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Assessing the Potential for CO_2 Storage in the Marcellus Shale in Pennsylvania by Conversion of Shale Gas Production Wells

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Abstract

Repurposing late-stage shale gas production wells into CO_2 injection wells may extend the valuable lifespan of these assets while providing alternative carbon storage opportunities in regions with limited saline storage resources. Dynamic multiphase reservoir simulations were conducted for a single wellbore and a cluster of hydraulically fractured horizontal wells located in Greene County, Pennsylvania to evaluate CO_2 storage potential in the Marcellus Shale of the Appalachian Basin. Reservoir models were calibrated to match historical gas production totaling 57 billion standard cubic feet at a single well pad site over the past decade. Multiple CO_2 injection scenarios were simulated following gas production, with the model incorporating the key physical process of CH_4-CO_2 adsorption-desorption.

Results for the single wellbore model indicate a storage potential of 0.6 million metric tons of CO_2 for a well with a ten-year prior production history of 8.2 billion standard cubic feet of CH_4. Notably, 80% of the total CO_2 storage was achieved within the first five years of injection. Results of the well cluster model suggest that conversion to CO_2 injection could store over 3 million metric tons at this well pad site by accessing 8 horizontal wells. This study suggests that assessing CO_2 storage potential should consider not only the key parameters of gas production history and stimulated rock volume, but also the operational history and level of depletion throughout the reservoir.

Introduction

Prior studies using volume replacement and other methodologies suggest that depleted Marcellus shale gas reservoirs in the Appalachian Basin may offer a CO_2 storage capacity of several billion metric tons.[1,2,3,4] These findings underscore the promising role of depleted shale gas reservoirs in advancing both carbon storage and energy sustainability objectives.

Compared to CO_2 storage in deep saline aquifers, depleted shale gas reservoirs exhibit several technical and economic advantages. First, these reservoirs benefit from extensive geological characterization data, accumulated over decades of oil and gas production. Critical reservoir rock and fluid properties, as well as potential hazards, can be readily analyzed using existing seismic surveys, well logs, core samples, and literature. Second, legacy well and pipeline infrastructure, along with established rights-of-way, are already in place. The familiarity of surrounding communities with these assets and the associated benefits promotes easier acceptance of the concept. Third, the reservoir characteristics of shale gas formations inherently favor CO_2 injection due to factors such as greater separation from freshwater aquifers, reduced reservoir pressures, and the ability to adsorb gas within the formation.

To further evaluate CO_2 storage potential in the Marcellus Shale, this study developed dynamic reservoir simulations of a cluster of hydraulic fractured wells that are emblematic of the thousands of other production wells throughout the region.

Methods

The study area is located near the Robena coal refuse disposal site in Greene County, Pennsylvania. This location was chosen as part of an ongoing effort supported by the U.S. Department of Energy (DE-FE0031998) to design the world's first carbon negative power plant fueled by coal mine waste and biomass. The Ridge Road (RR) horizontal well cluster, located nine miles from the Robena site, comprises a group of multistage hydraulically fractured shale gas wells (**Figure 1**). Natural gas production at the well pad began in 2013 with six of the eight wells still in active production.

A geologic model was developed using type logs for the Marcellus Shale in the region, identifying the Tully Limestone, Marcellus Shale, and Onondaga Limestone formations at average depths ranging from -6,507 ft to -6,667 ft below mean sea level (approximately 8,000 ft measured depth). A comprehensive petrophysical study revealed that the porosity and permeability of the Marcellus Shale correlate with confining pressure and net stress.[5] The reservoir's static and initial conditions used for modeling are summarized in **Table 1**.

Table 1 Input values of static and initial reservoir condition

Input Parameter	Unit	Value
Single w.b. model width	ft	1,250
Single w.b. model length	ft	7,000
Cluster model width	ft	4,150
Cluster model length	ft	83,700
Avg. reservoir thickness	ft	180
Well Lateral Length	ft	6,500 – 7,800
Frac stages	-	44 - 49
Single w.b. model SRV	cu.ft	337,000,000
Cluster model SRV	cu.ft	1,518,000,000
Matrix porosity	dec	0.001
Fracture porosity	dec	0.0425
Matrix permeability	mD	0.001
Fracture permeability	mD	0.00015
Initial reservoir pressure	psi	5,600
Initial reservoir temperature	F	130
Initial gas saturation	dec	0.75
Residual water saturation	dec	0.05
Max CH4 Langmuir	gmol/lb	0.035
Max CO2 Langmuir	gmol/lb	0.08

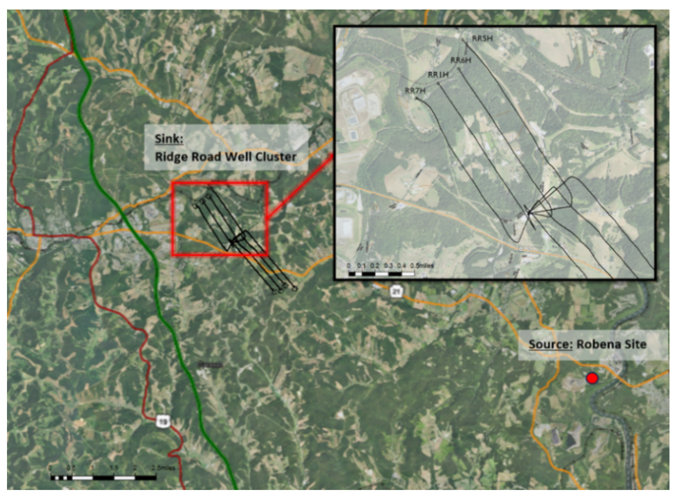

Figure 1 Map view of the study objects (Source and Sinks)

Reservoir simulations were conducted using compositional Equation of State (EOS) simulators to evaluate mechanisms such as structural, solution, and residual trapping of injected CO_2. The simulations also incorporated CH_4-CO_2 adsorption and desorption effects, modeled using the Langmuir isotherm. Initially, a single-well model based on the Ridge Road 7H well was tested to validate input parameters. The model was subsequently scaled up to represent the northwest branches of the Ridge Road well cluster. Both models were calibrated using historical methane production data from each well, enabling accurate history matching and the establishment of initial conditions prior to CO_2 injection. The results of the history matching are presented in **Figure 2** and **Figure 3**.

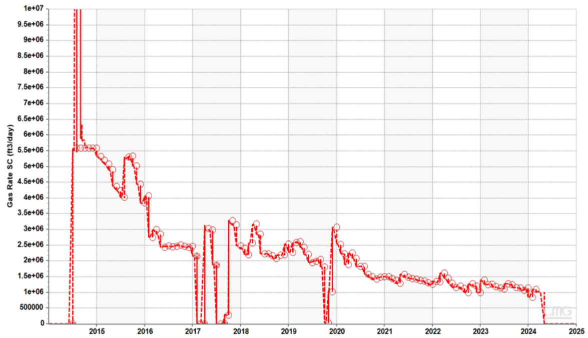

Figure 2 Ridge Road 7H legacy CH_4 production history matching

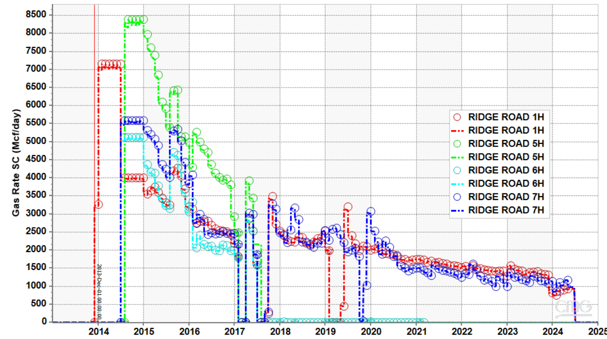

Figure 3 Ridge Road Cluster legacy CH_4 production history matching

Results and Discussion

The single-well base case simulation, covering the CH_4 production period (2014–2024), modeled CO_2 injection constrained by maximum fracture pressure for 30 years (2025–2055), followed by a 30-year post-injection monitoring period (2055–2085). As shown in **Figure 4** and **Figure 5**, the CO_2 injection rate declines sharply during the first five years as reservoir pressure replenishes. Over the 30-year injection period, a cumulative 0.6 million metric tons (Mt) was stored, given the reservoir conditions following production of 8.2 billon standard cubic feet (Bcf) of CH_4. Notably, 80% of the total CO_2 storage was achieved within the first five years.

Figure 6 illustrates the total and adsorbed CO_2 and CH_4 molarity within the reservoir over time. During the production phase, the total CH_4 volume decreases as reservoir pressure depletes, with adsorbed CH_4 being gradually released until pressure stabilizes. Once CO_2 injection begins, total and adsorbed CO_2 concentrations increase as expected, while further desorption of CH_4 occurs, enabling potential enhanced gas recovery. **Figure 7** presents the CO_2 concentration map at the end of the injection and post-monitoring periods. Following wellbore shut-in, CO_2 diffuses into the deeper reservoir matrix from hydraulic fractures, promoting additional CH_4 release for enhanced recovery opportunities.

The single-well simulation results demonstrate that the CO_2 injection profile in depleted shale reservoirs resembles the reverse of a CH_4 production decline curve. The majority of CO_2 storage occurs early in the injection process, highlighting the importance of strategic planning for staged well conversions. Such an approach could optimize financial outcomes by maximizing CH_4 recovery while utilizing CO_2 storage potential.

To further evaluate the effectiveness of this strategy and its impact on a group of adjacent wells, a cluster model comprising four horizontal wells with the same orientation was developed for additional simulations. As depicted in **Figure 1**, the four horizontal wells in the cluster model—RR5H, 6H, 1H, and 7H—are arranged from east to west. CO_2 injection is simulated to begin in 2025, coinciding with the conversion of all four wells from CH_4 production to CO_2 storage.

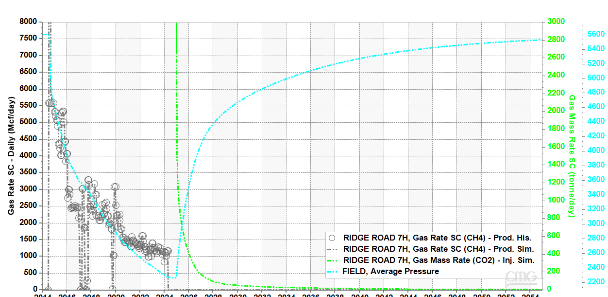

Figure 4 Single wellbore model CO_2 injection rate (Green) and average reservoir pressure (Blue)

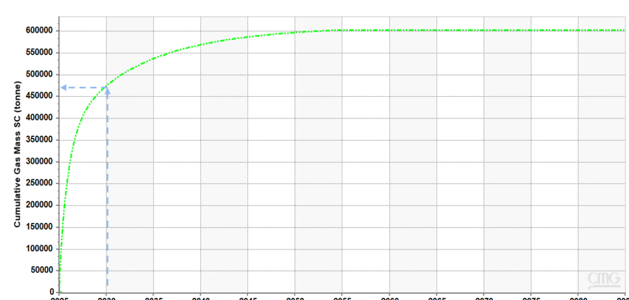

Figure 5 Single wellbore model cumulative CO_2 injected

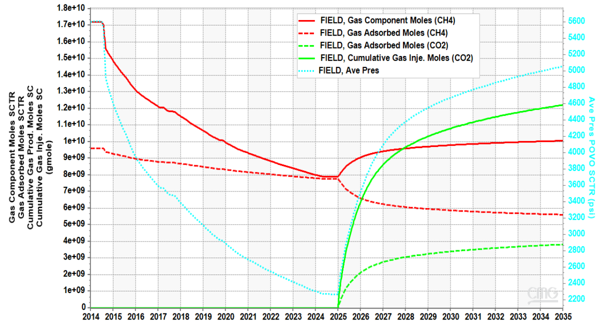

Figure 6 Single wellbore model CH_4 (Red) and CO_2 (Green) total and adsorbed molality, and reservoir average pressure (blue)

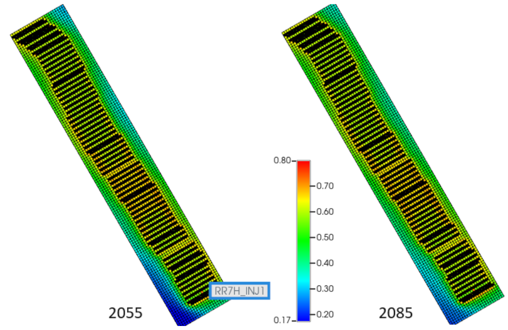

Figure 7 Single wellbore CO_2 molarity map at the end of injection (2055) and monitoring (2085)

Results of the cluster well model indicate a similar CO_2 injection profile as the single-well model, with a significant portion (~50%) of CO_2 storage occurring within the first five years (**Figure 8**). However, the per-well value is lower than in the single-well model due to the cluster model's inclusion of more non-stimulated reservoir volume (non-SRV) grids, which maintained a higher average reservoir pressure at the conclusion of CH_4 production. Additionally, the early shut-in of the RR5H and 6H wells resulted in higher reservoir pressure within their SRVs, which in turn influenced the bottomhole pressure of adjacent wells. Methane production from RR5H and 6H was notably lower compared to RR1H and 7H, establishing less effective pore space for CO_2 injection at the start. This is evident in **Figure 9**, which shows higher CO_2 molarity within the SRV and non-SRV regions of RR1H and 7H compared to the other two wells.

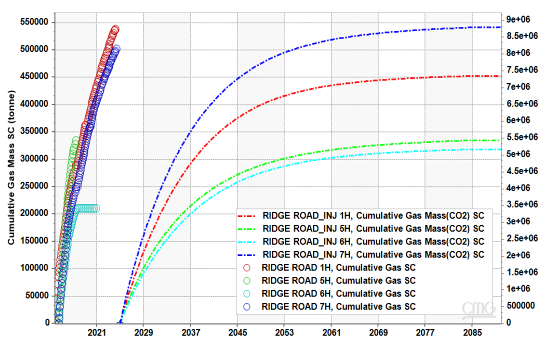

Figure 8 Cluster model individual well cumulative CH_4 production (right scale) and CO_2 injected (left scale)

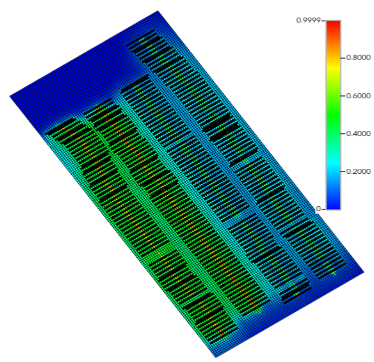

Figure 9 Cluster model CO_2 molarity map at the end of injection (2055)

Over the 30-year injection period, the four-well cluster model achieved a cumulative CO_2 storage of 1.65 Mt, which is lower on a per-well basis than the single-well model. This outcome highlights the significant impact of reservoir depletion levels on both early-stage and ultimate CO_2 storage potential in shale gas reservoirs. Wells with higher degrees of depletion at the start of injection exhibit greater storage capacity, emphasizing the importance of reservoir management strategies tailored to depletion histories.

Conclusions

This study indicates that conversion of a single Marcellus shale gas well from production to CO_2 injection may store more than 0.5 Mt of CO_2, and a single well pad may have the potential to store several million metric tons of CO_2. Given the abundance of Marcellus production wells with decade+ production histories, the Marcellus Shale could be a critical carbon storage resource for enabling deployment of carbon capture, utilization and storage technologies across the Appalachian Basin. Staged conversion of multiple adjacent horizontal shale gas wells from gas production to CO_2 injection is an approach that could achieve substantial secured CO_2 storage with the co-benefit of enhanced gas recovery.

Acknowledgements

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