Evaluating Saline Storage Opportunities in Offshore Alabama

Gabe Casanova[1], Jeremy Leierzapf[1], Mitchell Meyer[1], John W. Koster[1], David E. Riestenberg[1], George Koperna[1]
[1]Advanced Resources International, Inc 4110 Sutherland Ave, Knoxville, TN 37919
Contact: Gabe Casanova (gcasanova@adv-res.com) 337-552-3174

Advanced Resources International, Inc.

Introduction

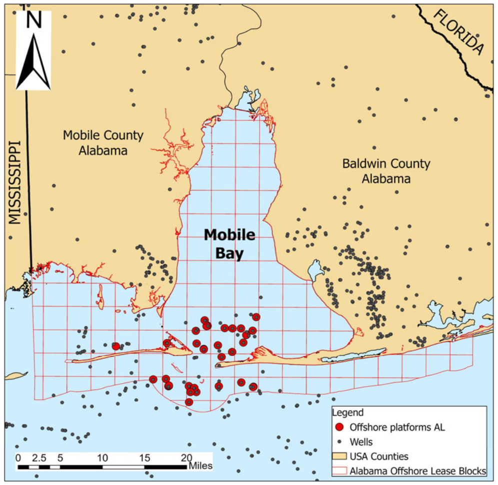

Figure 1: Map of oil and gas infrastructure in the Mobile Bay region

Southeast Regional Carbon Storage Partnership: Offshore Gulf of Mexico (SECARB Offshore) evaluates potential storage opportunities within a specifically defined GOM Study Area (Area of Interest). The evaluation focuses on active and depleted oil and gas fields, potentially associated CO_2-enhanced oil recovery (CO_2-EOR), and deep saline storage resources in the state waters of Louisiana, Mississippi, Alabama, and West Florida.

This poster displays the results of an Advanced Resources International, Inc. (ARI) evaluation of saline storage opportunities in offshore Alabama, specifically Mobile Bay **(Figure 1)**. The evaluation was done in three parts: building a geologic model of the Mobile Bay subsurface, creating a dynamic reservoir model of the highest potential storage zones, and finally constructing an injection model of existing Mobile Bay wells to investigate the feasibility of repurposing these wells as CO_2 injectors.

Reservoir Model

The reservoir model was constructed using geologic model outputs and provides information on the injectivity and plume migration of supercritical CO_2. This numerical modeled parameters are detailed in (**Figure 4**). Well log data was utilized to segregate three modeled flow units, the Tuscaloosa Massive Sand, Washita-Fredericksburg, and the Paluxy Formations. Among these three formations, the vertical column has been simplified into packages of pay and non-pay, where the numerical model is injecting into the pay units only. Work completed on the well design and existing well completions using nodal analysis indicates a maximum injection rate of 2.88 million tonnes per year of CO_2, given the well's size and tubulars. Accordingly, this value has been set as the maximum injection rate in the model. Additionally, the fracture gradient is assumed to be 0.65 psi/ft, so our maximum bottomhole pressure is 90% of this gradient, or 0.585 psi/ft. Both constraints were utilized for the well control within the numerical simulations. CO_2 injection is modeled for 30 years in each case. The Tuscaloosa Massive Sand, with 160 feet of net thickness and 650 feet of gross thickness, boasts the best injectivity of the three reservoirs modeled. Initially, the injection rate is slower as the brine in the system is dominating relative permeability effects. As more CO_2 is injected near the wellbore, relative permeability conditions become more favorable to CO_2 injection, resulting in an increasing injection rate. Within 4 years, the maximum CO_2 injection rate reaches 2.88 million tonnes per year; over a 30 year period, a total 84.7 million tonnes of CO_2 are injected **(Figure 5)**, The CO_2 plume, shown in **(Figure 6)** covers a lateral extent of approximately 9,760 feet or 10.7 square miles.

	Massive Sand	Wash Fred	Paluxy
Depth	7,950	8,650	11,150
Net Thickness	160	230	90
Dip	0.33	0.35	0.43
Porosity	20	19	16.5
Permeability	269	184	236
Salinity	151,000	151,000	151,000
Temperature Gradient[1]	0.0139 F/ft + 75 F		

Figure 4: Average Reservoir Properties

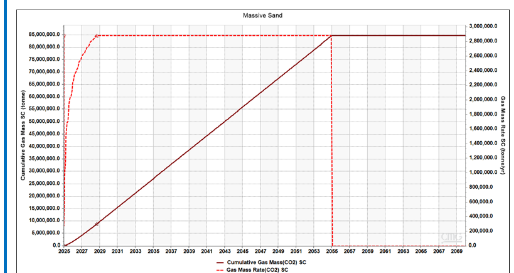

Figure 5: Injection Rate and Cumulative Volume Over 30 years

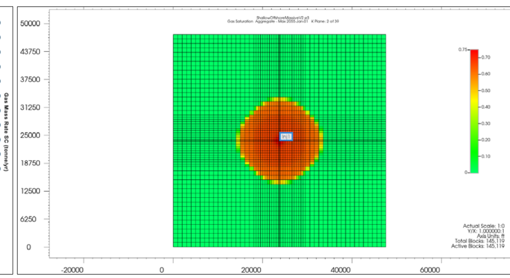

Figure 6: Plume Diameter Over 30 Years

Geologic Model

To build the geologic model, geophysical wells logs from the Geological Survey of Alabama and Enverus were used to build a geologic framework of the Mobile Bay region. Well headers, raster logs, digital logs, and shapefiles were added to the Kingdom software to facilitate the construction of the model. Formation tops were picked using references from previous work done in this region and to the north in the Mobile Graben area, and cross sections, structure maps, and gross isopach maps were generated using these extrapolated formation tops. Net reservoir was estimated by picking clean sandstone in each of the storage intervals. These inputs were then entered into volumetric calculations which we used to estimate the mass of CO_2 that can be stored per unit area.

The three most promising formations for geologic storage of CO_2 were the fluvial-deltaic sands of the Paluxy Formation, Washita-Fredericksburg Interval, and lower Tuscaloosa Massive Sand, which are overlain by the Tuscaloosa Marine Shale a suitable confining unit **(Figure 2).** The Lower Tuscaloosa Massive sand was determined to have the highest net to gross ratio and porosity across the evaluated wells. The estimated storage resource potential of these formations suggests that between 3.39 and 11.33 million metric tonnes of CO_2 per square mile can be stored in the area of interest. **(Figure3)**

Formation	Average depth (ft)	Net thickness (ft)	Porosity	P10 (MMtonne)	P50 (MMtonne)	P90 (MMtonne)
Paluxy Formation	10610	84	15%	0.56	1.05	1.80
Washita-Fredericksburg Interval	8298	188	20%	1.64	3.10	5.31
Massive Sand	7640	143	21%	1.3	2.46	4.22
Total				***3.49***	***6.61***	***11.33***

Figure 3:Summary of Static Storage Analysis

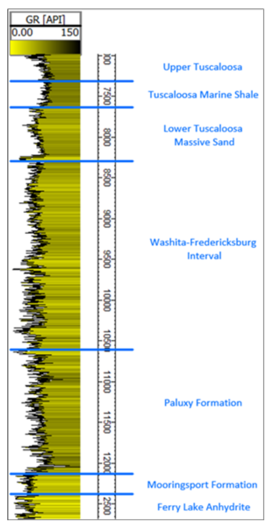

Figure 2: Type log of ROY A. AMOS 32-12 #2 well, Baldwin County, AL

Injection Model

The Mobile Bay injection simulations were modeled at the maximum possible rate that the wellbore can accommodate into the Tuscaloosa Massive Sand at 7,950ft. The guidelines used to create the models were as follows: Surface injection pressure cannot exceed 2500psi, erosional velocity constant of injection tubing cannot exceed 1, existing wellbore sizes (production casing size) would be used to build models, surface temperature for each model was 75F, and CO_2 composition was modeled to be 99.5% CO_2 and .05% Nitrogen.

The existing wellbore chosen for the model was Bon Secour Bay State Lease 534 Well #1(API# 01-297-20224) which has 9.625" OD casing(7" tubing was used for the model) **(Figure 7)**. The maximum achievable rate of the wellbore is approximately 2.88 Mtpa (149.13 MMCF/Day) which was limited by the erosional velocity of the 7" injection tubing. At this rate, the wellhead pressure would be 2168psi which is below the max allowable wellhead pressure of 2500psi **(Figure 8)**

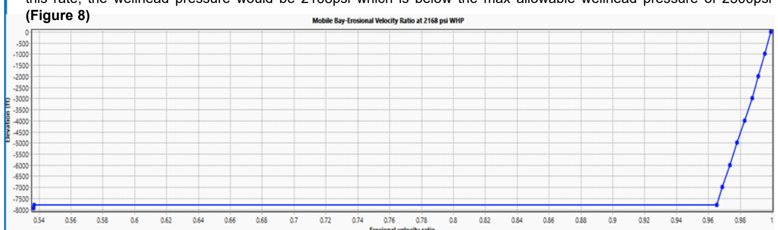

Figure 8:Erosional Velocity Ratio vs Depth

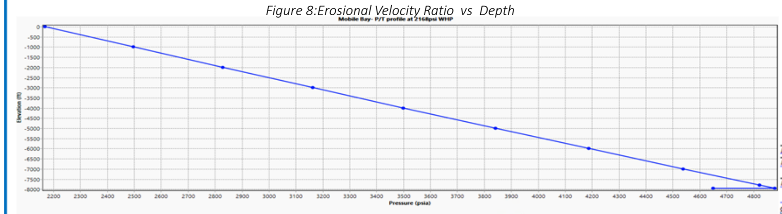

Figure 8: Pressure vs Depth

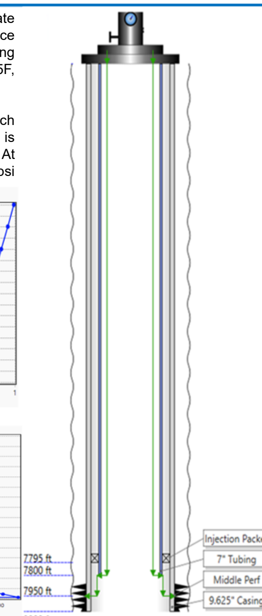

Figure 7: SL 534 Well #1 Well Diagram