Assessing CO_2 Injection Risks Using National Risk Assessment Partnership (NRAP) Tools

Authors: Esmail Ansari, Eugene Holubnyak, and Martin Dubois

Introduction: In this document, CO_2 injection risks are assessed using Department of Energy National Risk Assessment Partnership (NRAP) tools. We obtain the range and distribution of the reservoir and the seal properties from detailed geological and numerical models and use the Monte Carlo approach offered by NRAP for assessing the CO_2 storage risks. This document describes each tool and presents corresponding results. The tools used in this assessment are the reservoir evaluation (REV), seal evaluation (NSealR), storage capacity evaluation (NETL CO_2 SCREEN), Reduced Order Model Generator (RROM), NRAP integrated assessment model (NRAP-IAM-CS), and well leakage analysis (WLAT) tools.

Reservoir Evaluation (REV) tool: The REV tool from NRAP (King, 2016a) was used to assess CO_2 injection into the Osage, Viola, and Arbuckle formations at the Patterson Field. The REV tool uses results from other simulators and visualizes several important metrics for studying the response of the formation to carbon storage. These metrics include CO_2 plume size and pressure plume size. Obtaining these metrics are useful for determining the post-injection fate of carbon dioxide, such as the post shut-in decay rate of pressure, plume growth rate in a long-term period, and maximum pressure increase at the shut-in time.

The inputs for the REV tool are the pressure and saturations for all grid blocks as time series obtained from reservoir simulation models. The tool has a defined threshold for pressure and saturation. It calculates the differential pressure and CO_2 plume size in all grid blocks and maps it into a 2-D horizontal surface to visualize the area of the plume and its evolution through time. The saturation threshold defines the extent of the CO_2 plume and is set to 0.2 in the current study while the pressure threshold defines the extent of the overpressure front, depending on factors such as wellbore pressure, and is set to 400 psi, as deemed appropriate for this study. Other parameters in the tool, such as depth of the storage reservoir or brine density, are the same values used in the source reservoir simulation model.

The REV tool was not able to process corner point grids. We created an equivalent regular-rectangular Cartesian grid for our corner point gridding of the Patterson area (Figure 1). The REV metrics for assessing CO_2 injection into the Arbuckle and Osage formations are shown in Figures 2–5. This study used the REV tool version 2018.

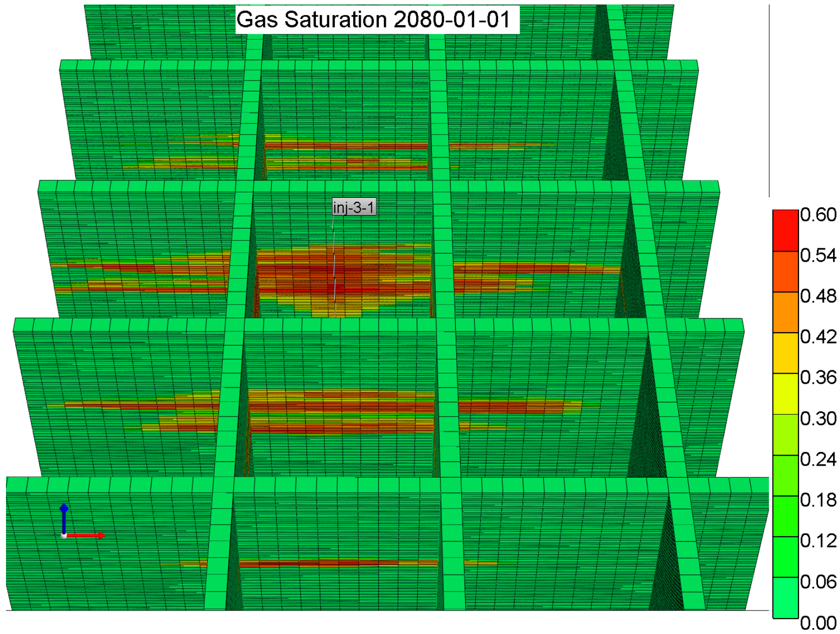

Figure 1: Projected grid blocks from corner point to the Cartesian grid. This figure shows the CO_2 plume in the Osage formation after 60 years (30 years of injection).

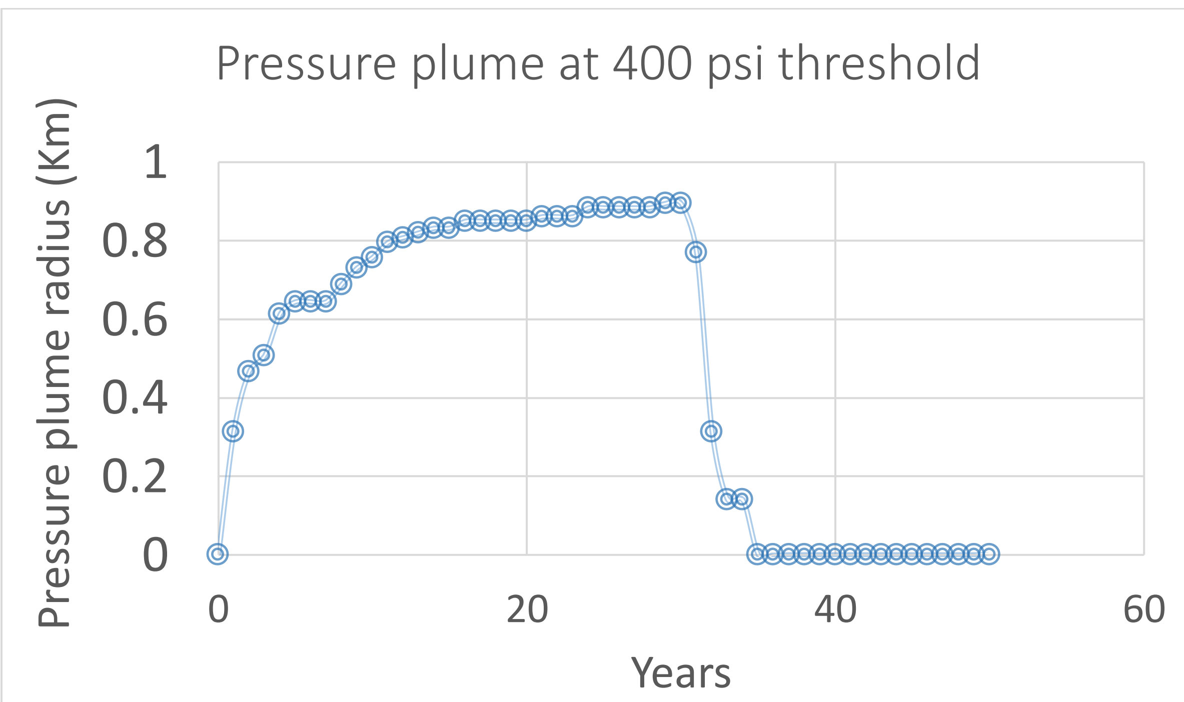

Figure 2: Pressure plume evolution in the Arbuckle. Injection stops after 30 years and within ~5 years the overpressure plume dissipates in the Arbuckle formation.

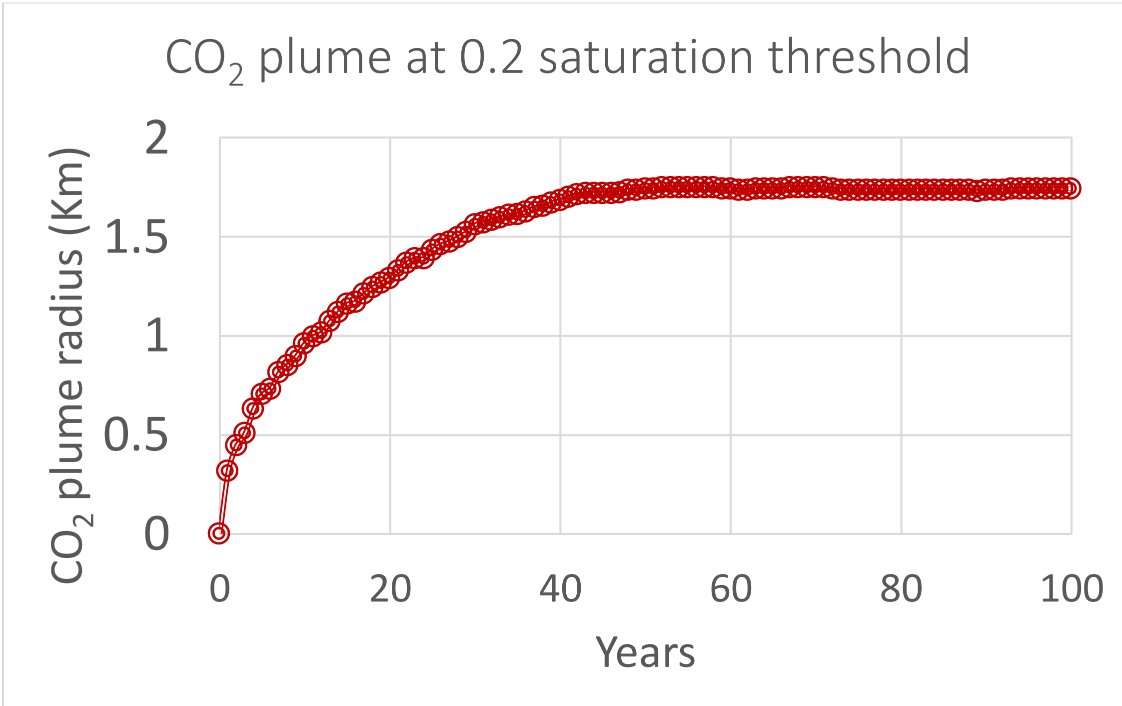

Figure 3: CO_2 plume evolution at 0.2 saturation threshold in the Arbuckle formation. The plume growth rate decreases after the injection period (30 years) and its growth stops after another ~15 years at ~1.75 km distance from the well.

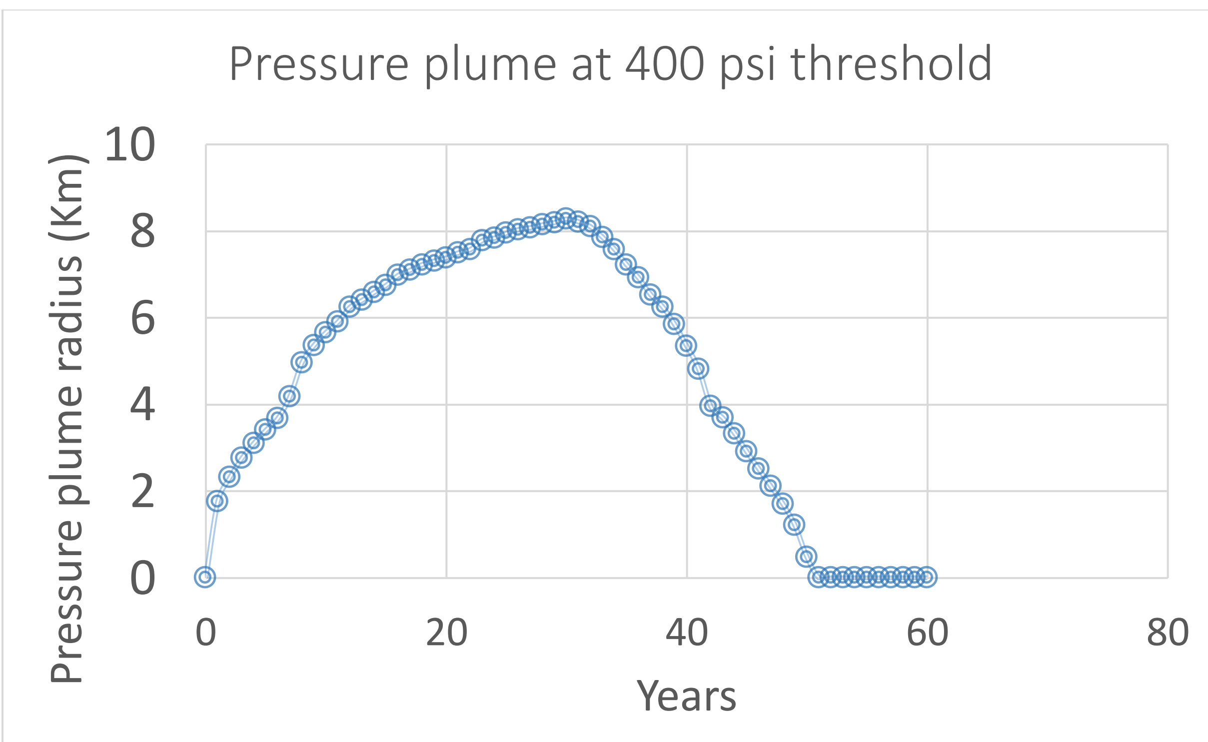

Figure 4: Pressure plume evolution at 400 psi threshold in the Osage formation. The overpressure plume dissipates in the formation and disappears 20 years after shut-in (30 years).

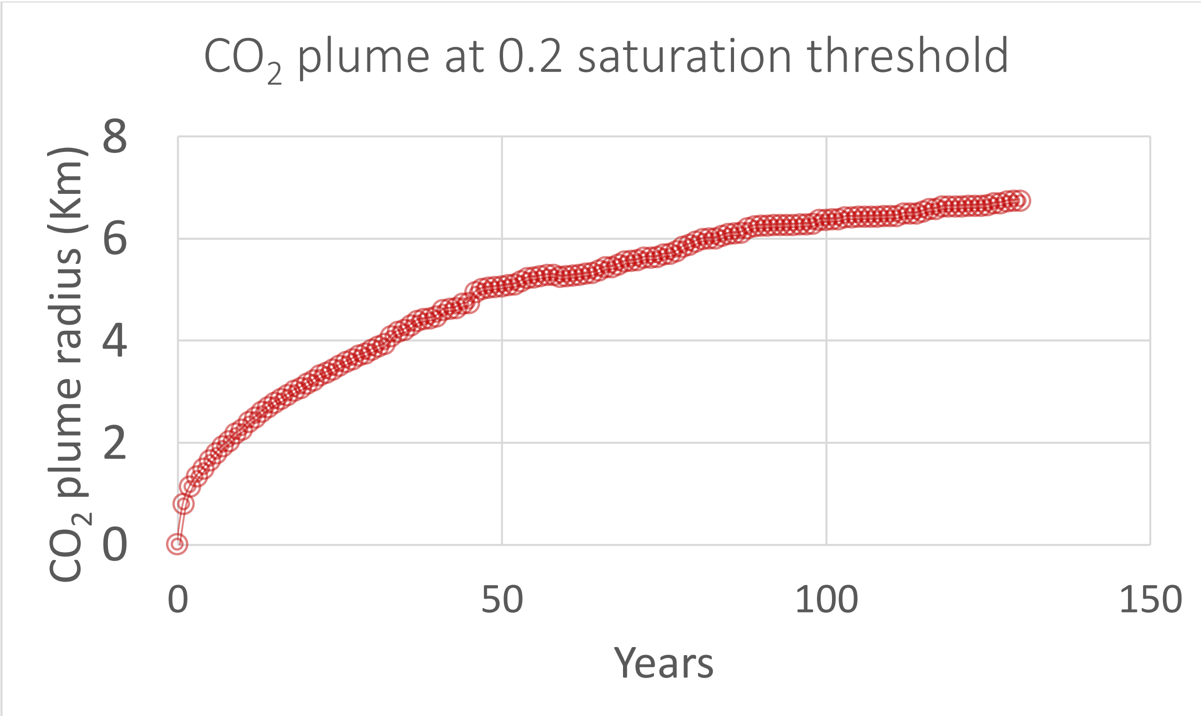

Figure 5: CO_2 plume evolution at 0.2 saturation threshold in the Osage formation. The CO_2 plume reaches a distance of ~4 km when injection stops (30 years) and its slower rate growth reaches 6 km after ~90 years.

NSealR (NRAP Seal Barrier Reduced-Order Model) tool: NSealR offers a one-dimensional model for analyzing two-phase flow of supercritical CO_2 through brine-saturated rock (Lindner, 2016). This toolkit uses a 1-D Darcy equation to describe the flow and leakage of CO_2 through the seal (i.e., low permeability rock) and uses two-phase (CO_2-brine) relative permeability models.

We use NSealR to quantify and assess the leakage risk of injected CO_2 into the Arbuckle, Osage, and Viola groups in the Patterson Field. Simpson shale, Kinderhook, and Spergen-Meramec are the caprock barriers for the Arbuckle, Viola, and Osage, respectively. The main barrier is the thick, non-permeable limestone, Spergen-Meramec, overlying the Osage. Additionally, the Morrow shale, the seal of Kansas petroleum reservoirs, acts as the ultimate barrier. Tables 1 and 2 summarize the properties of the seals used in the NSealR. Morrow shale properties are based on the S1537 and S1461 samples presented by Krushin (1997).

Table 1: Range of properties of the caprock seals

Caprock seal $Min - Max$	Formation top (ft)	Elevation Depth (ft)	Thickness (ft)	Porosity	Horizontal Permeability (md)
Morrow-Chester shale	4,750	1,300–1,968	44.6–282.5	0.0141–0.18	0.0117–3.926
Morrow shale	4,750	1,300–1,968	40–70	1e-10–0.03	5.13e-11–0.001
Meramec limestone	4,900	1,435–2,028	0–225.4	1e-10–0.1	1e-10–0.6832
Lower Meramec	4,965	1,500–2,111	28.6–126.8	1e-10–0.12	1e-10–0.9315
Spergen limestone	5,100	1,578–2,235	82.63–124.8	1e-10–0.16	1e-10–76.061
Kinderhook limestone	5,475	1,900–2,646	102.5–168.8	1e-10–0.2	0.0021–5.45
Simpson shale	5,775	2,170–2,853	19.9–35.57	0.0334–0.14	0.1–69.11

Table 2: μ_x and σ_x for the properties of the caprock seals

Caprock seal	Porosity μ_x, σ_x	Horizontal Permeability (md) μ_x, σ_x
Morrow-Chester shale	0.0458, 0.0231	0.269, 0.4357
Morrow shale	0.022, 0.010	5.1e-6, 0.001
Meramec limestone	0.0249, 0.0201	0.0677, 0.122
Lower Meramec	0.0260, 0.0182	0.0739, 0.1321
Spergen limestone	0.0265, 0.018	0.7696, 4.3102
Kinderhook limestone	0.0587, 0.0319	0.5784, 0.7846
Simpson shale	0.0682, 0.0201	2.0850, 2.4329

The vertical permeability is assumed to be 0.1 of the horizontal permeability. The maximum and minimum values for the vertical permeability are assumed to come from a log-normal distribution. We use NSealR's default relative permeability and capillary pressure model for caprock. At a reference depth of 5,260 ft, the reference brine pressure is 1,650 psi and the reference temperature is 140 ^{o}F. The salinity is assumed to be

100 g/l. The affected seal area (i.e., maximum plume area) is calculated using CMG GEM to have an average diameter of 2.9 mi (4.6 km) when approximately 8 Mt CO_2 is injected per well into the Osage (storage zone below Meramec). Fifty realizations are sampled using the Monte Carlo method. Figures 6–9 show the seal assessment results for the Morrow shale and Meramec limestone, the topmost seal barriers.

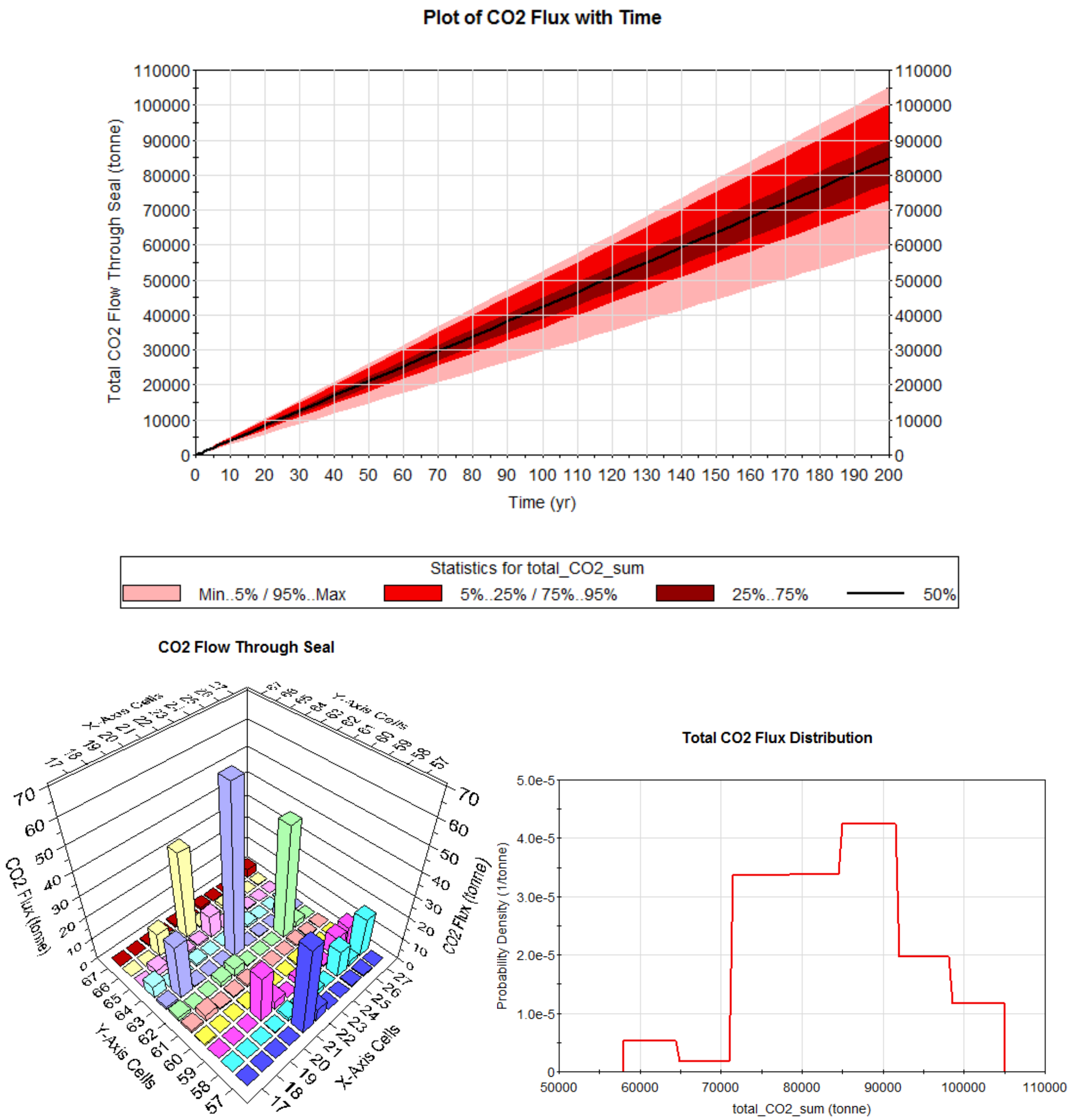

Figure 6: CO_2 flux through the Morrow shale. The top figure shows total CO_2 leakage and its corresponding probability versus time. The bottom left figure shows one realization for the CO_2 leakage rate assuming the entire seal is divided into 100 × 100 grid blocks. The bottom right figure shows the probability distribution for total CO_2 leakage.

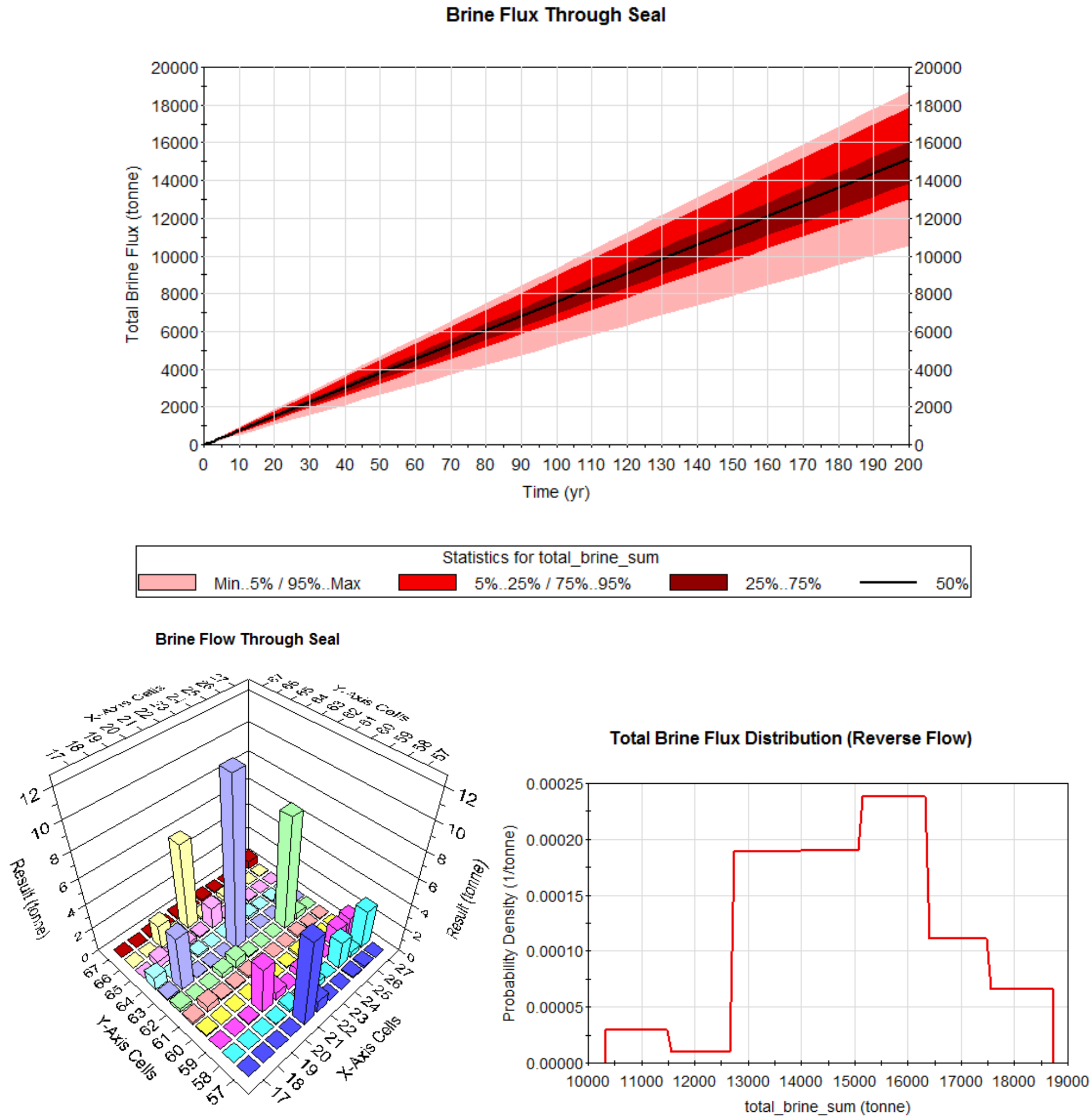

Figure 7: Brine flux through the Morrow shale. The top figure shows total brine leakage and its corresponding probability versus time. The bottom left figure shows one realization for the brine leakage rate assuming the entire seal is divided into 100×100 grid blocks. The bottom right figure shows the probability distribution for total brine leakage.

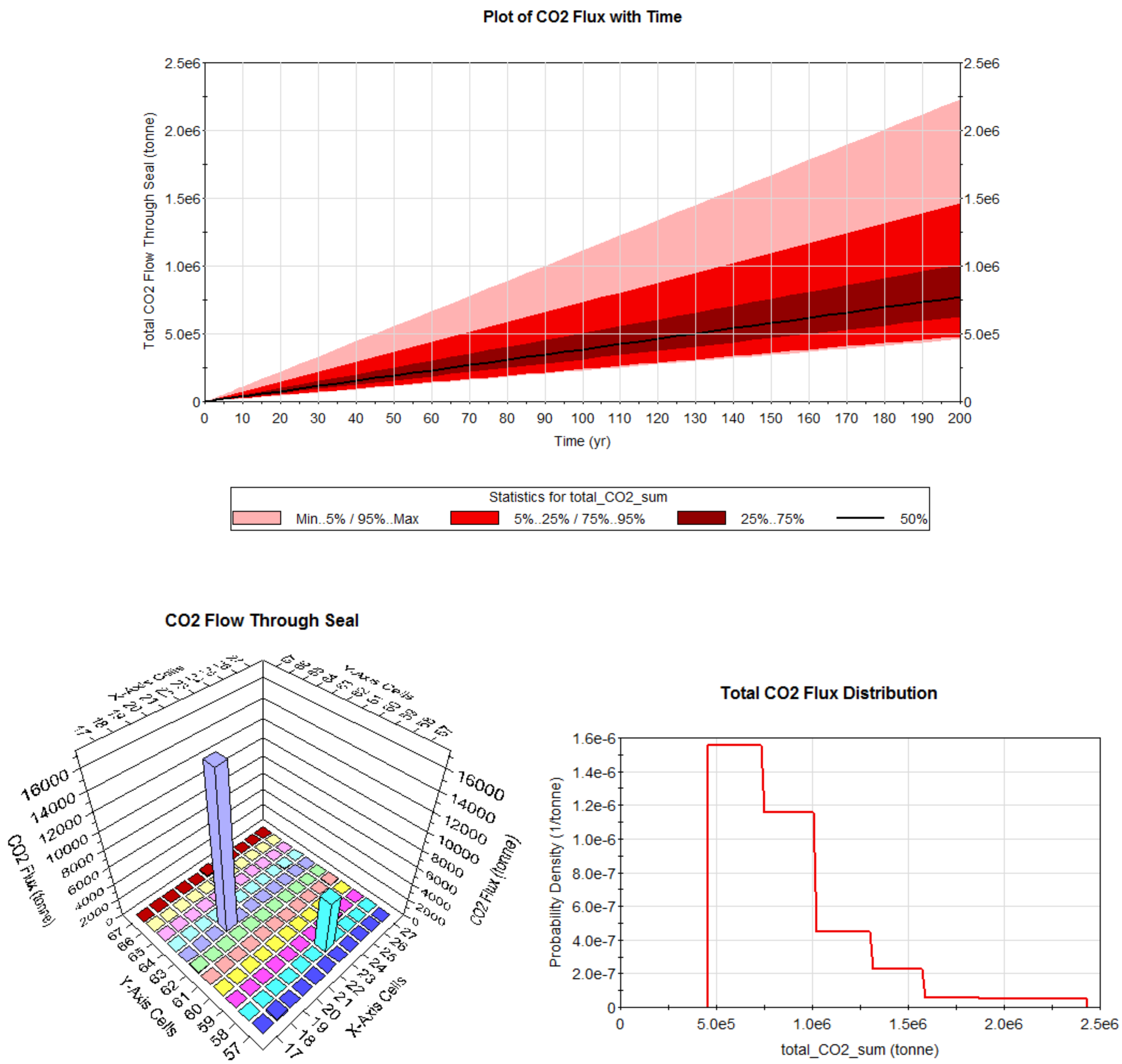

Figure 8: CO_2 flux through the Meramec limestone. The top figure shows total CO_2 leakage and its corresponding probability versus time. The bottom left figure shows one realization for the leakage rate assuming the entire seal is divided into 100×100 grid blocks. The bottom right figure shows the probability distribution for total CO_2 leakage.

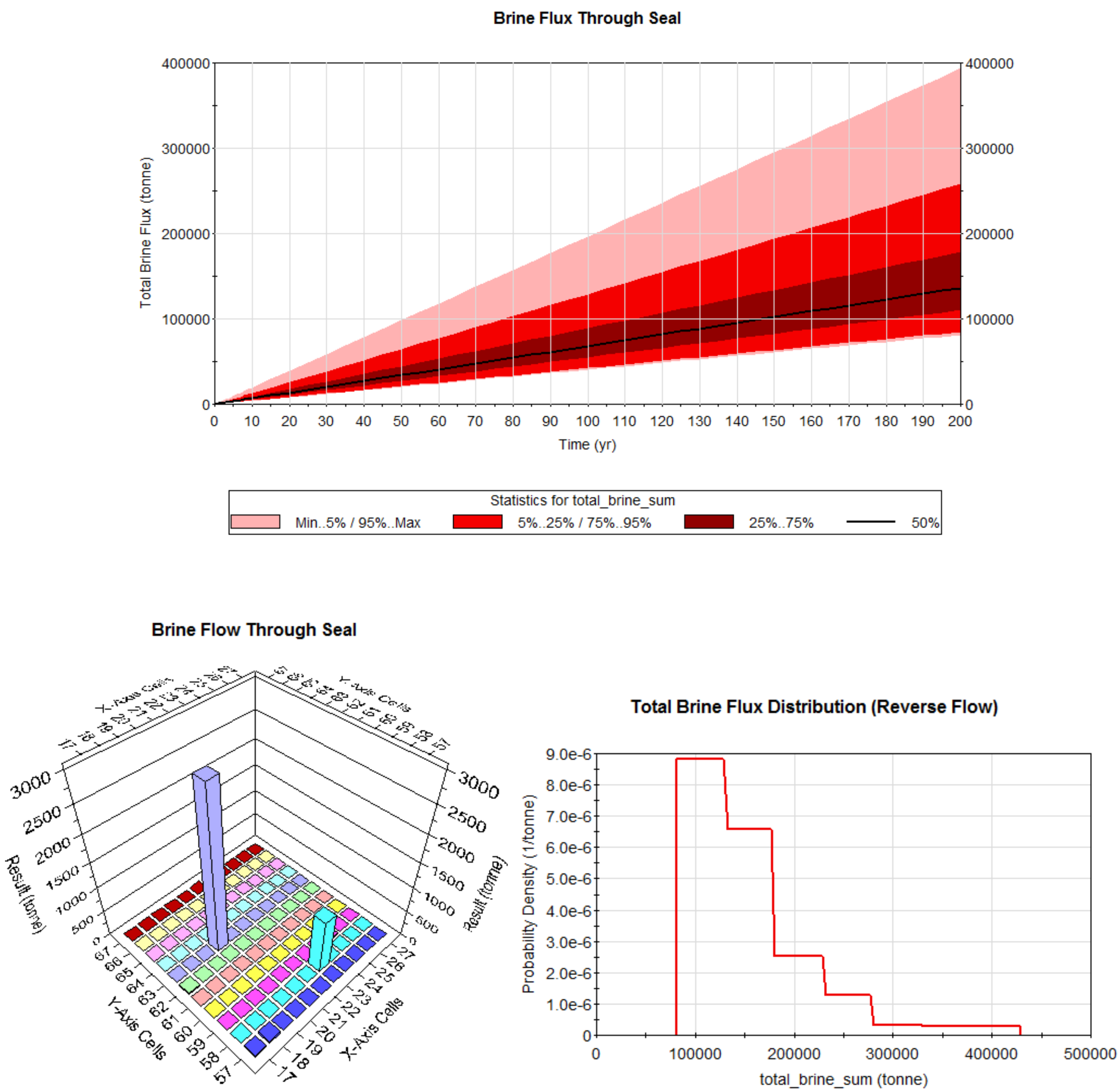

Figure 9: Brine flux through the Meramec limestone. The top figure shows total brine leakage and its corresponding probability versus time. The bottom left figure shows one realization for the leakage rate assuming the entire seal is divided into 100×100 grid blocks. The bottom right figure shows the probability distribution for total brine leakage.

NETL CO_2–SCREEN

The US-DOE methodology known as NETL CO_2-SCREEN (Goodman et al., 2016) is used for estimating CO_2 storage potential in the Patterson area. The methodology is general and could be applied globally; however, we refined the required data using the currently available information for the Patterson area. The Patterson area is an open system (no impermeable boundary) with closures to vertically constrain and trap the injected CO_2 within the injected area. Thus the percentage of pore space that can be filled with CO_2 primarily depends on storage efficiencies and is independent of bottomhole pressure. The Patterson Field has an approximated area of 50 mile^2 (129.5 km^2) with three potential injection formations: Osage (limestone), Viola (dolomite), and Arbuckle (dolomite). Table 3 summarizes the geological properties of each formation as needed by CO_2-SCREEN.

Table 3: Properties of the Patterson area

Grid #	Area* (km^2)	Gross Thickness* (m)		Total Porosity* (%)		Pressure† (MPa)		Temperature† (°C)	
	Mean	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
1	129.5	45.72	0	12.3	6.4	11.38	0	53.89	0
2	129.5	54.86	0	7.5	2.5	11.51	0	55.56	0
3	129.5	173.7	0	5.4	3.7	11.72	0	58.33	0

The storage efficiency of the saline formations (G_{CO2}) is calculated by:

$$G_{CO2} = A_t h_{gross} \phi_{tot} \rho_{CO_2} E_{saline}$$

in which pore space ($A_t h_{gross} \phi_{tot}$) obtained using Table 3 parameters is multiplied by ρ_{CO_2} to convert to CO_2 mass in the reservoir and then multiplied by storage efficiency factor for saline formations (E_{saline}) defined as:

$$E_{saline} = E_A E_h E_\phi E_v E_d$$

in which E_A is the net-to-total area, E_h is the fraction of total thickness that meets minimum permeability and porosity requirements, E_ϕ is the fraction of interconnected porosity, E_v is the volumetric displacement efficiency defining the volume that can be contacted by the CO_2 plume, and E_d is the microscopic displacement efficiency describing the fraction of water in water-filled pore volume that can be displaced by contacting the CO_2. Table 4 summarizes the efficiency values based on Goodman et al. (2011). The E_A and E_h values chosen are higher than the global recommended values considering that the Osage, Viola, and Arbuckle formations in the Patterson area have good net-to-total area and net-to-gross thickness. These values can be refined as more data become available.

Table 4: Storage efficiencies for the Patterson area

Grid #	Lithology and Depositional Environment	E_A		E_h		E_ϕ		E_v		E_d	
		P_{10}	P_{90}	P_{10}	P_{90}	P_{10}	P_{90}	P_{10}	P_{90}	P_{10}	P_{90}
1	Limestone: Unspecified	0.6	0.9	0.85	0.95	0.64	0.75	0.27	0.42	0.33	0.57
2	Dolomite: Unspecified	0.6	0.9	0.75	0.85	0.53	0.71	0.57	0.64	0.26	0.43
3	Dolomite: Unspecified	0.6	0.9	0.35	0.65	0.53	0.71	0.57	0.64	0.26	0.43

Table 5 summarizes the injection capacity of each formation and the probability results for the calculated storage efficiency factors (i.e., $p(E_{saline})$), assuming one grid block for each formation. The injection capacity of the Arbuckle and Osage are high because of the greater thickness of the former and because the latter has higher porosity and is limestone. Table 6 shows the total CO_2 capacity for the Patterson area. Figures 10 and 11 summarize the results listed in Tables 5 and 6.

Table 5: Calculated storage efficiency factors for each formation

Grid	P_{10} (Mt)	P_{50} (Mt)	P_{90} (Mt)	Lithology and Depositional Environment	Saline Efficiency (%)		
					P_{10}	P_{50}	P_{90}
1	9.940	21.244	44.767	User Specified	4.54	7.21	10.57
2	9.887	17.570	30.728	User Specified	5.18	7.73	10.87
3	7.892	20.415	50.436	User Specified	2.79	4.72	7.32

Table 6: Calculated storage for the Patterson area.

	P_{10}	P_{50}	P_{90}	
Summed CO_2 Total	27.72	59.23	125.93	Mt
Average CO_2 per Grid	9.24	19.74	41.98	Mt

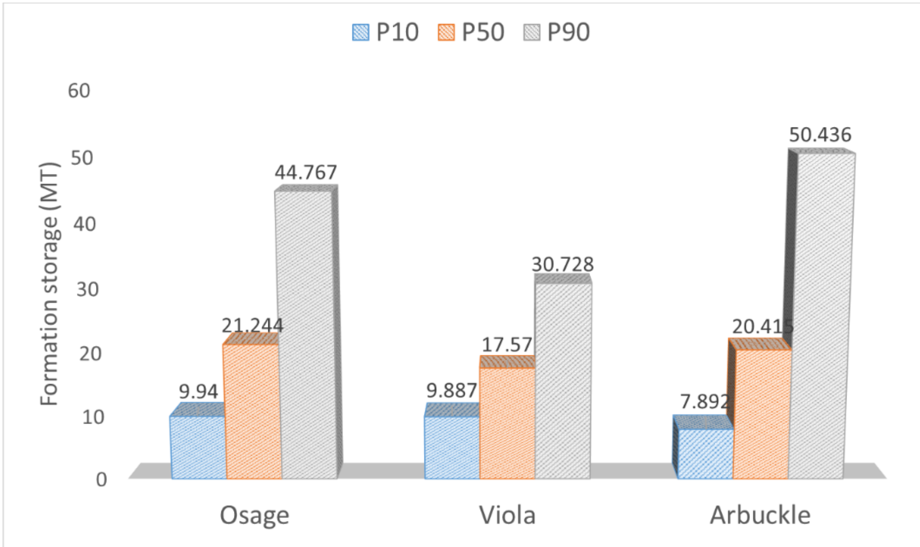

Figure 10: Formation capacity for the formations in the Patterson area.

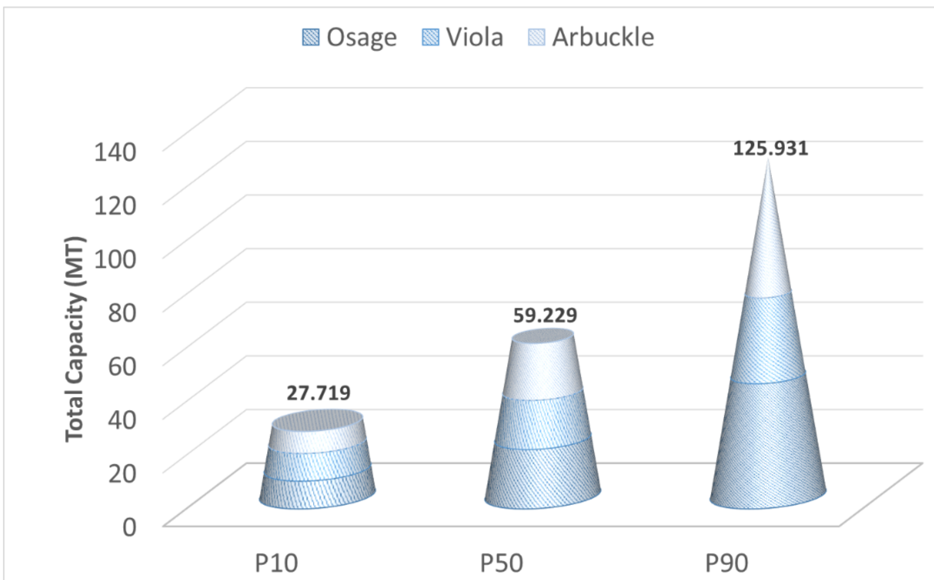

Figure 11: Maximum storage for the Patterson area.

RROM-GEN tool (Reservoir Reduced Order Model Generator)

The RROM-GEN tool (King, 2016b) uses interpolation to reduce the simulation model dimension into a 100×100 grid block representation in the horizontal direction and outputs the file in a format readable by the Integrated Assessment Model (IAM) tool. RROM-GEN also extracts a single layer for representing the reservoir-seal boundary. Figure 12 shows the reduced order model generated for the Patterson area. RROM-GEN version 2018 was obtained from the author for this study.

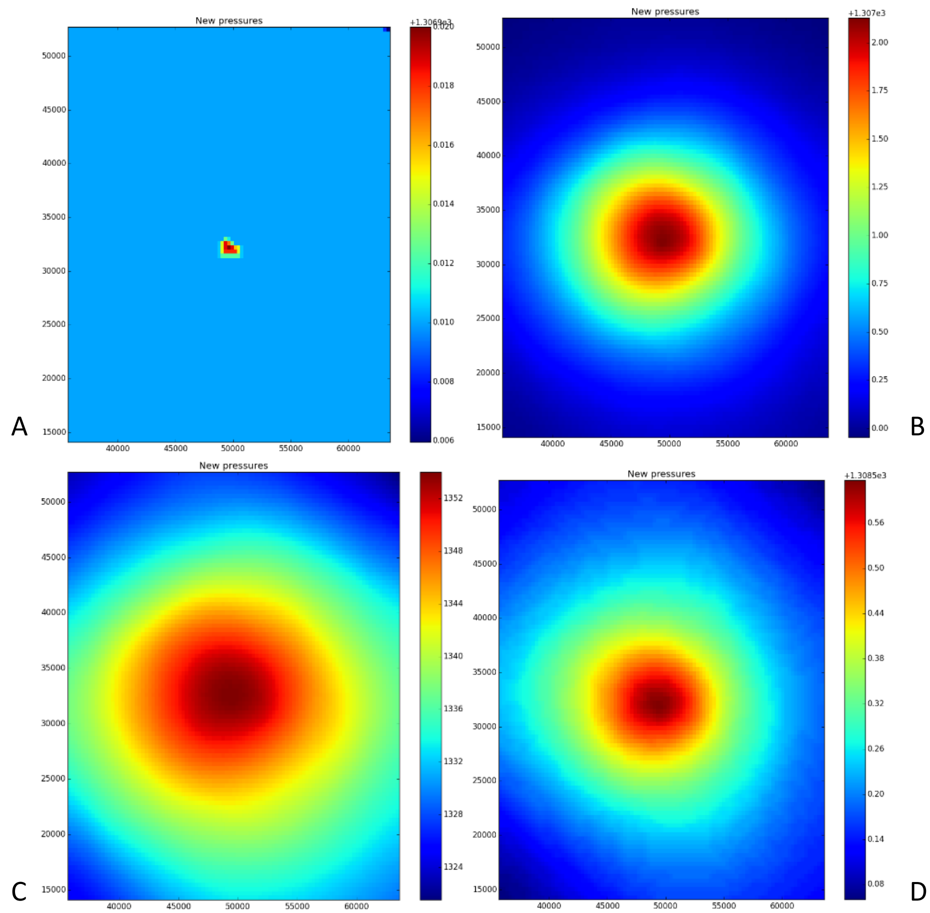

Figure 12: Pressure plume after (A) 31 days, (B) 1 year, (C) 30 years, and (D) 100 years. RROM-GEN is used to reduce the CMG-GEM model to 100×100 grid blocks. The Integrated Assessment Model (IAM) tool requires the reduced order model generated by RROM-GEN as input.

NRAP-IAM-CS

The NRAP Integrated Assessment Model (IAM) for Carbon Storage (CS) tool (Stauffer et al., 2016) accounts for key geological parameters to model long-term leakage behavior to the groundwater aquifer or atmosphere through legacy wellbores and caprock. The tool quantifies the uncertainty and probability of leakage using the Monte Carlo approach. The tool was used to model leakage from the Osage formation in the Patterson Field given the range of properties described in Tables 7–8.

Table 7: Osage formation properties

Storage zone $Min - Max$	Formation top (ft)	Elevation depth (ft)	Thickness (ft)	Porosity	Horizontal Permeability (md)
Osage	5,310	1,767–2,520	129.3–155.98	0.0229–0.3118	0.0876–184.3813

Table 8: Osage formation properties

Storage zone μ_x, σ_x	Porosity	Horizontal Permeability (md)
Osage	0.1124, 0.0645	18.4587, 29.535

The Patterson Field is assumed to be a rectangle having an area of 50 square miles (129.5 km^2) with a 3/1 aspect ratio and the injection well located in the middle of the reservoir. The legacy wells are cemented and their density in the Patterson area is ~2.5 to 3 wells/km^2. The cement permeability, chosen from a list of options available in the tool (FutureGen low rate wells distribution, based on Alberta wells, based on Gulf of Mexico wells, high rate FutureGen wells), is set to FutureGen low rate wells because Kansas wells are not overpressured and their flow rates are low. The groundwater aquifer and atmosphere properties are set to the tool's default and will be refined as more data become available. Tables 9–10 summarize the default properties of the groundwater aquifer and atmosphere. Figures 11–12 show the CO_2 and brine leakage, respectively, through all legacy wells to the groundwater aquifer, and Figure 13 shows CO_2 leakage to the atmosphere. Figure 14 shows the importance of the various factors that contribute to the leakage, indicating that legacy wellbores and their cement permeability pose the highest leakage risk among other factors, such as reservoir permeability, reservoir porosity, or caprock permeability.

Table 9: Shallow aquifer properties

Depth	100 m (below mean sea-level)
Pressure	1 MPA
Temperature	20.25 °C
Permeability	$1.148 \times 10^{-12}\ m^2$
Porosity	0.2

Table 10: Atmosphere properties

Wind speed at 10 m above land surface	1 m/s
Ambient temperature	20 °C
Ambient pressure	1 atm
Leaked gas temperature	20 °C
Threshold concentration	0.002
Number of checking points	7

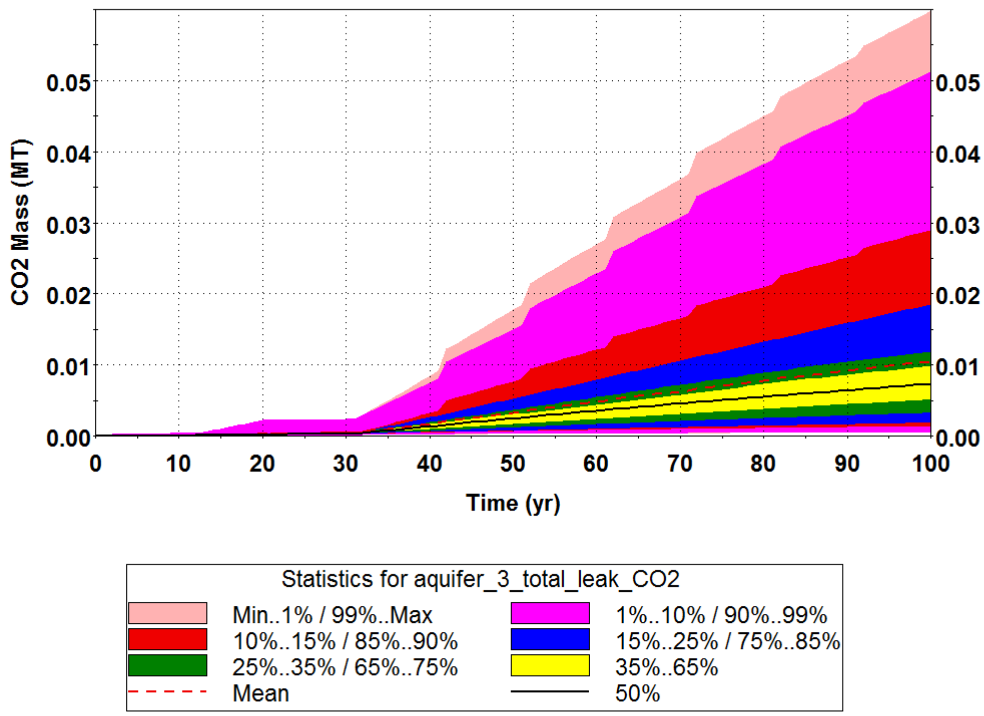

Figure 13: The probability of total CO_2 leakage to groundwater aquifers through legacy wellbores.

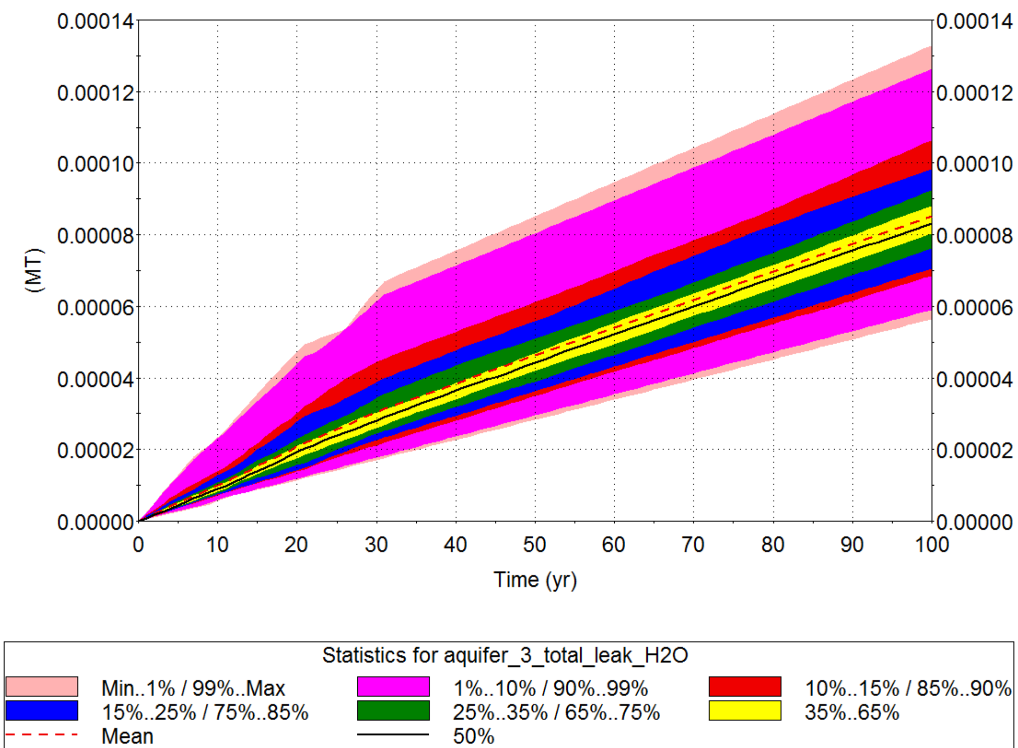

Figure 14: The probability of total brine leakage to groundwater aquifers through legacy wellbores.

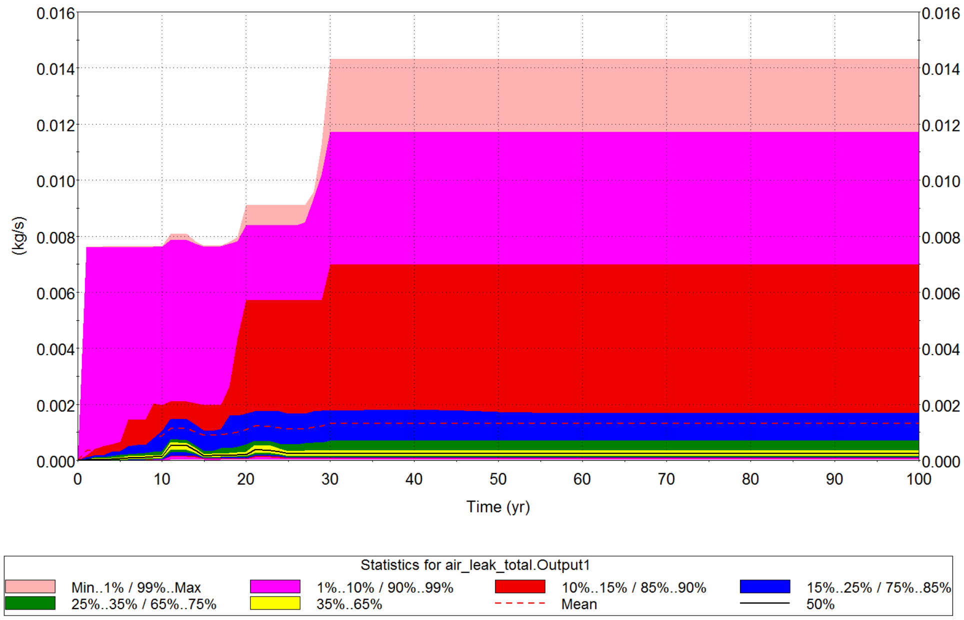

Figure 15: The probability of CO_2 leakage to the atmosphere (in kg/s) through legacy wellbores.

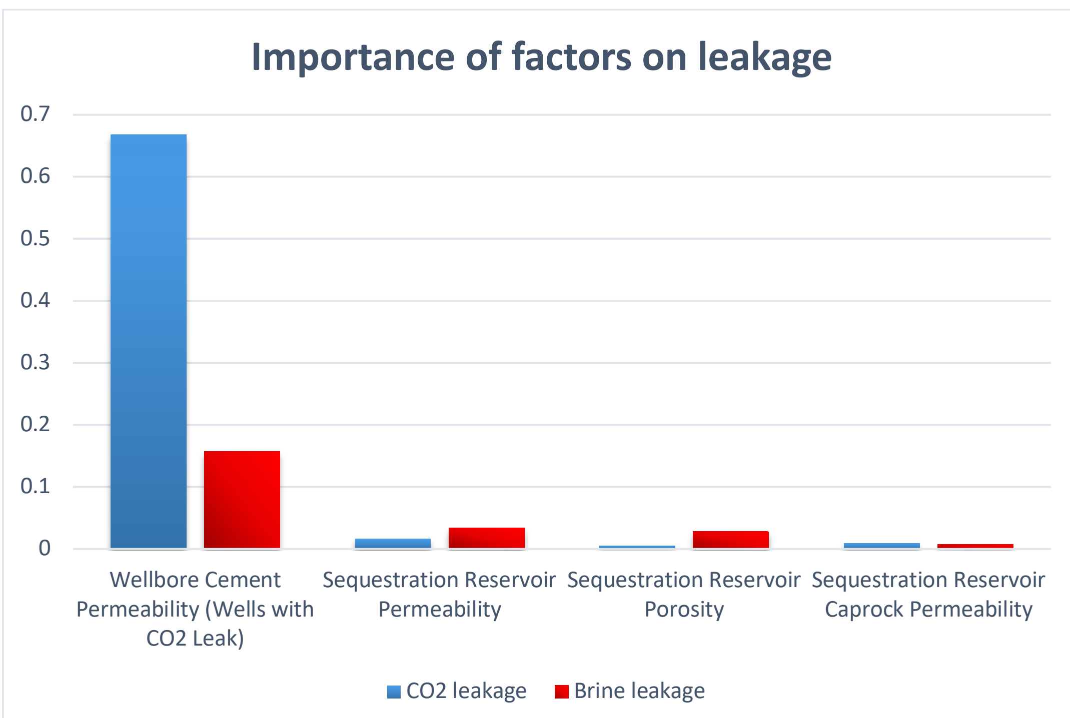

Figure 16: The importance of different factors on CO_2 and brine leakage. Legacy wellbores and their cement permeability pose the highest leakage risk.

WLAT (Well Leakage Analysis Tool)

The WLAT tool is useful for evaluating leakage through the injection well or legacy wells (Huerta and Vasylkivska, 2016). The tool has options for a thief zone and a shallow aquifer to calculate the leakage to each of these zones and to the atmosphere. The critical data for the tool are the wellbore diameter, cement permeability, thief zone, and shallow aquifer properties (i.e., permeability and depth). The tool also requires pressure and saturation at the leak point (i.e., wellbore) over time inferred from the numerical simulation in the format of separate time series. The well can be cemented, multi-segmented or open (in the case of legacy wells). An effective wellbore permeability (k_{eff}) of 1e-4 md, Osage depth of 5,310 ft, and pressure and saturation profile at the bottom of the CO_2 injector (Figure 17) and the tool's default properties for the shallow aquifer and atmosphere are used to calculate the leakage rates. NOTE: IAM-CS results are more reasonable for cemented wellbores. Currently the cemented wellbore model in WLAT is giving an error and an open wellbore model with very small permeability (1e-4 md) is used here.

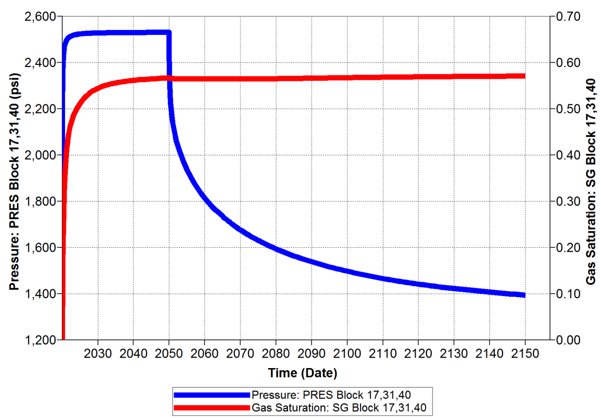

Figure 17: Pressure and saturation profile at the CO_2 injection well.

References

Goodman, A., Hakala, A., Bromhal, G., Deel, D., Rodosta, T., Frailey, S., … Guthrie, G., 2011, U.S. DOE methodology for the development of geologic storage potential for carbon dioxide at the national and regional scale: International Journal of Greenhouse Gas Control, v. 5, no. 4, p. 952–965. https://doi.org/10.1016/j.ijggc.2011.03.010

Goodman, A., Sanguinito, S., and Levine, J. S., 2016, Prospective CO_2 saline resource estimation methodology: Refinement of existing US-DOE-NETL methods based on data availability: International Journal of Greenhouse Gas Control, v. 54, p. 242–249. https://doi.org/10.1016/j.ijggc.2016.09.009

Huerta, N. J., and Vasylkivska, V. S., 2016, Well Leakage Analysis Tool (WLAT) User's Manual, (November).

King, S., 2016a, Reservoir Evaluation and Visualization (REV) Tool User's Manual, Version: 2016.

King, S., 2016b, Reservoir Reduced-Order Model – Generator (RROM-Gen) Tool User's Manual, Version: 2016.11-1.2, (November).

Krushin, J. T., 1997, Seal capacity of nonsmectite shale: Seals, Traps, and the Petroleum System, v. 67, p. 31–47. http://search.datapages.com/data/specpubs/mem67/ch03/ch03.htm

Lindner, E. N., 2016, NRAP Seal Barrier Reduced-Order Model (NSealR) Tool User's Manual, Version: 2016.11-14.1, (November).

Okwen, R. T., Stewart, M. T., and Cunningham, J. A., 2010, Analytical solution for estimating storage efficiency of geologic sequestration of CO_2: International Journal of Greenhouse Gas Control, v. 4, no. 1, p. 102–107. https://doi.org/10.1016/j.ijggc.2009.11.002

Stauffer, P., Chu, S., Tauxe, C., and Pawar, R., 2016, NRAP Integrated Assessment Model- Carbon Storage (NRAP-IAM-CS) Tool User's Manual, Version: 2016.