Modeling CO_2 Storage in a Gulf of Mexico Reservoir Using Coupled Flow and Geomechanics

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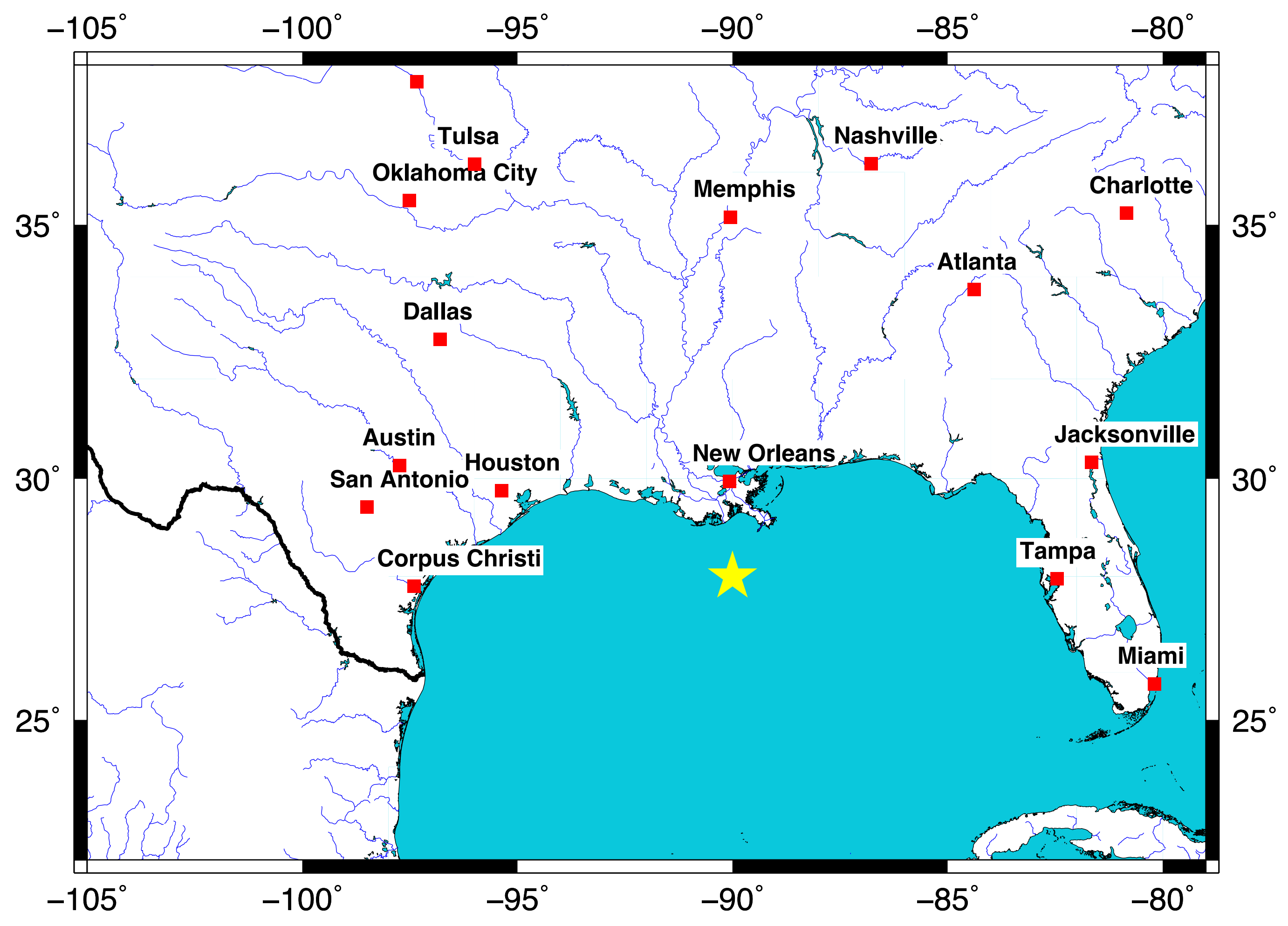
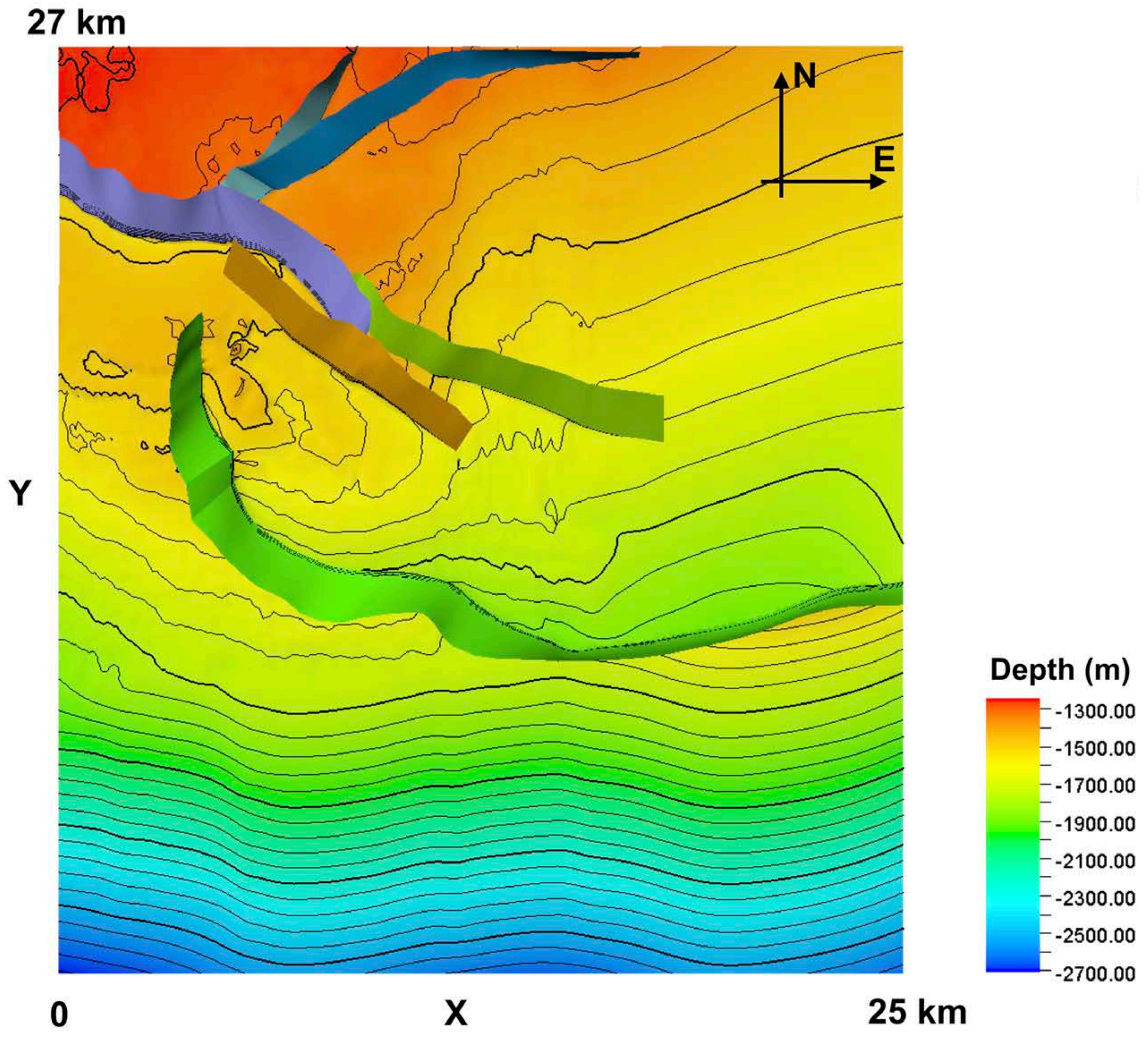
Large scale CO_2 injection in a Gulf of Mexico reservoir

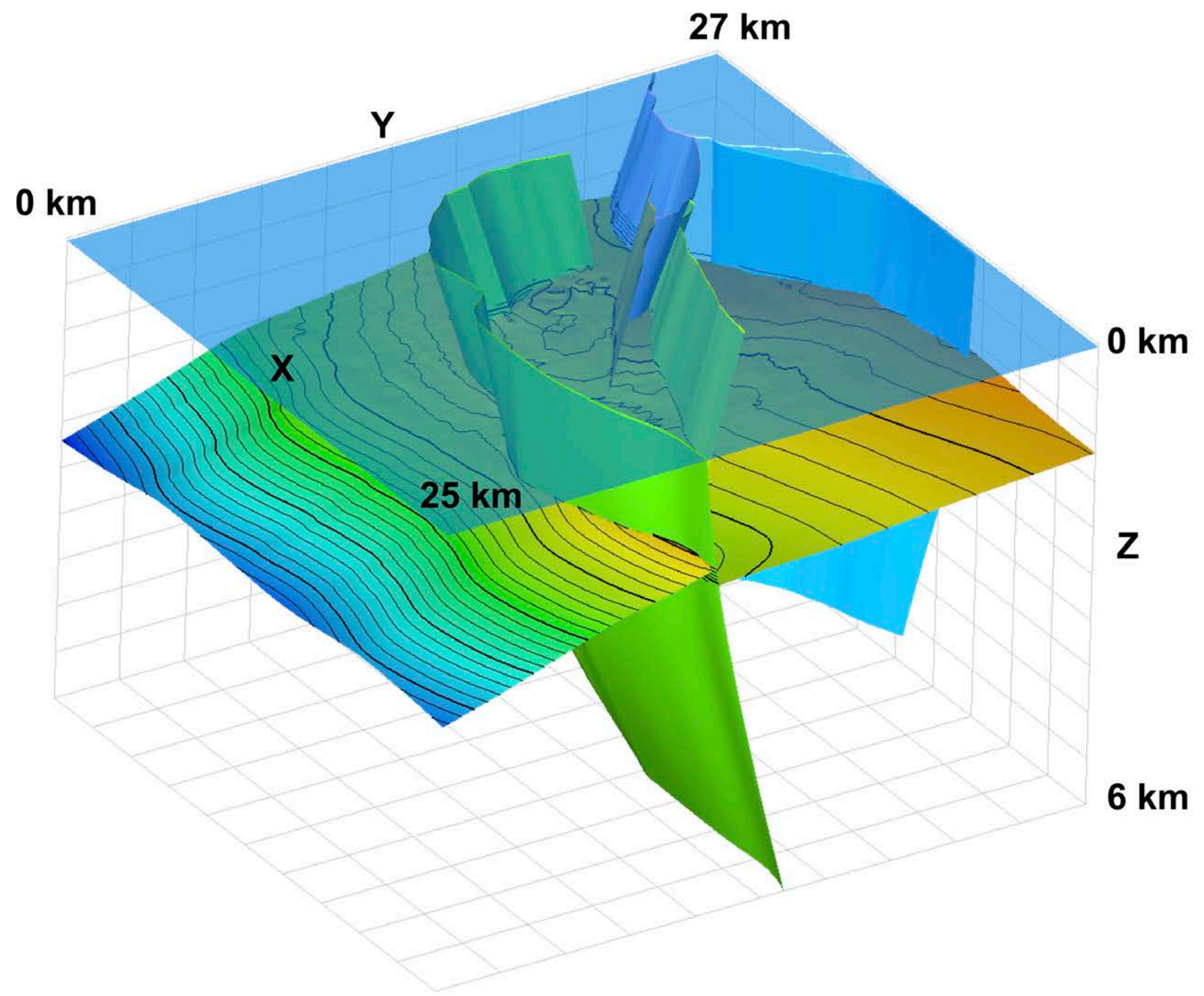
Field location in the GoM



Storage aquifer depth variation



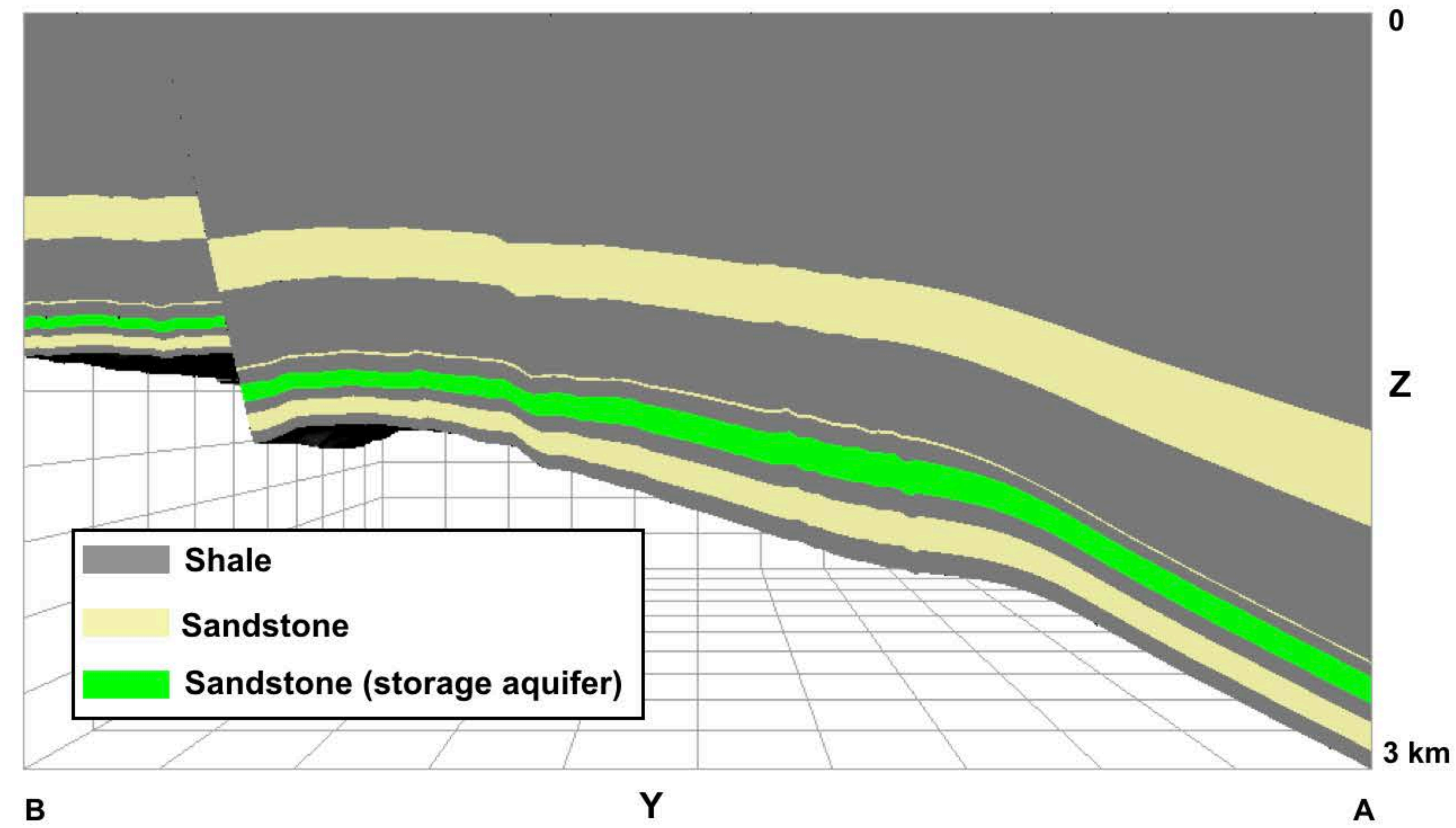
Fault structure in the field



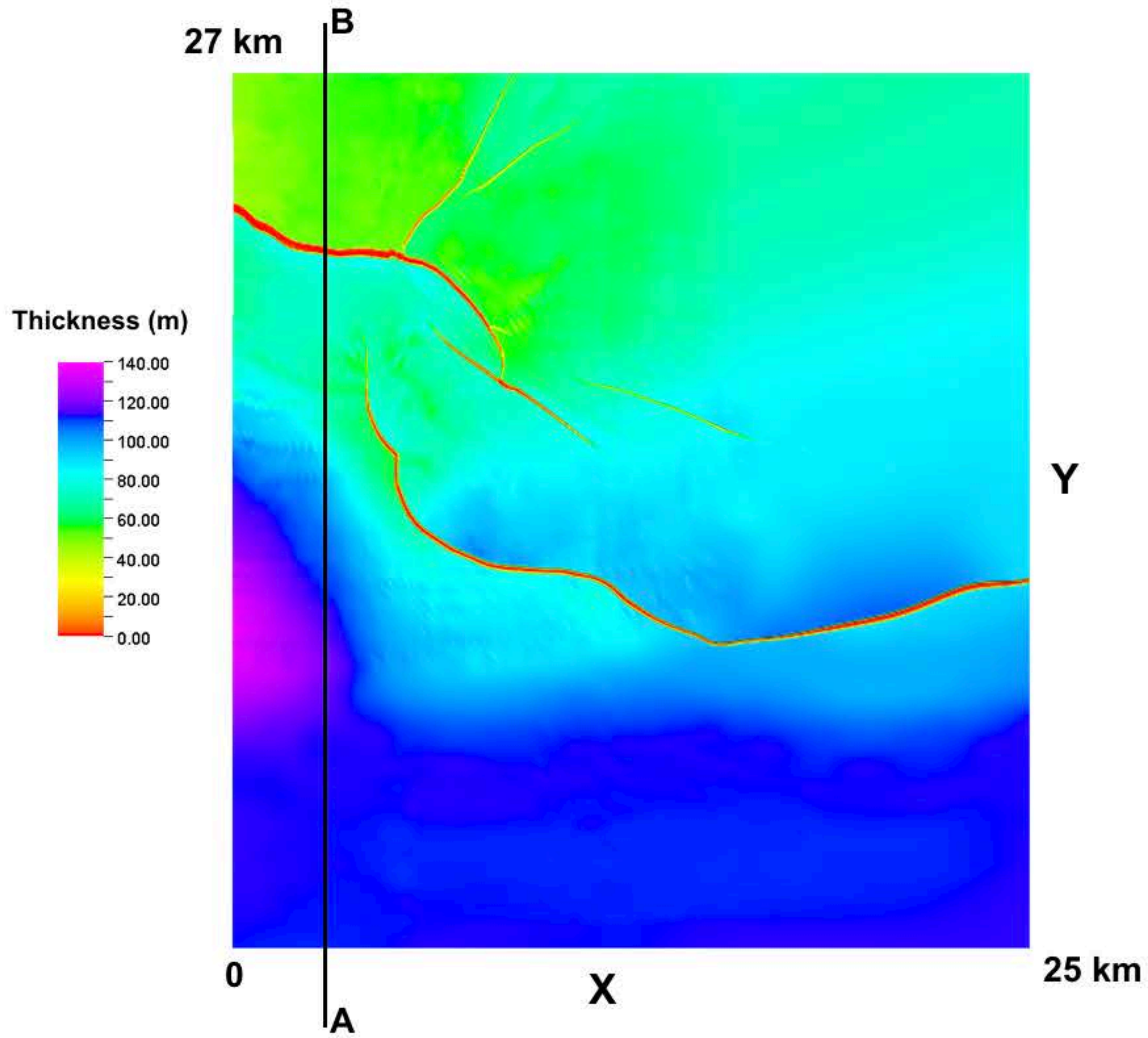
- The field is located south of New Orleans, at the shallow waters of the GoM
- Typical of GoM sites having potential for large-scale, long-term CO_2 storage
- Assessment of long term CO_2 storage and fault leakage potential
- Investigation of fault destabilization due to injection operations

General stratigraphy and injection interval

Model stratigraphy

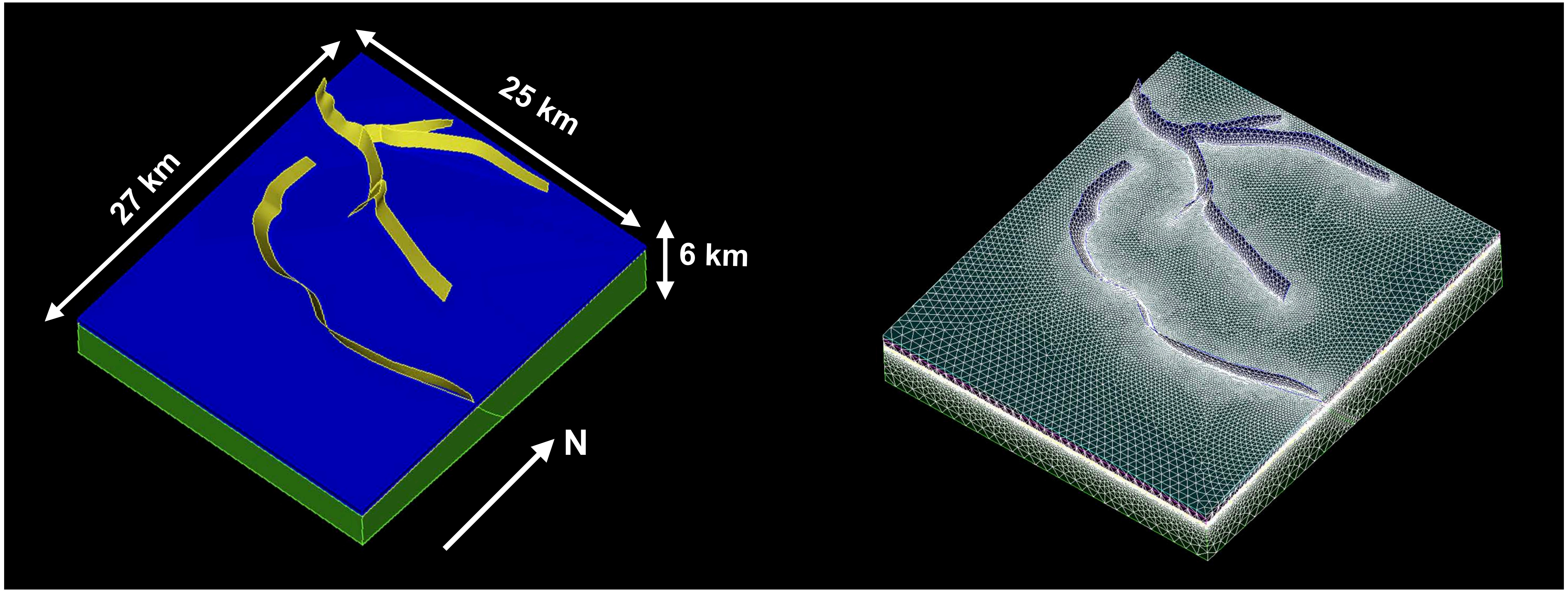


Storage aquifer thickness



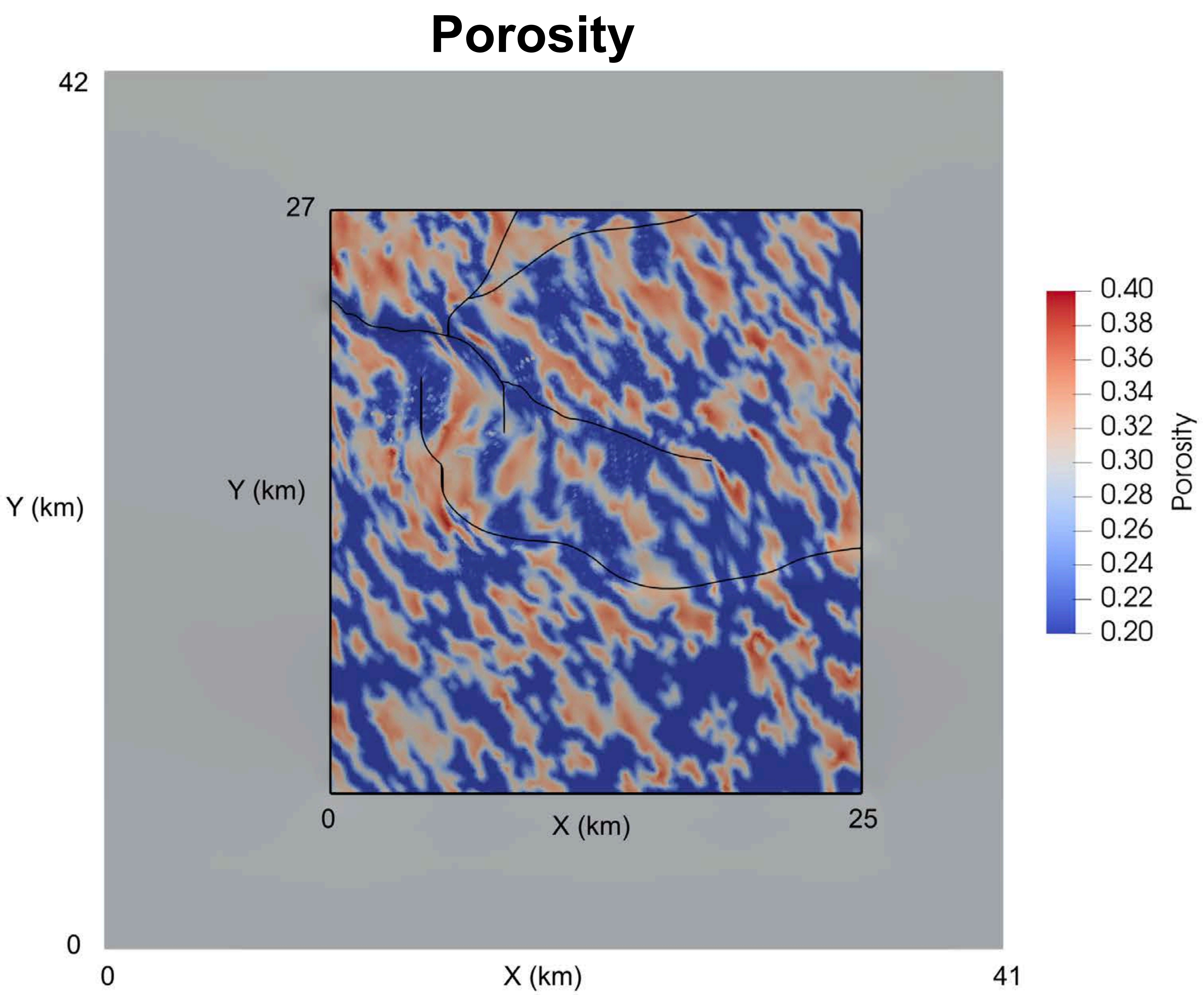
- Extensive set of well logs indicates complex alternation of shale and sand layers
- Here, we use a simplified model composed of fewer zones, but still maintaining the main shale-sand intervals
- Reservoir injection interval thickness: ~130 m to ~20 m from south to north

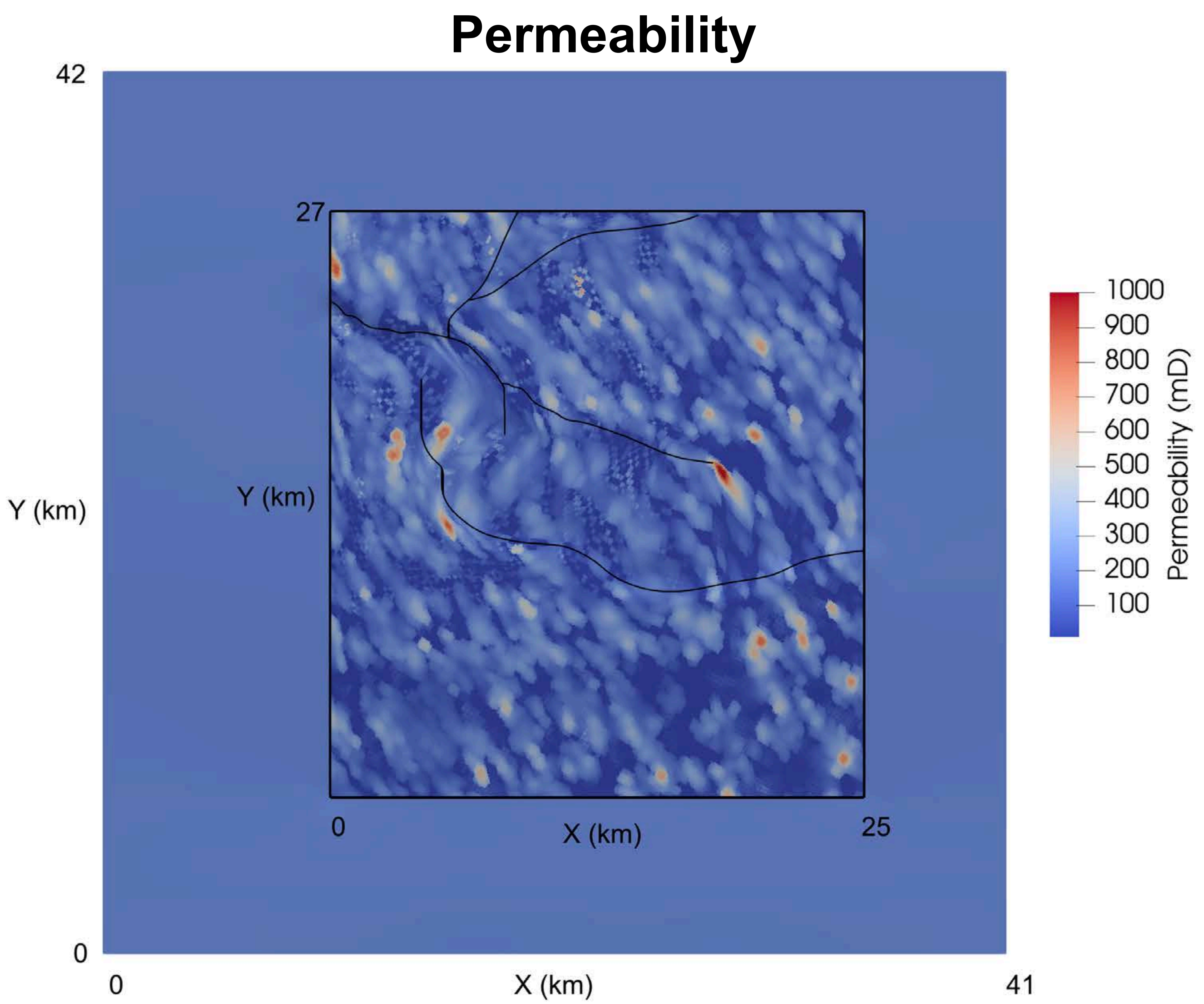
Unified unstructured mesh used for both flow and geomechanics



- Original domain size: 25 km x 27 km x 6 km, then extended to 42 km x 41 x 6 km to minimize boundary effects
- Faults are modeled as 2D surfaces, with assigned thickness, embedded in a 3D domain
- 3D Tetrahedral elements with varying size
- Total number of elements: ~14 Million
- Smaller elements near the faults and on the injection interval

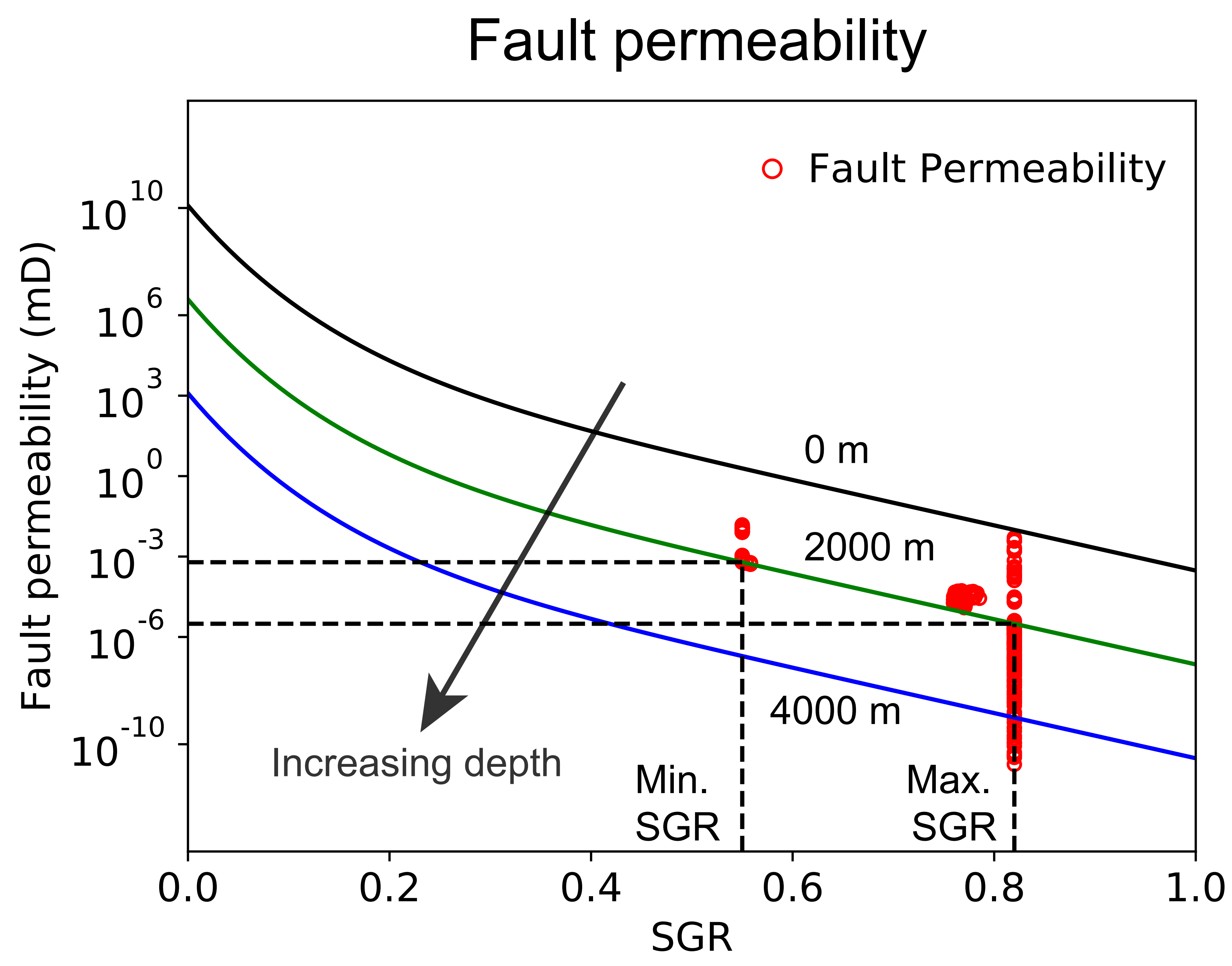
Reservoir property spatial variation

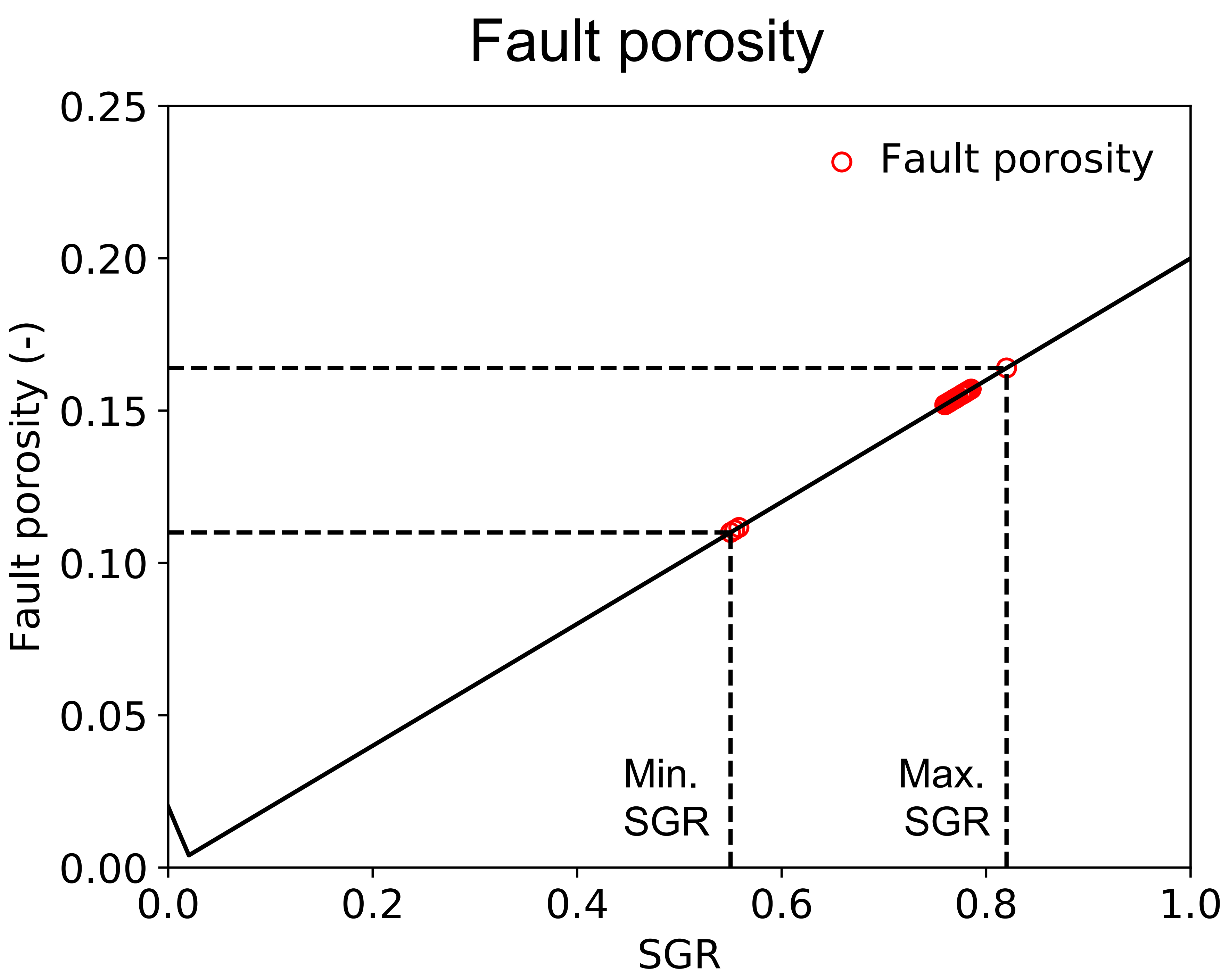




- The original field dimension were extended in order to minimize boundary effects
- Permeability and porosity variations are localized within the boundaries of the field location. Constant values are assigned outside of the field.

Fault property definition based on empirical equations





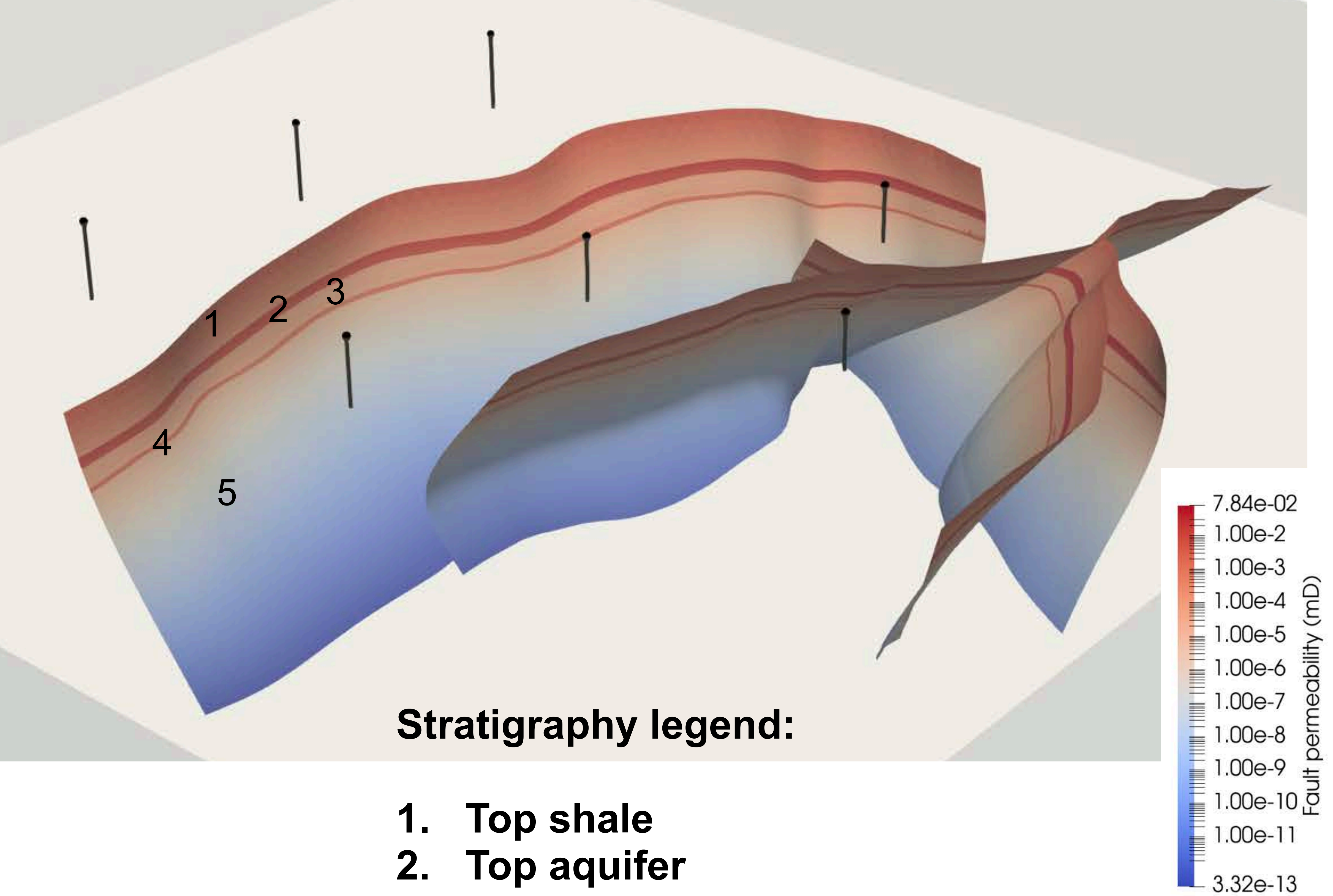
Reference for fault permeability:
Sperrevik et al., *Hydrocarbon Seal Quantification* 2002

Reference for fault porosity:
Revil and Cathles, *WRR* 1999

- Max. fault permeability at the reservoir depth: ~0.07 mD
- Max. fault porosity at reservoir depth is ~0.10
- Fault permeability along the fault set to be one order of magnitude larger

Overview of the fault permeability and fault porosity at the different zones in the model

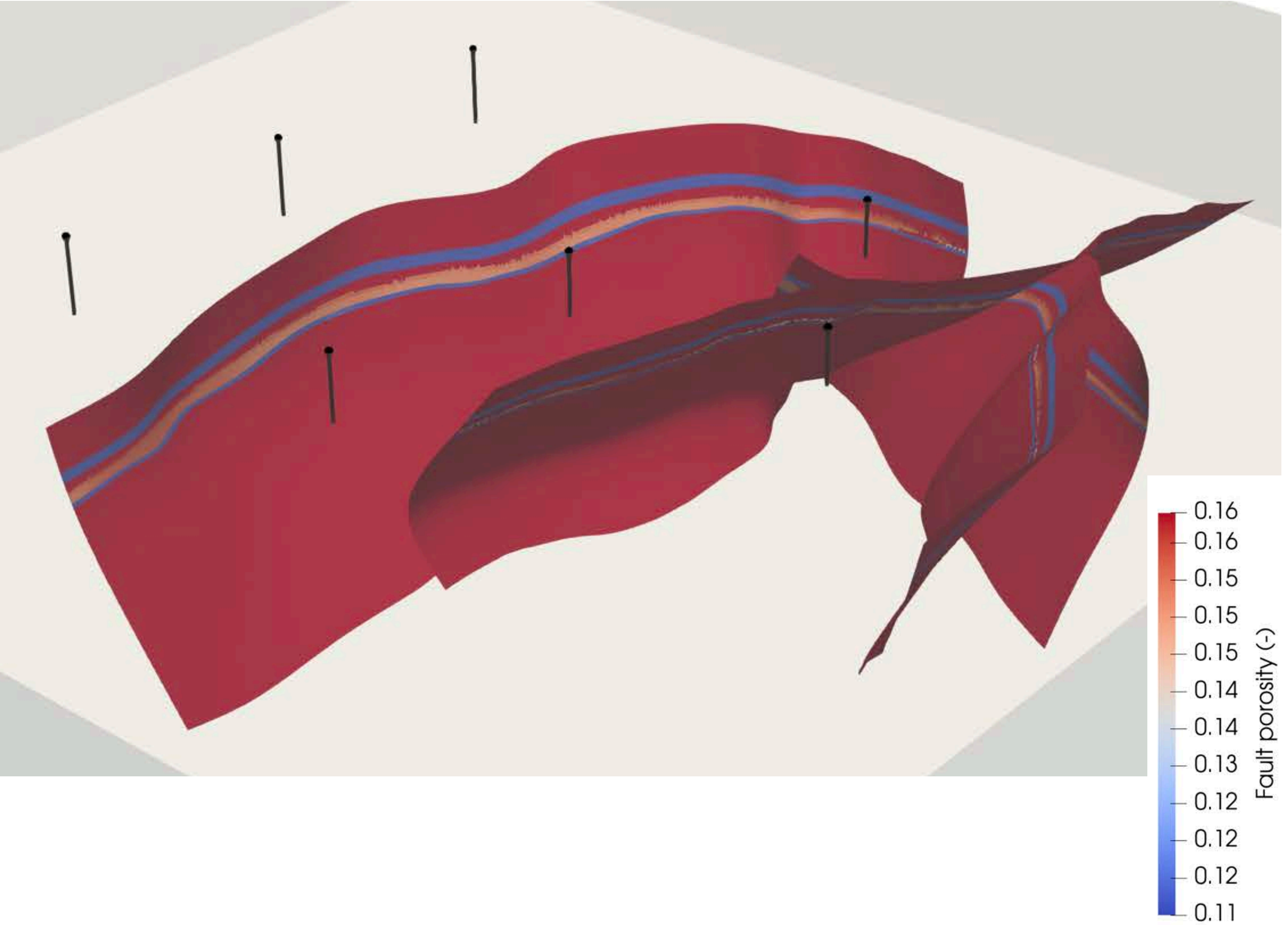
Fault permeability



Stratigraphy legend:

1. **Top shale**
2. **Top aquifer**
3. **Middle shale**
4. **Bottom aquifer (injection interval)**
5. **Bottom shale**

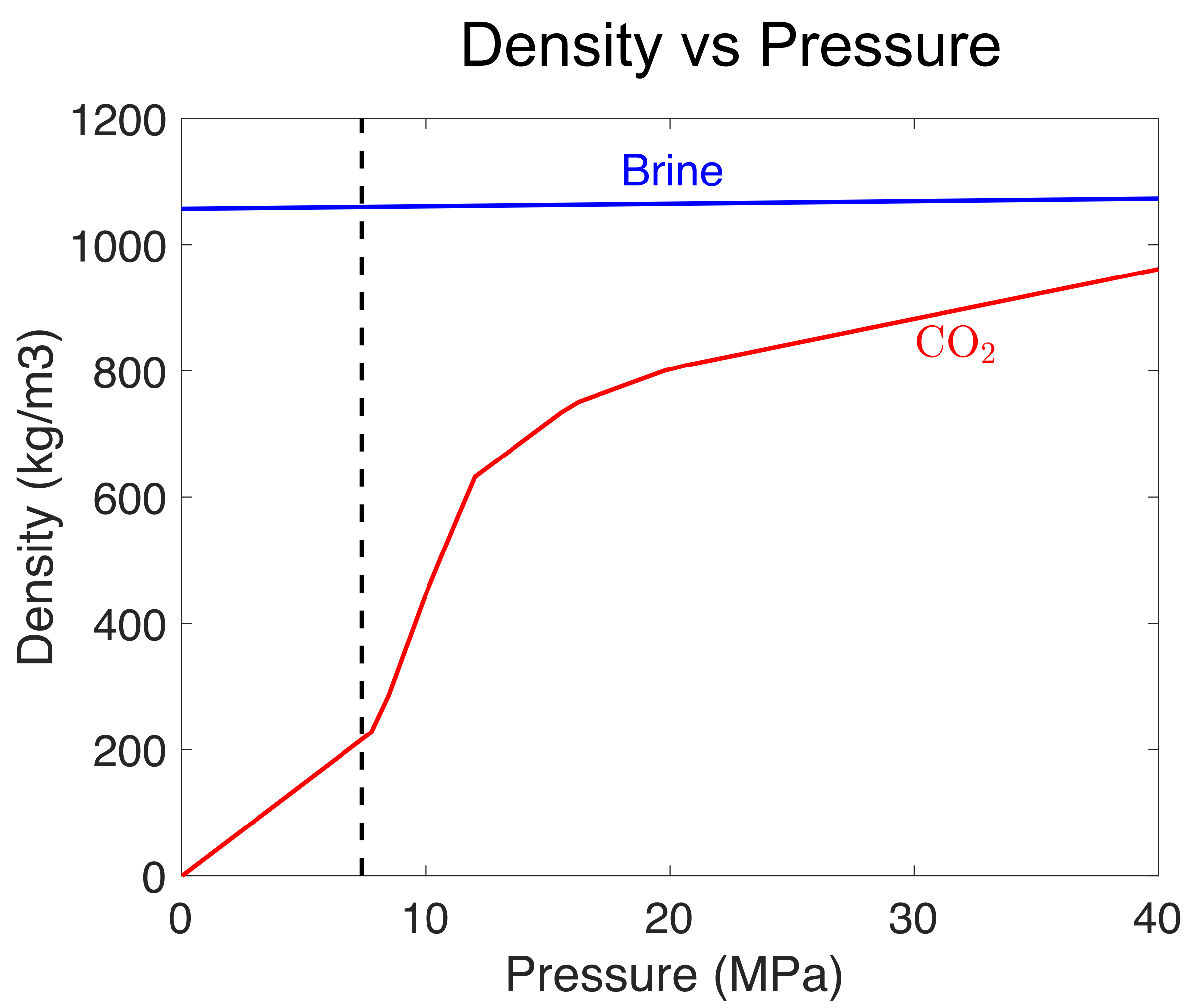
Fault porosity

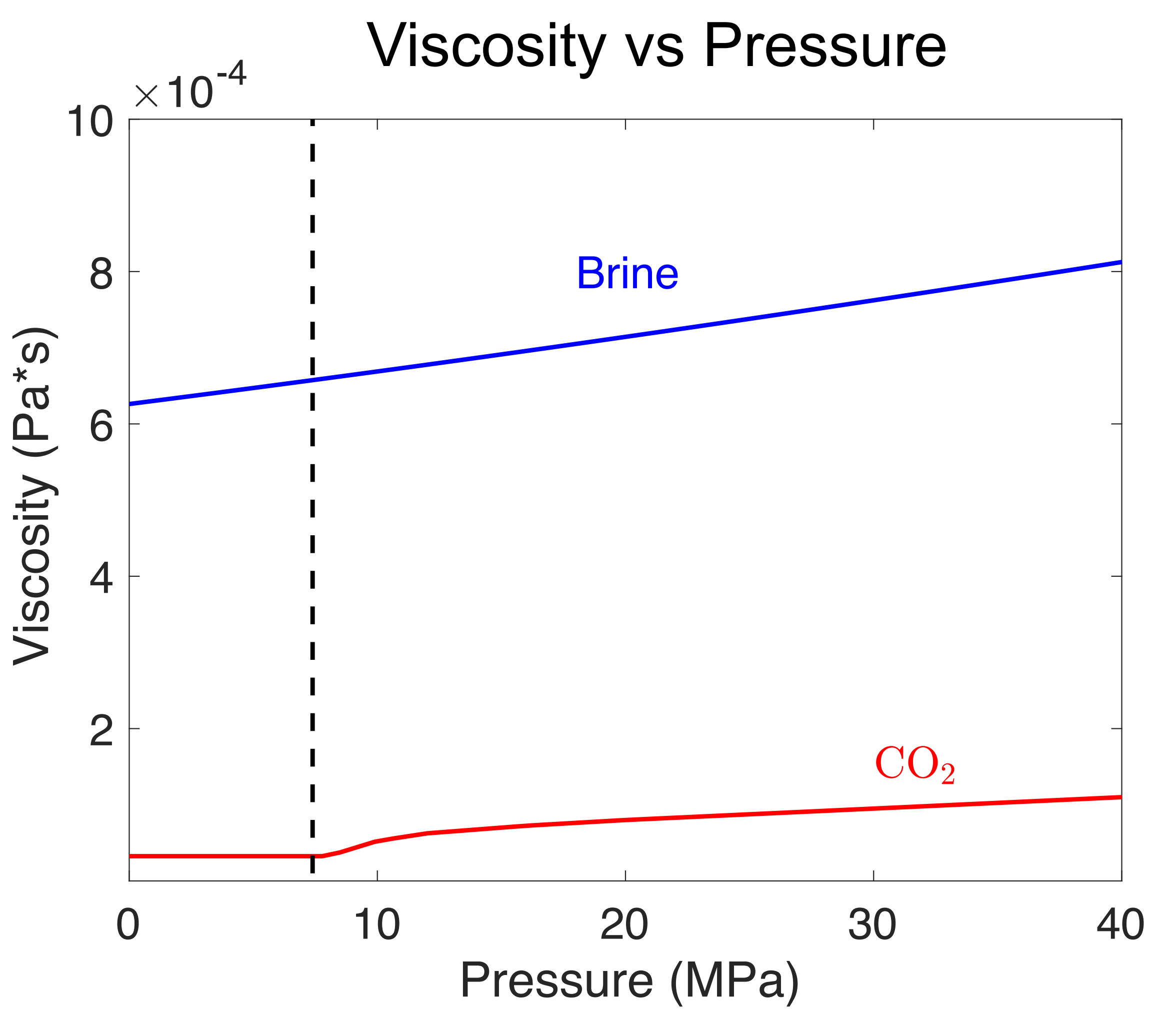


Two-phase flow immiscible reservoir simulation

1) Reservoir properties and model assumptions:

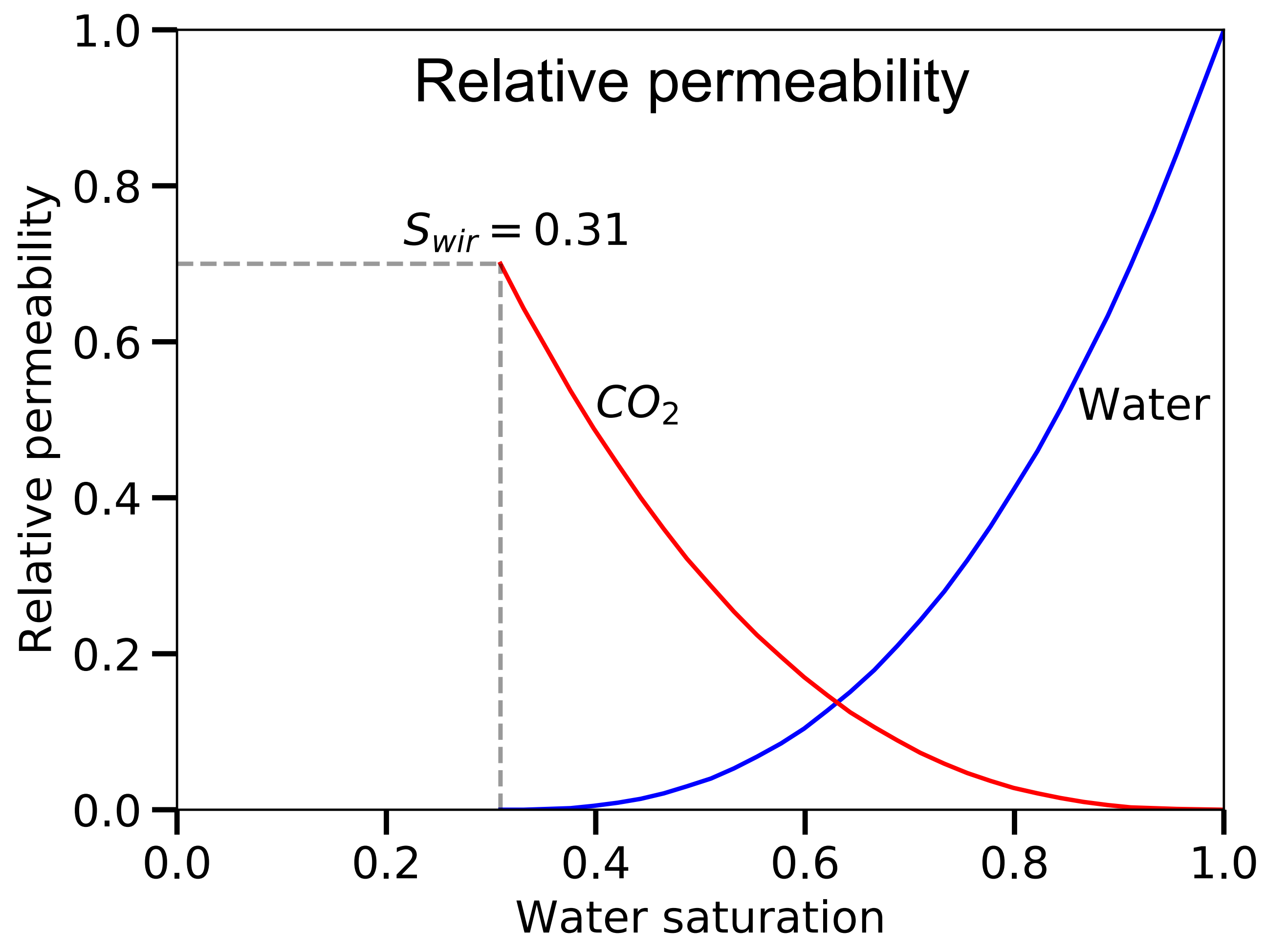
- Shale permeability and porosity (inactive cells) = 0
- No capillary pressure or relative permeability hysteresis
- MATLAB Reservoir Simulation Toolbox (MRST)
- Total number of active cells: ~4 Million cells





2) Injection schedule:

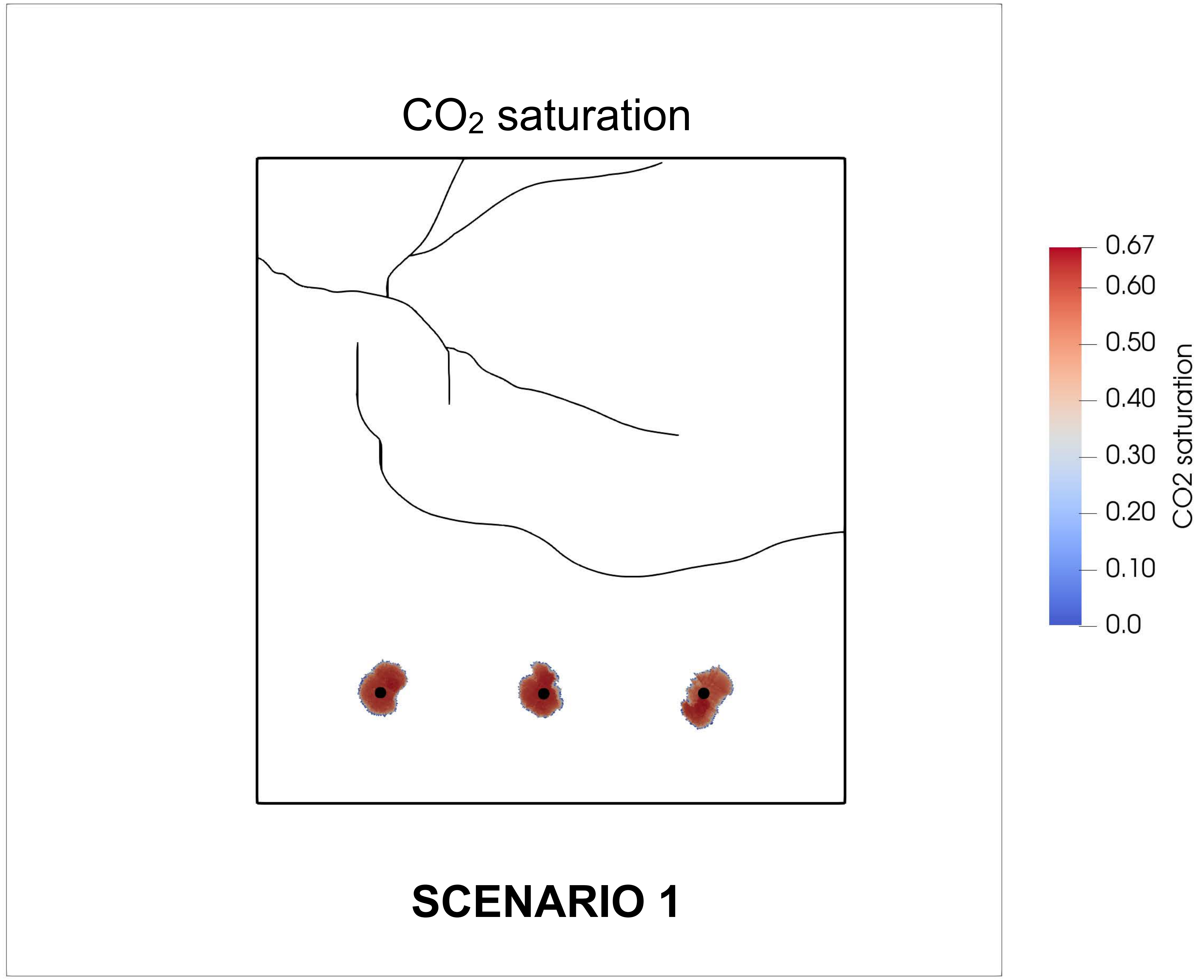
Injection rate	Injection duration	Total injected CO2	Total simulation time
1 MtCO2 / year / well	20 years	60 MtCO2	45 years

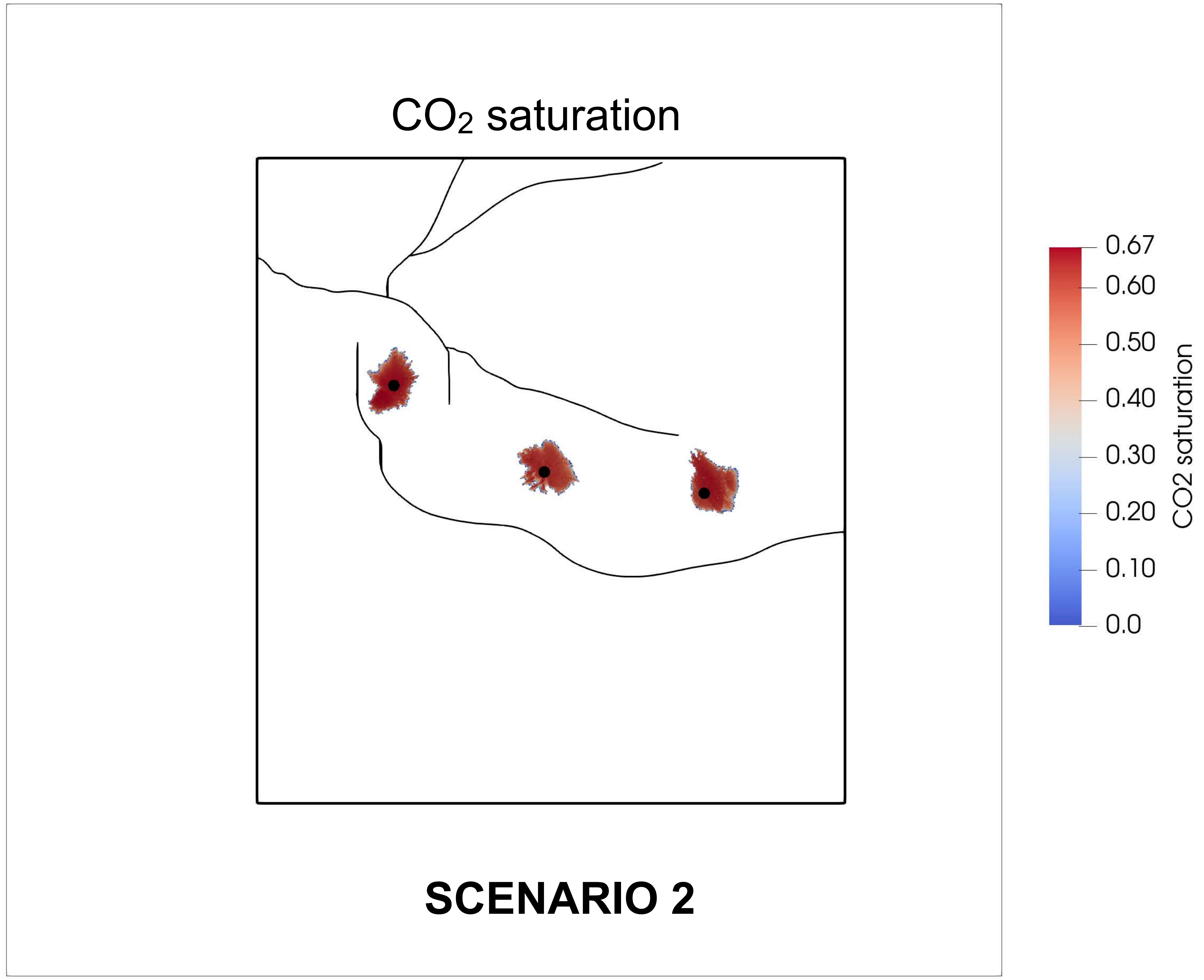


3) Boundary conditions:

- We multiply the pore volumes of the elements at the boundary by 1e4 to account for aquifer support

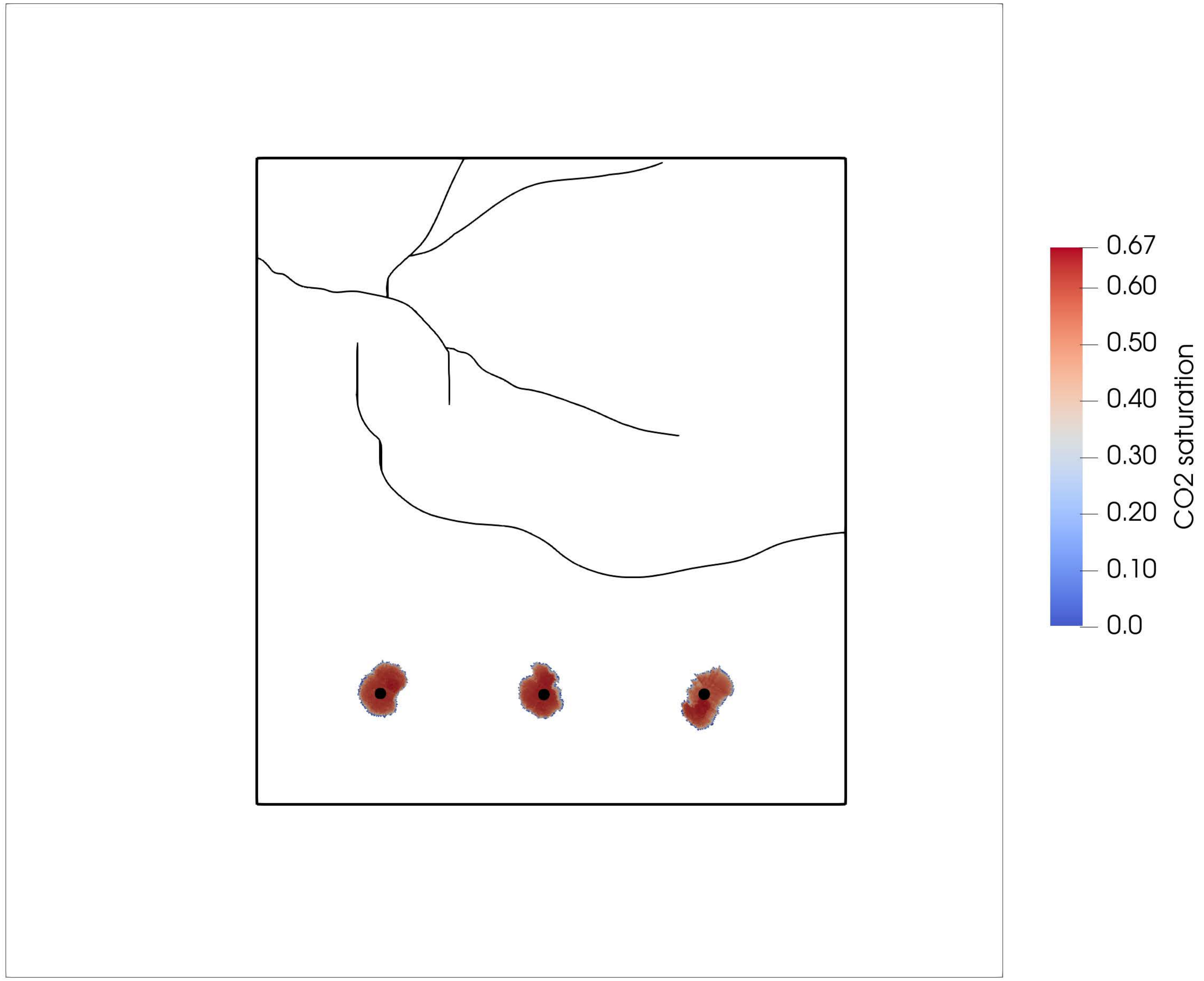
Reservoir simulation results (map view of the injection interval) after 20 years of injection

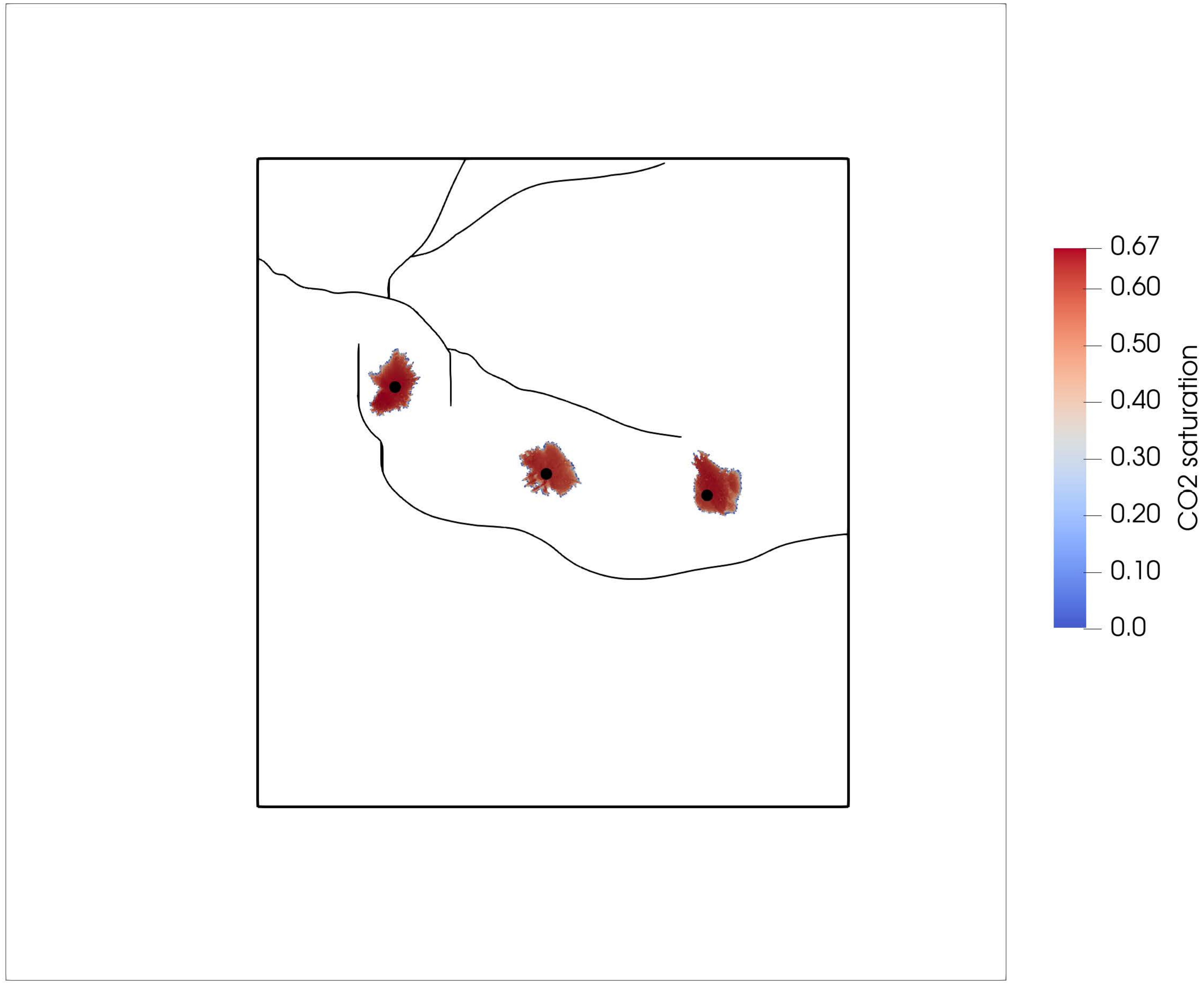




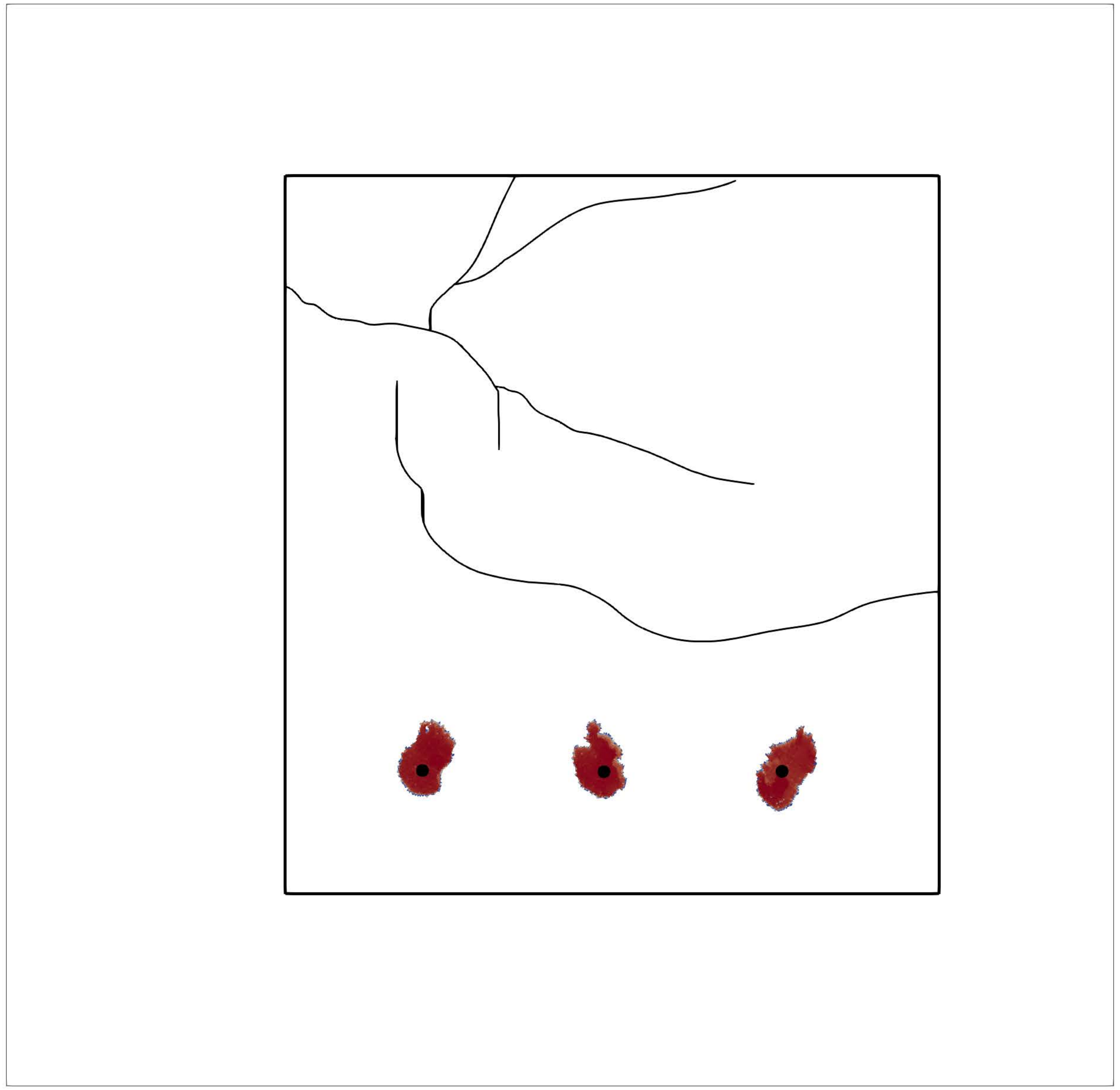
- We propose to perform simulations for two sets of injection locations
- For both cases the total amount of CO_2 injected is 60 $MtCO_2$, with 20 $MtCO_2$ per well for 20 years
- After 20 years, our model show that CO_2 saturation is localized near the injection wells

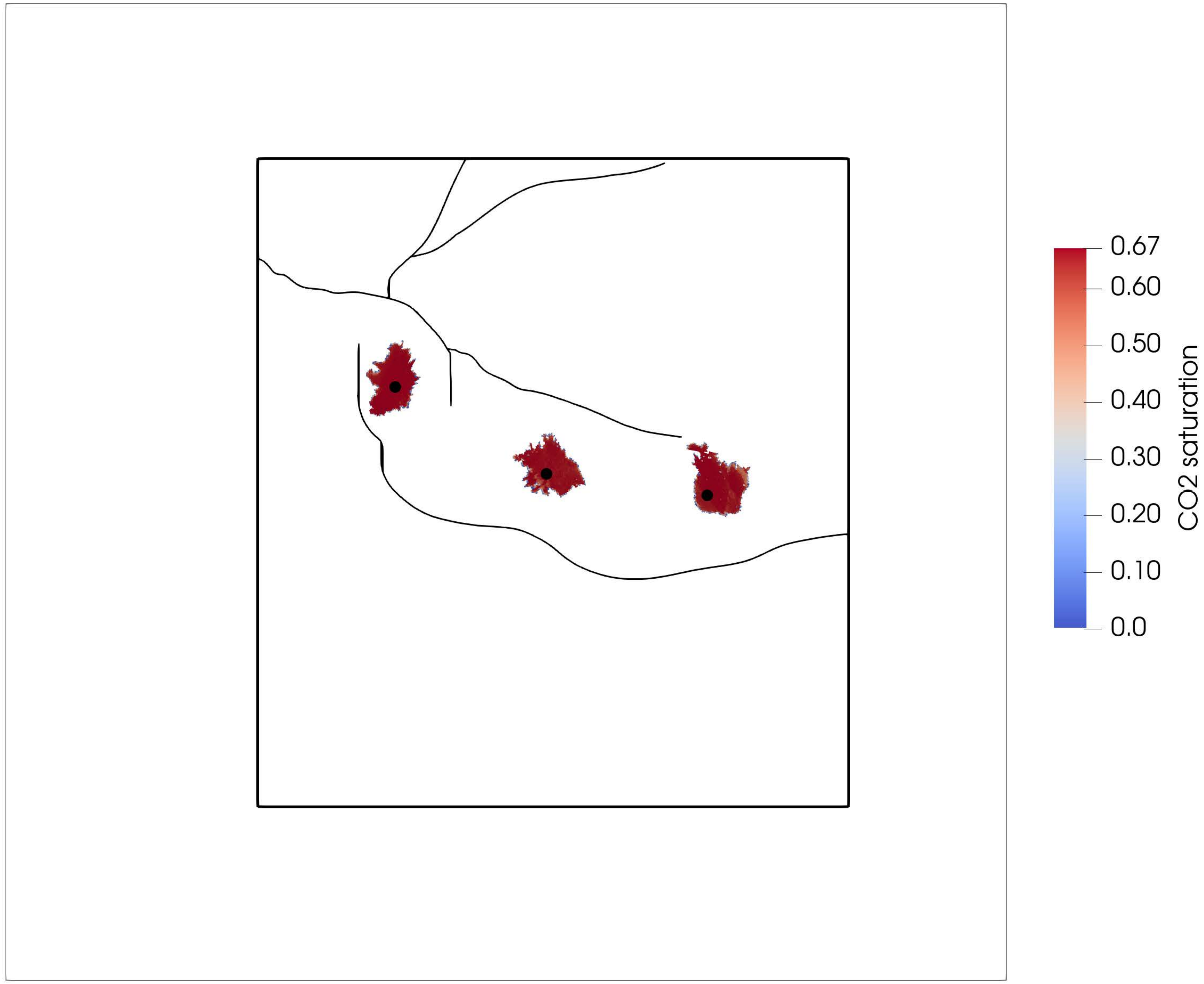
Reservoir simulation results (map view of the injection interval) after 20 years of injection



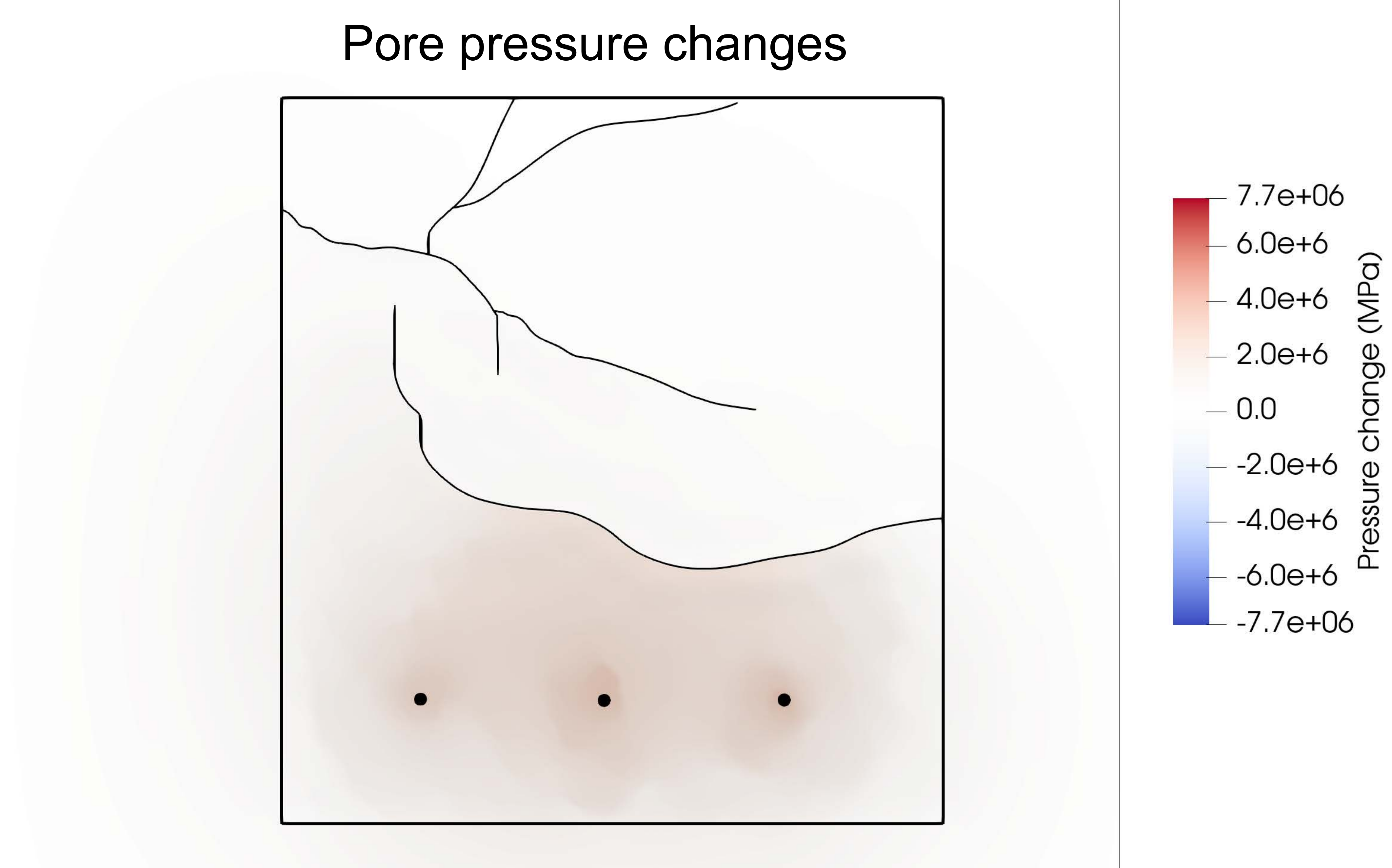


Reservoir simulation results (map view of the injection interval) after 40 years of injection

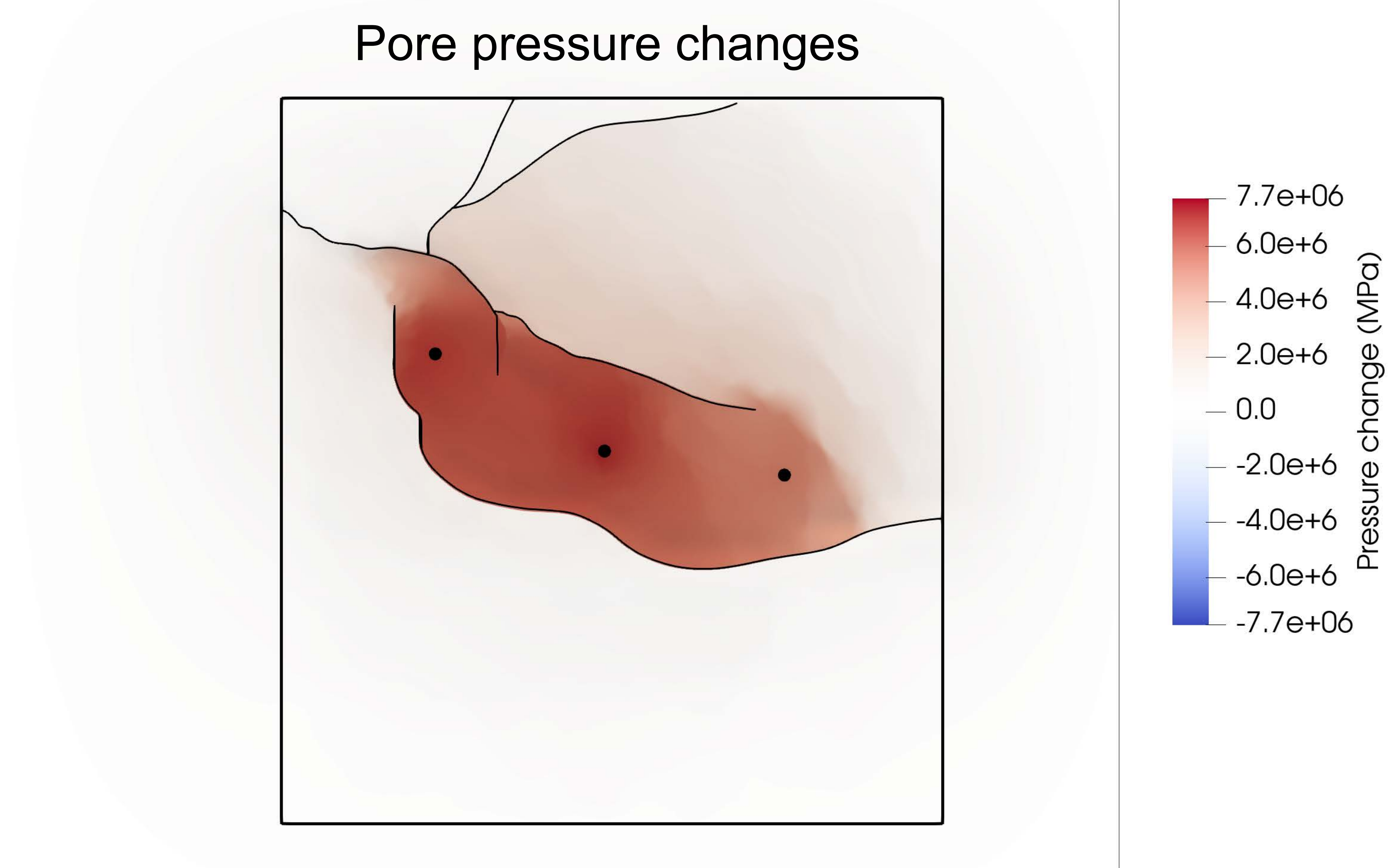




Reservoir simulation results (map view of the injection interval) after 20 years of injection



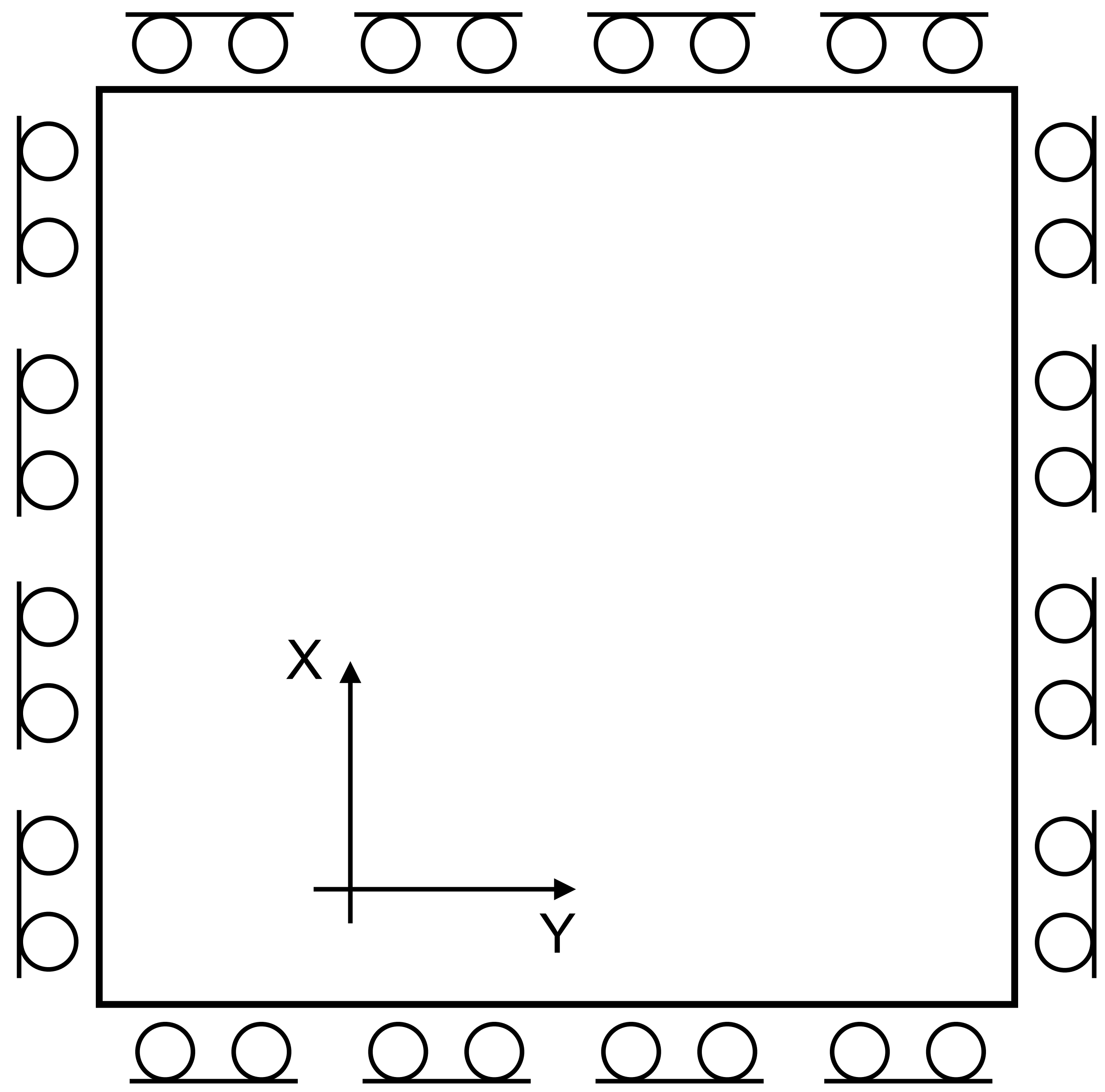
SCENARIO 1

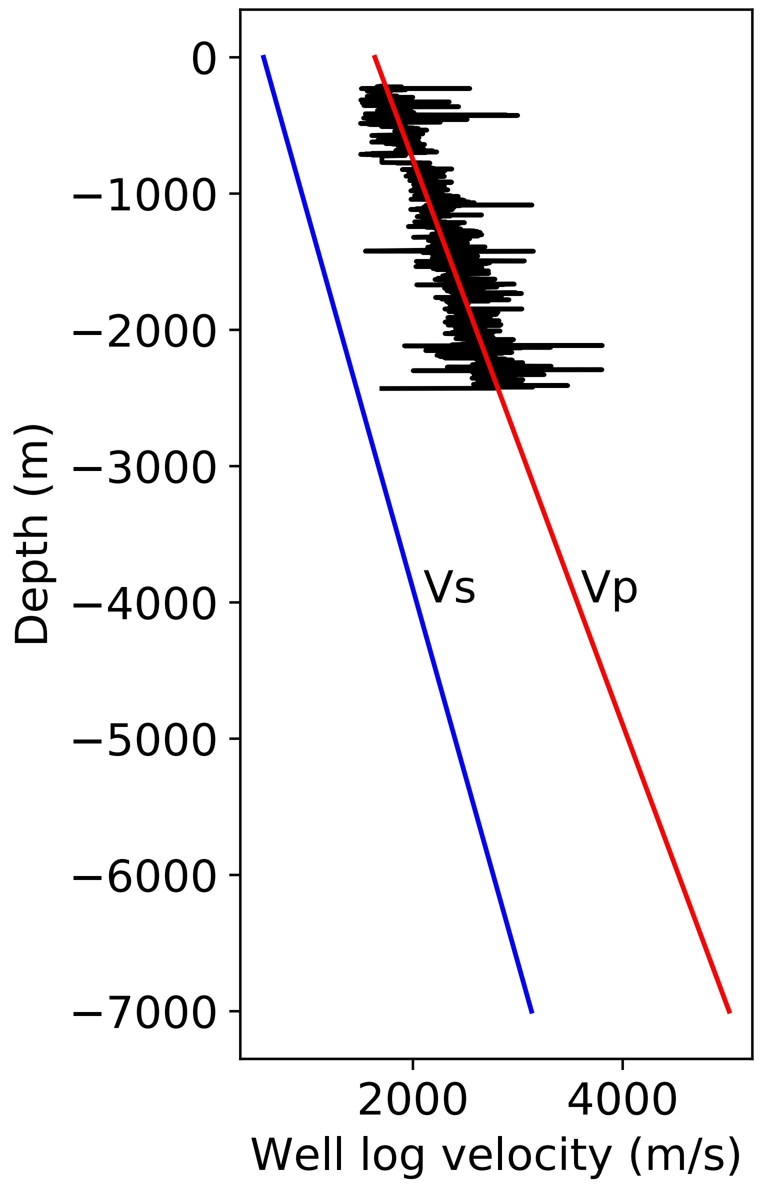


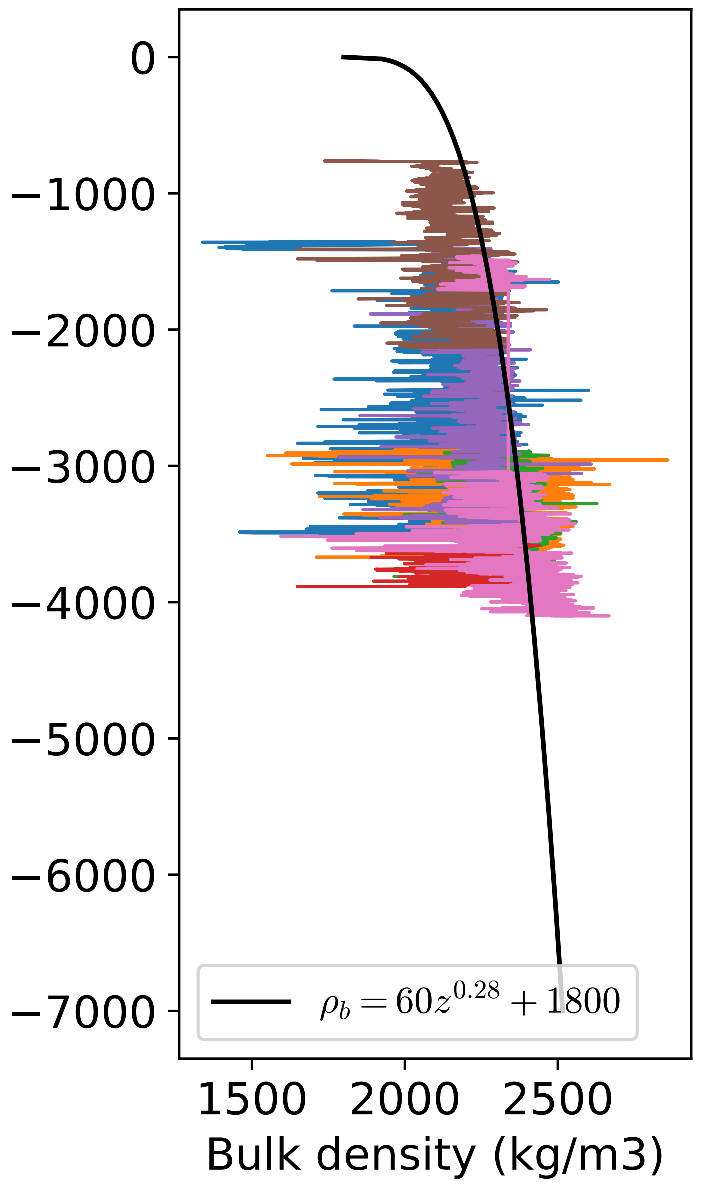
SCENARIO 2

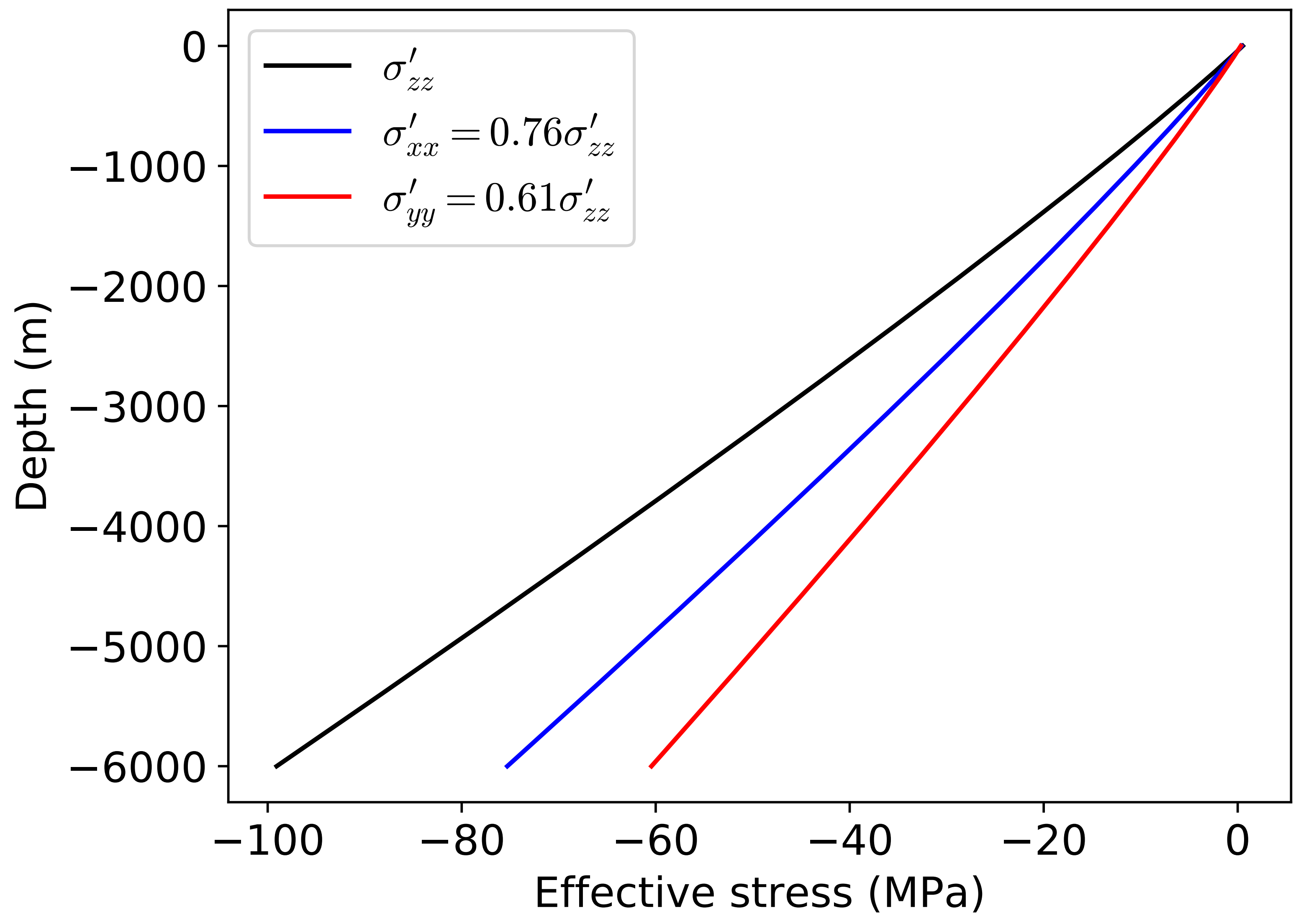
- Pressure changes show the significant differences between the two scenarios
- Pore pressure changes are as large as 7.7 MPa on the footwall of the main east-west fault (scenario 2)
- For the scenario 1, pore pressure changes are as large as 4 MPa near the wells, with smaller values aways from them

One-way coupled modeling, geomechanics boundary conditions and pre-stress



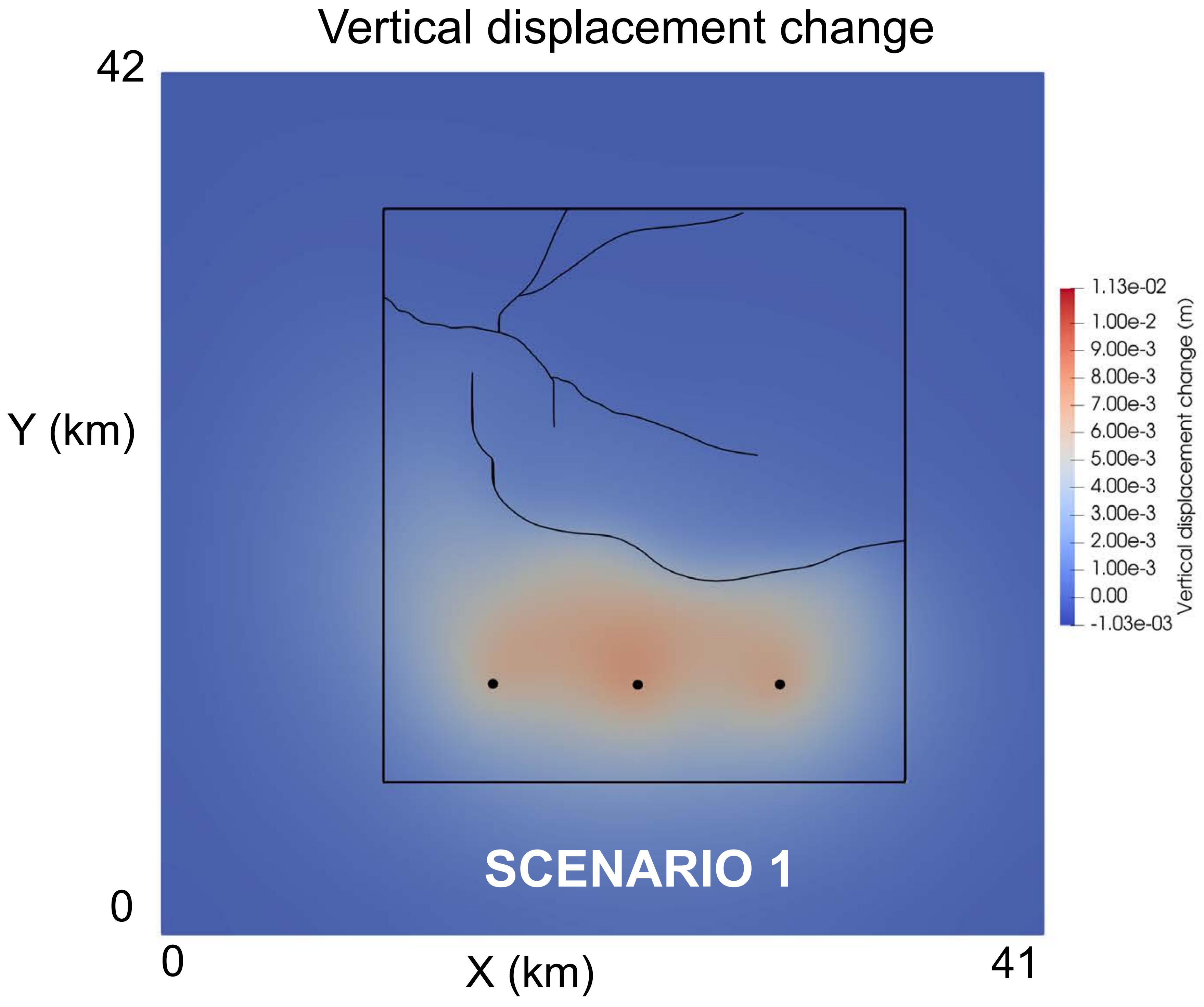


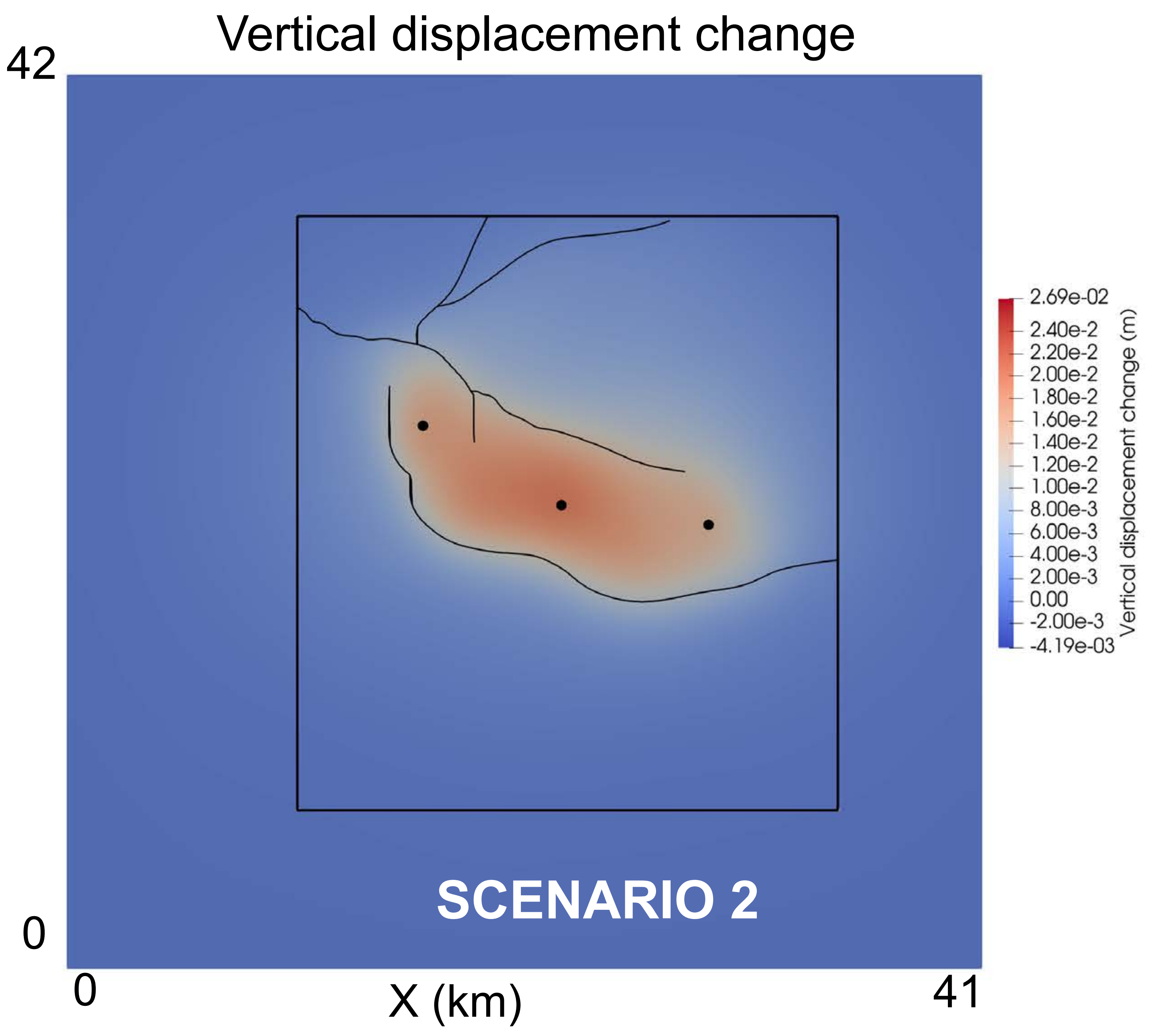




- For initial stresses we use: Shmin = 0.61 Sv and SHmax = 0.71 * Sv.
- The modeled pressures are loaded into PyLith, a finite element open source code, to solve for displacements and stresses
- Fixed boundary conditions on all sides and bottom of the domain, with a free surface on top
- Depth-dependent initial stresses

Seafloor displacement changes after 20 years of injection





- Seafloor uplift are as large as 2.7 cm for the scenario 2, localized around the center of the field
- For scenario 1, the maximum sea floor uplift is 1.13 cm.
- As expected, in both cases the uplift area is localized nearly above the injection wells

Changes in Coulomb Failure Function (DCFF)

- The DCFF is defined as:

$$
\begin{aligned}
CFF_{t_0} &= |\tau_0| + \mu\sigma_0^{'} \\
CFF_{t_1} &= |\tau_1| + \mu\sigma_1^{'} \\
DCFF = CFF_{t_1} &- CFF_{t_0}
\end{aligned}
$$

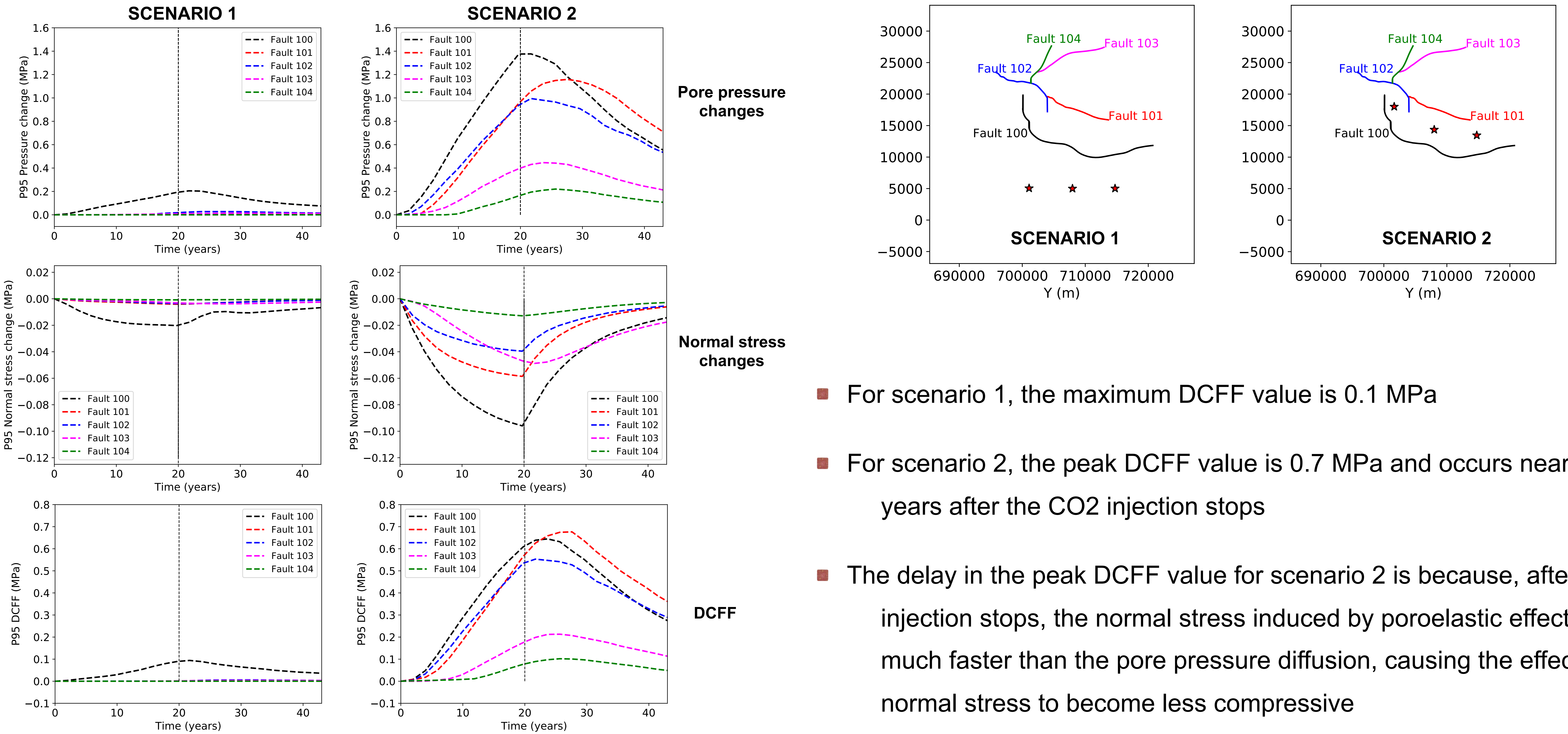
- Where:

$$
\begin{aligned}
\tau &\rightarrow \text{Total shear stress} \\
\sigma' &\rightarrow \text{Effective normal stress} \\
\mu &\rightarrow \text{Fault friction coefficient, typically } 0.6
\end{aligned}
$$

- Where:

$$
\begin{aligned}
DCFF > 0 &\implies \text{Fault tends towards destabilization} \\
DCFF < 0 &\implies \text{Fault tends towards stabilization}
\end{aligned}
$$

Temporal evolution of fault stresses and pore pressure (95th percentile of all the fault locations)



- For scenario 1, the maximum DCFF value is 0.1 MPa
- For scenario 2, the peak DCFF value is 0.7 MPa and occurs nearly 8 years after the CO2 injection stops
- The delay in the peak DCFF value for scenario 2 is because, after CO2 injection stops, the normal stress induced by poroelastic effects relaxes much faster than the pore pressure diffusion, causing the effective normal stress to become less compressive

Conclusions

- Injection of 60 $MtCO_2$ over 20 years does not result in fault leakage over a period of 45 years
- Our model indicates that the fault is moved towards destabilization (DCFF > 0), with DCFF reaching a peak value nearly 7 years after the CO2 injections ends.
- For scenario 1, the analogous of an open aquifer, the 95th percentile of the fault locations show DCFF as large as 0.1
- For scenario 2, the analogous of a closed aquifer, the 95th percentile of the fault locations show DCFF as large as 0.7
- Thus, our model strengthens the notion that aquifer connectivity is essential for CO_2 injection project design