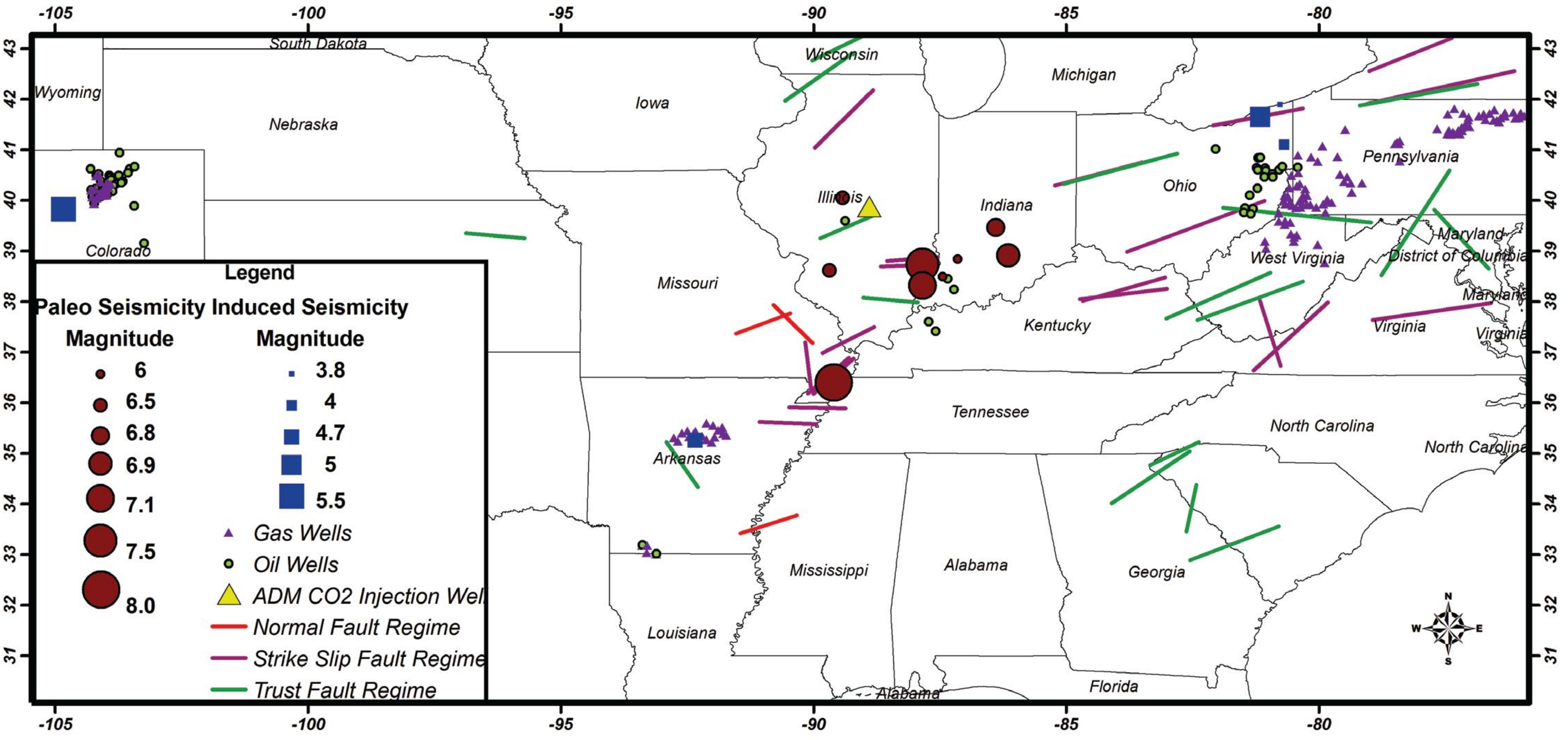
Key Findings

- Pore pressure envelope propagation on the order of 50 km laterally
- Pore pressures in Knox may approach Frac Limit if Injection rates are high, many wells would be needed
- Risk of CO_2 leakage along abandoned wells is minimal
- Risk of Lateral Brine Migration is Low
- From the Perspective of Upward Leakage, the Mt. Simon appears to be a Good Choice for CCS

But What About the Risk of Induced Seismicity?

Additional Collaborators: Jim Evans, Tom Dewers, Peter Mozley

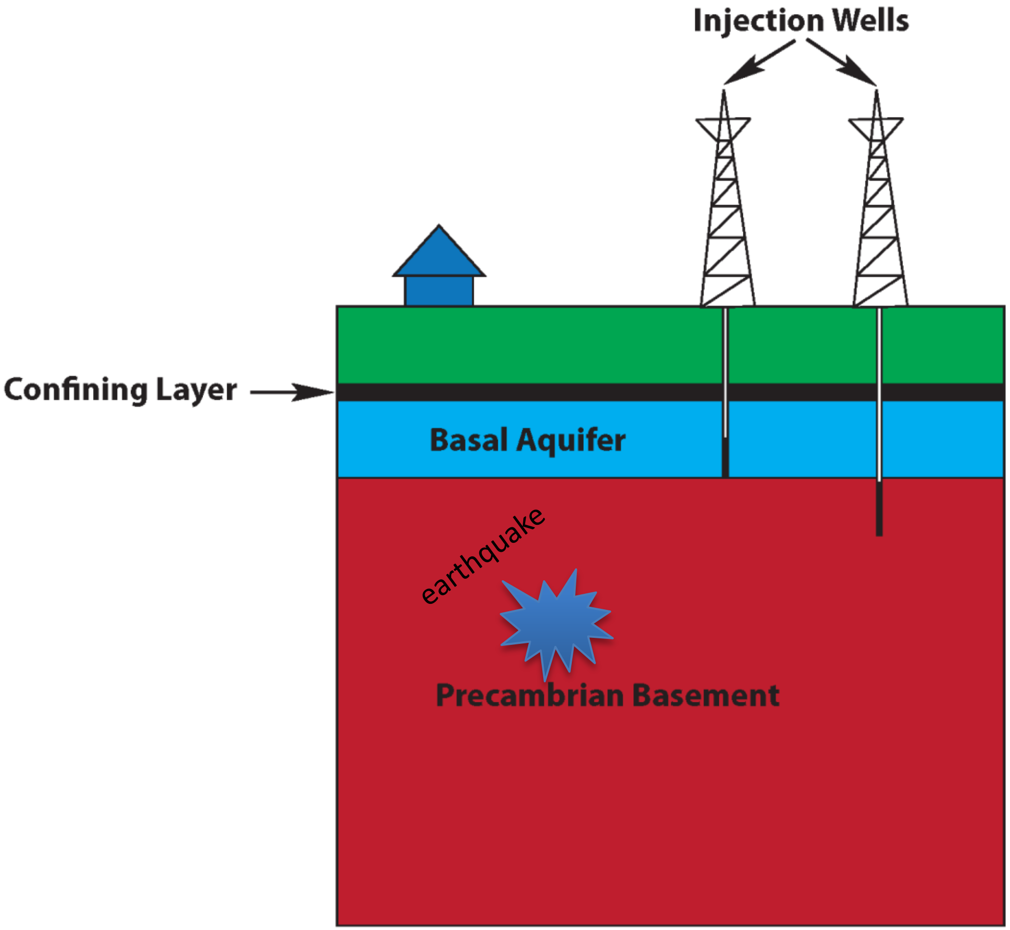
Midcontinent Seismicity



Data sources: Zoback and Zoback (1989); Nicholson and Wesson (1990); Wheeler and Cramer (2002); Person et al. (2010)
Ohio Natural Resource Department (2012); Horton (2012); Baker Hughes, http://gis.bakerhughesdirect.com/RigCounts/default2.aspx

Zhang et al. (2012)

Key Observations of Injection Schemes Associated with Induced Seismicity



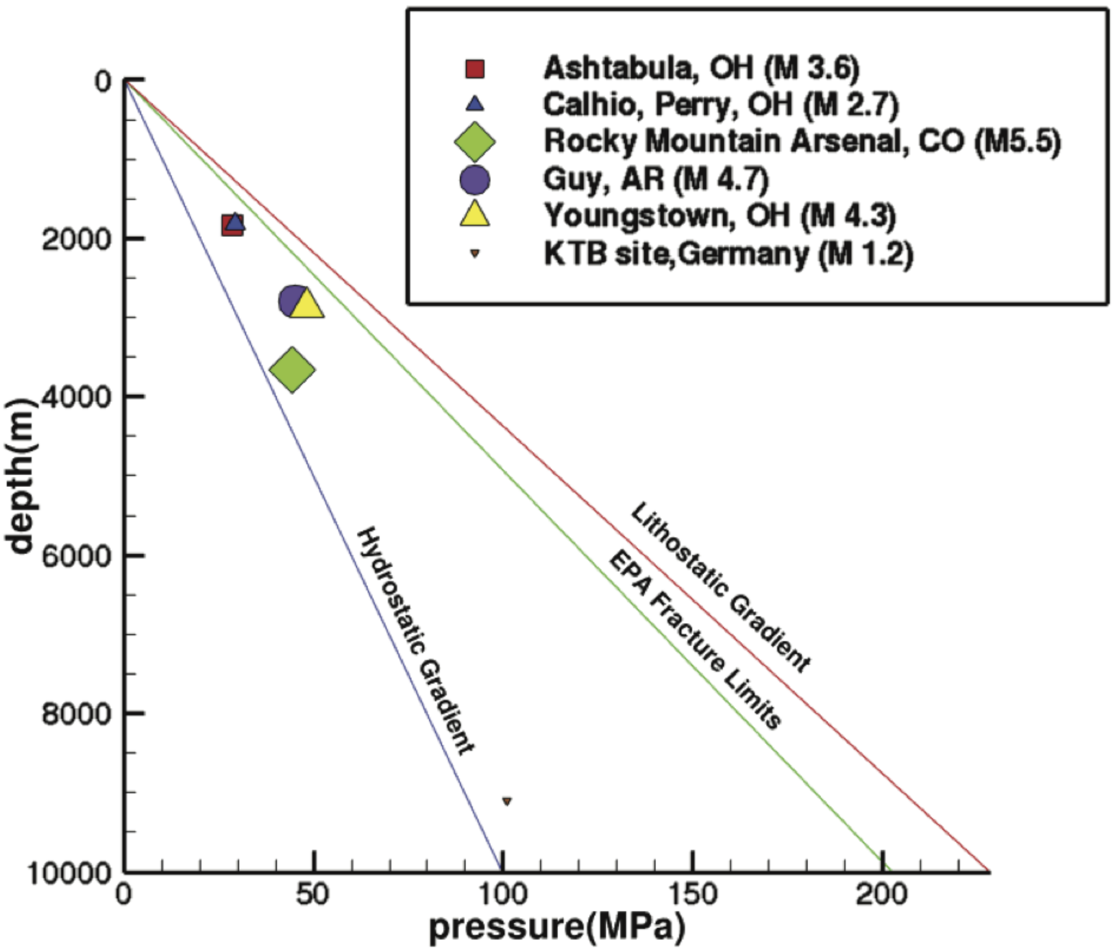
1. Largest induced Earthquakes <u>always</u> occur in <u>crystalline basement</u>

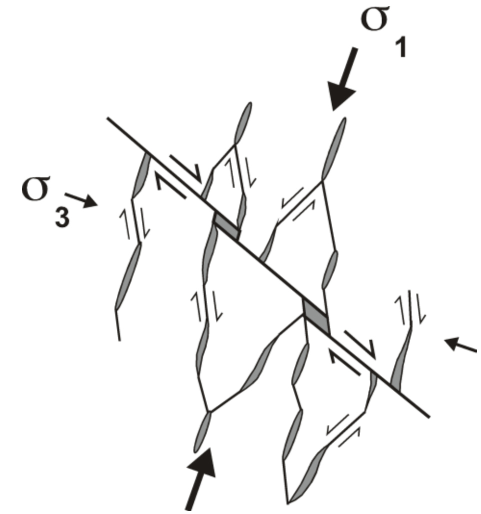
2. Injection is typically into basal aquifer with no bottom seal separating the injection horizon from crystalline basement (Ashtabula, Ohio, Guy, Arkansas)

3. In some instances, injection was directly into crystalline basement (e.g. Youngtown Ohio, Rocky Mountain Arsenal, Colorado).

Zhang et al. (2012)

Key Observations on Injection Pressures Associated with Induced Seismic Events





1. Injection Pressures were well below the frac limits (80% of lithostatic pressure)

2. These are Pressures at the injection site. Pressures at the earthquake foci (up to 10 km away) were much <u>lower</u>.

1. This indicates faults that failed must have been critically stressed (typically the orientation of σ_1 ~ 30^o to failure plane).

Key Questions

1. What hydrogeologic setting and injection scenarios are likely to trigger earthquakes?

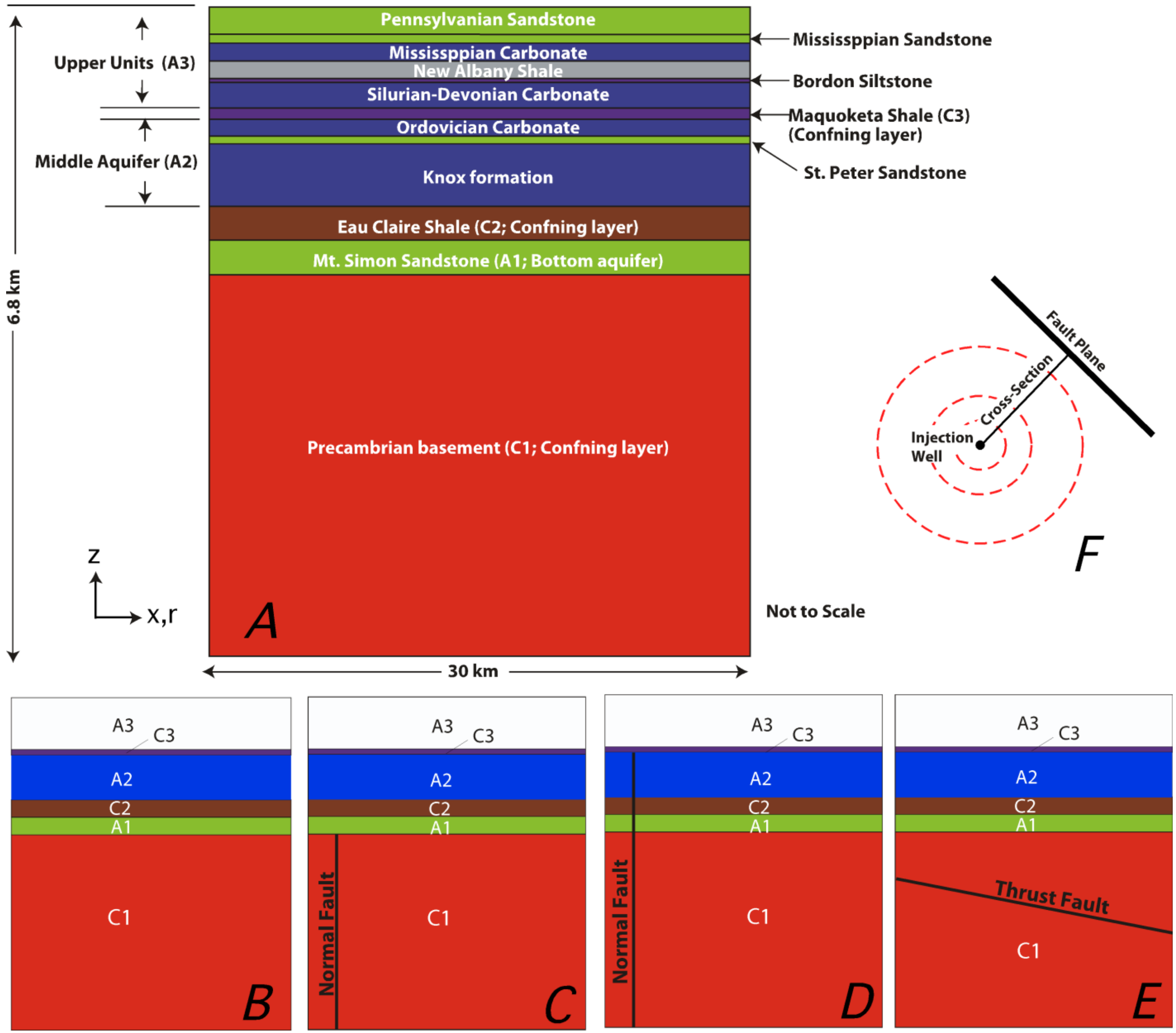
2. What hydrogeologic settings reduce the risk of earthquakes?

1. Given the historical and geologic record of seismicity in the midcontinent, should new regulations be put in place to reduce the risk of induced seismicity?

Injection well, Youngstown Ohio

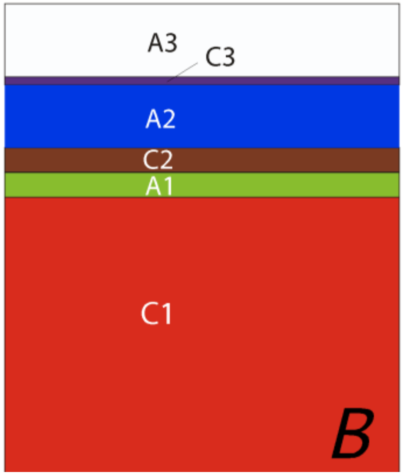
Kerr (2012)

Sensitivity Analysis



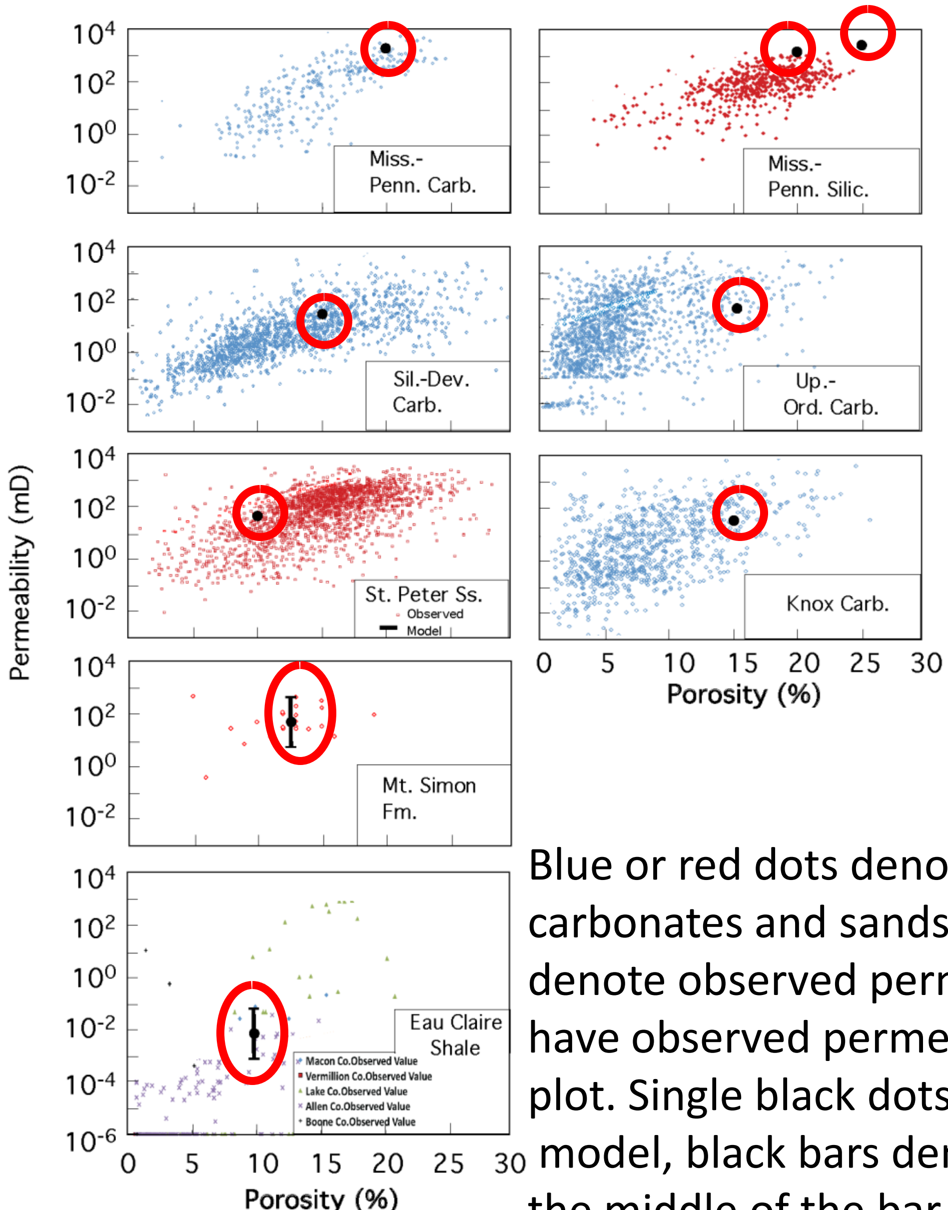
Effect of Petrophysical Properties

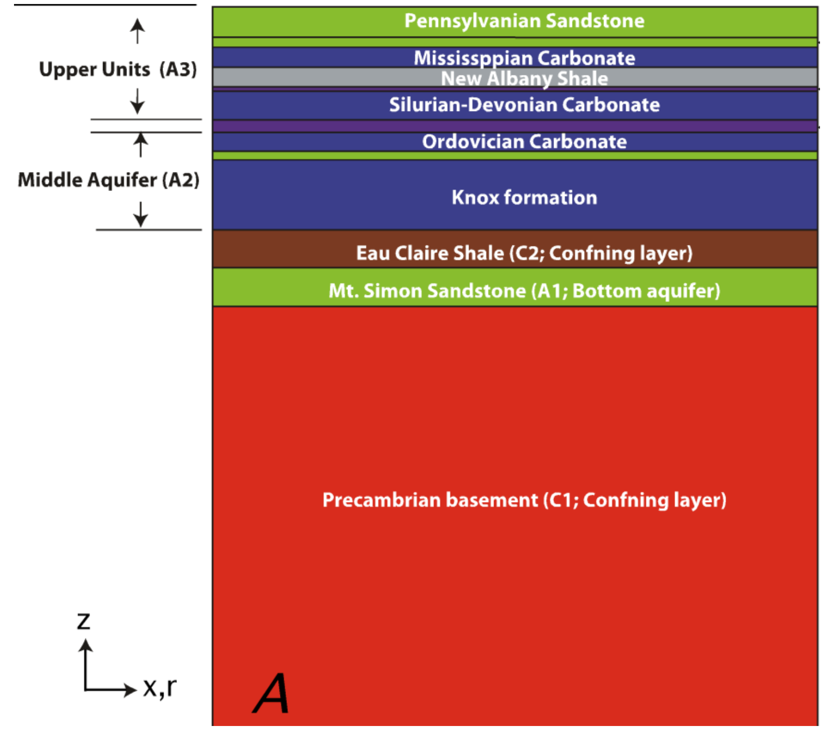
Vary Permeability of Basal Aquifer (A1), the Crystalline Basement (C1) and Top Seal (C2)



Run #	Crystalline Basement Permeability - (m^2) (C1)	Mt. Simon Ss. Permeability (m^2) (A1)	Eau Claire Shale Permeability (m^2) (C2)
1	10^{-16}	10^{-13}	10^{-17}
2	10^{-17}	10^{-13}	10^{-17}
3	10^{-18}	10^{-13}	10^{-17}
4	10^{-17}	10^{-12}	10^{-17}
5	10^{-17}	10^{-13}	10^{-17}
6	10^{-17}	10^{-14}	10^{-17}
7	10^{-17}	10^{-13}	10^{-16}
8	10^{-17}	10^{-13}	10^{-17}
9	10^{-17}	10^{-13}	10^{-18}

Comparison of Permeability Range Used in Sensitivity Study to Core Permeability-Porosity Data from Illinois Basin





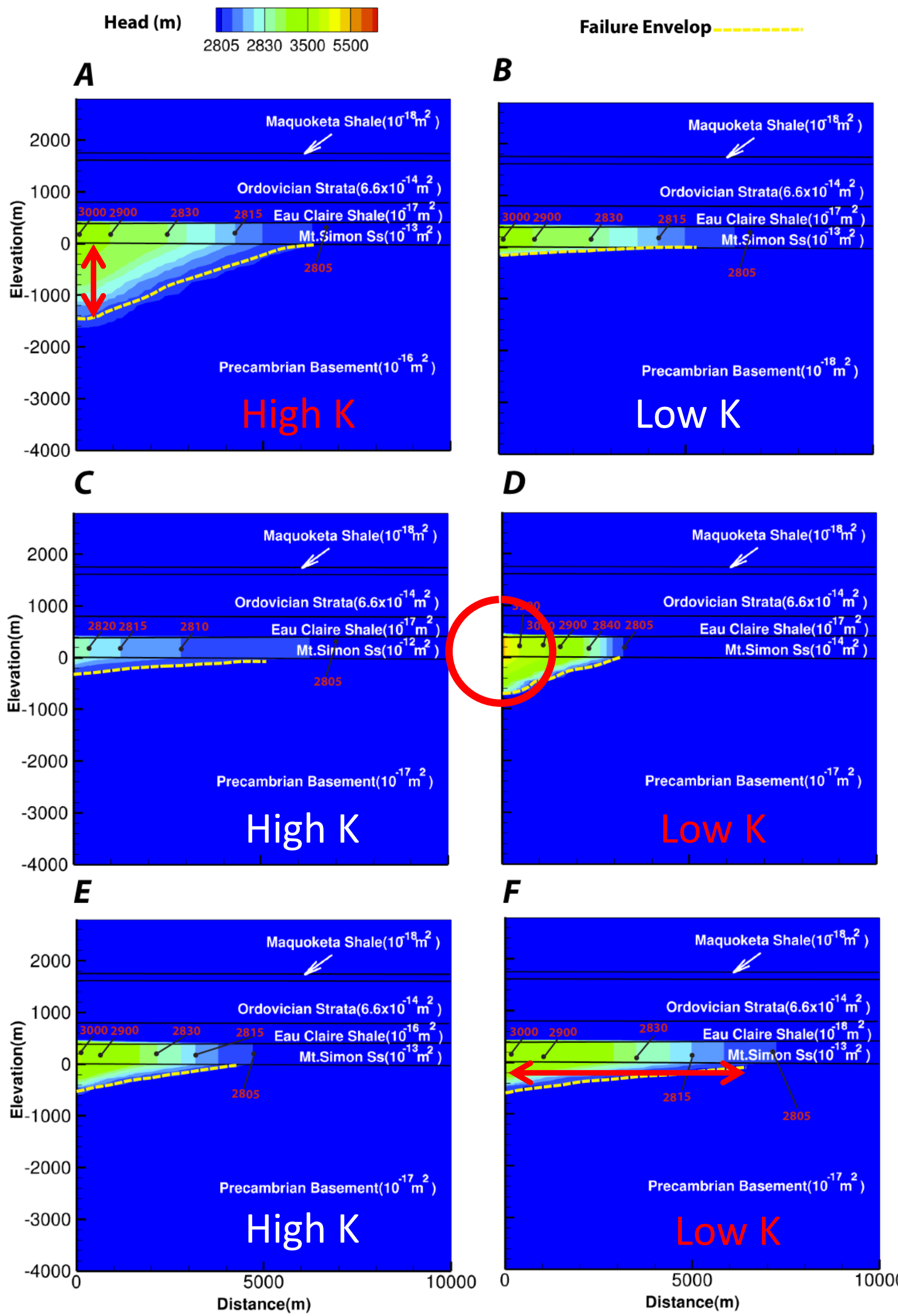
Blue or red dots denote the observed permeability values of carbonates and sandstone respectively. Green and purple dots denote observed permeability values of shale. The strata that we have observed permeability data available are indicated in the left plot. Single black dots indicate the permeability value we used in our model, black bars denote the range we varied and black dots in the middle of the bar denote the base case value used in our model

What conditions promote Induced seismicity?

Varying Crystalline Basement Permeability

Varying Reservoir Permeability

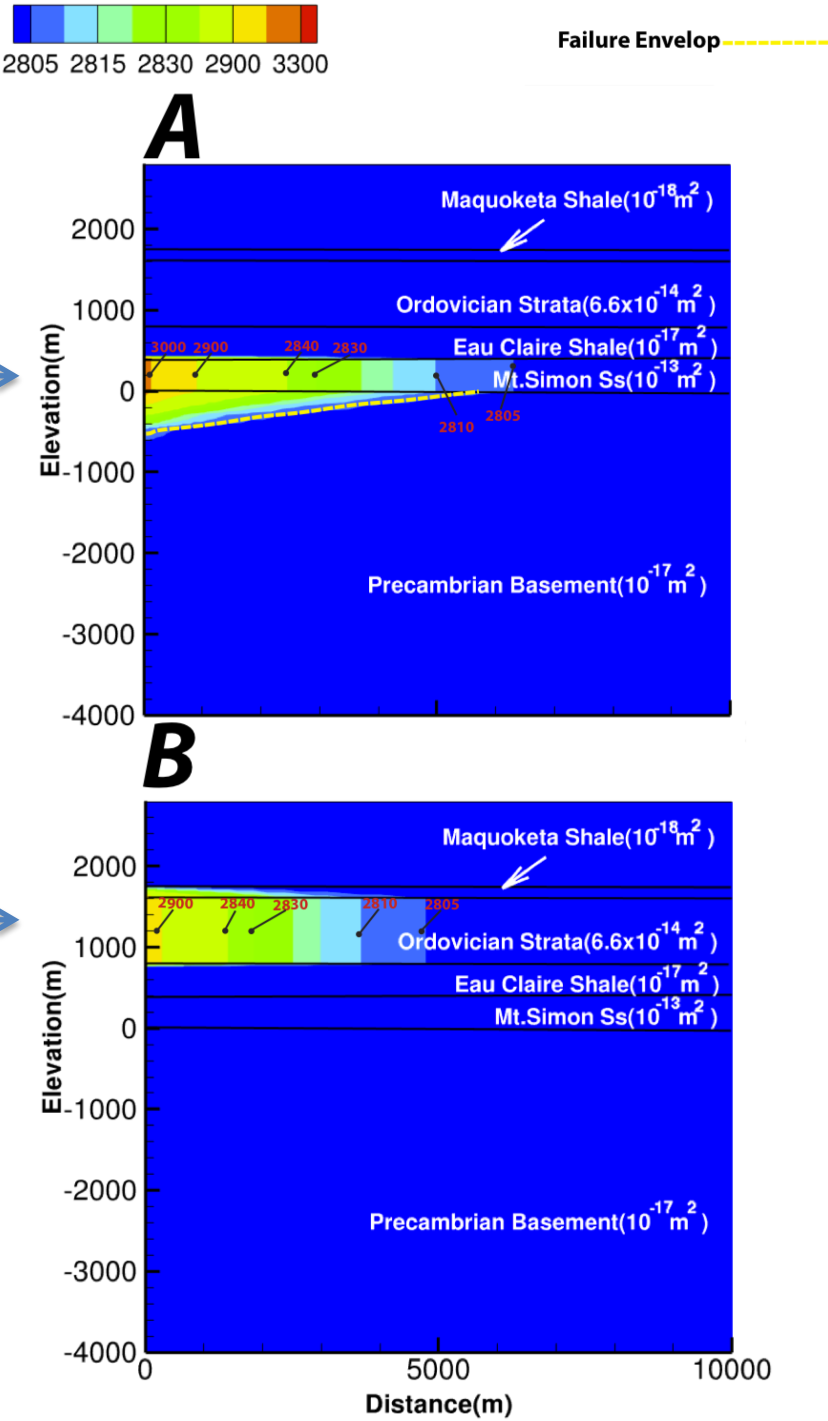
Varying Top Confining Unit Permeability



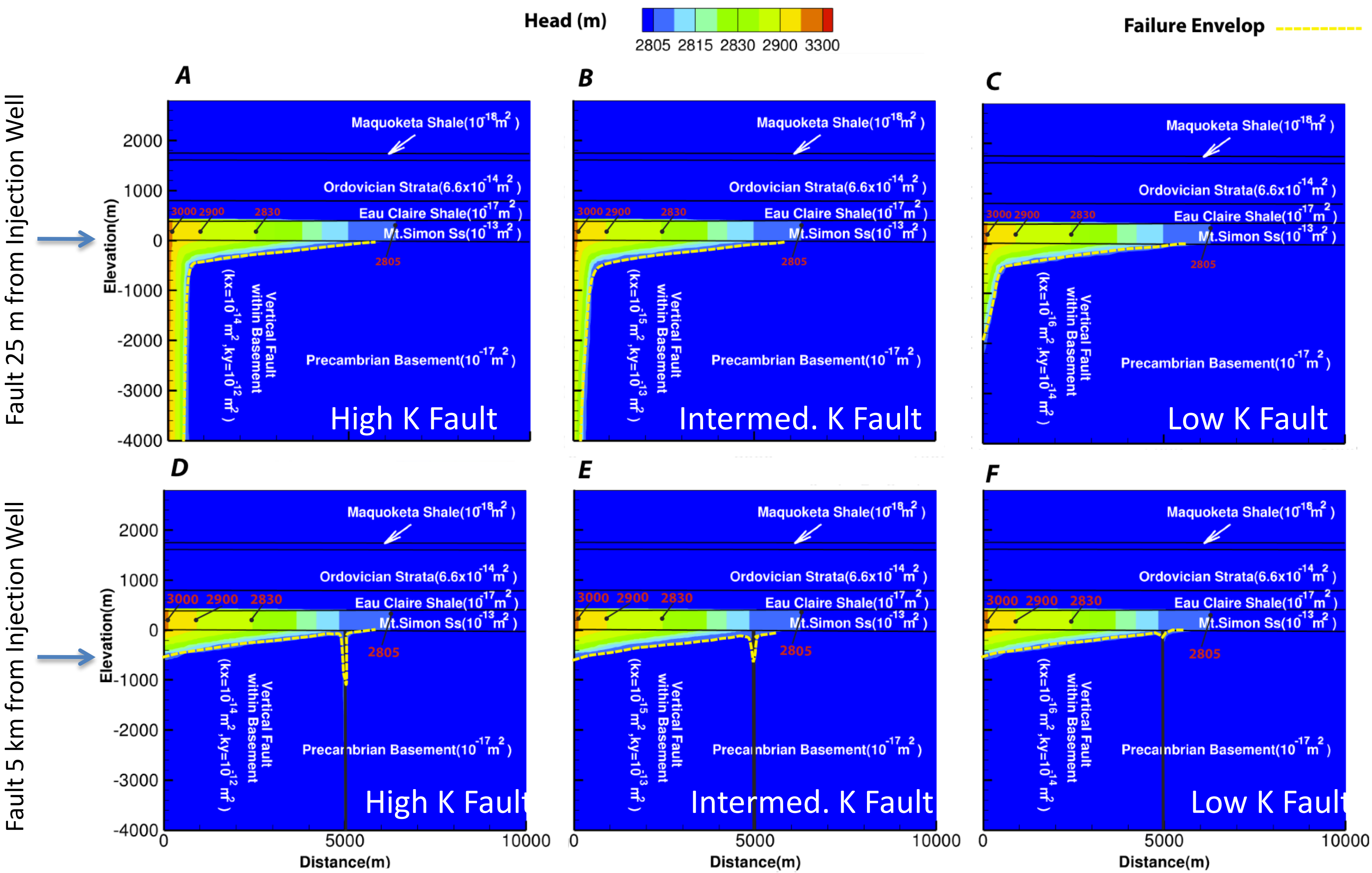
Effect of Injection Scheme

Basal Aquifer Injection

Middle Aquifer Injection



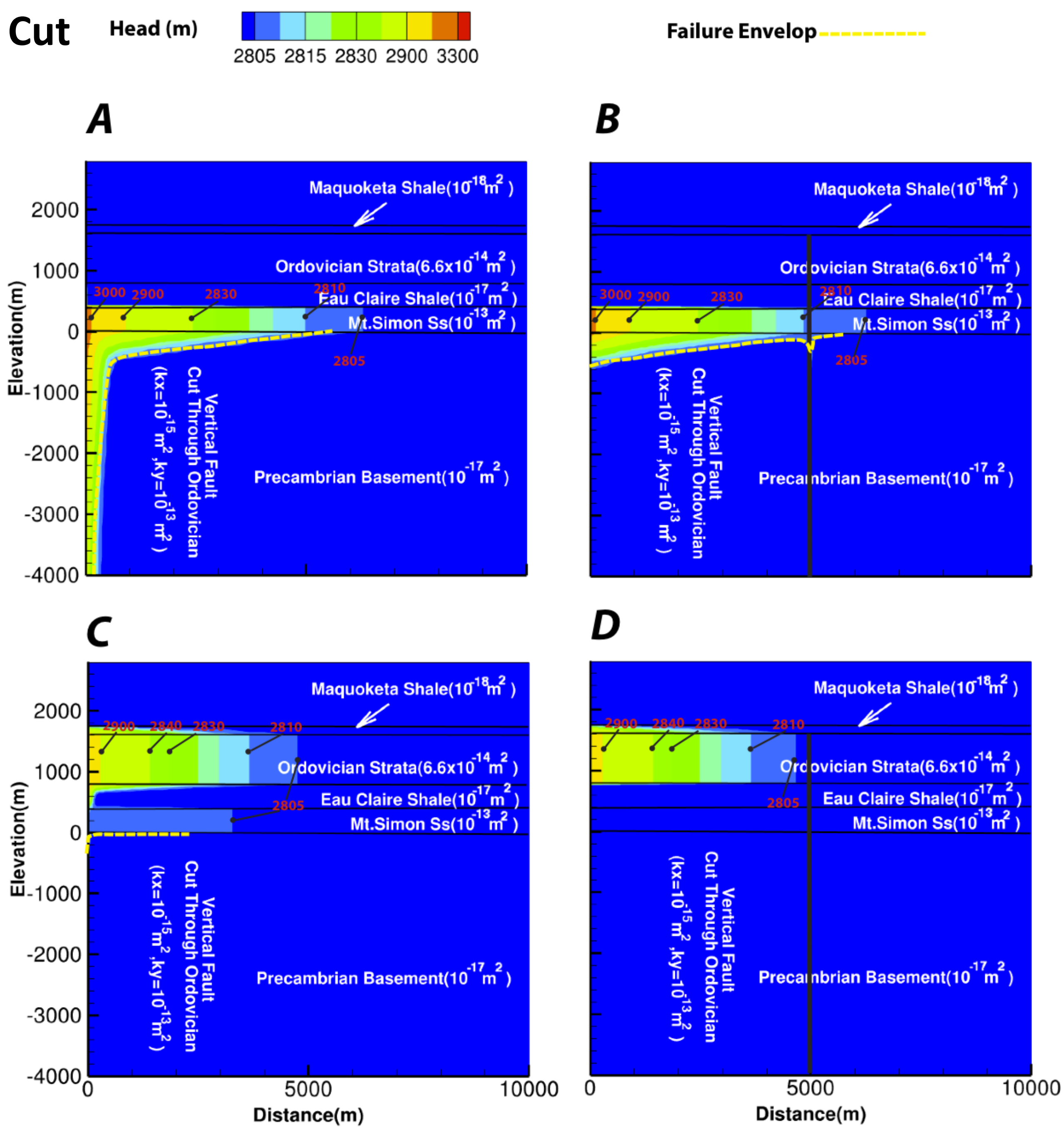
Effect of Proterozoic Normal Faults



Paleozoic Faults that Cut Sedimentary Units

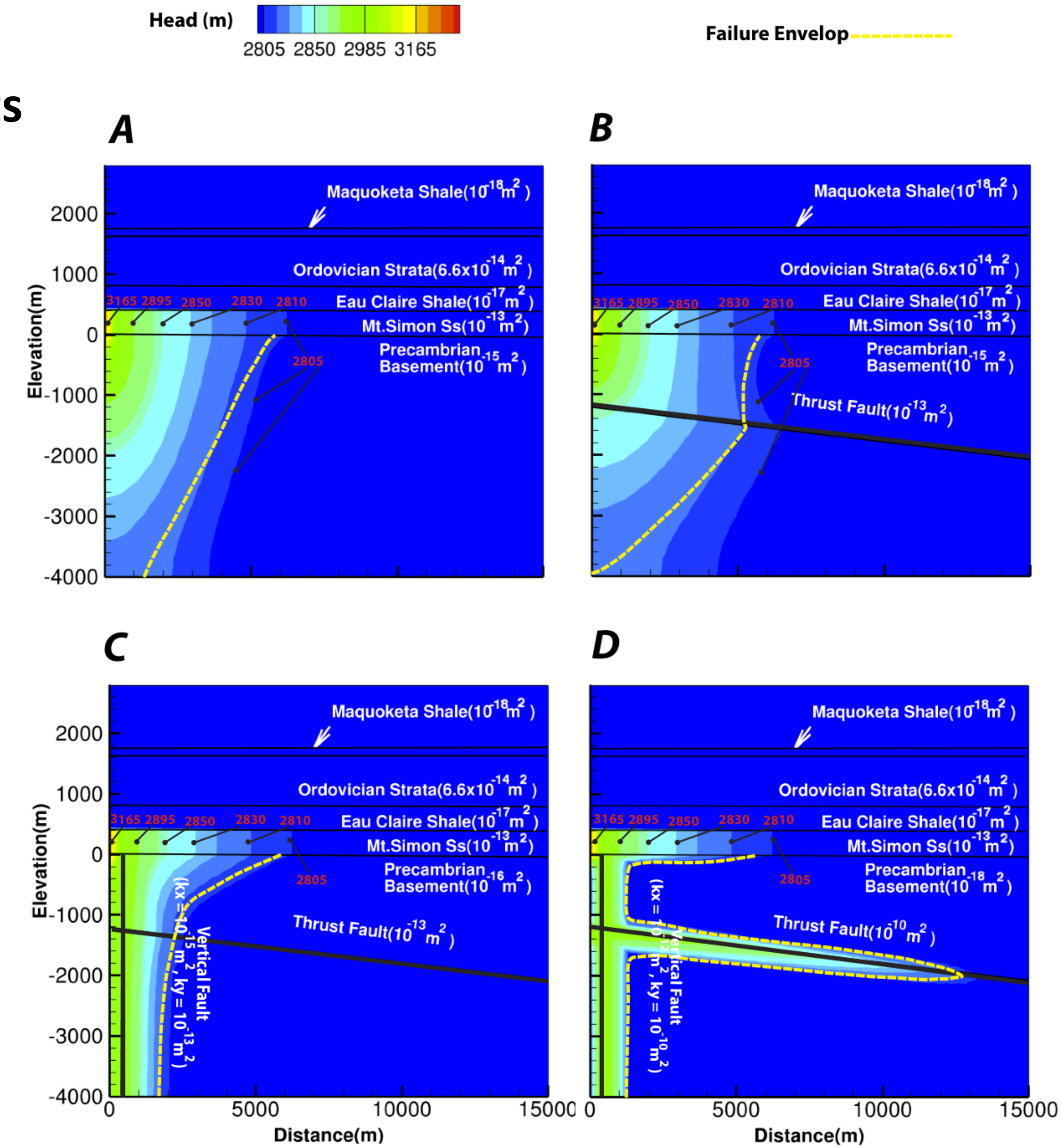
Basal Aquifer Injection

Middle Aquifer Injection



Effect of Thrust Faults

Thrust fault
with low permeability
contrast to basement



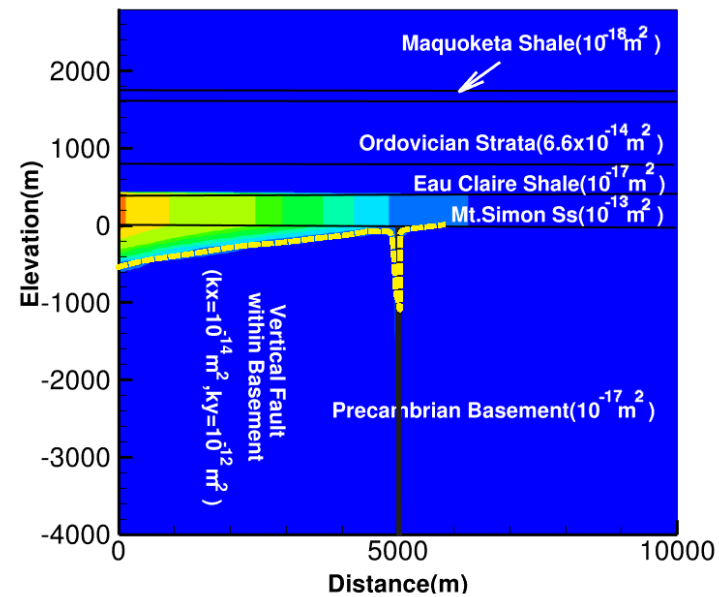
Thrust fault with high permeability contrast to basement & connected to normal fault

Head (m)

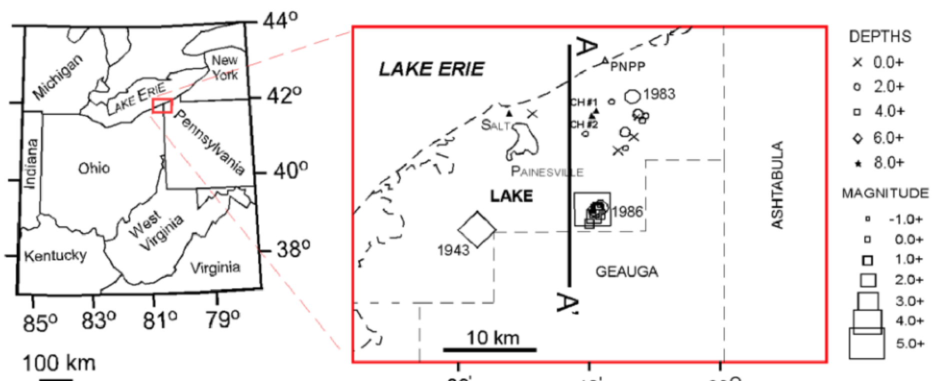
Failure Envelop

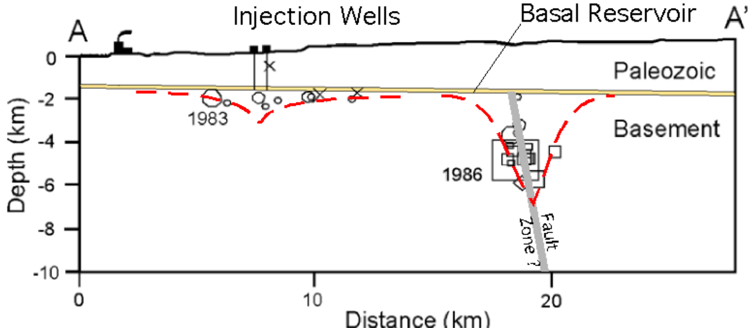
How do Proterozoic normal fault model results compare to cases of induced seismicity?

Model



Field Observations



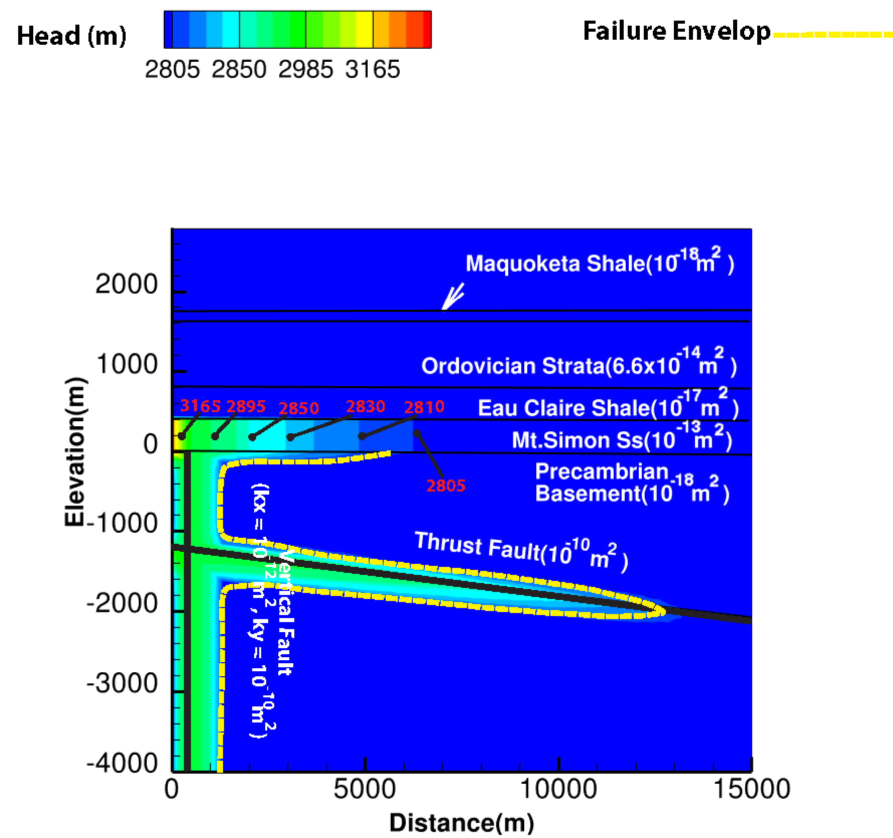


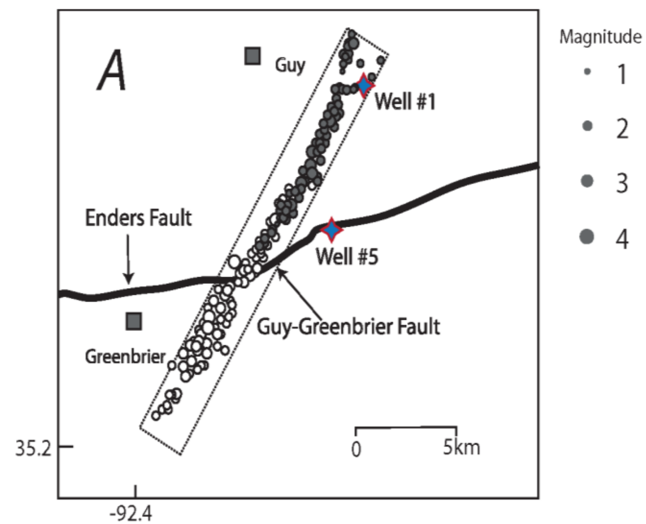
Lake, Ohio Case

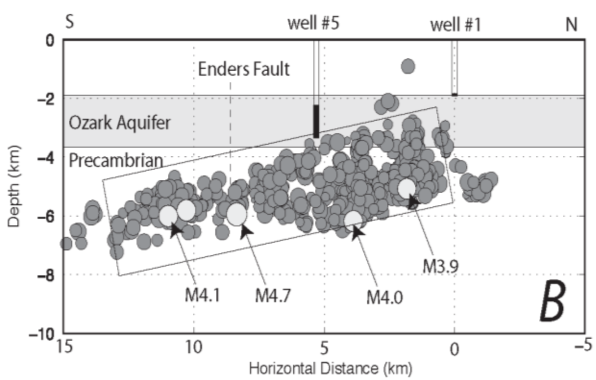
Failure Envelop

(Nicholson et al., 1988)

How do thrust fault model results compare to cases of induced seismicity?



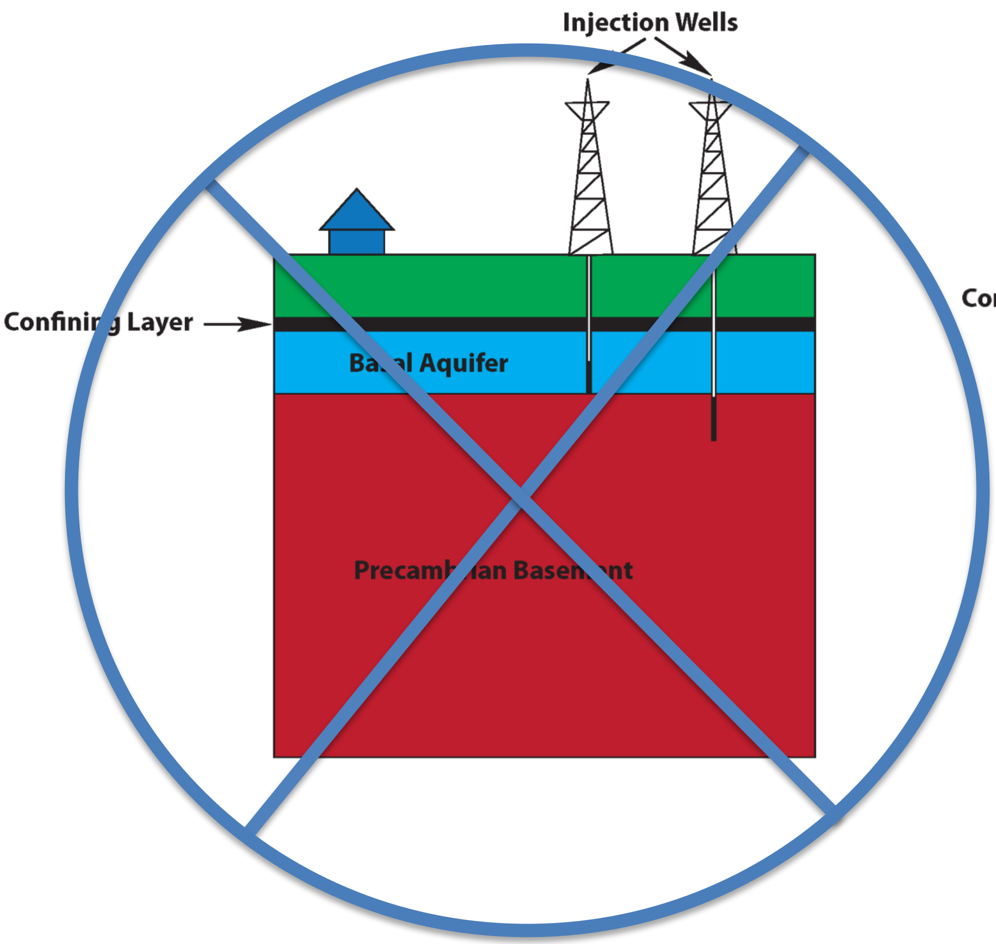


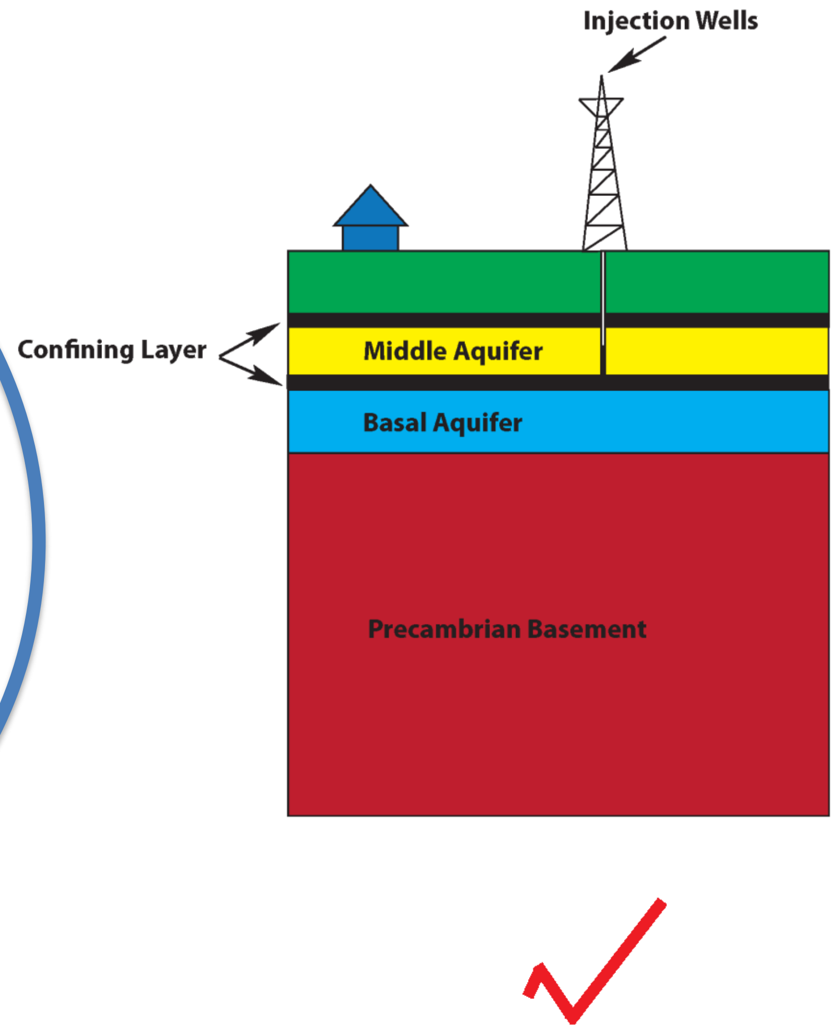


Guy, Arkansas Case

(Horton, 2012)

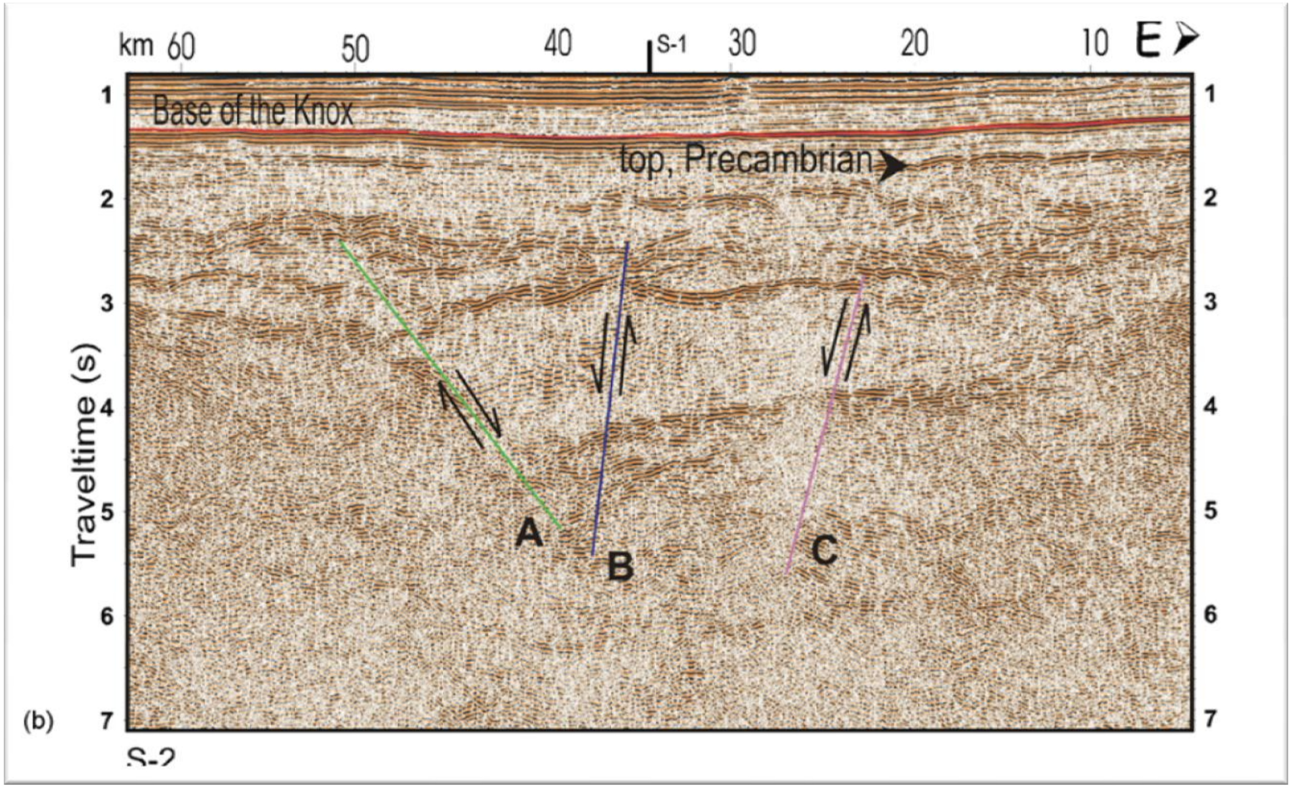
Conclusion: If Induced Seismicity is a regulatory concern, regulators should consider banning hazardous waste/CO_2 injection into basal reservoirs. Only hazardous waste injection into reservoirs *with top and bottom seals*.





New Regulations

- In order to minimize the chance of inducing earthquakes near injection sites, detailed Seismic Analysis of basement should be done looking for basement faults.
- Stress analysis & shut in tests (e.g. Lucier et al. 2006) should be preformed in basement rocks.



McBride et al. (2007)

QUESTIONS?

Base Case Parameters

Run the model with a injection rate of 1000 gallon per minute for 10 years

Strata Unit	Thickness (m)	Hydraulic Conductivity (m/s)	Specific Storativity (m^{-1})	Storativity	Transmissivity (m^2/s)	Porosity	Permeability (m^2)
Penn. Ss.	300	7.55×10^{-7}	1×10^{-5}	3×10^{-3}	2.27×10^{-4}	0.25	2.10×10^{-12}
Miss. Ss.	100	3.96×10^{-7}	1×10^{-5}	1×10^{-3}	3.96×10^{-5}	0.2	1.10×10^{-12}
Miss. Carb.	150	8.27×10^{-7}	1×10^{-4}	1.5×10^{-2}	8.27×10^{-7}	0.2	2.30×10^{-12}
New Albany Sh.	200	3.60×10^{-13}	1×10^{-3}	0.2	7.19×10^{-11}	0.2	1.00×10^{-18}
Bordon Slt.	50	3.60×10^{-13}	1×10^{-3}	5×10^{-2}	1.80×10^{-11}	0.1	1.00×10^{-18}
Sil.-Dev. Carb.	250	1.94×10^{-7}	1×10^{-5}	2.5×10^{-3}	4.86×10^{-5}	0.15	5.40×10^{-13}
Maq. Sh.	150	3.60×10^{-13}	1×10^{-3}	0.15	5.40×10^{-11}	0.1	1.00×10^{-18}
Ord. Carb.	150	2.37×10^{-8}	1×10^{-5}	1.5×10^{-3}	3.56×10^{-6}	0.15	6.60×10^{-14}
St. Peter Ss.	100	2.37×10^{-8}	1×10^{-5}	1×10^{-3}	2.37×10^{-6}	0.1	6.60×10^{-14}
Knox	550	2.37×10^{-8}	1×10^{-5}	5.5×10^{-3}	1.1×10^{-5}	0.15	6.60×10^{-14}
Eau Claire Sh.	400	3.60×10^{-12}	1×10^{-3}	0.4	1.44×10^{-9}	0.1	1.00×10^{-17}
Mt. Simon Ss.	400	3.60×10^{-8}	1×10^{-5}	4×10^{-3}	1.44×10^{-5}	0.13	1.00×10^{-13}
Bedrock	4000	3.60×10^{-12}	1×10^{-6}	4×10^{-3}	1.44×10^{-8}	0.01	1.00×10^{-17}

Model Validation

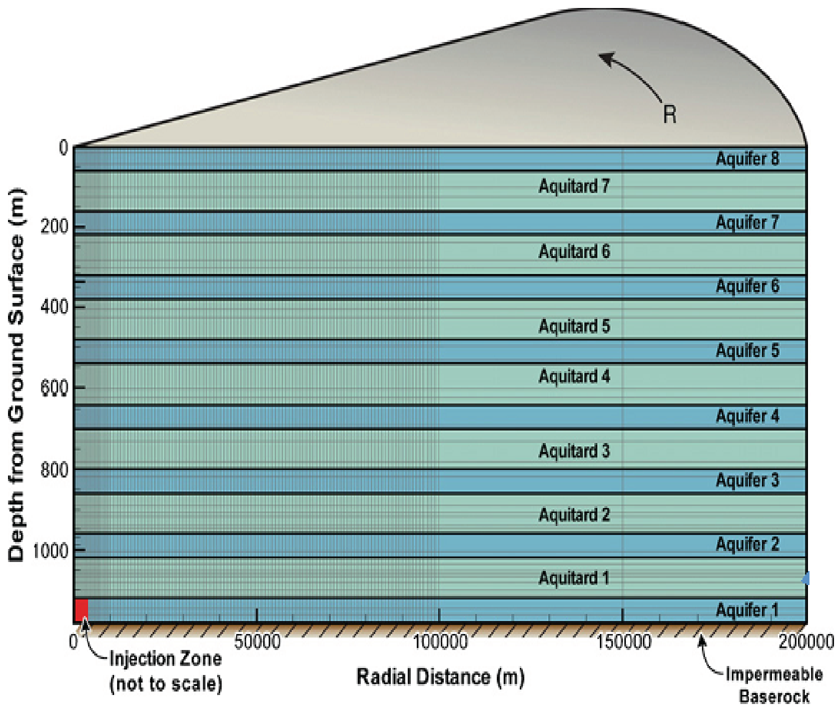
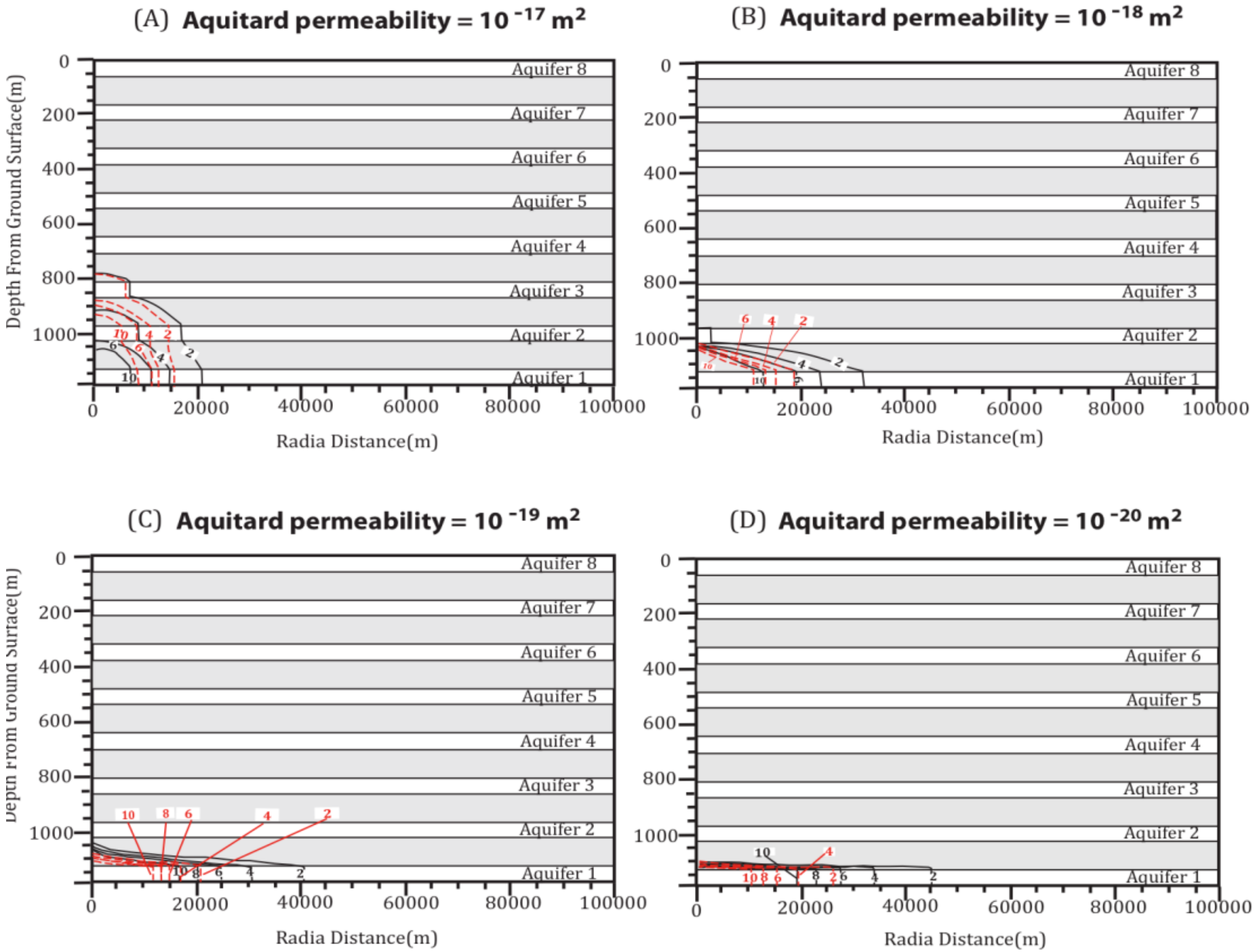


Figure 5. Schematic diagram showing a vertical cross-section of the radially symmetric model domain with a deep formation for CO_2 storage and overlying aquifer/aquitard sequence.
(Birkholzer et al. 2009)

Permeability of Aquifer (m^2)	Permeability of Aquitard (m^2)	Specific Storativity of Aquifer (m^{-1})	Specific Storativity of Aquitard (m^{-1})	Pumping Rate (gpm)
10^{-13}	10^{-17} to 10^{-20}	4.41×10^{-6}	8.83×10^{-6}	763

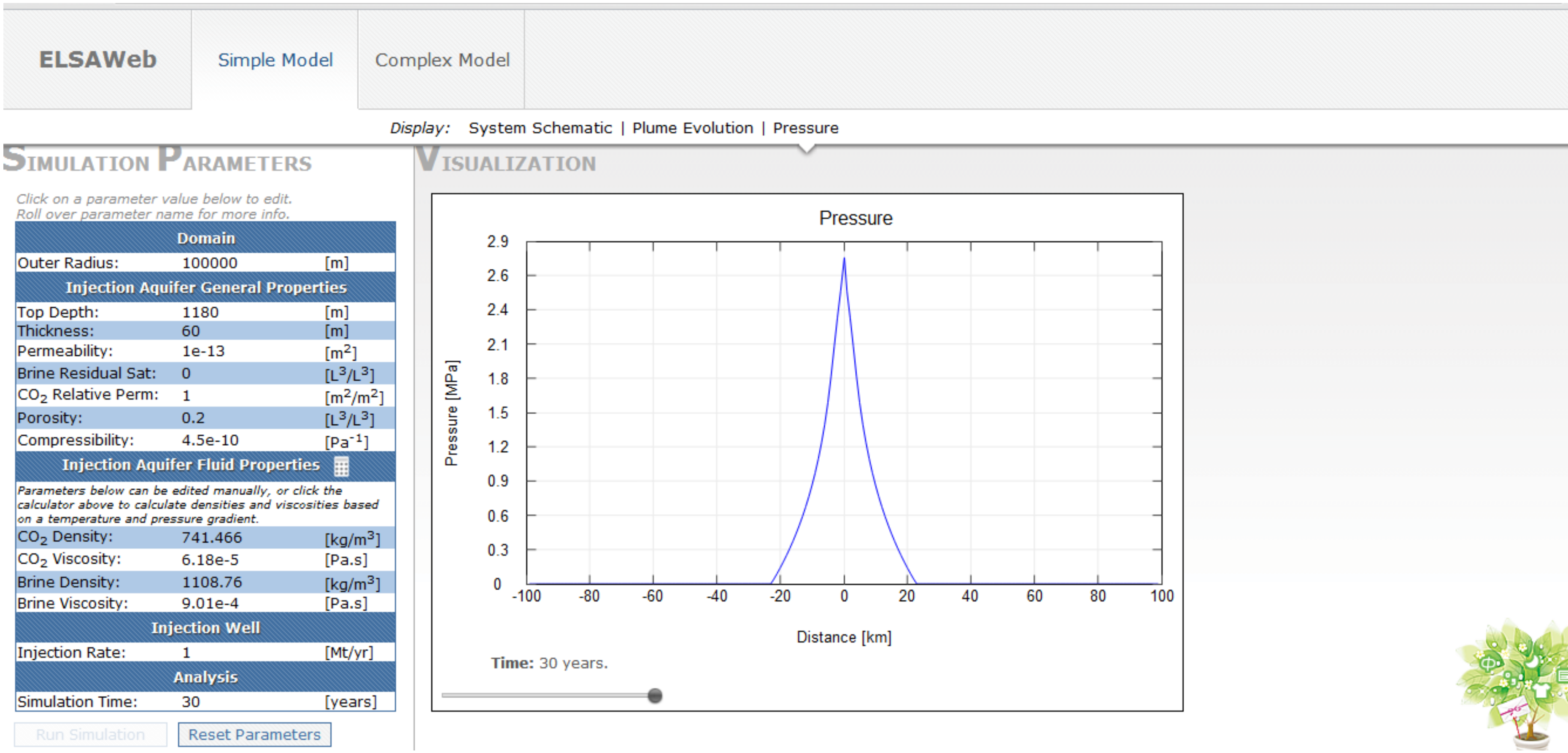
We tested our model by comparing the simulation results of pore pressure changes due to CO2 injection in an idealized multilayer aquifer/aquitard system of our model with that produced by TOUGH2 in Birkholzer et la. (2009) study.

Model Validation



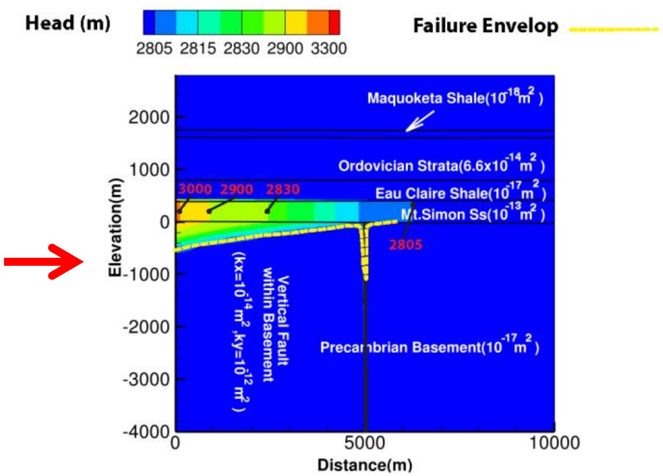
Deviatoric pressure in bars, 0.1 bar = 1 m excess head,
red dashed – this study, black solid – Birkholzer et al. (2009)

Analytical solution using the online ELSA program of Princeton Group

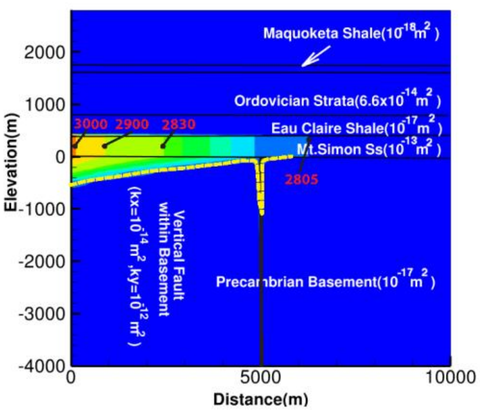


No Flux Boundary
vs
Constant Head Boundary

No flux boundary on the right edge of the domain



Constant head boundary on the right edge of the domain



Did we violate assumptions of analytical solution?

A

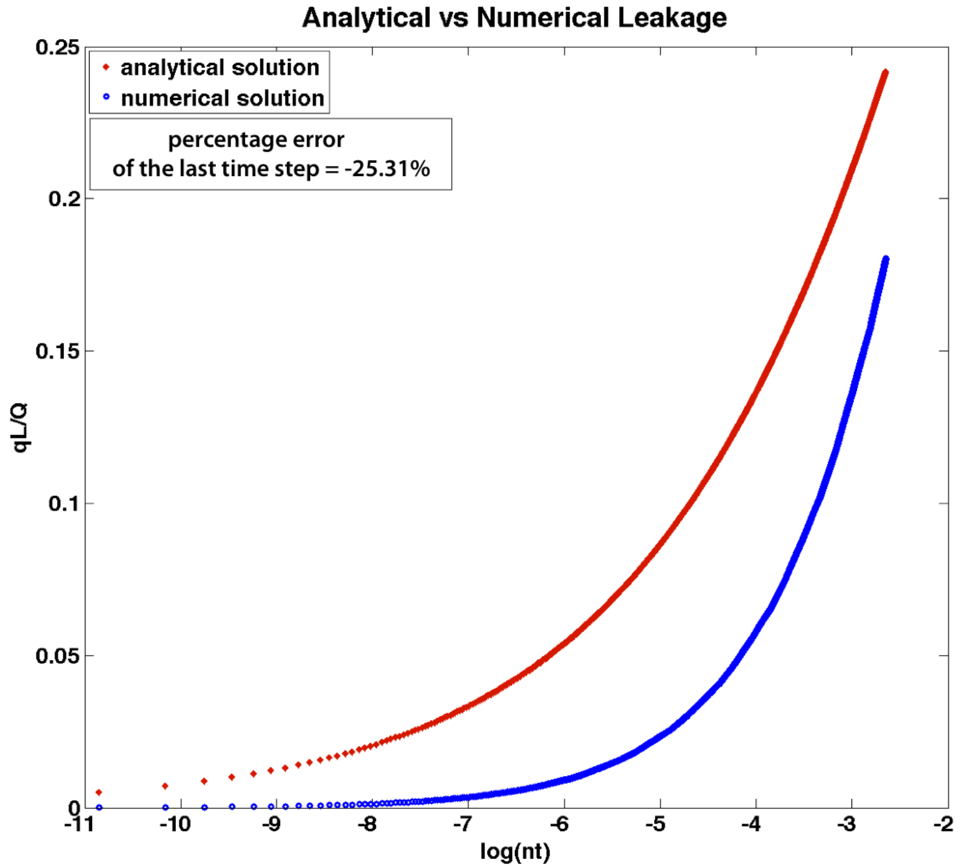


Figure 12. Analytical leakage (Eq. 10) vs numerical leakage. The percentage error $\left(\frac{\text{numerical-analytical}}{\text{analytical}} \text{x100\%}\right)$ of the last time step is -25.31%.