Commercial Scale CO_2 Injection and Optimization of Storage Capacity in the Southeastern United States

Project Number: DE-FE0010554

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Advanced Resources International, Inc.

2:10pm, Wednesday, August 17, 2016

U.S. Department of Energy
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Mastering the Subsurface Through Technology Innovation and Collaboration:
Carbon Storage and Oil and Natural Gas Technologies Review Meeting
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Presentation Outline

- Benefit to the Program
- Project Overview
- Technical Status
- Accomplishments to Date
- Summary
- Appendix
  - Organization Chart
  - Gantt Chart
  - Bibliography

Benefits Statement

The project will model **commercial-scale CO_2 storage capacity** optimization strategies to effectively manage the CO_2 plume and pressure field **within stacked reservoir systems**. These strategies will utilize geologic and performance data collected from SECARB's Anthropogenic Test Site, and will be high-graded based on cost and storage efficiency, considering reservoir geomechanics (pressure field) and laboratory-derived cap rock data.

Major Advances:

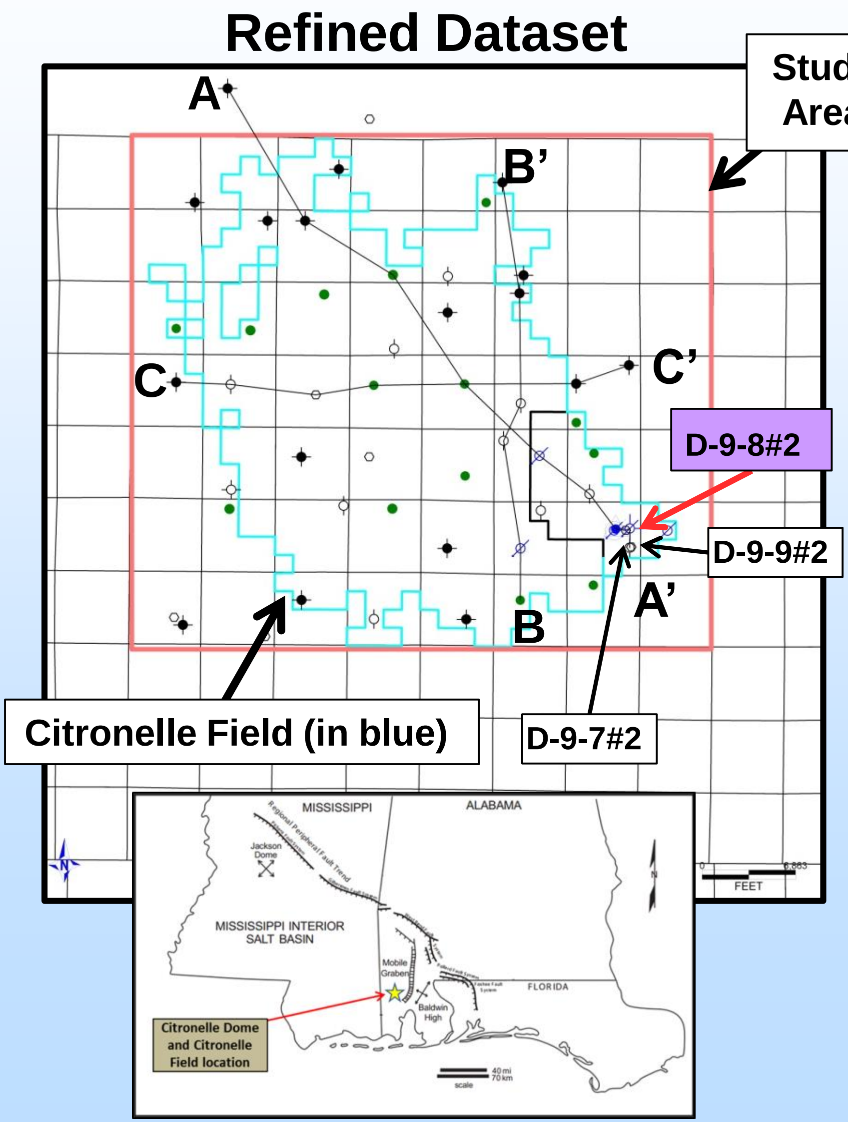
- Estimating commercial scale storage efficiency factors (*Support industry's ability to predict CO_2 storage capacity in geologic formations to within ±30 percent*)
- Detailed confining unit core characterization
- Generation of reduced order models
- Stacked Reservoir System Best Practices Manual

Project Objectives

- Optimize capacity and ensure storage containment in stacked Gulf Coast saline and oil bearing reservoirs
- Leverage modern and historical geologic characterization and injection performance data to develop detailed geologic models
- Overlay economic and risk management scenarios for each simulation case to determine the overall feasibility of commercial scale storage.
- Conduct detailed cap rock core analysis testing
- Develop new storage efficiency factors based on these project results
- Develop reduced order models to approximate the ‘super computer’ results
- Summarize the results in a Best Practices Manual

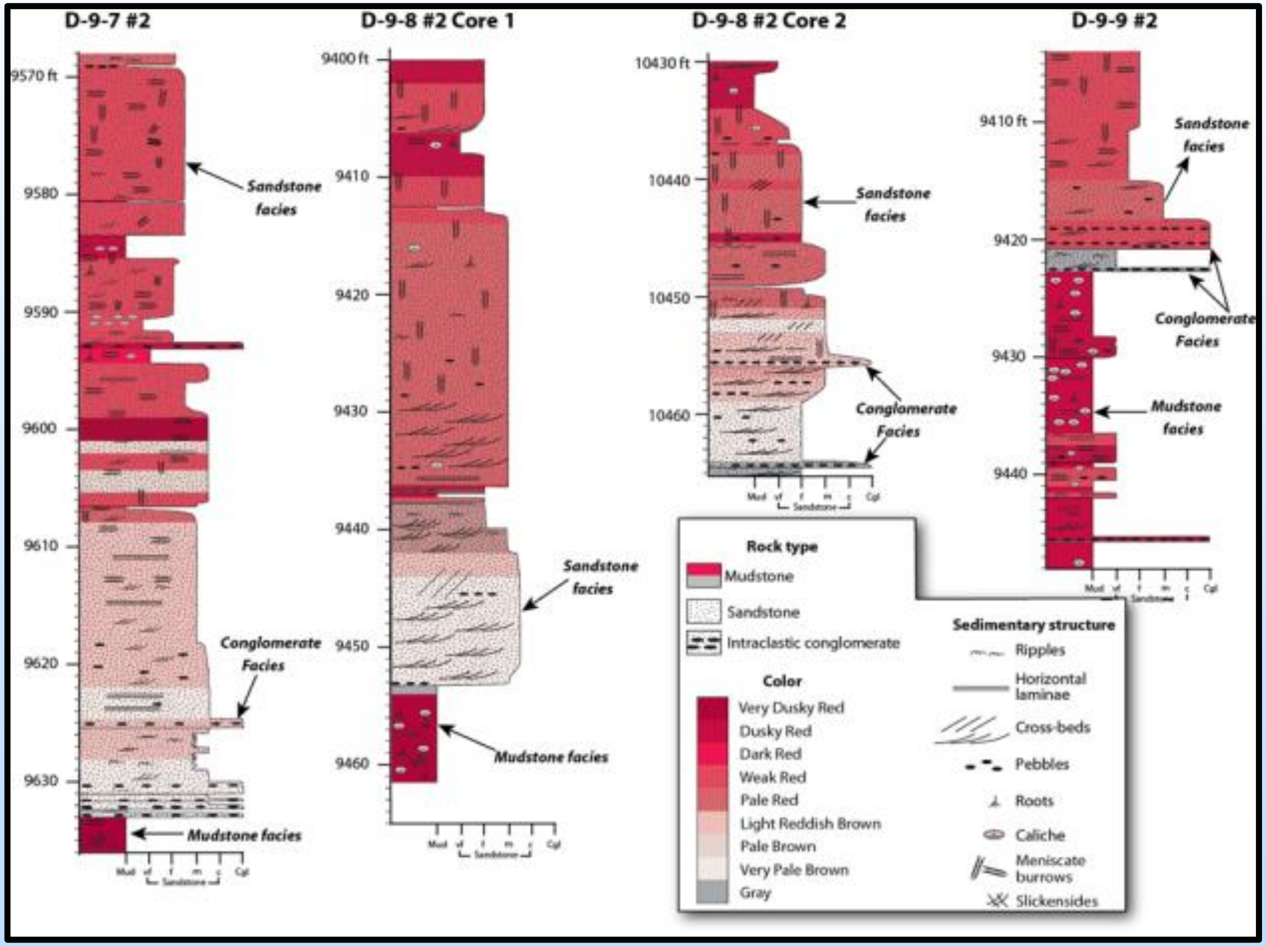
Project Status: Study Area & Well Data Set

- The Citronelle Field is a 56 sq. mile study area with 400+ wells on 40-ac spacing
- Geologic model characterizes injection zones and confining units from surface though the Donovan sandstones at depths >12,000 ft.
- D 9-8 #2 well in Citronelle Southeast Unit selected as Type Log for geologic correlations of injection zones & confining units.
- Multiple cross-sections constructed for geologic correlation of model layers.
- Digitized the SP & resistivity curves for 36 well logs. These data input to neural net software to estimate porosity.

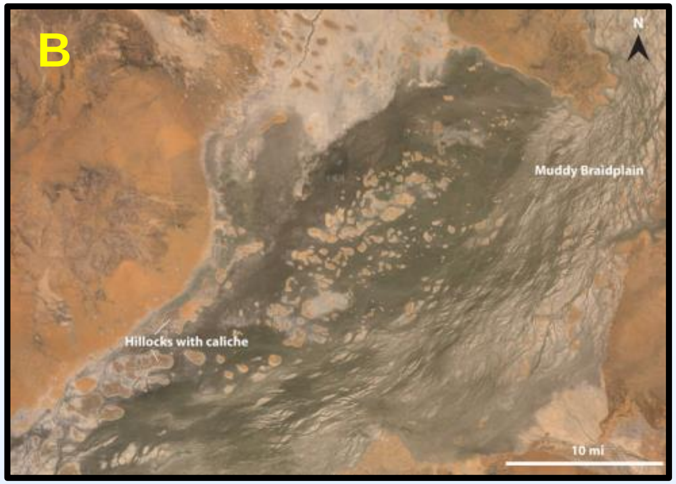


Depositional Systems Analysis

- Core and well logs were analyzed to assess depositional environment of the field area



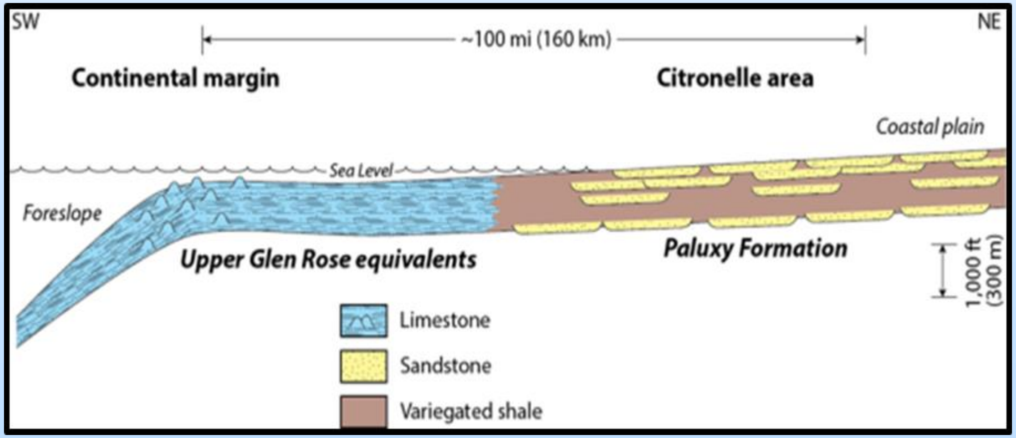
Depositional Systems Analysis



Modern Day Analogues

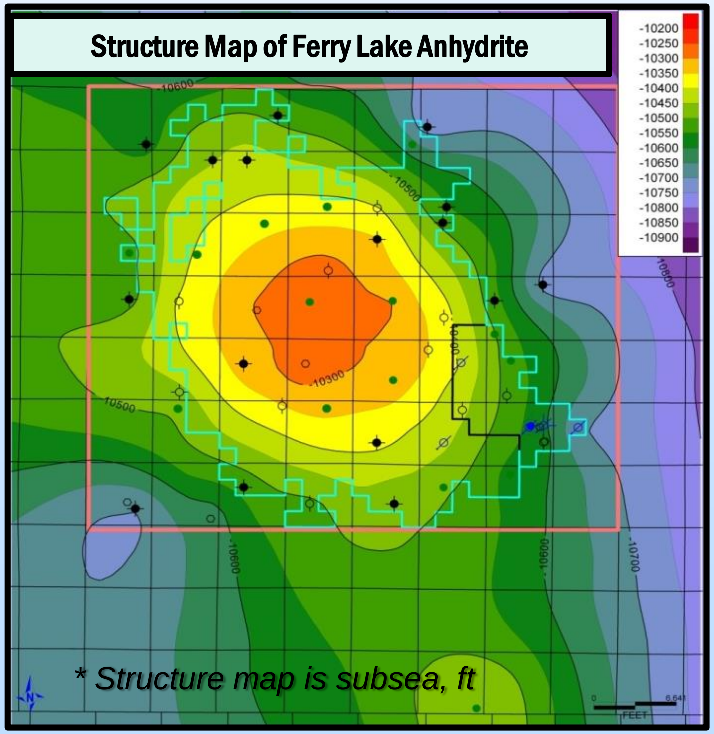
A: South Saskatchewan River, Canada
B: Cooper's Creek, Lake Eyre Basin, Central Australia
C: Ganges River, India

- Data interpreted from logs and core were applied to infer modern day depositional analogues
- These data were used to create a depositional model of the Citronelle Study area



Project Status: Building the Geologic Model

- Potential storage and confining layers were identified and correlated laterally
- Structural closure is present at all horizons from surface through the Donovan (Rodessa) sandstone



Stratigraphic Column

System	Series	Stratigraphic Unit	Major Sub Units	Potential Reservoirs and Confining Zones
Tertiary	Plio-Pliocene		Citronelle Formation	Freshwater Aquifer
	Miocene	Undifferentiated		Freshwater Aquifer
	Oligocene		Chicasawhay Fm.	Base of USDW
		Vicksburg Group	Bucatunna Clay	Local Confining Unit
	Eocene	Jackson Group		Minor Saline Reservoir
		Claiborne Group	Talahatta Fm.	Saline Reservoir
		Wilcox Group	Hatchetigbee Sand	Saline Reservoir
	Paleocene		Bashi Marl	
			Salt Mountain LS	
		Midway Group	Porters Creek Clay	Confining Unit
Cretaceous	Upper	Selma Group		Confining Unit
		Eutaw Formation		Minor Saline Reservoir
		Tuscaloosa Group	Upper Tusc.	Minor Saline Reservoir
			Mid. Tusc — Marine Shale	Confining Unit
			Lower Tusc. — Pilot Sand, Massive sand	Saline Reservoir
Cretaceous	Lower	Washita-Fredericksburg	Dantzler sand	Saline Reservoir
			Basal Shale	Primary Confining Unit
		Paluxy Formation	'Upper' 'Middle' 'Lower'	Proposed Injection Zone
		Mooringsport Formation		Confining Unit
		Ferry Lake Anhydrite		Confining Unit
		Donovan Sand	Rodessa Fm. 'Upper'	Oil Reservoir
			'Middle'	Minor Saline Reservoir
			'Lower'	Oil Reservoir

Assessed Zone

Logged Interval

Porosity and Permeability Extrapolated for each Model Layer

- **Tertiary/ Quaternary** Model Layers (Midway-Surface):
  - Predicted porosity from neural net not successful due poor log data quality/ missing data.
  - A single porosity and permeability value applied for each model layer over the entire study area.
- **Cretaceous** Model Layers (Donovan to Selma):
  - Good prediction of porosity from neural net correlation.
  - Apply geostatistics to interpolate predicted porosity.
  - Apply porosity-permeability transforms from core data to extrapolate reservoir permeability from predicted porosity.

Formation	# Model Layers	Perm
Alluvium	1	500,000 mD
Citronelle	1	17,500 mD
Miocene	1	34,600 mD
Chickasawhay	1	1,100 mD
Vicksburg	1	0.032 mD
Jackson	1	0.032 mD
Claiborne	3	0.032 to 386 mD
Wilcox	5	3.09E-5 to 660 mD
Midway	5	3.24E-6 to 1,680 mD
Selma	20	$K = 0.0033(e^{(0.1735*\phi)})$
Eutaw	20	$\text{Log } k = (0.13*\phi)-1.56$
Upper Tuscaloosa	50	$\text{Log } k = (0.18*\phi)-2.92$
Tuscaloosa Marine Shale	10	$k = (6E-19)*(\phi^{12.52})$
Lower Tuscaloosa	30	$k = (2E-14)*(\phi^{12.176})$
Washita	60	$k = (1E-9)*(\phi^{8.257})$
Fredericksburg	60	$k = (1E-9)*(\phi^{8.257})$
KWF Confining	5	1.21E-4 mD
Upper Paluxy	60	$k = (4E-10)*(\phi^{9.0365})$
Lower Paluxy	20	$K = 0.0004(e^{(0.6242*\phi)})$
Mooringsport	5	$K = 0.0033(e^{(0.1735*\phi)})$
Ferry Lake Anhydrite	1	5.5E-05 mD

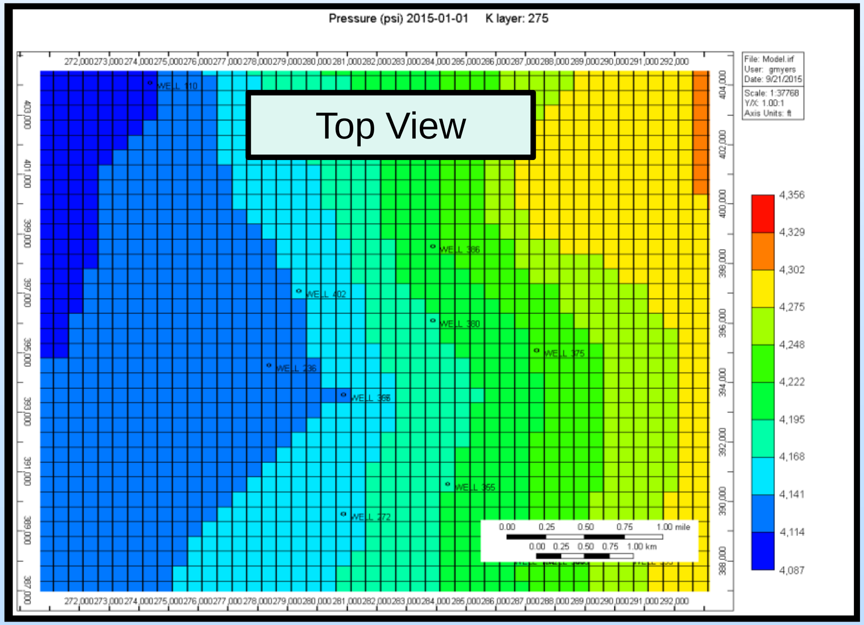
Model Parameters

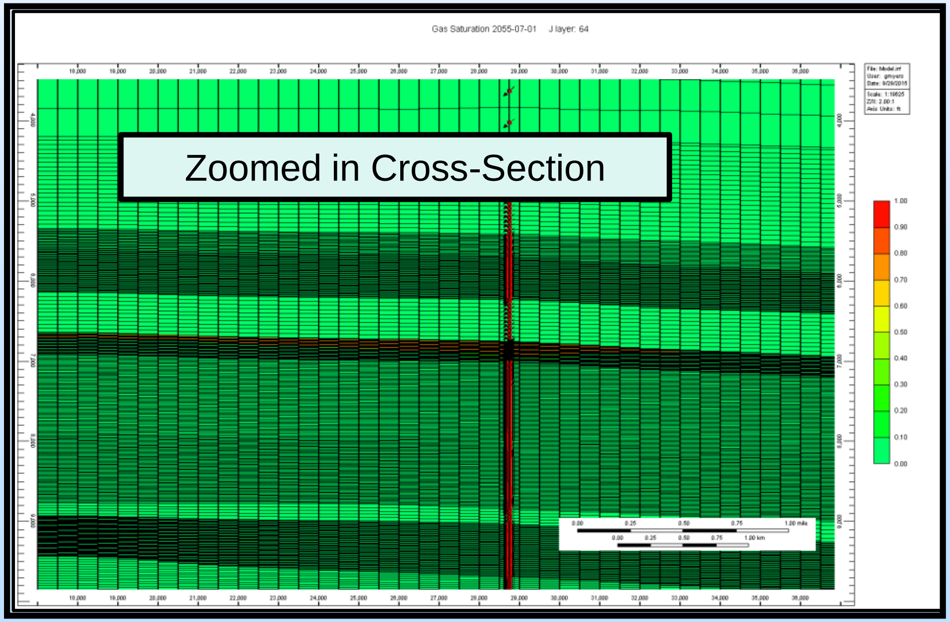
Model area consists of a volume of 1.9E+13 ft^3

- *(56 square miles x 12,000 vertical feet)*

The model is comprised of a total of 4.8 million cells:

- 120 Cells in the X direction, 100 Cells in the Y direction, and - 400 Cells in the Z direction
- all grid blocks are 500 feet by 500 feet





Model Execution Run Time

- The initial run time of the large-scale model was 120 to 240 hours
- Optimization of the model reduced the run time to 30 hours
  - Adjusted *GEM* multiprocessor/threading allowing the model to run on multiple cores
  - Reduction of the maximum delta saturation resulted in a lower number of repeat time steps
- Obtained a license for *GEM* allowing access to a larger number of cores
  - Current run times are now between 4 and 12 hours
- Potential exists for further improvement
  - Optimize delta saturation and adjustment of time steps

Model Scenarios

The model has been executed and run on several layers:

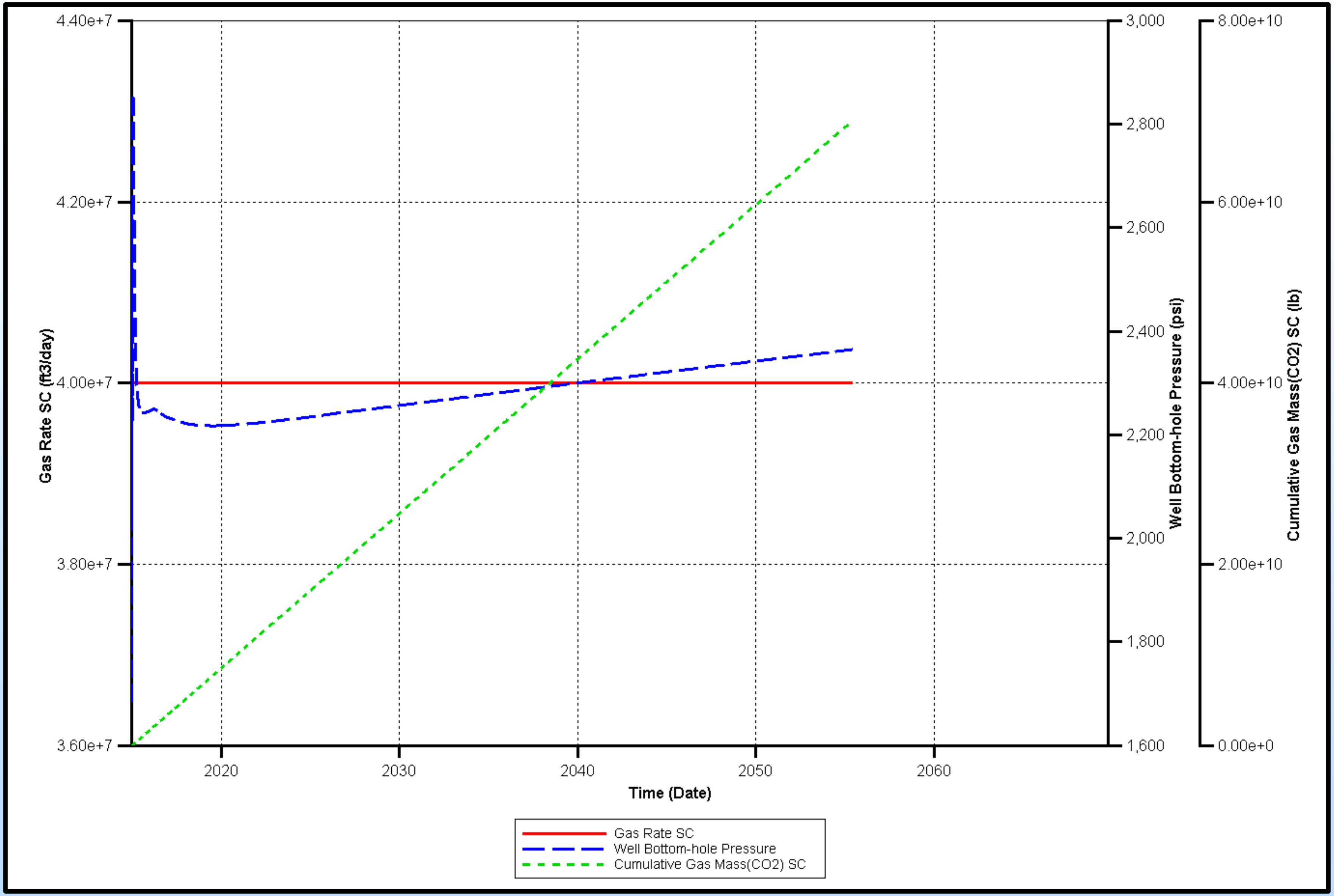
- Baseline: Injection, independently into one of the five target saline storage
- Injection of 40 MMscf/d CO_2 into the Formation over a period of 40 years

Formation	CO_2 Injection Volume *†, ft^3	Farthest Movement of CO_2 Plume*, ft	Layer No.	Model Output Downloaded
Upper Paluxy	5.84×10^{11}	4,910	275	7/25/16
Fredericksburg	5.14×10^{11}	4,140	254	5/17/16
Washita	5.84×10^{11}	5,510	156	5/17/16
Lower Tuscaloosa	5.84×10^{11}	13,530	125	5/17/16
Wilcox	9.28×10^{9}	4,010	9	5/17/16

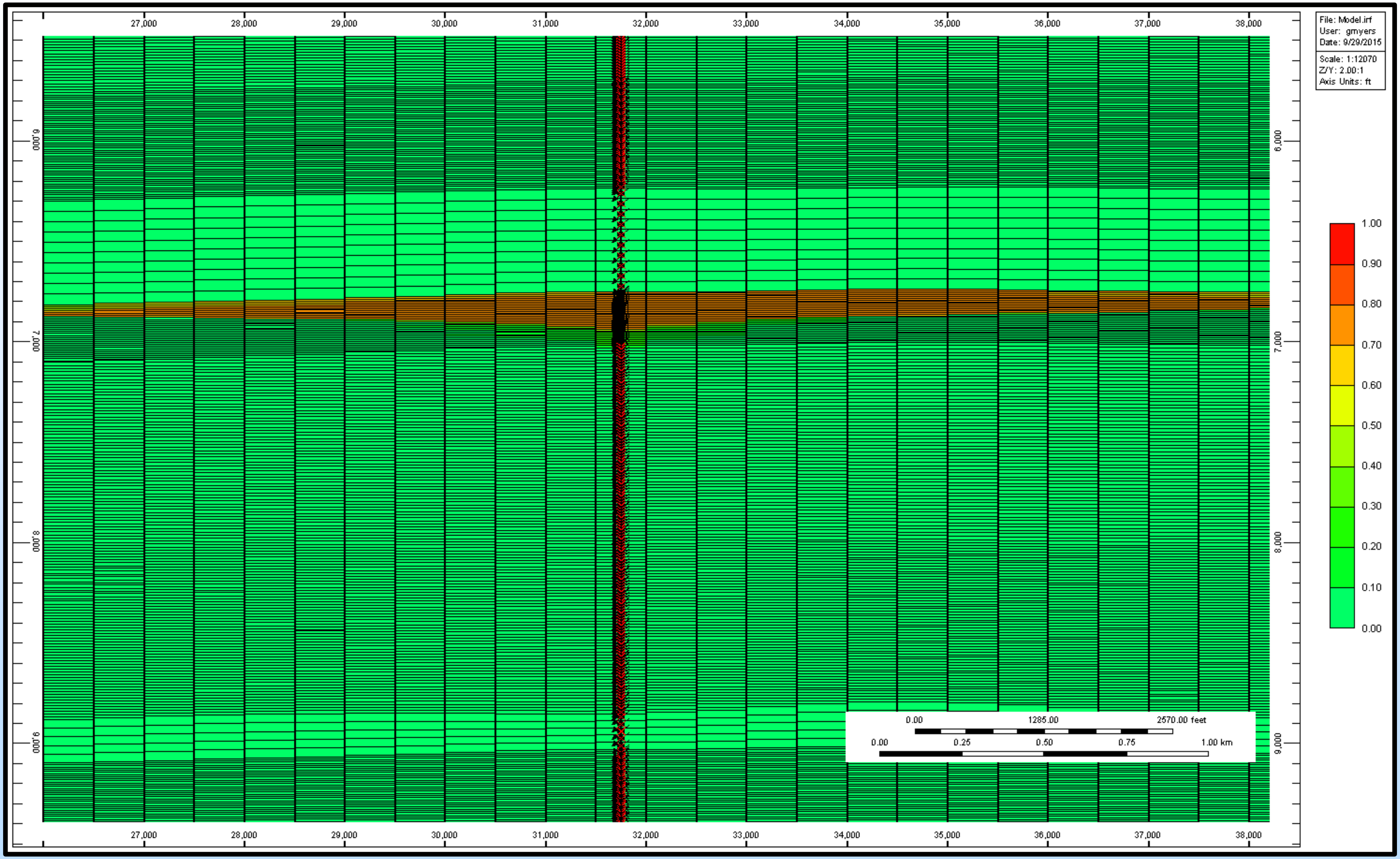
* After 40 years of CO_2 injection.
† At surface conditions.

Note: 5.84×10^{11} ft^3 = 30.9 megatonnes

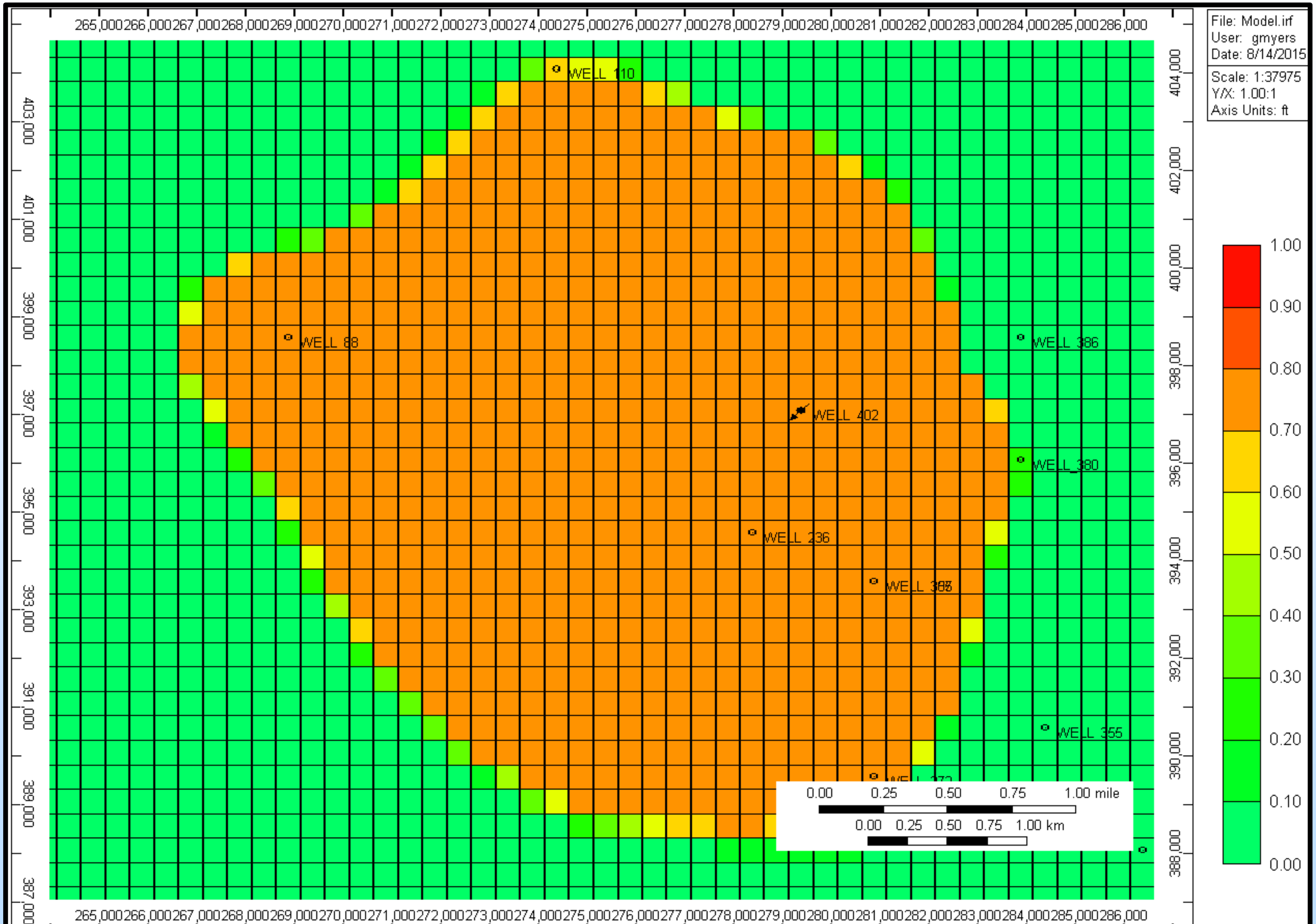
Well 402 Model Multi-Plot



Lower Tuscaloosa Gas Saturation (cont'd.)



Lower Tuscaloosa Gas Saturation



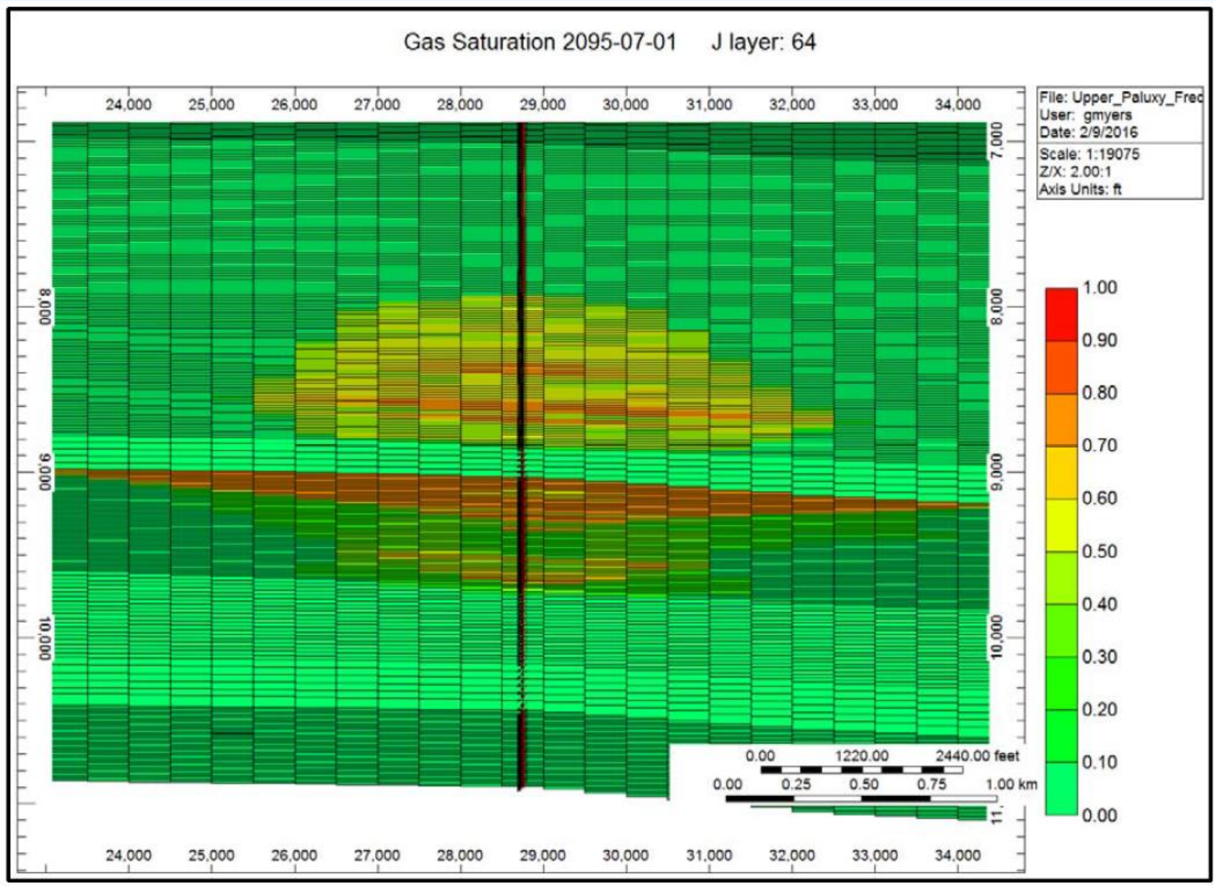
Model Run Details

A number of injection scenarios are under review to ascertain their impact on the geologic continuum in terms of the interrelated injectivity, storage capacity and efficiency as well as geomechanical effects.

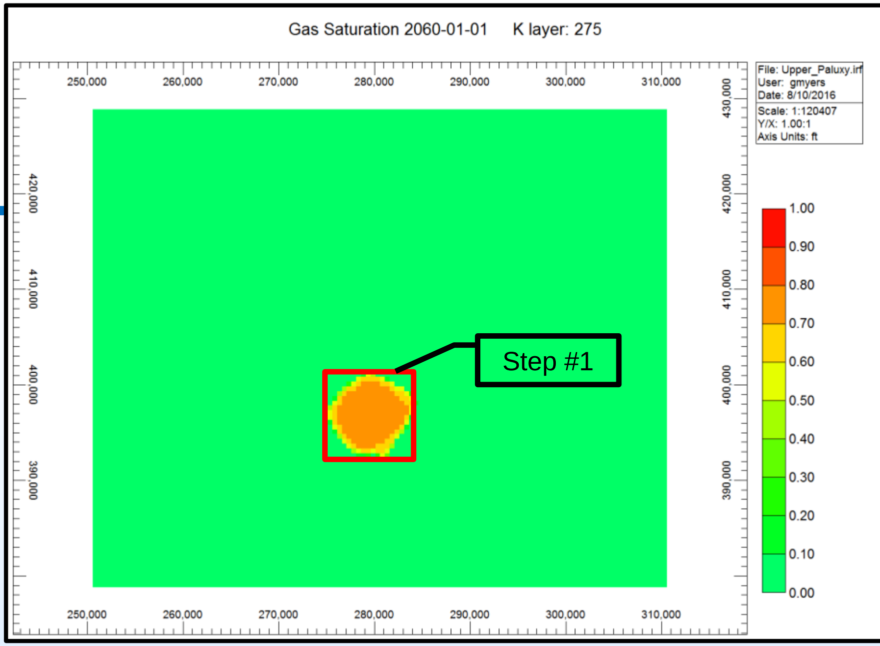
1. **Initial standalone injection cases into each sand body:**
   - **Inject into Paluxy Sandstone to establish a baseline storage factor**
   - **Subsequent injection into all other amenable saline reservoirs**
   - **6 or 7 runs**
2. **Injection into two reservoirs:**
   - **Injection into the Paluxy Sandstone along with each amenable reservoir in the suite**
   - **5 or 6 runs**
3. **Injection into three reservoirs:**
   - **Injection into the Paluxy Sandstone and the two highest capacity reservoirs determined from the initial runs conducted in step one**
   - **3 or 4 runs**
4. **Comparison of heterogeneity cases**
   - **Comparisons will be made among the base case Paluxy model runs with the low and high heterogeneity cases to compare and contrast injection scenarios**

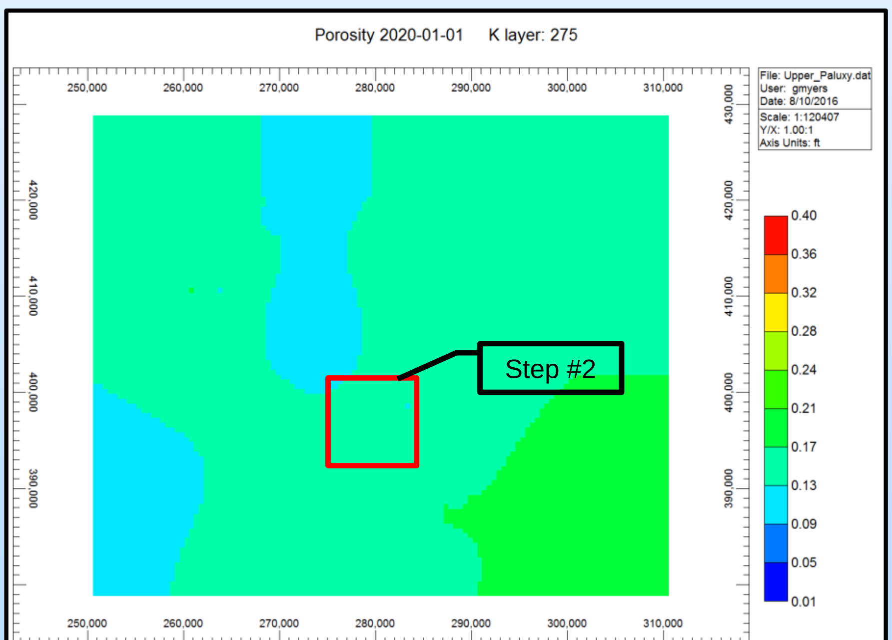
Multiple Layer CO_2 Injection Example

Cross section showing the distribution of gas saturations in the Paluxy and Fredericksburg formations after 40 yrs. of injection into the Paluxy, followed by 40 yrs. of injection into the Fredericksburg at the rate of 40 MMscfd.



Assessment of Storage Efficiency Factors





Total Pore Volume:

1. Establish rectilinear boundary around the maximum CO_2 plume for all layers.
2. Apply the same rectilinear boundary to the Porosity map for each layer.
3. Using the Porosity map and linear interpolation of layer thickness, determine the total volume and total void volume for each layer.
4. Calculate the total volume and total void volume for the entire rectilinear volume.

Total Gas Storage:

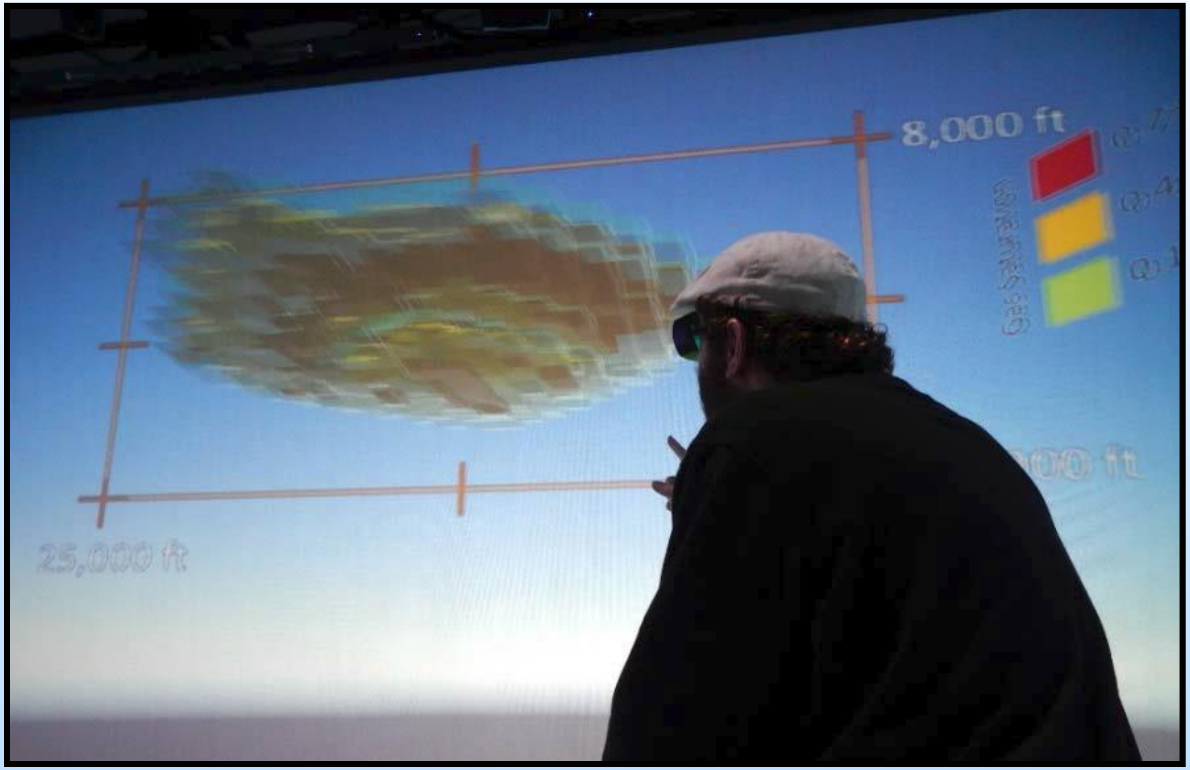
5. Calculate the total gas volume injected into the rectilinear volume.

Gas Storage Efficiency:

6. Using the total injected gas volume and the total void volume, calculate the storage efficiency for the entire rectilinear volume.

Milestone 5

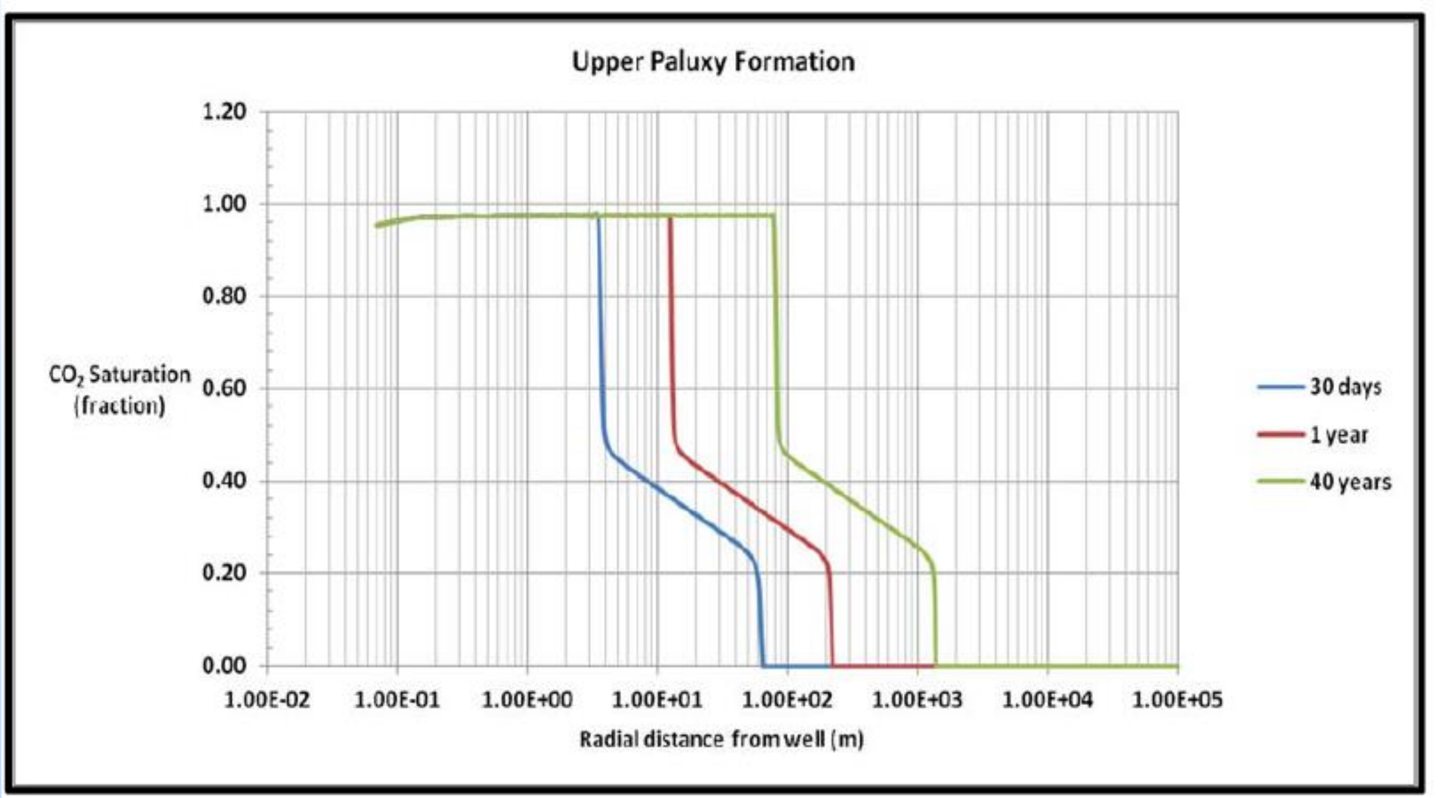
- UAB has successfully uploaded the model into their Four-Wall Virtual Reality Viewing Room



Shows the Spatial Distribution of CO_2 Saturation in the Upper Paluxy Formation after 40 yrs. injection

TOUGH2 Modeling

Results from model calculations using UAB's upscaled geologic model are being compared with simulations performed using the TOUGH2 and TOUGHREACT simulators from Lawrence Berkeley National Laboratory.



Fate and Transport Modeling

Despite *TOUGH2* being one-dimensional in its current form:

- After 40 years of injection, **the "dried out" region extends to a distance of 240 ft from the well**. Several percent of the pore space is now occupied by salts precipitated from the brine.
- Distribution of CO_2 saturation over a vertical cross section of the plume using the upscaled geologic model in ***GEM* reaches 4,750 ft, compared with the distance of 4,570 ft** from the *TOUGH2* simulation is only a difference of only 4%.
- An average CO_2 saturation was estimated for grid blocks adjacent to the injection well. Those grid blocks cover distances from 250 to 750 ft from the well. The average CO_2 saturation in those grid blocks, **from *GEM*, is 55%**. In the radial distance interval from 80 to 225 m from the injector, the ***TOUGH2* simulation produced an average CO_2 saturation of 54.5%.**
- Toward the leading edge of the CO_2 plume, at a distance of 4,200 ft from the injector, the average CO_2 saturation in the grid blocks centered at that distance, **is 25%, compared with 23% from the *TOUGH2*** simulation.

Reduced Order Model

(uploaded to EDX)

- A standalone Reduced Order Model (ROM) was developed to estimate storage capacity and area of review for a multi-layer injection project.
- The ROM was established using data driven modeling and neural networks to yield capacity and AoR assessments from a suite of reservoir properties.

Properties	Minimum	Maximum	Unit
Depth (Top Layer)	2400	10000	feet
Reservoir Thickness	20	100	feet
Porosity	5	25	%
Horiz. Permeability	10	1000	mD
Vert. Permeability	50% of Kh	100% of Kh	mD
Formation Compressibility (Cp)	0.000001	0.000008	psi^{-1}
Confining Unit Thickness	100	1000	feet
Confining Unit Porosity	5	5	%
Confining Unit Horiz. Perm.	1E-05	0.001	mD
Confining Unit Vert. Perm.	10% of Kh		mD
Confining Unit Compressibility (Cp)	5E-05	1E-04	psi^{-1}
Max Injection Rate In Quarter Well	0.5	10	MMcfd
Max Injection Pressure	Base on PGrad of 0.55 psi/ft		
Injection Length	5	30	years

Accomplishments to Date

- Completed geologic model.
- Successful implementation of the Neural Network approach to predict porosity
- Generated low, base and high heterogeneity input models.
- Completed simulation models, handed over to UAB for testing, debugging and execution.
- Time running 4.8 million grid cell model has been reduced from 230 hours to ±10 hours (40 years injection).
- Laboratory measurements/estimates of:
  - effective permeability,
  - minimum capillary displacement pressure, and
  - leakage impact.
- OSU has completed petrographic and x-ray diffraction analysis of Paluxy core.
- An M.S. thesis was written on the Paluxy Sand, titled, “Geologic Characterization of a Saline Reservoir for Carbon Sequestration: The Paluxy Formation, Citronelle Dome, Gulf of Mexico Basin, Alabama”.
- A Reduced Order Model has been developed for multi-layer injection.

Key Findings/Lessons Learned

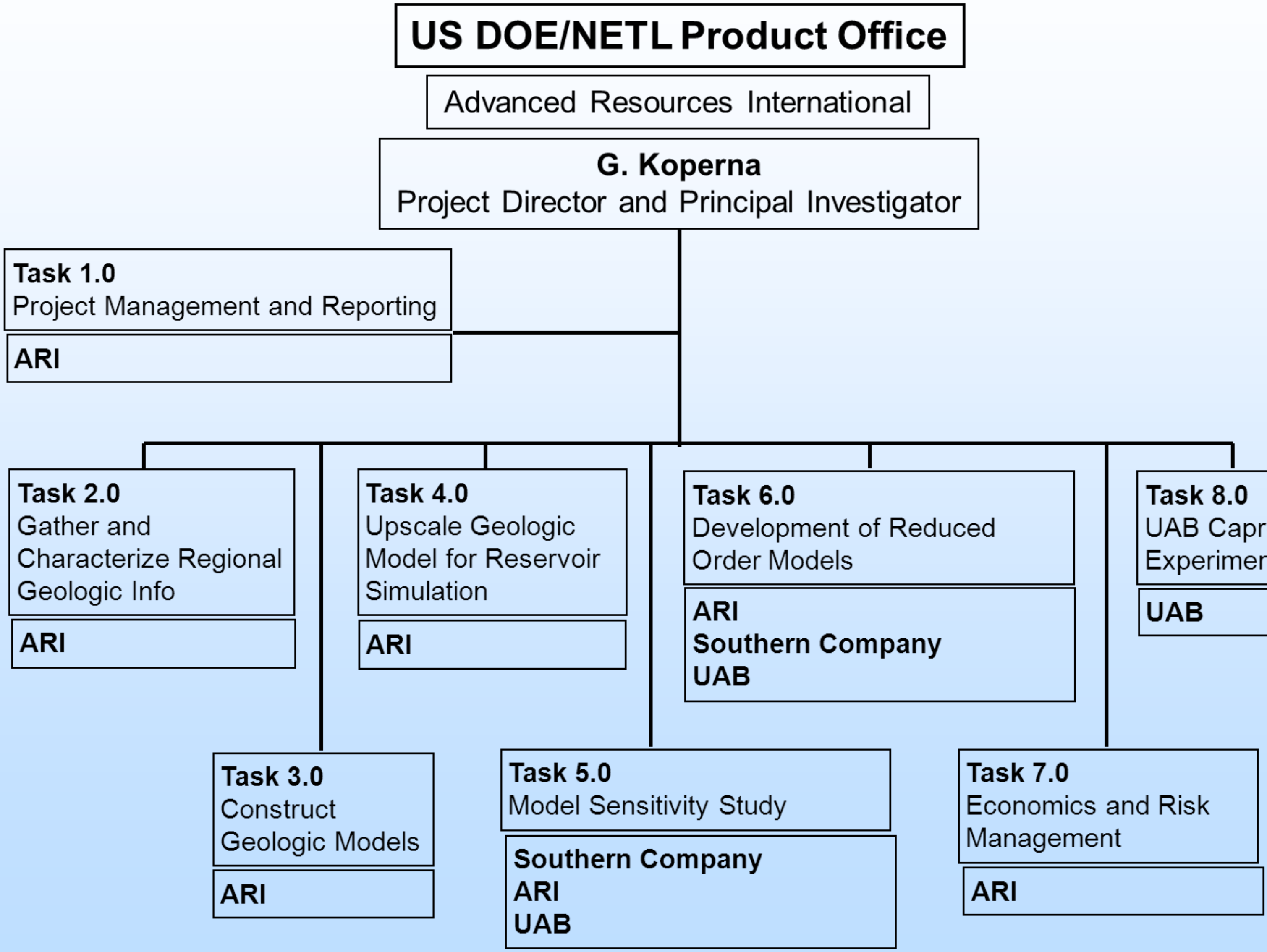
- The Project Team is able to successfully characterize a subsurface volume of 1.9E+13 ft^3 for reservoir simulation *(56 square miles x 12,000 vertical feet),* by combining legacy geophysical log data with modern log data, core data, and state of the art interpretive tools like neural net and geostatistics software.
- Neural network tools were extremely effective in "modernizing" the vintage geophysical well logs to ascertain spatial variations in porosity and, by proxy, permeability.
- Effective permeablities through brine-filled confining units appear to be on the order of $1/30^{th}$ of the absolute permeability*.
- CO_2 containment through significantly thick and low permeability confining units appears to be >99%, based on Paluxy data*.

*based on UAB laboratory work reported in earlier status presentations.

Future Plans

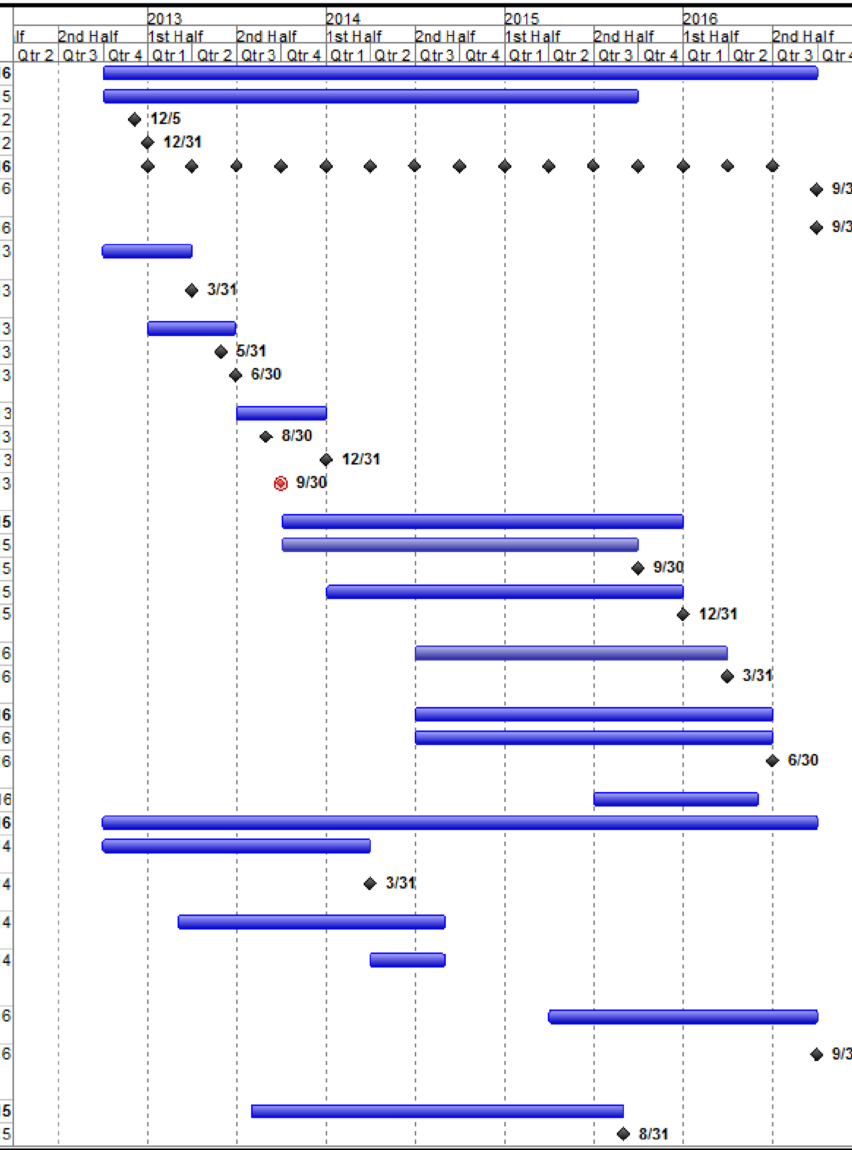
- **Sensitivity Study**: Will explore sensitivities such as well design and lateral heterogeneity to maximize storage capacity while minimizing the operation's footprint.
- **Optimization**: Will incorporate economic and risk management considerations which will be overlain on the modeling results to ascertain their financial impact.
- **Cap Rock Analysis**: Caprock analysis will provide regional seal characteristic data to be used in numerical modeling.
- **New Storage Efficiency Factors**: Will develop new commercial storage efficiency factors.
- **Best Practices Manual**: Will produce a Best Practices Manual for optimized commercial-scale storage.

Appendix: Organization Chart



Appendix: Gantt Chart

Task Name	Start	Finish
Task 1: Project Management	**Tue 10/2/12**	**Fri 9/30/16**
Subtask 1.1 – Project Management Plan	Tue 10/2/12	Wed 9/30/15
Deliverable 1.1 – Report, Project management plan	Wed 12/5/12	Wed 12/5/12
Deliverable 1.2 – Kickoff Meeting	Mon 12/31/12	Mon 12/31/12
Deliverable 1.3 – Report, Quarterly progress reports	**Tue 1/1/13**	**Fri 9/30/16**
Deliverable 1.4 – Best Practices Manual for CO2 storage in the U.S. Eastern Gulf Coast	Fri 9/30/16	Fri 9/30/16
Deliverable 1.5 – Final project reports	Fri 9/30/16	Fri 9/30/16
Task 2: Gather and Characterize Regional Geologic Information	Mon 10/1/12	Sun 3/31/13
Deliverable 2.1 – Report, Using neural network algorithms to modernize vintage well logs	Sun 3/31/13	Sun 3/31/13
Task 3: Construct Geologic Models	Tue 1/1/13	Fri 6/28/13
Deliverable 3.1 – Meeting, Geologic data review and critique	Fri 5/31/13	Fri 5/31/13
Deliverable 3.2 – Report, Geostatistical analysis of southeastern sediments	Sun 6/30/13	Sun 6/30/13
Task 4: Upscale Geologic Model for Reservoir Simulation	Mon 7/1/13	Tue 12/31/13
Deliverable 4.1 – Meeting, Modeling data review and critique	Fri 8/30/13	Fri 8/30/13
Deliverable 4.2 – Report, Upscaling comparison to geologic data	Tue 12/31/13	Tue 12/31/13
Decision Point – Demonstration of capability to effectively model geology and subsurface CO2 flow	Mon 9/30/13	Mon 9/30/13
Task 5: Model Sensitivity Study	**Wed 10/2/13**	**Thu 12/31/15**
Subtask 5.1 – Injection Scenario Simulations	Wed 10/2/13	Wed 9/30/15
Deliverable 5.1 – Meeting, Modeling data review and critique	Wed 9/30/15	Wed 9/30/15
Subtask 5.2 – Visualization of Simulation Results	Thu 1/2/14	Thu 12/31/15
Deliverable 5.2 – Report, Modeling results and storage efficiency factors	Thu 12/31/15	Thu 12/31/15
Task 6: Development of Scoping/Screening Level Models	Tue 7/1/14	Thu 3/31/16
Deliverable 6.1 – Report, Reduced order model and code module	Thu 3/31/16	Thu 3/31/16
Task: 7: Economics and Risk Management	**Wed 7/2/14**	**Thu 6/30/16**
Subtask 7.1 – Economic Assessment	Wed 7/2/14	Thu 6/30/16
Deliverable 7.1 – Report, Economic and risk management modeling results	Mon 8/31/15	Thu 6/30/16
Subtask 7.2 – Risk Assessment	Thu 7/2/15	Tue 5/31/16
Task 8: UAB Task - Ensuring Containment	**Mon 10/1/12**	**Fri 9/30/16**
Subtask 8.1 Measurement of Minimum Capillary Displacement Pressures	Mon 10/1/12	Mon 3/31/14
Deliverable 8.1 – Measurements of permeability and capillary displacement pressure of cap rock samples	Mon 3/31/14	Mon 3/31/14
Subtask 8.2 Simulation and Visualization of CO2 Seepage in the absence of Chemical Reactions	Mon 3/4/13	Sat 8/30/14
Deliverable 8.2 - Dynamic visualization of CO2 seepage based on simulations of CO2 behavior in cap rocks, in the absence of chemical reactions	Mon 3/31/14	Sat 8/30/14
Subtask 8.3 Evolution of Cap Rock Properties in the Presence of Carbon Dioxide	Thu 4/2/15	Fri 9/30/16
Deliverable 8.3 - Measurements and modeling of changes in cap rock properties and CO2 injection, migration, and trapping in the presence of chemical reactions, including cumulative CO2 loss	Fri 9/30/16	Fri 9/30/16
Task 9: Depositional Systems Analysis	**Thu 8/1/13**	**Mon 8/31/15**
Depositional System Analysis	Mon 8/31/15	Mon 8/31/15



Appendix: Bibliography

- *Geologic Characterization for the U.S. SECARB Anthropogenic Test; Combining Modern and Vintage Well Data to Predict Reservoir Properties,* Shawna R. Cyphers, Hunter Jonsson, and George J. Koperna, Jr., poster presentation, American Association of Petroleum Geologists, Annual Convention & Exhibition, Pittsburgh, PA, May 19-22, 2013.

- *Constructing a Geologic Model to Simulate Commercial Scale CO_2 Injection and Optimization of Storage Capacity in the Southeastern United States*, Hunter Jonsson, Shawna Cyphers, George Koperna, Robin Petrusak, presentation abstract accepted for Carbon Management Technology Conference, CMTC 2013, Alexandria, Virginia, October 21 – 23, 2013

- *Constructing a Geologic Model to Simulate and Optimize the Commercial Scale Injection and Storage of CO_2 at Citronelle Field, Mobile County, Alabama*, J. MacGregor, R. Petrusak, S.R. Cyphers, H. Jonsson, A. Oudinot, and G.J. Koperna, poster presentation, 2014 AAPG Annual Convention & Exhibition, Houston, Texas, April 6- 9 2014.

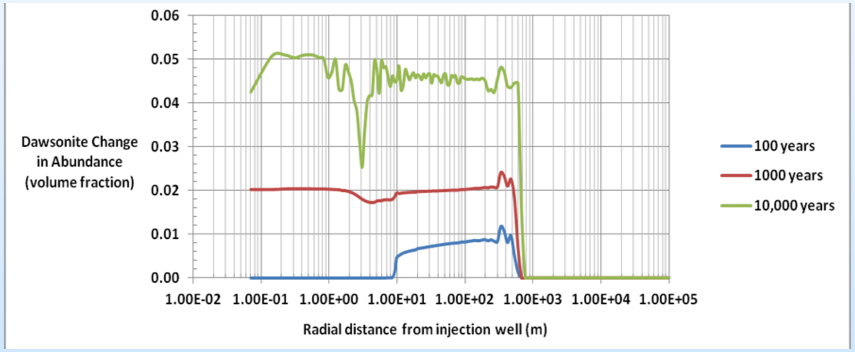
- *Geologic Characterization of a Saline Reservoir for Carbon Sequestration: The Paluxy Formation, Citronelle Dome, Gulf Of Mexico Basin, Alabama*, A. T. Folaranmi, M.S. Thesis, 2015 Oklahoma State University, Stillwater, Oklahoma, May 2015.

- *Developing Porosity with a Neural Network Application for Geologic Modeling in an Active Oil Field (EOR*), H. Jonsson, G.J. Koperna, oral presentation, 2014 Pittsburgh Coal Conference, Pittsburgh, Pennsylvania, October 6-9 2014.

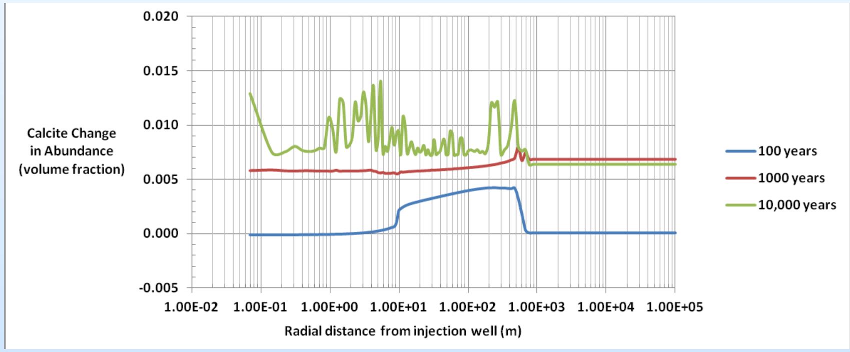
Simulation of CO_2-Mineral Reactions

Calculations using the TOUGH2 and TOUGHREACT Software Packages for simulation of CO_2 injection, migration, and trapping in saline formations, with the ECO2N Module for fluid properties. Lawrence Berkeley National Laboratory (Pruess et al., 1999; Xu et al., 2004; Pruess and Spycher, 2006).

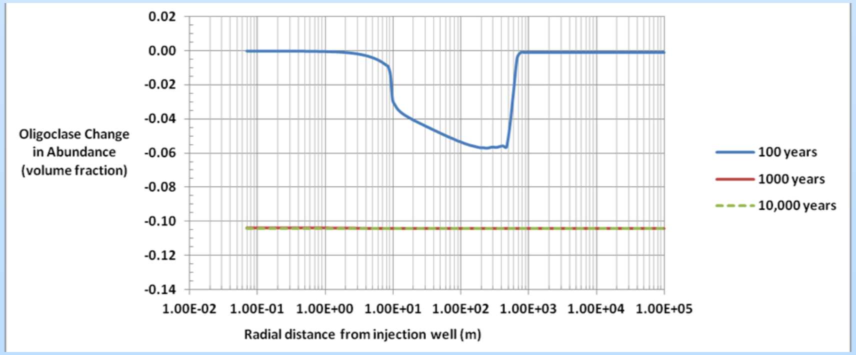
CO_2 is injected through a single well into the Middle Donovan Sand at a depth of 11,000 ft and rate of 50 tons/day for 40 years. The figures show (clockwise from top left) changes in abundance of representative minerals dawsonite, calcite, and oligoclase, and permeability of the formation as functions of distance from the injection well and time.



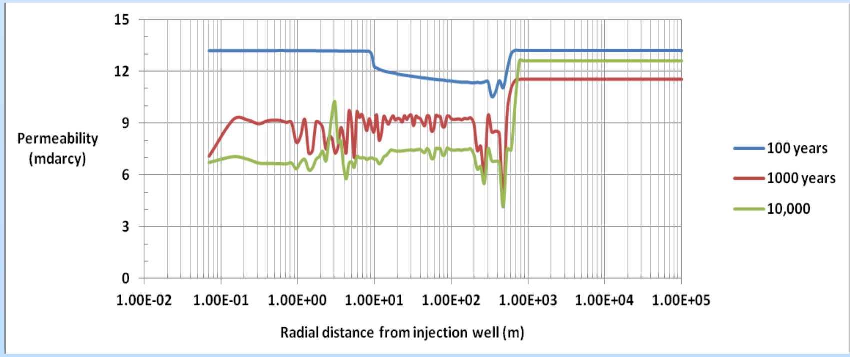
Dawsonite, $NaAlCO_3(OH)_2$



Calcite, $CaCO_3$



Oligoclase, $(Ca,Na)(Al,Si)_4O_8$



Permeability