UNDERGROUND STORAGE OF PRODUCED NATURAL GAS

Final Report

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EXECUTIVE SUMMARY

Extraction of oil and gas from the Bakken petroleum system (BPS), consisting of both the Bakken and Three Forks Formations, has increased dramatically over the past 15 years. Until recently, the development of gas capture infrastructure was not commensurate with the volumes of gas that were being produced, resulting in flaring of produced gas at wellsites with limited or no gas takeaway capacity. The Sixty-Sixth Legislative Assembly of North Dakota included wording in Section 25 of House Bill 1014 to help facilitate the evaluation of potential mechanisms to mitigate flaring, which was signed into law by Governor Burgum, stating funding was to be made available to the Energy & Environmental Research Center (EERC) for "pilot projects relating to the underground storage of produced natural gas." The goal of the funding was to evaluate the technological and economic feasibility of produced gas injection into porous and permeable saline formations and oil-bearing formations for the purpose of enhanced oil recovery (EOR), with the added benefit of temporary gas storage. Storing produced gas temporarily allows for the continued drilling and completion of Bakken and Three Forks wells while producers are waiting for additional gas takeaway infrastructure to become available.

The funding made available to the EERC was used to evaluate a variety of subsurface produced gas storage concepts in conjunction with industry partners. To better understand the potential of temporary gas storage, industry partners collaborated with the EERC to evaluate the technical and economic feasibility of produced gas injection into porous and permeable saline formations for temporary storage and into oil-bearing formations for the purpose of EOR. The EERC worked closely with XTO Energy (XTO), Marathon Oil Company (Marathon), Liberty Resources LLC (Liberty), and Maroon Bells Partners (Maroon Bells) on the assessment of six conceptual pilot projects: 1) two produced gas storage efforts in the Broom Creek Formation, 2) an investigation into produced gas storage potential in the Duperow Formation, 3) an evaluation of the potential for produced gas storage in the Inyan Kara Formation, and 4) two assessments of produced gas injection for EOR in the BPS. Across these various investigations, the EERC performed site characterization work; performed geologic model construction and numerical simulation of produced gas injection that were focused on evaluating potential plume extents and gas recovery rates; assessed legacy wells and potential monitoring wells; evaluated the necessary gas conditioning and compression equipment; and, in the case of future potential produced gas injection into the BPS for EOR, assessed gas injection rates/volumes necessary to maximize incremental oil recovery.

With respect to produced gas storage in saline formations, the results of the various investigations suggest that recovery factors could have a wide range, from less than 30% to upwards of 70%, depending on the combination of injection rates, injection period, storage period, and producing well bottomhole pressure. While higher gas recovery rates are achievable with extended periods of gas recovery, those scenarios were deemed uneconomic because the rate of water recovery (and associated disposal costs) quickly increases at the expense of gas recovery. Shorter-duration gas storage periods, coupled with higher production rates, resulted in the highest estimated gas recovery factors and lowest cumulative water production. Coinjection of water and gas in saline formations for temporary gas storage resulted in the lowest estimated gas recoveries.

The surface facility evaluation results indicated that using multiple smaller rental compressors over a single, large, purchased compressor would allow for flexibility, allowing individual units to go offline as gas production rate declines. Multiple smaller compressors can assist with redundancy and continuous operations at the cost of more maintenance and operational costs. Trailer-mounted mechanical refrigeration units (MRUs) capable of 1-MMscf/d gas treatment are typically available and would allow for flexibility in reducing the number of compression units needed as gas volumes decline over time.

With respect to produced gas injection for EOR in the BPS, the novel rapid-switched, stacked-slug (RSSS) coinjection technology has demonstrated an ability to significantly reduce the surface compression requirements needed for gas injection into the subsurface and provide a mechanism to more effectively build reservoir pressure for gas-based EOR in the Bakken. The results of the evaluation suggest that huff-n-puff gas injection could result in significant increases in incremental oil recovery. The results of this work suggest that produced gas EOR pilot tests in the Bakken, especially those using higher gas injection rates, are warranted.

The EERC worked closely with the industry partners and various state agencies to define the key tax, royalty, and regulatory components that would need to be addressed to implement the produced gas storage and produced gas EOR projects. Senate Bill 2065 (SB 2065), effective as of August 1, 2021, created North Dakota Century Code (NDCC) 38-25, which granted the North Dakota Industrial Commission (NDIC) authority to adopt rules for the geologic storage of oil or gas. Subsequently, NDIC promulgated regulations for the geologic storage of oil or gas by the creation of a new chapter in the North Dakota Administrative Code (NDAC) as Chapter 43-02-14 Geological Storage of Oil or Gas, which then took effect April 1, 2022. Prior to NDCC 38-25, NDIC had developed and used a “Produced Gas Storage Facility Permit Application Guideline” based on general authority granted to NDIC to regulate “the underground storage of oil or gas” (NDCC 38-08-04-01[b][6]). Prior to issuance of an underground gas storage facility permit, the storage operator is mandated by North Dakota statute to obtain the majority consent of landowners who own the pore space of the storage reservoir. In the case of storage in an oil/gas reservoir, 55% of the pore space owner consent and 55% of the mineral/lease owner consent is required. With regard to storage in a saline reservoir, 60% of the pore space owner consent is required. Clarification regarding royalties has also been a positive advancement in potential produced gas storage scenarios. Senate Bill 2065 also made clear that, unless otherwise expressly agreed by the storage operator, mineral owners, and lease owners, royalties on gas produced but not sold and that is injected into a storage facility instead of flaring or for lack of market are not due on the produced and stored gas until gas volumes are withdrawn from the storage facility, sold, and proceeds are received from the sale.

Overall, the pilot studies reported here, coupled with the regulatory clarifications noted above, have shown that geologic storage in North Dakota is a promising and viable means to store and recover produced gas in locations with no or limited gas takeaway capacity. While this effort focused on relatively small volumes of gas storage, western North Dakota’s geology is conducive for storage of large volumes of gas, which could be a mechanism to help manage produced gas and/or natural gas liquids in locations where there is insufficient processing capacity and/or large-scale pipeline export capacity.

UNDERGROUND STORAGE OF PRODUCED NATURAL GAS

1.0 INTRODUCTION

The Bakken petroleum system (BPS) in the Williston Basin of central North America is an unconventional tight oil play with oil-in-place estimates in the hundreds of billions of barrels (Nordeng and Helms, 2010). The BPS includes both the Bakken and underlying Three Forks Formations. As shown in Figure 1, oil production from the BPS has rapidly expanded from just over 10,000 barrels per day (bbl/day) in January of 2007 to a peak of 1.46 million barrels per day (MMbbl/d) in October 2019, with an average of 1.0 MMbbl/d through 2021 and 2022 (North Dakota Industrial Commission, 2023). As oil production has increased, so has the volume of coproduced gas, also referred to as produced gas or associated gas. Gas production has rapidly increased from early Bakken development (11.3 Mscf/d in January 2007), peaking at over 3 Bscf/d in October 2019 and has maintained between 2.5 and 3 Bscf/d since mid-2020 (North Dakota Industrial Commission, 2023). Perhaps the more relevant metric is the gas-to-oil ratio (GOR), which has continued to rise from the time that oil production first started in the BPS (Figure 1). In 2019, 2.0 Mcf of gas was produced on average for every barrel of oil. That number increased to approximately 2.8 Mcf of gas per barrel of oil as of December 2022. Based on the typical composition of rich produced gas in the Bakken, this is the equivalent of about 0.7 pounds of gas produced for every pound of oil.

The rapid increase of oil and gas production from the BPS has resulted in significant investment in infrastructure to transport oil and gas from the wellsite to market. Associated gas is a valuable resource, and there is a strong desire by all stakeholders—oil companies, midstream gas companies, mineral owners, and the state of North Dakota—to minimize waste and extract value from this resource. Produced gas is transported from well pads via gas-gathering pipelines and gas compressors to centralized gas-processing facilities to be separated into marketable products. If there is insufficient gas takeaway capacity at a site, the excess gas is often flared or, in some cases, oil production is voluntarily curtailed to limit the amount of gas produced and limit emissions generated from flaring. Factors that may contribute to gas flaring or curtailed oil production include a lack of gas-gathering pipelines to a wellsite, insufficient capacity of gas-gathering infrastructure, or temporary operational issues that upset gas gathering or processing (e.g., maintenance).

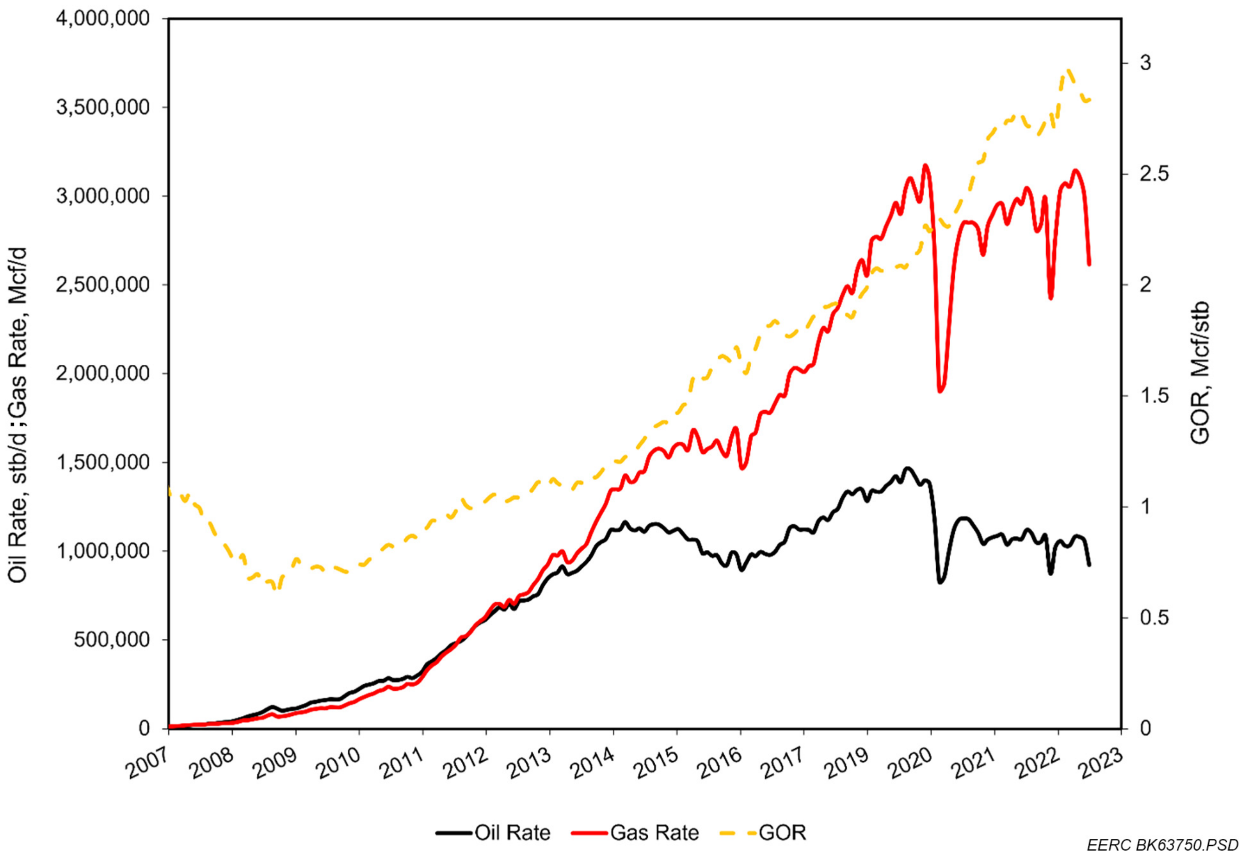

Figure 1. Illustration of increasing Bakken–Three Forks oil production (black), gas production (red), and GOR (yellow) from January 2007 to December 2022 (developed with data from the North Dakota Industrial Commission website [North Dakota Industrial Commission, 2023]).

To proactively manage the amount of gas being flared, the North Dakota Industrial Commission (NDIC) worked with industry in establishing gas capture requirements to encourage a reduction in gas flaring. Historically, industry has struggled to meet gas capture requirements established by the state. The gas capture target from November 1, 2018, through October 31, 2020, was 88% while the average gas capture rate throughout 2019 was 81% (U.S. Energy Information Administration, 2020). With the decline in oil prices in 2020, the drop in oil and gas production, a reduction of new wells brought online, and implementation of company-defined gas capture targets to meet environmental, social and governance (ESG) initiatives, industry was able to meet the gas capture requirements throughout most of 2020, even with an increase in the gas capture target from 88% to 91% as of November 1, 2020. As of March 2023, 95% of Bakken associated gas was being captured statewide (Helms, 2023).

To identify potential mechanisms to mitigate flaring of produced gas, the Sixty-Sixth Legislative Assembly of North Dakota included wording in Section 25 of House Bill 1014, signed into law by Governor Burgum, stated funding was to be made available to the Energy & Environmental Research Center (EERC) for "pilot projects relating to the underground storage of produced natural gas." The overall goal of the funding was to evaluate the technological and economic feasibility of produced gas injection into porous and permeable geologic formations for temporary storage. Produced gas injection into oil-bearing formations for the purpose of enhanced oil recovery (EOR) was also assessed for the added benefit of temporary gas storage. Storing produced gas temporarily allows for the continued drilling and completion of BPS wells while providing the producer with additional time to install gas takeaway infrastructure.

Funding made available to the EERC was used to conduct a variety of activities in conjunction with industry partners to evaluate subsurface produced gas storage. Goals for the pilot studies included assessing key technical, economic, and regulatory components required for the following gas injection and storage scenarios:

- Reinjection into the BPS for pressure maintenance and EOR.
- Injection into saline formations for storage.
- Injection into conventional, legacy oil field for storage or EOR.

This final report includes lessons learned; identifies regulatory-related aspects associated with produced gas storage; and highlights scenarios for produced gas storage, recovery, and reuse within oil producing regions of North Dakota.

Industry partners that collaborated with the EERC on the concept of subsurface produced gas injection and storage included XTO Energy (XTO), Marathon Oil Company (Marathon), Liberty Resources LLC (Liberty), and Maroon Bells Partners (Maroon Bells). The EERC worked closely with these industry partners beginning in July 2019 and extended that work through the spring of 2023 to assess six conceptual pilot projects: 1) two produced gas storage efforts in the Broom Creek Formation, 2) an investigation into produced gas storage potential in the Duperow Formation, 3) an evaluation on the potential of produced gas storage in the Inyan Kara Formation, and 4) two assessments of produced gas injection for EOR in the BPS. Across these various investigations, the EERC performed site characterization, geologic model construction, and numerical simulation of produced gas injection. Simulation results were evaluated for gas plume extents, gas recovery rates, effects to legacy wells, potential monitoring well locations, necessary gas conditioning and compression equipment, and gas injection rates and volumes to maximize incremental oil recovery. The EERC also partnered with Liberty Resources on a field demonstration of a technology developed by EOR ETC for gas injection for EOR in the BPS. In addition, the EERC and industry partners worked closely with NDIC Department of Mineral Resources (DMR), the North Dakota Office of the State Tax Commissioner, the North Dakota Department of Trust Lands, and the U.S. Department of the Interior Bureau of Land Management (BLM) to define key tax, royalty, and regulatory components that would need to be addressed to implement projects, including needed regulatory clarity with respect to gas storage project implementation.

2.0 LESSONS LEARNED AND KEY RECOMMENDATIONS

The key lessons learned by the EERC's assessment of produced gas storage in the various subsurface formations of the Williston Basin include both technical findings and a summary of regulatory clarity that was implemented during the course of this effort to facilitate gas storage projects. As the EERC worked with multiple industry partners to evaluate produced gas injection projects, for temporary geologic storage or EOR, one finding is clear—the diversity of the efforts considered is an excellent illustration of industry's spirit of creativity and innovation in trying to find alternatives for flaring. Just as the oil and gas industry found ways to initially harness and then improve the recovery of the hydrocarbon resources existing in unconventional tight oil formations such as the Bakken, it is now exploring a variety of ways to reduce flaring and better conserve the gas resources that exist in the Bakken.

The pilot studies have shown that geologic storage in North Dakota is a viable means to hold and recover produced gas. Numerical simulation has shown that maximizing storage and recovery of produced gas is mostly based on operational parameters of injection rates, soak time, and production rates. Porosities and permeabilities for more conventional clastic formations (e.g., Inyan Kara and Broom Creek Formations) and carbonates (e.g., Duperow Formation) provide operators an alternative to flaring to support Bakken development in locations not connected to gas-gathering pipelines to allow for oil production and later recovery of produced gas. EOR with produced gas within the BPS has the potential to provide incremental oil production in addition to temporary storage of produced gas.

2.1 Temporary Produced Gas Storage in Saline Formations and Depleted Oil Reservoirs

The Inyan Kara, Broom Creek, and Duperow Formations were evaluated for temporary geologic storage of produced gas. The Inyan Kara and Broom Creek are clastic saline formations without hydrocarbon production. Where evaluated, the Duperow is a carbonate saline formation with structurally controlled hydrocarbon producing fields. For temporary storage, each of the geologic formations target for storage was evaluated for gas recovery factors and gas compression/conditioning optimization.

A variety of produced gas injection rates (ranging from 5 to 30 MMscf/d), injection durations (1, 2, and 9 years), storage periods (0, 1, 2, 5, and 10 years), and recovery production periods (10–50 years) were evaluated using reservoir models to evaluate produced gas storage. This resulted in total stored gas ranging from 5 to 119 Bscf and recovery factors ranging from 43% to greater than 70%, depending on the combination of storage formation, storage location, injection rates, injection period, storage period, and gas and water recovery rates. While greater than 70% recovery of gas was found to be achievable within some simulations, it is likely not economically realistic, given the length of time to achieve higher recovery factors or the costs for water disposal over that time frame. Using the same location for repeated cycles of gas injection and recovery is the best way to establish a gas cushion and maximize gas recovery factors. Upon start of the gas recovery operation, a high proportion of gas is recovered with a low proportion of water. Over time, more water is produced with less gas recovered. Eventually, the cost to handle and dispose of the volume of water produced economically outweighs the benefit of recovering additional gas.

The Inyan Kara Formation was evaluated to assess the approach of coinjecting gas along with saltwater disposal for the purposes of temporary gas storage, with the idea that the gas would gravity separate from the brine over time, allowing for recovery of the gas. This approach does not appear to be viable for temporary gas storage given that future gas recovery potential was predicted to be low (less than 36%) as the relatively short storage duration was insufficient for gravity separation. The results suggest that traditional gas compression and injection is a better strategy for temporary gas storage and future recovery because it does not add additional water to the reservoir, resulting in a more connected gas plume.

If possible, bringing wells online in a staggered approach on multiwell pads allows for optimization of surface facilities to better handle the initially large volumes of gas that are produced from each well. Otherwise, pads with multiple wells coming online at once require facility designs with the ability to handle immediate large volumes of gas, with volumes diminishing with production declines resulting in "oversized" surface facility equipment and capacity. Evaluating surface facility requirements suggests that rather than using larger, more expensive, and less readily available gas compressors and conditioning units, purchasing or renting smaller, modular system compressors and gas conditioning units and configuring them to work in parallel allows for more flexible and economical options. Using readily available equipment could shorten acquisition time to support needed gas conditioning and compression, allowing for capacity to be ramped up to support gas production at a given site or reduced based on production declines or as gas takeaway capacity becomes available.

2.2 Produced Gas Injection for EOR in the Bakken

While only a very limited number of produced gas EOR pilot projects have been performed in the Bakken, conformance (i.e., keeping the gas in the areas of the reservoir where it is needed) has been a key challenge. Several successful produced gas EOR pilots have been reported in the Eagle Ford play of Texas, and a key question is whether similar success could be achieved in the Bakken. Results from reservoir modeling simulations and a pilot injection project are promising, provided sufficient rates/volumes of gas are injected. The recent East Nesson pilot test project that the EERC performed in conjunction with Liberty Resources and EOR ETC, with funding from the NDIC-funded Bakken Production Optimization Program and from this project, demonstrated that rich-gas EOR can generate incremental barrels of Bakken oil. However, the past EOR pilot projects in the Bakken have injected gas at much lower rates (<5 MMscf/d) than successful Eagle Ford pilots (>15 MMscf/d based on anecdotal evidence). The results of modeling and simulation work conducted through this effort in conjunction with XTO Energy suggest that huff 'n' puff (HnP) gas injection EOR using produced gas could yield an incremental oil recovery of up to 60% in the primary HnP well using gas injection rates of 17 MMscf/d or higher.

In the East Nesson pilot injection test, oil recovery was estimated to increase 25% from the 1-month duration test using an average gas injection rate of 1.5 MMscf/d and 1.3 MBW/d using a rapid-switched, stacked-slug (RSSS) system coinjecting both gas and water. EOR ETC's technology allowed us to coinject water and surfactant along with the gas at significantly lower surface pressure than required for standard high-pressure gas compressors to achieve higher bottomhole pressure and helped achieve conformance. The use of the RSSS system was effective at building reservoir pressure and achieving conformance in the East Nesson pilot project. That technology appears to be viable for EOR projects that include injection of water (including surfactants) or to build reservoir pressure while limiting the amount of gas injection required; however, the gas injection rate of the system evaluated in the field test was relatively low and may not be suitable for EOR projects requiring higher rates of gas injection and/or those that are focused solely on gas injection.

With produced gas EOR, offset well production performance is strongly dependent on the nature of the hydraulic and natural fracturing and completion operations, particularly with respect to the resulting stimulated reservoir volume (SRV) around these wells. An offset well with a large SRV close to the primary HnP well could see increases to incremental oil recovery with higher gas injection rates. The promising results of this modeling work and field pilot suggest that produced gas EOR pilot tests in the Bakken using higher gas injection rates or multiple cycles are warranted.

2.3 Regulatory, Tax, and Royalty Considerations

Over the course of the six projects, valuable insights were gained with respect to areas in which legislative clarity would help support the implementation of pilot projects to evaluate gas storage. These insights were gained through the evaluation of the regulatory guidelines from the perspective of industry partners and through multiple conversations between the EERC, partner personnel, and various state entities including NDIC DMR, the North Dakota Office of the State Tax Commissioner, the North Dakota Department of Trust Lands, and BLM. Following discussion with various state agencies throughout this effort, North Dakota Senate Bill 2065 (SB 2065) provided legislative clarity with respect to temporary storage of produced gas.

2.3.1 Pore Space

North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Administrative Code [NDAC] Chapter 47-31). Explicit pore space regulations pertaining to underground gas storage did not exist in North Dakota prior to 2021. Senate Bill 2065 (SB 2065), introduced in 2021, created North Dakota Century Code (NDCC) 38-25 that took effect August 1, 2021. Prior to NDCC 38-25, NDIC had developed and used a “Produced Gas Storage Facility Permit Application Guideline” based on general authority granted to NDIC to regulate “the underground storage of oil or gas” (NDCC 38-08-04-01(b)(6). After statutory authority was established in NDCC 38-25, the NDIC was granted authority to adopt reasonable rules, after notice and hearing, for the geological storage of oil or gas. Subsequently, NDIC promulgated regulations for the geological storage of oil or gas by the creation of a new chapter in the NDAC as Chapter 43-02-14 Geological Storage of Oil or Gas, which then took effect April 1, 2022.

Prior to issuance of an underground gas storage facility permit, the storage operator is mandated by North Dakota statute to obtain the majority consent of landowners who own the pore space of the storage reservoir. Table 1 lists the differences in consent required based on the storage reservoir type.

Table 1. Amalgamation Requirements by Reservoir Type

Underground Gas Storage Type	Pore Space Owner Consent Required	Mineral/Lease Owner Consent Required
Oil/Gas Reservoir	55%	55%
Saline Reservoir	60%	None
Salt Cavern	60%	55%

2.3.2 Tax Implications

North Dakota tax law mandates gross production (prior to the LACT [Lease Automatic Custody Transfer] unit) tax is due when gas is produced (NDCC 57-51-02.2); however, a provision in the tax code allows for a 2-year and 30-day production tax exemption if natural gas liquids (NGLs) are removed from the produced gas (NDCC 57-51-02.6). In many gas reinjection scenarios, the NGLs would likely be stripped at the wellsite from the produced gas prior to injection into the subsurface; however, based on the planned gas injection period coupled with the intended gas recovery date, a 2-year and 30-day tax exemption could put the operator in a position where it is paying tax on gas that has not yet been sold.

2.3.3 Royalties

Gas royalties are paid after the gas sales point when the gas passes through the lease custody meter (i.e., sales meter or LACT unit). Produced gas can be used on lease for oil and gas operational purposes prior to the sales meter. Royalties are typically not paid on gas that is either utilized on-site for oil and gas operations or flared at the wellsite, so long as gas is being sold at the wellsite. For temporary gas storage where the gas is produced and injected prior to the sales meter, there is uncertainty regarding when royalty payment is due (e.g., prior to injection or at the sales meter following gas extraction).

NDCC 38-25-10 states that unless otherwise expressly agreed by the storage operator, mineral owners, and lease owners, royalties on gas produced but not sold and that is injected into a storage facility instead of flaring or for lack of market are not due on the produced and stored gas until gas volumes are withdrawn from the storage facility, sold, and proceeds are received from the sale.

3.0 GAS FLARING IN THE BAKKEN

As previously mentioned, significant quantities of natural gas and NGLs are coproduced with BPS oil production, and volumes of produced gas continue to increase for every barrel of oil. While oil can be stored in tanks on-site until it is transported from the wellsite by pipeline or truck, produced gas cannot be stored easily and is typically gathered via small, low-pressure pipelines.

Produced gas is transported to large gas-processing facilities where methane (i.e., natural gas) is separated from NGLs, including ethane, propane, butane, pentane, hexane, and heptane. The proportion of methane to NGLs for BPS produced gas varies across the basin with a basin average methane concentration of 58%, whereas basin average ethane, propane, and butane concentrations are 20%, 11%, and 4.9%, respectively (Figure 2). Smaller concentrations of other hydrocarbons and nonhydrocarbon gases, such as pentane, hexane, nitrogen, carbon dioxide, and hydrogen sulfide are also present (Kurz and others, 2020). The NGLs contained within produced gas are not only valuable fuels for heating, transportation, and drying but are also valuable feedstocks for the petrochemical industry where they are used to develop value-add products such as plastic, synthetic rubber, solvents, and resins, among other products (U.S. Energy Information Administration, 2023).

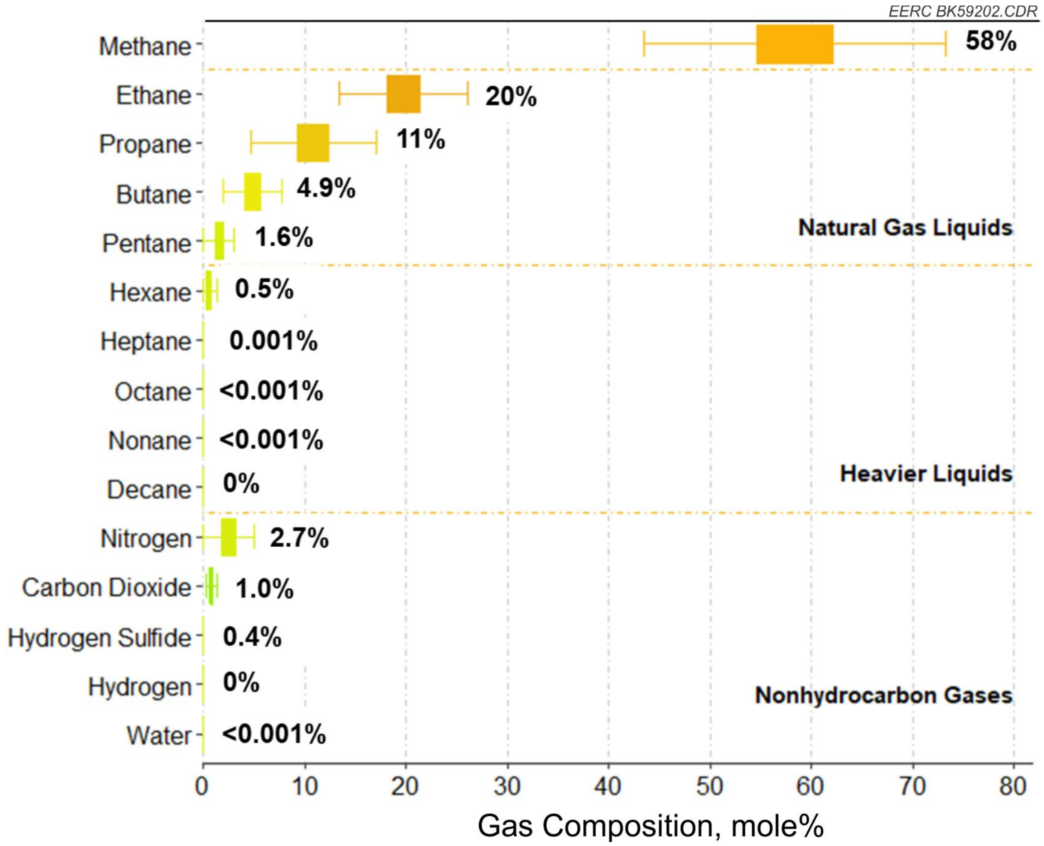

Figure 2. The average concentration and range in concentration (in mole percent) for individual gas components within Bakken produced gas. The values are based on basin-wide gas composition data compiled by the EERC (Kurz and others, 2022).

The NDIC Oil and Gas Division implements and enforces oil- and gas-related regulations. Typically, these regulations allow oil production to occur at varying rates during the first several months of operations to determine production rates. During these early months of production, gas can be flared while production data are collected to determine the gas-gathering capacity requirements. Following this exemption period, production may be restricted if statewide gas capture goals are not met. NDIC Order No. 24665 defines a graduated set of gas capture targets aimed at reducing associated gas flaring through 2020. As of November 1, 2020, the statewide gas capture target is 91%, compared to the 88% target that was in effect from November 1, 2018, through October 31, 2020.

In general, the preferred fate of associated gas is to gather it from wellsites using gas-gathering pipelines for subsequent processing at gas-processing plants. These plants aggregate associated gas from multiple wellsites, remove contaminants like H_2S, and separate the hydrocarbons into marketable products, including pipeline-quality natural gas (methane) and ethane, liquefied petroleum gas (LPG), and NGLs. Unfortunately, especially in the first decade of Bakken development, the rapid increase in oil production and growing GOR, extremely high initial gas production from multiwell pads, and challenges with installation of gas-gatheringinfrastructure (short construction season, pipeline right-of-way approval, challenging terrain in badlands areas, and large geographic area) all contributed to areas in which gas-gathering and processing capacity were unable to accommodate all of the gas produced.

As indicated in Figure 3, the percentage of produced gas that was flared has ebbed and flowed over the years, moving from 12% to 36% to 6% in 2006, 2011, and 2022, respectively. This fluctuation is a result of changes in the midstream infrastructure over time, e.g., the increased availability and capacity of gathering pipelines and compressor stations as well as gas processing capacity as Bakken produced gas volumes have increased. For example, in 2006, the bulk of the total flaring of 12% was primarily attributed to the lack of gathering pipelines; whereas by 2011, in the early days of Bakken development (and unprecedented growth in oil and gas production), an analysis conducted by the North Dakota Pipeline Authority (NDPA) suggested that gas-processing capacity constraints within existing gathering systems was a major contributing factor, resulting in an increase in flaring to 36%. By 2022, as the midstream capacity infrastructure continued to expand, the flaring of produced gas due to a lack of connectivity to gathering pipeline networks and capacity constraints had been reduced to 6% (North Dakota Pipeline Authority, 2023).

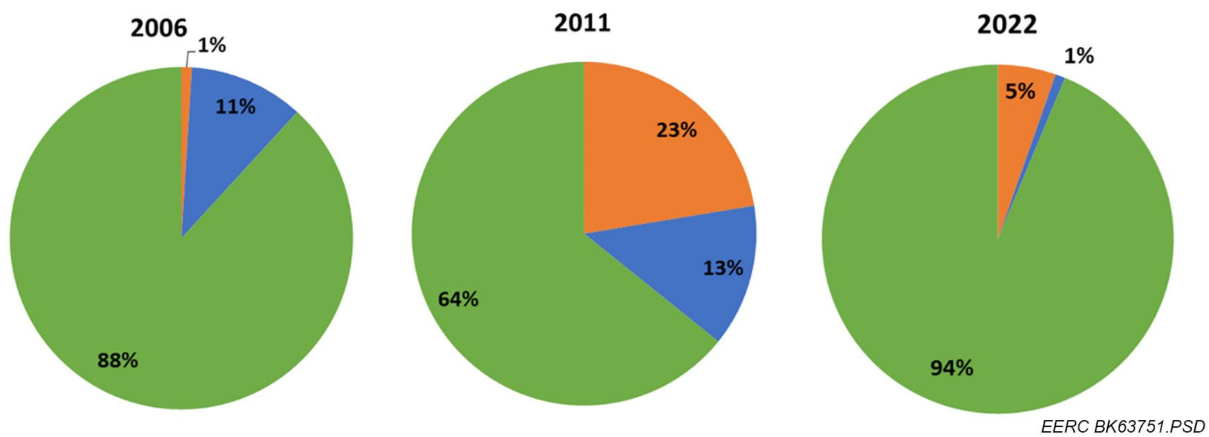

Figure 3. Percentages of associated natural gas flared by year. Green is the percent of associated natural gas captured and sold; blue is the percent of associated natural gas flared due to lack of gathering pipelines; and orange is the percent of associated natural gas flared due to capacity challenges on existing infrastructure (North Dakota Industrial Commission, 2023).

The midstream service industry continues to expand gas-gathering and processing infrastructure to help meet gas capture targets; however, there are still isolated locations where well pads do not have sufficient gas takeaway infrastructure. In addition, current NDPA production forecasts (Kringstad, 2023) suggest that the volumes of gas being produced in the Bakken will continue to increase potentially double the volumes that are currently produced. Thus the locations with stranded gas, or insufficient capacity, may increase in the future, which may necessitate the need for alternate gas management options, such as temporary produced gas storage, until a time that gas takeaway capacity is sufficient to handle all of the produced gas.

3.1 Challenges Associated with Flare Gas Utilization

A key challenge associated with capturing and utilizing flare gas from Bakken well locations that have started producing is the variation in flare gas volumes both spatially and temporally. The amount of gas being flared at a wellsite can vary widely depending on the age of the well, the rate of production, the properties of the oil at that location, and influences from other wells connected to the same gas-gathering infrastructure. A single well can produce as much as several million standard cubic feet of gas each day during the first several months of production. This rate tends to decline with time, with rates of decline varying by well.

Flaring, especially from wells connected to gas-gathering pipelines, is transient. This transience is largely due to the dynamic nature of gas-gathering system operation. The capacity of a gas-gathering system at any wellsite connection is impacted by the gas production rate and operating pressures of wells connected to the same gathering system. When several new wells from a single pad are brought into production, the associated gas from those wells can overwhelm gathering pipeline capacity, causing gas from nearby wells to flare, when previously 100% of their production had been captured. An illustration of the transient nature of flaring is provided in Figure 4. The duration of flaring from any production location can be as short as 1 day to as long as 2 years, depending on a variety of factors discussed previously.

In the past, if a well had no gas-gathering pipeline connection, 100% of the produced gas would likely be flared. However, beginning in approximately 2018, producers have been implementing strategies to reduce their volumes of flared gas to meet the gas capture targets established by North Dakota and, increasingly, to meet ESG standards that have been set by individual oil and gas companies. One of the key strategies that has been implemented by industry is to shift early well production strategies to curtail initial high-volume oil and gas production to avoid exceeding gas takeaway capacity, thereby reducing flared gas volumes (Kringstad, 2022).

4.0 TEMPORARY SUBSURFACE GAS STORAGE

Gas injection into subsurface formations as a mechanism to store large volumes of gas or for EOR is not a new concept. Commercial gas storage has been practiced at a very large scale for over a century, typically to balance the relatively steady production of natural gas in North America with the relatively seasonal demand associated with heating. Common large-volume natural gas storage sites include depleted or partially depleted oil/gas reservoirs, saline formations, and anthropogenic caverns within salt formations (salt caverns), with depleted reservoirs generally being the preferred candidate because of the demonstrated ability to retain hydrocarbons (Katz and Tek, 1981). In these large-scale environments, geologic structure is used to create a gas–water cushion zone surrounding the gas bubble. The gas bubble, often referred to as working gas, is the gas that is added to or withdrawn to help meet current demands. The cushion/base gas is generally unrecoverable and can account for over half of the injected gas and 70% of the initial facility cost (Berger and Arnoult, 1989). Figure 5 is a map that depicts the distribution of U.S. natural gas storage reservoirs by type (U.S. Energy Information Administration, 2023). As illustrated, many commercial gas storage facilities are larger than 50 billion cubic feet (Bcf), a volume ten times larger than a typical Bakken wellsite could supply in a year.

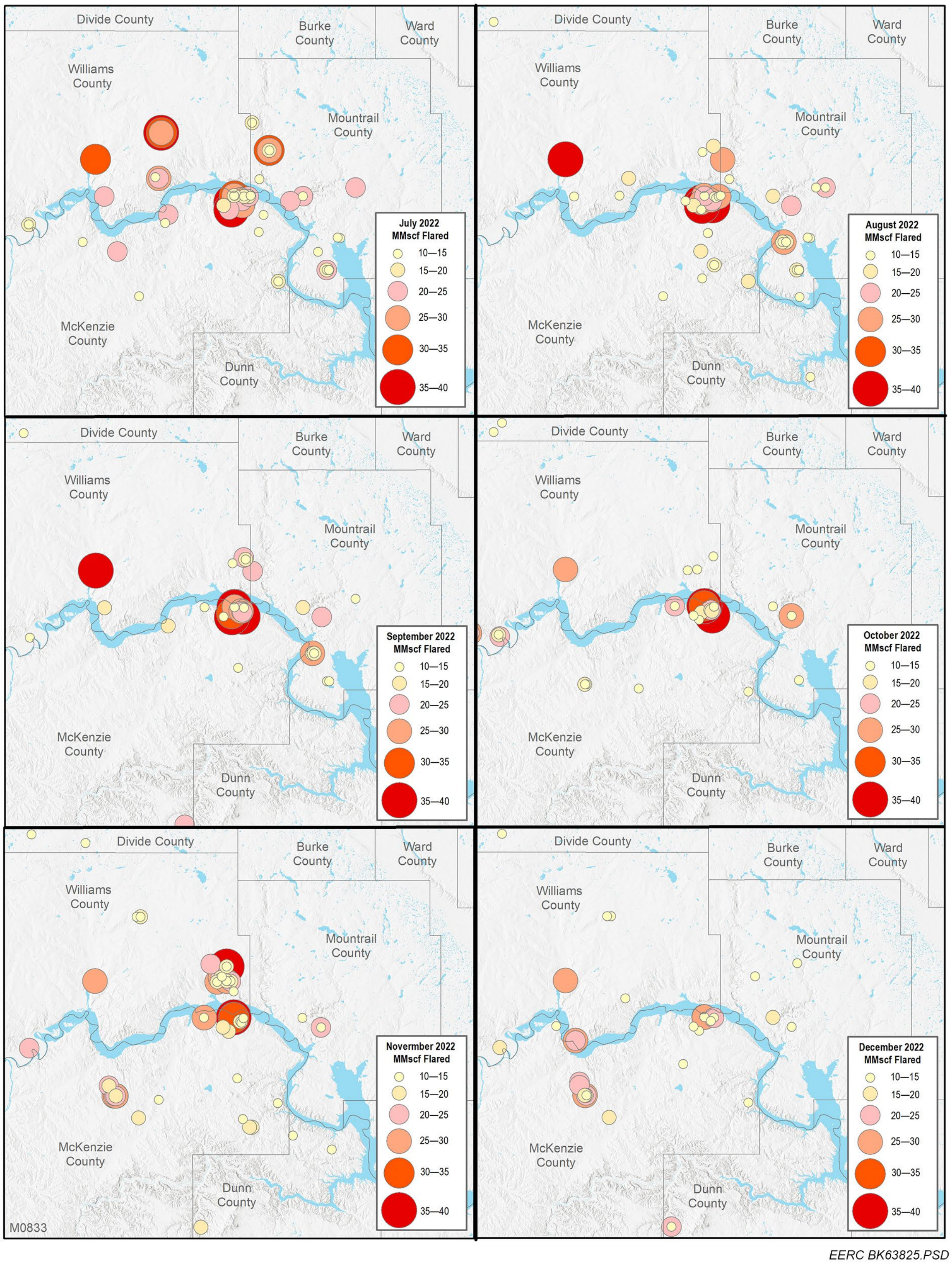

Figure 4. Illustration of the transient nature of flaring, with flares larger than 0.3 MMscf/day mapped for each month (North Dakota Industrial Commission, 2023).

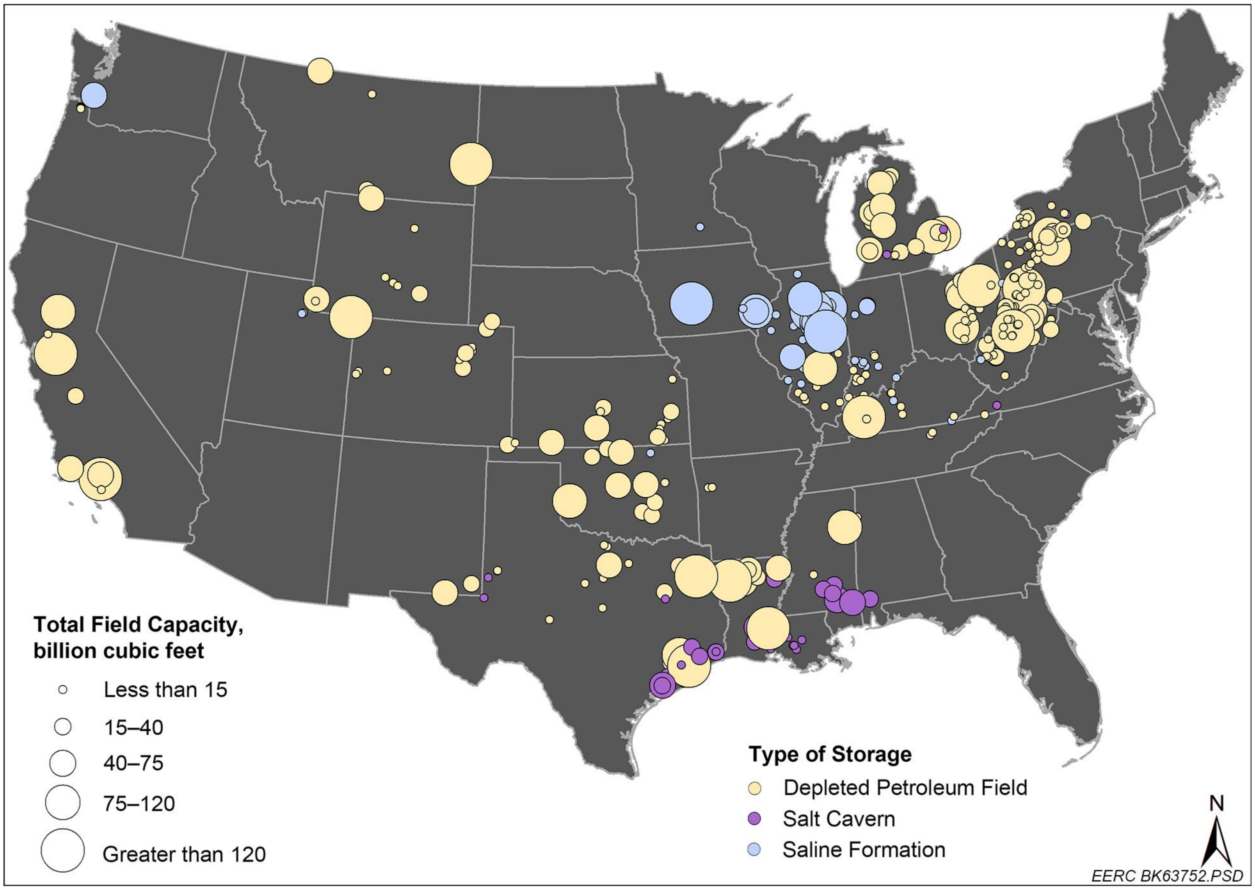

Figure 5. Distribution of U.S. natural gas storage reservoirs by type (modified from U.S. Energy Information Administration, 2023).

The Williston Basin is well-suited for gas storage in that there are multiple potential options for subsurface produced gas injection, including saline formations and depleted oil reservoirs for temporary produced gas storage as well as conventional and unconventional oil reservoirs that are candidates for EOR through produced gas injection. An illustration of potential means of subsurface storage/injection in the Williston Basin is shown in Figure 6. Ideally, storage formations should have adequate reservoir thickness and injectivity (a combination of porosity and permeability) to accommodate a target volume of gas for storage. Additionally, an overlying low-permeability cap rock lithology (shales, salts, or tight carbonates) is important for the containment of the injected gas within the reservoir formation.

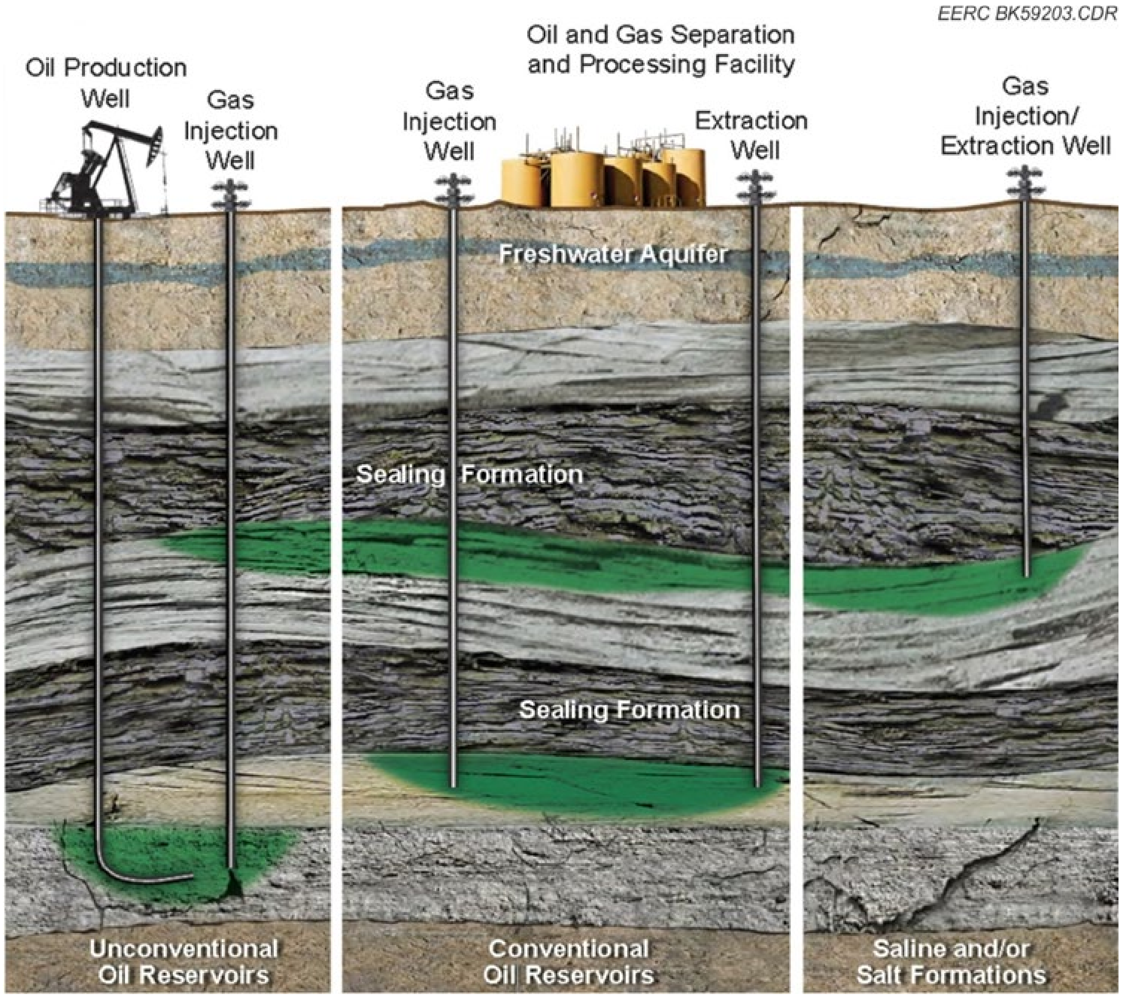

Figure 6. Illustration of potential means of subsurface gas storage/injection, including unconventional and conventional oil reservoirs and saline formations. Image is not to scale.

In addition to determining the geologic suitability of a site for gas storage or EOR, several additional aspects must be considered or addressed prior to implementing a gas injection pilot project. The first step typically entails an initial site assessment that includes an evaluation of the availability of produced gas at the site, the gas storage potential of the site, formation injectivity, gas compression requirements and general costs, availability of existing infrastructure to facilitate the project, and additional infrastructure and/or equipment needs.

Once the initial site assessment is complete, additional work must be performed to elucidate the details of the project. Rock characterization data from the injection target (or from nearby locations) are needed to better understand the gas storage potential at the injection location, to predict gas injection rates, to determine the potential for adsorption of the various gas components within the reservoir, and to evaluate the overlying formation as a reservoir seal. If the goal of the pilot is to demonstrate EOR and storage in an oil reservoir, laboratory tests to determine key reservoir properties that control effective EOR (such as minimum miscibility pressure [MMP] of the oil and relative permeability of the injected gas) must be conducted. The rock and fluid characterization and analytical data are used to support development of geologic and reservoir simulation models of the injection targets to better define and estimate the injectivity of the target, the gas storage potential, gas and water recovery rates, stored gas plume extents in the formation and, if applicable, incremental oil recovery. The modeling and simulation results are then used to help design and inform the field demonstration tests.

Another key component includes the determination of the surface facilities and equipment required for produced gas injection and recovery, including the gas conditioning and compression requirements, brine disposal options, stored gas recovery system requirements and costs, and other surface-related infrastructure. Depending on the nature and duration of the pilot project, equipment rental options may also need to be evaluated as an alternative to purchasing equipment.

Ultimately, the information derived from the above components is used to determine the technical and economic viability of each project. The costs to implement the project are then compared with the benefits associated with the operator being able to bring new wells online at locations with limited or no gas takeaway capacity while still meeting state-mandated or company-mandated produced gas capture targets.

While the technical and economic feasibility of potential gas storage projects are important, a key consideration is the regulatory process needed to permit each project. Some aspects of the process are well defined, such as the need to ensure the geologic suitability of the injection target and to review the integrity of any wells that penetrate the subsurface storage area (plus a buffer). Other aspects, such as the percentage of pore space owners that must be amalgamated within the storage area, are not so well-defined. The following section discusses key aspects of the regulatory processes needed for approval of produced gas injection/storage and key areas where additional regulatory clarity is needed.

5.0 REGULATORY CONSIDERATIONS FOR PRODUCED GAS INJECTION AND STORAGE

Underground injection of produced natural gas in North Dakota for the purpose of EOR or temporary geologic storage is regulated by NDIC’s Oil and Gas Division, herein after referred to as the Commission. The Commission’s oil and gas jurisdiction is defined by statute in NDCC Section 38-08-04 and includes Subsection 1b, which identifies in part the Commission’s authority to regulate “operations to increase ultimate recovery such as cycling of gas, the maintenance of pressure, and the introduction of gas, water, or other substances into producing formations” and “the underground storage of oil and gas.” (NDCC §38-08-04.1).

The underground storage of gas is regulated by NDAC 43-02-14 Geologic Storage of Oil or Gas, which “pertains to the geological storage of hydrogen and produced oil or gas with little to no processing involved” (NDAC §43-02-14-02). Prior to the enaction of 43-02-14, gas injection for EOR or to temporarily store produced gas were predominately regulated under North Dakota’s Class II underground injection control (UIC) program. The regulatory frameworks for unitized EOR in North Dakota are well established, with over 200 conventional EOR units and four unconventional Bakken units. Pilot-scale injectivity tests, which were permitted to inject produced gas into the Bakken pool in a drilling and spacing unit, were regulated through a combination of the individual Commission order and the Class II UIC requirements. Specific underground gas storage rules were enacted in April 2021.

The Commission's gas storage guidance and regulatory jurisdiction does not apply to transportation-related gas storage regulated under federal authority. If processing plants or pipelines are federally regulated, the storage facility is federally regulated. Temporary geologic storage of produced gas in the context of this report focuses on produced gas with little to no processing involved that has been produced from the BPS in association with crude oil production. Gas storage in nonoil-bearing geologic strata (geologic storage) has been identified as a temporary solution to mitigate flared gas.

Through recently enacted underground gas storage regulations, North Dakota has established a complete and comprehensive statutory and regulatory framework for geologic storage of oil or gas. The next step for future produced gas storage project development will be charting a path forward through the implementation of these newly established permitting regulations. Project developers can draw from three important analogs when developing the first produced gas storage facility permit. First, oil and gas unitization is a well-established process, and aspects of unitization can be used when developing permit applications for produced gas storage, especially if the project developer is targeting an oil and gas reservoir. Second, the Class II UIC injection well permit application requirements (NDAC §43-02-05-04) align with the gas storage injection well permit requirements (NDAC §43-02-14-06, Subsection 3b[1]–[16] and NDAC §43-02-14-07, Subsection 3b[1]–[16]), and project developers can use the numerous examples of approved UIC permit applications to develop the injection well component of a gas storage permit. Third, the gas storage statute (NDCC §38-25) and regulations (NDAC §43-02-14) mirror the geologic storage of CO_2 statute (NDCC §38-22) and regulations (NDAC §43-05-01). The first CO_2 storage facility was permitted on October 19, 2021, creating the Red Trail Richardton Ethanol Broom Creek Storage Facility 1 (NDIC Case No. 28848, Order No. 31453), and the first pore space amalgamation was approved as part of that CO_2 storage project (NDIC Case No. 28849, Order No. 31454). This CO_2 storage permit acts as a partial template for certain aspects of a produced gas storage permit application that align with the CO_2 storage facility permit requirements. These three analogs (oil and gas unitization, Class II UIC permitting, and CO_2 storage facility permitting) form the framework for a produced gas storage facility permit template. Additional regulatory details can be found in the North Dakota Underground Gas Storage Permitting guidance document (Olsen and others, 2023).

6.0 PILOT PROJECT SUMMARIES

The EERC worked closely with XTO, Marathon, Liberty, and Maroon Bells beginning in July 2019 and extended that work through the spring of 2023 to assess six conceptual pilot projects: 1) two produced gas storage efforts in the Minnelusa Group (Broom Creek and Amsden Formations), 2) an investigation into produced gas storage potential in the Duperow Formation, 3) an evaluation on the potential of produced gas storage in the Inyan Kara Formation, and 4) two assessments of produced gas injection for EOR in the BPS. Across these various investigations, the EERC performed site characterization activities, geologic model construction, and numerical simulation of produced gas injection. The EERC also partnered with Liberty Resources on a field demonstration of a technology developed by EOR ETC for gas injection for EOR in the BPS.

Reservoir models were constructed by coupling a geologic model developed using SLB's Petrel E&P software platform (SLB, 2022) with numerical simulation software developed by Computer Modelling Group (CMG) (Computer Modelling Group Ltd., 2021). Once developed, the reservoir models were used to evaluate a variety of different gas injection and recovery scenarios, which are discussed in subsequent sections of this report. Simulation scenarios were created to evaluate gas plume extents, gas recovery rates, affects to legacy wells, potential monitoring wells locations, necessary gas conditioning and compression equipment, and gas injection rates and volumes to maximize incremental oil recovery. For all simulations, pressure constraints were used to ensure conditions within the simulation were not so great to cause failure of surface equipment or fracture the rock in the reservoir. Bottomhole pressure (BHP) limits were set to 90% of reservoir fracture pressure. Wellhead pressure (WHP) limits were used to indicate the class of surface equipment necessary to handle the pressures at the surface. Higher WHP simulation scenarios may require specialty surface equipment in the field.

6.1 Collaboration with Marathon

The EERC partnered with Marathon in the technical evaluation of temporary produced gas storage in two potential storage formations: the Duperow and Broom Creek Formations. At the time collaboration began, Marathon had several locations with no or limited gas takeaway capacity. Initially, Marathon was interested in evaluating the concept of aggregating gas produced from multiple pads to a centrally located temporary gas storage location in the Duperow Formation; however, toward completion of the technical evaluation, Marathon decided not to pursue a full-scale gas storage project because of emerging agreements with midstream service providers. Following the Duperow assessment, a second evaluation was performed for a second area of the Bakken with limited gas takeaway capacity. That evaluation focused on injection of smaller volumes of gas than in the first assessment, and the target was the Broom Creek Formation.

6.1.1 Marathon Duperow Investigation

The objective of the Duperow Formation evaluation performed in partnership with Marathon was to estimate the injectivity, gas storage potential, gas recovery rates, and stored gas plume extents for a location within the core Bakken production area. The injection target averages 11,000 feet deep and is self-sealed by low-permeability limestones of the upper Duperow. A series of geologic and numerical simulation models were developed and implemented to evaluate a target injection of 117-Bscf produced gas over a 7-year time frame using existing and, as necessary, new injection wells. Based on Marathon's input, realistic operational cases were created to evaluate staggered starting well injection, variable injection rates over time, injectivity of the Duperow, and optimal well count. This section summarizes salient information from Kurz and others (2023b), which contains additional and supplemental details.

Evaluation and optimization of existing well locations without gas injection rate constraints and a maximum BHP of 0.75 psi/ft resulted in five legacy wells injecting up to 40.2 Bscf and

17.2 Bscf with a BHP of 0.62 psi/ft within the Duperow, well short of the targeted gas injection volume. Additional well locations were evaluated and optimized within the proposed area to achieve the target volume. The best scenario used five new injection well locations and two existing high-potential legacy wells to inject 119 Bscf with a final WHP of 5850 psi with maximum allowable BHP of 0.75 psi/ft and gas injection rates of 10 MMscf/d. Reducing the gas injection rate to 5 MMscf/d or limiting the WHP to 5000 psi was estimated to reduce the gas injection volume to 87.4 and 73 Bscf, respectively.

Staggered injection well start time simulations were also evaluated. Using the five optimized well locations, each new injection well was brought online at a rate of one per year for 5 years. An estimated 74 Bscf could be stored over 7 years, with the staggered wells using maximum allowable BHP and maximum 12-MMscf/d injection rate resulting in a gas plume radius of 1.2 miles around each well (Figure 7). Sensitivity analysis of the input assumptions tested a lower BHP (0.62 psi/ft), a fixed lower WHP (4500 psi), and a lower injection rate (2MMscf/d), yielding final injected gas volumes to 42, 28, and 18 Bscf, respectively. The observed gas footprint after 7-year gas injection periods and 5-year postinjection for all cases illustrated that the plume of injected gas had a slight southern movement up dip.

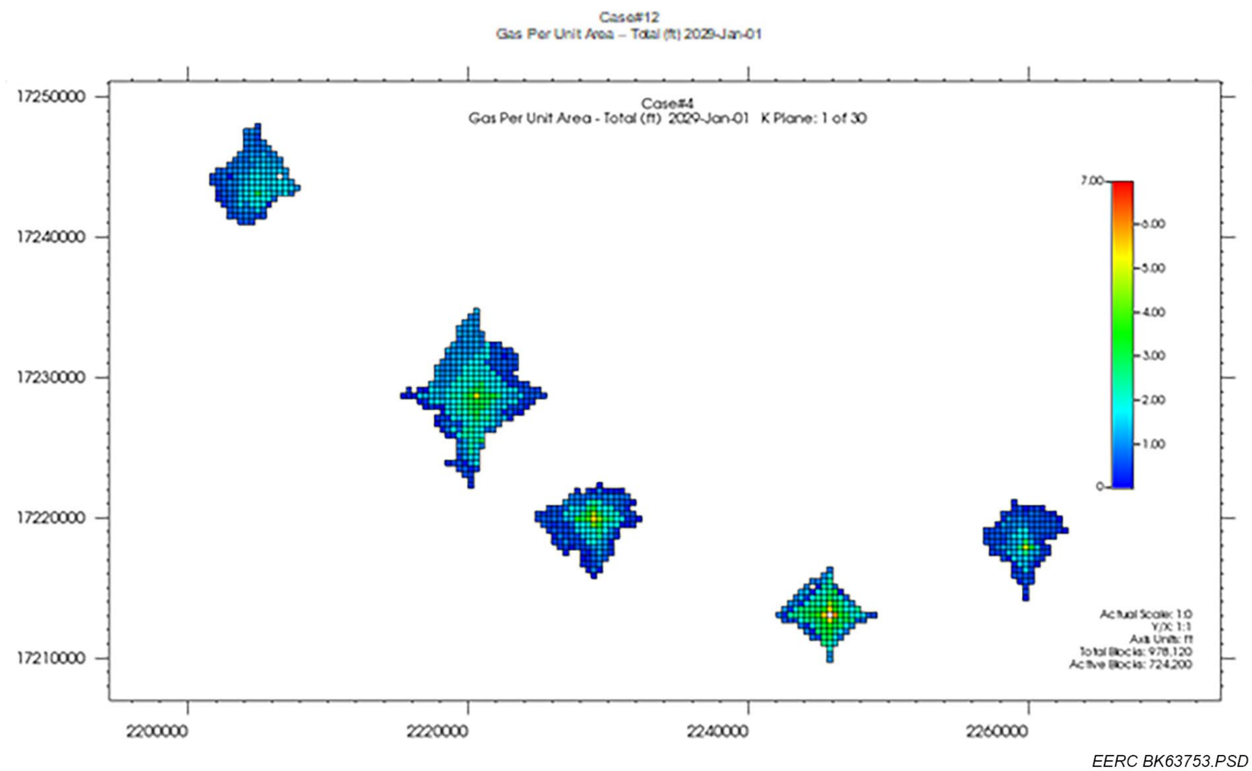

Figure 7. Produced gas injection plume extension after 7-year injection with rate 12 MMscfd. Maximum plume radius 1.2 mi (Kurz and others, 2023b).

Variable injection rate scenarios were created to simulate gas production rate decline over time. Two production well pads were used to test the variable injection rate scenarios, one with an estimated 620-MMscf total gas production over 3 months and the other with 1415-MMscf total gas production over 12 months. Gas production rates varied between 2 MMscf/d to 9.2 MMscf/d. Simulation results suggest that to inject 620 MMscf over 3 months, one injection well at maximum BHP injection can achieve the target; however, the WHP would be as high as 5200 psi at the early time of injection. Operating the injection with two wells showed a WHP reduction to 4800 psi. One operational well was insufficient to handle the scenario to inject a total volume of produced gas of 1415 MMscf over 12 months at maximum BHP constraints, and at least two wells would be required to handle operations with the pressure response approaching 5100 psi for both injection wells. The predicted plume extent showed insignificant movement at the end of the 3- or 12-month injection period compared with the 5-year postinjection, suggesting plumes would be well contained at this location over the time frame.

Numerous simulation scenarios were developed and implemented based on the staggered five injection wells case. Wells were brought online one by one each year to evaluate gas recovery for 5-, 10-, and 40-year extraction periods. The base injection scenario resulted in a 66% recovery factor using a constant injection rate of 12 MMscf/d for 7 years (73.6 Bscf), a 5-year shut-in period, and 5 years of gas production at a rate of 15 MMscf/d and BHP of 2000 psi. The same scenario except with a 10-year gas recovery period resulted in an estimated gas recovery of 75%. However, the gas extraction recovery factor can vary based on the different operating parameters such as well constraints, well location, and shut-in time before starting the production process. The simulation findings are highlighted below:

1. Producing without limiting the gas production rate increased the gas recovery to 71% and 79% for the 5-year and 10-year recovery periods, respectively.

2. Adding water production rate constraints (2000 bbl/d) to the production wells was predicted to decrease the gas recovery to 64% and 71% following 5- and 10-year recovery periods, respectively.

3. The simulation results indicate that soaking time would reduce gas recovery. Without implementing a soaking period, gas recovery could increase to 70% and 80% for the 5-year recovery and 10-year recovery scenarios, respectively. As expected, the gas footprint could become larger for longer storage periods and dispersion of gas within the target storage reservoir would increase, thereby decreasing the recoverable volume of gas.

Based on simulation results, the currently existing wells in the oil field could be used as injectors, producers, and monitoring wells. However, the simulation results showed that gas recovery factors using the legacy well location with the allowable gas production rate of 15 MMscf/d would produce gas at the lowest recovery factor (57%) compared to optimized well locations.

6.1.2 Broom Creek Evaluation

The model area selected for evaluation of produced gas storage feasibility in the Broom Creek Formation covered two locations of interest (referred to as the northern and southern acreage units) for Marathon, including a couple of multiwell pad locations without current gas takeaway capacity. Geologic and numerical simulation models were developed to estimate the produced gas injection volume, gas storage potential, injected gas plume development, and gas recovery potential. The Broom Creek simulation models were generated based on geologic model and operator inputs. To limit model size, the northern and southern acreage units were simulated separately. A pressure, volume, and temperature (PVT) model and relative permeability data from previous EERC Broom Creek studies were used to represent reservoir fluid properties and fluid mobility during gas injection. Several injection scenarios were designed to evaluate gas injectivity and recovery performance and optimize operational design of a potential future gas storage pilot test. This section summarizes key findings reported in Kurz and others (2023a).

The technical feasibility of the proposed area was assessed for produced gas injection into the Broom Creek over a 3-year period by evaluating the number and location of injection wells and injection operation scenarios needed to support the gas volumes anticipated from producing wells without takeaway capacity. Four wells in the northern acreage and three in the southern were selected, and several scenarios were evaluated to optimize gas injection and recovery. Injection wells were constrained within the simulation model to a maximum allowable bottomhole pressure (BHP) based on 90% of formation fracture gradients (0.63 psi/ft) and a constant WHP (Table 2).

Table 2. Summary of Gas Injection Scenarios Implemented on Injection Wells for the Marathon Broom Creek Evaluation

Injection Scenarios	Case Description	Max. Gas Injection Rate, MMscf/d	WHP, psi	BHP, psi
Northern Acreage	Northeast well	68	3500	4593
	Northwest well	46	3500	4717
	Central west well	59	3500	4707
	Southwest well	53	3500	4621
	Northeast well + variable rate from one pad	9.3	2950	4593
	Northeast well + variable rate from two pads	18.7	3050	4593
	Northeast well + variable rate from ten pads	56.5	3200	4593
Southern Acreage	West well	80	3500	4866
	East well	93	3500	4663
	Middle well	83.5	3500	4830
	Middle well + constant rate	10	3000	4830
	Middle well + constant rate	30	3200	4830
	Middle well + variable rate	19	3000	4830

Maximum gas injection volumes for any of the simulated injection wells, and constrained only by BHP and WHP, varied between 46.0 Bscf to 74.5 Bscf for 3 years of injection. To predict optimal injection volumes into the Broom Creek Formation, numerous simulation scenarios were developed based on constant and variable gas injection rates. Constant injection cases included injection rates of 10 or 30 MMscf/d over 3 years, resulting in injected gas plumes with 0.9- – 1.5-mile radii (Figures 8 and 9). Variable injection cases, selected to imitate field production conditions, were evaluated to account for the gas production rate decline or variation over time. Simulations demonstrate that Broom Creek injectivity is sufficient for a single well to inject the targeted volumes of produced gas at maximum BHP. Surface pressure responses from all scenarios were predicted to be below 3200 psi.

A declining gas injection rate was provided by Marathon to assess more realistic produced gas injection. The scenario that was evaluated included 33,350 MMscf of gas injected over 9 years with a maximum gas rate of 19 MMscf/d. The results suggest that one operational well would be sufficient to handle the volume of produced gas injection at maximum BHP. The WHP was predicted at approximately 3000 psi, which is lower than the constraint WHP of 3500 psi. In addition, the gas plume footprint at the end of 9 years of injection reached a maximum radius of 1 mile (Figure 10).

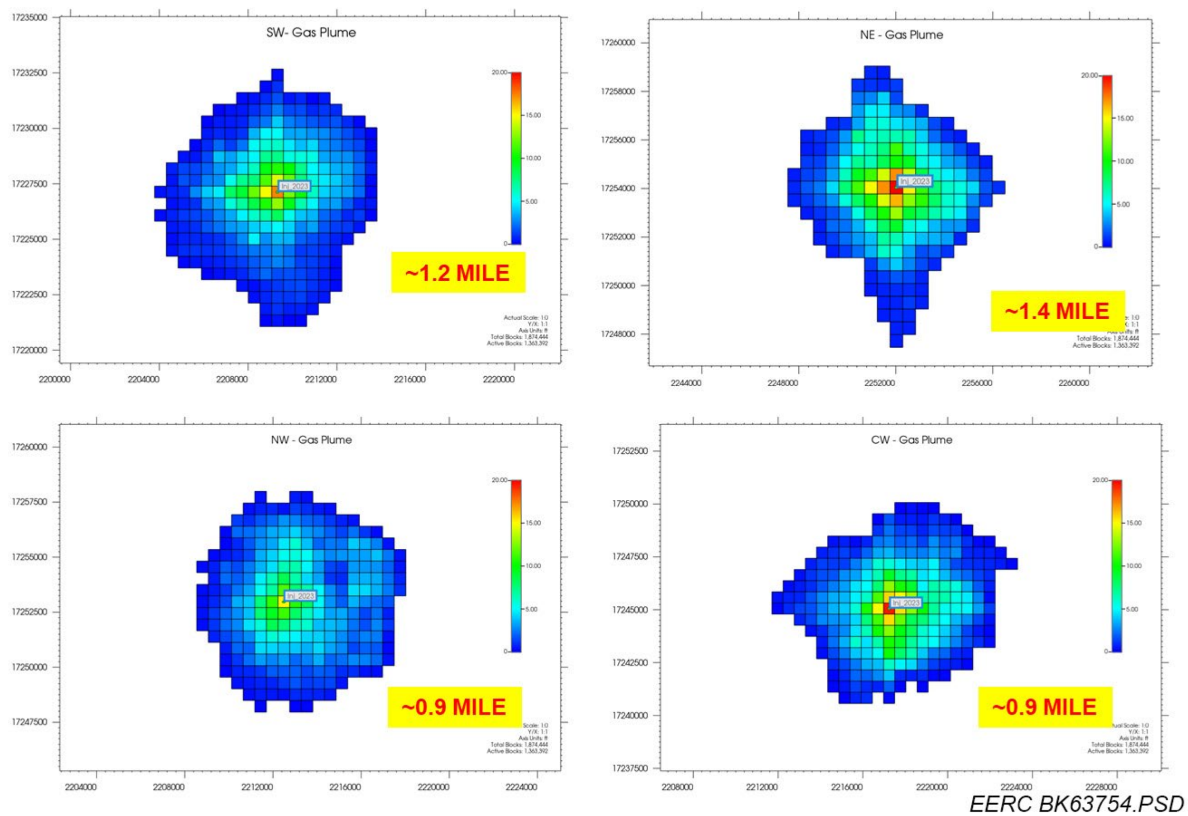

Figure 8. Produced gas injection plume extent after 3-year injection with maximum allowable injection pressure for the northern acreage wells: northeast, southwest, central west, and northwest well locations at 1.4-, 1.2-, 0.9-, and 0.9-mile radii, respectively (Kurz and others, 2023a).

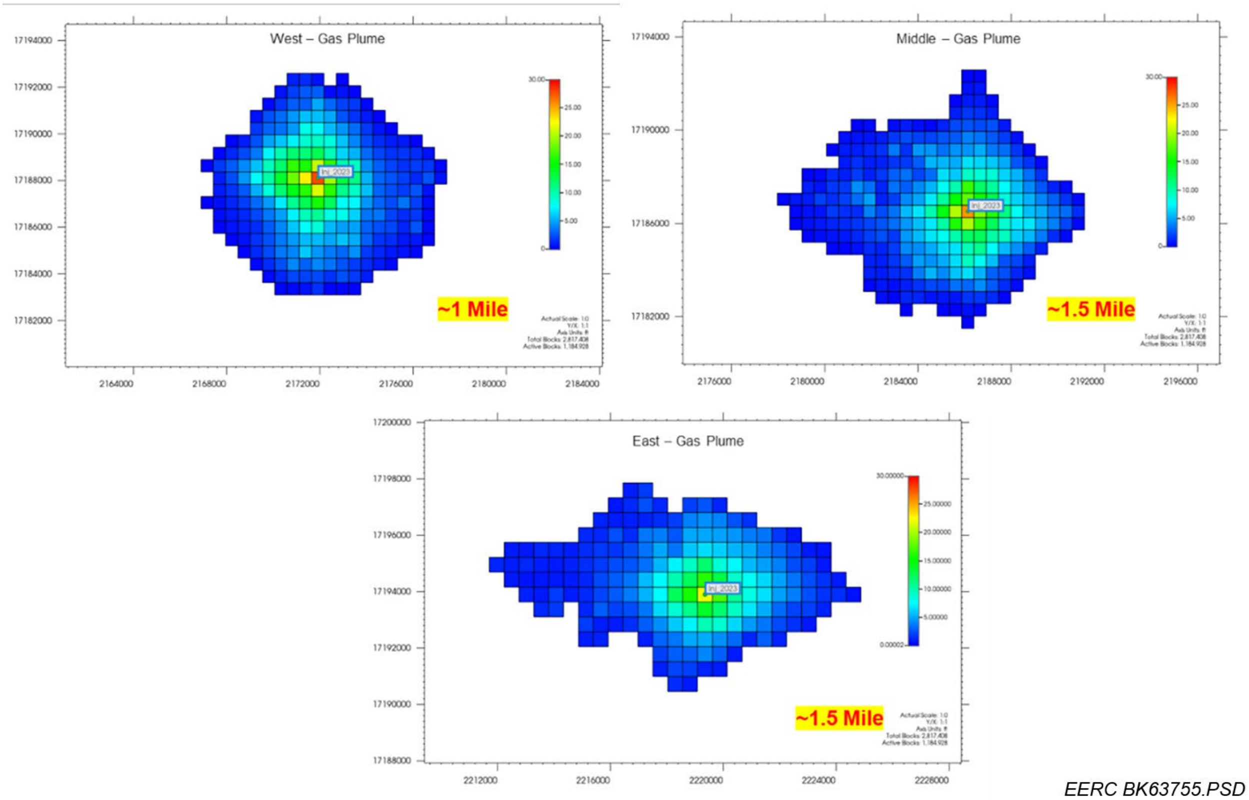

Figure 9. Produced gas injection plume extent after 3-year injection with maximum allowable injection pressure for the southern acreage wells: west, middle, east well locations at 1.0-, 1.5-, and 1.5-mile radii, respectively (Kurz and others, 2023a).

Extraction scenarios with limited well constraints of gas extraction rate, minimum producing BHP, liquid extraction rate, and operational duration were evaluated. The gas recovery simulation result highlights:

1. Injecting 10 MMscf/d and 30 MMscf/d over 3 years using one injection well and extracting the injected gas with the same constant gas rate and BHP of 3500 psi (close to initial reservoir pressure) was predicted to result in gas recoveries of 53% and 55% after 5 years of production, respectively.

2. Operating the gas extraction at 2000 psi BHP after 30 MMscf/d of injection improved the recovery factor to 81%. However, the depletion process caused higher initial water extraction, and the water rate increased sharply from 3500 bbl/d to 83,500 bbl/d, which requires a large handling infrastructure and is not considered practical.

3. Sensitivity of gas recovery to the water extraction rate was performed to evaluate the effect of controlling water production. Limiting water rates to 5000, 10,000, and 20,000 bbl/d resulted in gas recovery factors ranging from 62% to 73%.

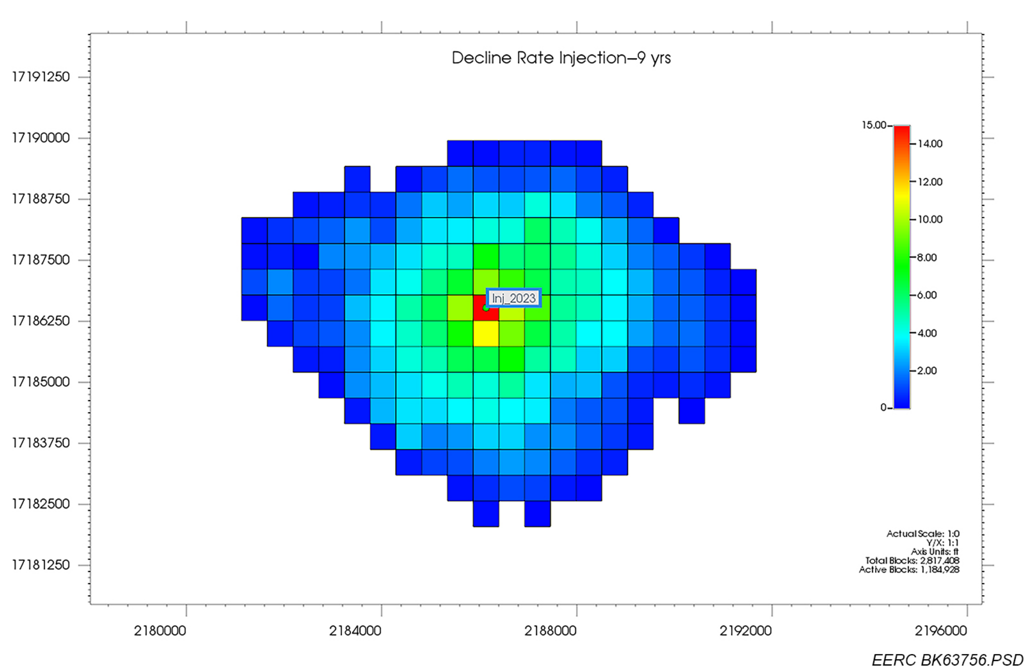

Figure 10. Produced gas injection plume extension after 9 years of injection in the southern acreage middle well location at 1-mile radius (Kurz and others, 2023a).

4. The sensitivity of the simulation scenarios to producing BHP was performed to evaluate 10-year extraction scenarios after the declining injection rate profiles. The recovery factor varied between 48% at a BHP of 3500 psi to 85% at a BHP of 2000 psi with no water extraction rate limit.

5. In the scenarios that included simulation of a declining gas injection rate, the water extraction rate over 10 years of production showed that as the maximum allowable water extraction rate increased (5000, 10,000, and 20,000 bbl/d), the gas recovery factor increased from 62% to 77%.

6. The maximum gas recovery after a 9-year injection period of 33 Bscf was 77% for a 10-year extraction period when maintaining a minimum 2000 psi BHP and limiting gas and water extraction rates to 30 MMscfd and 20,000 bbl/d, respectively.

Based on a 9-year gas production profile, the surface facility evaluation required gas injection with rates up to 19 MMscf/d at WHPs of 3500 psig. The most favorable option to support the requirements was a single purpose-built compressor package with additional smaller compressors providing support during peak gas flow. Using a single centralized compressor at the injection well avoids the cost and logistics of moving smaller compressors between well sites, though some gas boosting would likely be required to push gas from production wells to the injection site. Some considerations are necessary for a single centralized compressor during shut-in periods or compressor maintenance to the incoming gas volumes. Multiple smaller compressors could assist with redundancy and continuous operations at the cost of more maintenance and operational costs. Projects must balance plans for continuous operations (e.g., multiple smaller compressors) versus reduced maintenance and operational costs (e.g., single centralized compressor); however, it may be desirable to install several smaller compressors to provide redundancy during maintenance periods of centralized compressors.

6.2 Maroon Bells Inyan Kara Investigation

The purpose of this study was to evaluate injecting produced gas along with saltwater disposal (SWD) into the Inyan Kara Formation for temporary geologic storage and feasibility of future recovery. The EERC worked closely with Maroon Bells, a privately owned oil and gas company, to identify subsurface mechanisms for temporary produced gas injection at a previously identified potential injection site. A key goal of the evaluation was to assess whether the injected gas would gravity separate and accumulate at the top of the storage reservoir following a period of storage, thereby increasing the efficiency and volumes of gas recovery. This section summarizes key findings reported in Kurz and others (2023c).

Geomodeling and numerical simulation activities were conducted to assess key technical factors for gas injection and production cycles within the Inyan Kara. A geologic model was built for the Maroon Bells injection site using petrophysical well logs to describe the depth, thickness, rock facies, porosity, and permeability of the Inyan Kara and surrounding formations. Bakken produced gas PVT data were estimated using an equation-of-state (EOS) calculation to simulate the gas behavior based on a ten-component composition data set provided by Maroon Bells. Using the geologic model and EOS, a numerical simulation model was developed and history-matched to brine injection data from an SWD well close to the proposed injection well.

Maroon Bells provided 10 years of predicted data to simulate the oil, brine, and produced gas injection rates. The concept that was evaluated entailed the injection of produced brine and gas into the Inyan Kara Formation together through the same injection well. The proposed 10-year injection schedule was to store 4.05 Bcf of gas and 5.9 MMbbl of water in the formation. These data were integrated into the simulation model scenario, and injection rates were used as primary constraints. A maximum BHP of 3860 psi was set as a secondary constraint in the model to prevent fracturing of the formation.

A sensitivity analysis of operational parameters was performed to evaluate water and gas injectivity and gas recovery performance. Numerical simulation cases were conducted to evaluate well injectivity integrating the planned water and gas injection data into the history-matched model. Figure 11 compares the input and simulated injection rates for water and gas, demonstrating that the simulation well has adequate injectivity to meet the proposed gas injection rates but has difficulty reaching the first 1.5 years of high water injection rates. Well stimulation could be needed to achieve higher water injection targets.

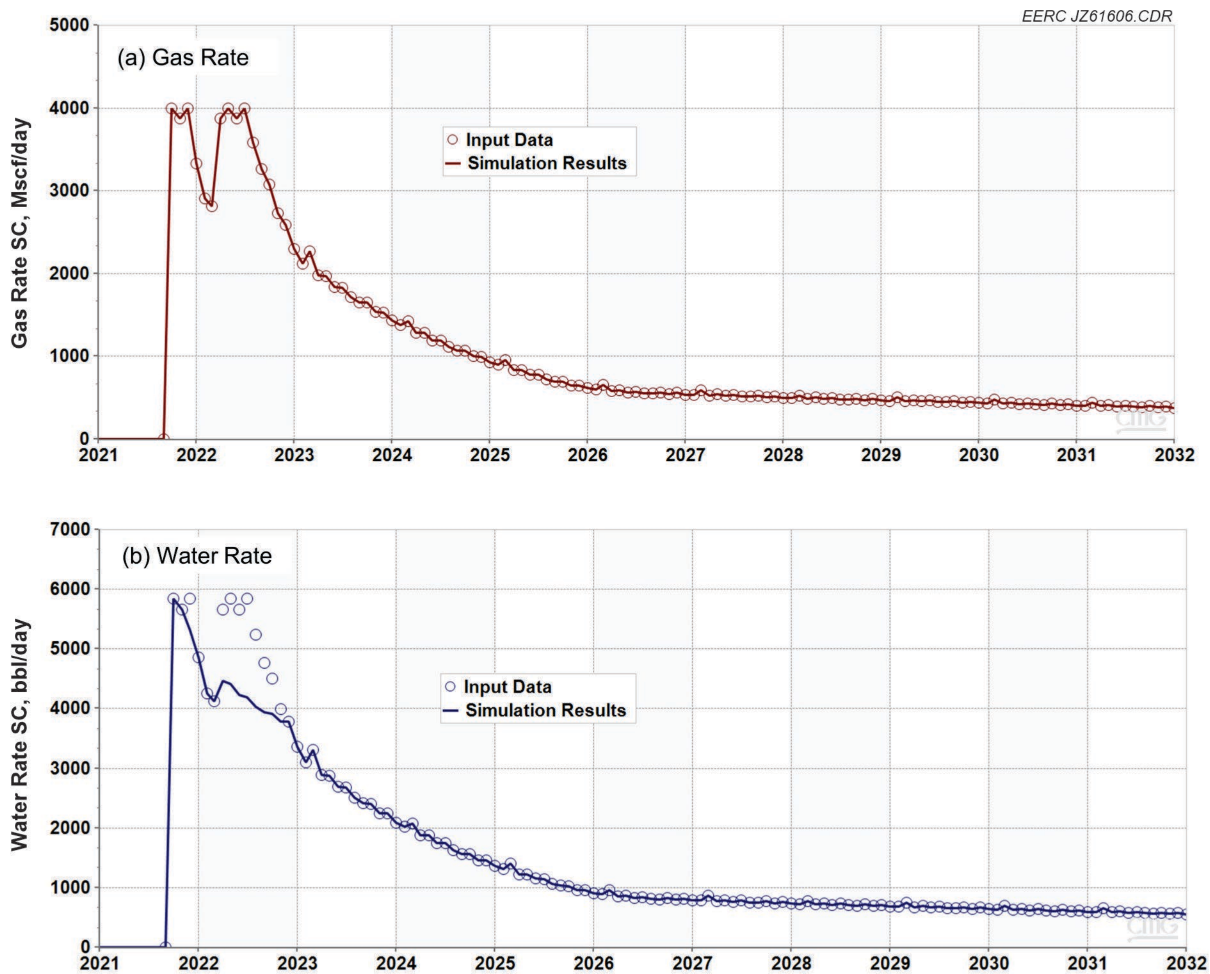

Figure 11. Comparison of input and simulated injection rates for a) gas and b) water (Kurz and others, 2023c).

To evaluate the potential improvement of water injectivity in the proposed injection well, different levels of stimulation were simulated by varying skin factors. A negative skin factor indicates a well is stimulated for improved injection rates at a given flowing BHP. Water injectivity was improved gradually within the simulations by decreasing the well skin factor and the water injection target was achieved at skin factor of −3 (Figure 12).

Two scenarios were considered to evaluate maximum gas storage potential without exceeding maximum injection pressure. The first was coinjection of both gas and water at the maximum allowed BHP of 3860 psi without a rate constraint. The second was gas injection only at a BHP of 3860 psi without a rate constraint. Comparing the two scenarios suggested that a significantly larger volume of gas can be injected into the formation when gas is the only injectant. Compared to the 4.05-Bscf proposed gas injection volume, these two scenarios exceeded the targeted volumes with an estimated 27 and 128 Bscf with and without coinjection of water, respectively. The simulation results suggest that the proposed site has more than adequate injectivity and pore volume for gas storage operations.

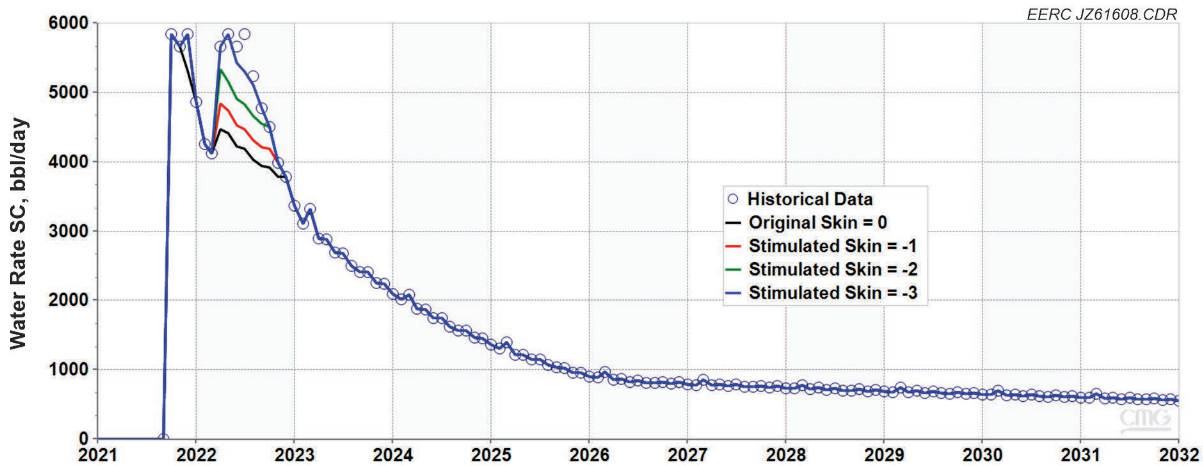

Figure 12. Water injectivity improvement with skin reduction through well stimulation (Kurz and others, 2023c).

The rate of change in injected gas plume size was observed to correlate to injection gas rates within the simulation. The gas plume size expanded quickly for the first 3 years then more slowly over the remaining 7 years as the production sourced gas volume reduced based on modeled production well declines. The final gas plume radius was estimated at 0.2 mi at the end of 10 years of injection (Figure 13).

Although a significant volume of gas can be stored in the Inyan Kara, the volume of gas recovered after the storage period is an important consideration for the viability of the concept. Compared to gas injection, additional operational factors can affect gas production performance, and a variety of gas production scenarios were analyzed to explore different factors on gas recovery performance.

Gas recovery performance is impacted by field operational decisions during production such as well type, well location, producing pressure, and well stimulation (e.g., skin reduction) (Kelkar, 2008; Lyons and Plisga, 2011; Wang and Economides, 2013; Guo and Ghalambor, 2014). Because the Inyan Kara is a saline formation, soaking time between injection and production becomes a factor for gas recovery. To investigate gas recovery performance, simulation cases were designed to test producing well location, minimum producing BHP, soaking time, positive skin factor (e.g., formation damage), and negative skin factor (e.g., stimulation).

Well location has a large effect on gas recovery potential in fluvial settings like the Inyan Kara. Different well locations have access to geologic heterogeneity and reservoir quality that may not be present in all locations. Proximity to operating injection or production wells affects pressure responses during injection and production. Structural features can affect gas recovery potential, with domes or anticlines possibly retaining injected gas in a smaller footprint and potentially enabling greater gas recovery. Simple low-dipping structures could allow injected gas to migrate and disperse under gravity segregation (buoyancy) effects, potentially decreasing gas recovery.

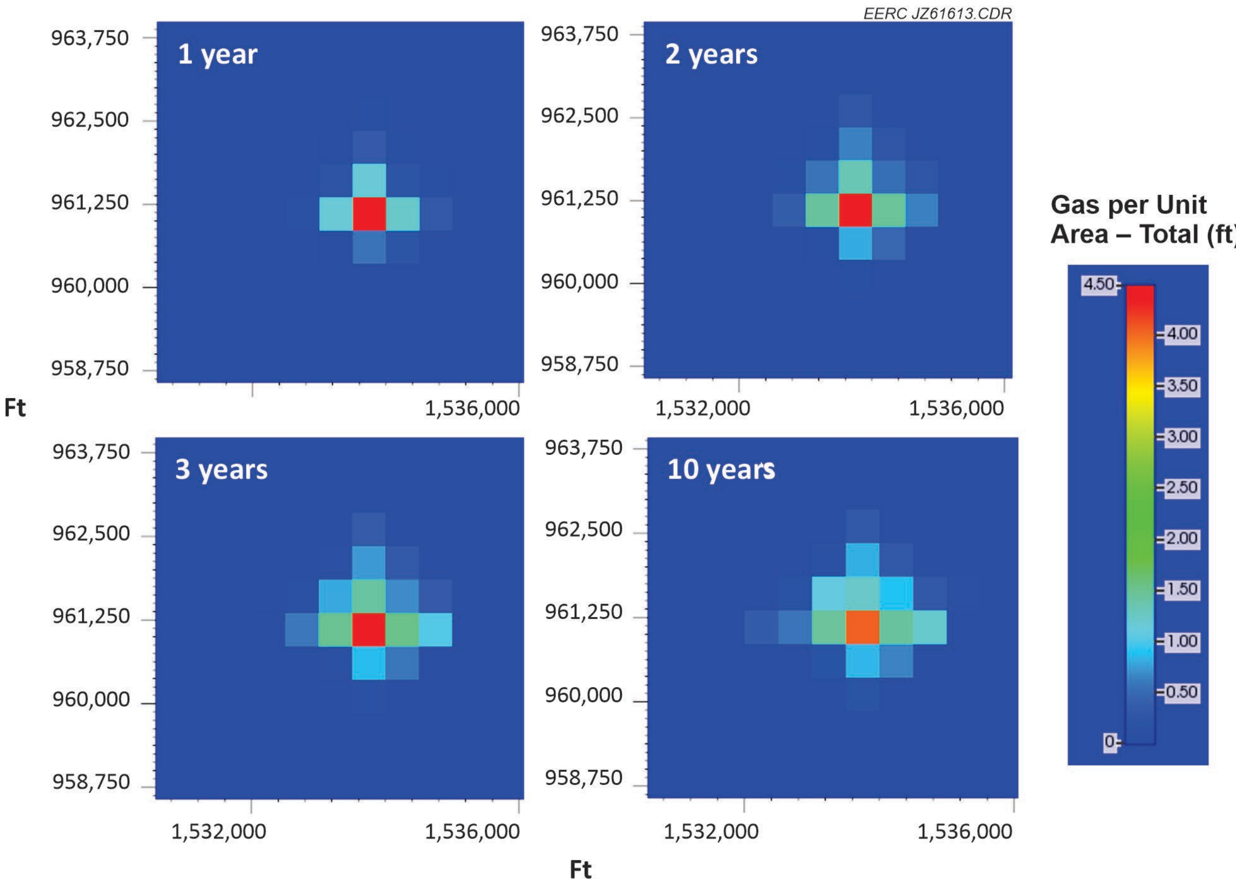

Figure 13. Gas plume extents during the injection process (Kurz and others, 2023c).

A lower operating bottomhole producing pressure is beneficial for gas recovery because the greater the pressure difference between the reservoir and the producing well, the more readily fluid will move toward the producer. The downside to operating at a lower BHP is that water production also increases, leading to greater costs for water disposal.

Simulation results indicated that a shorter soaking time (e.g., time between end of injection and start of production) improves gas recovery. Shorter soaking time provides less time for pressure dissipation and less migration time for gas to move away from the production well, allowing for better pressure support.

Formation damage, scale buildup, and skin factor are also important considerations. Plugging of reservoir perforations contributes to decreased producibility of injected gas. Stimulation or perforation treatment to enhance near-wellbore permeability (e.g., acidizing) can reduce skin factor and enhance performance during both injection and production.

Based on simulation results, coinjection of produced gas along with SWD is technically feasible; however, coinjecting water along with gas resulted in (predicted) gas recovery factors that were less than 36% for all scenarios evaluated. Simulation results did not demonstrate significant gas migration and accumulation because of fluid density differences (e.g., gas vs.

formation fluid or injected brine). In other words, gravity separation did not appear to drive gas movement over the relatively short cycles of gas and brine injection, planned storage, and recovery times evaluated by this effort.

6.3 Collaboration with XTO Energy

XTO was the first industry partner to collaborate with the EERC on the evaluation of subsurface produced gas injection and storage. Between July 2019 and June 2020, the EERC collaborated with XTO to evaluate produced gas storage in the Minnelusa Group (specifically the saline Broom Creek and Amsden Formations) and to evaluate using produced gas for EOR in the Bakken. XTO also worked closely with the EERC to better define areas where regulatory clarity was needed with respect to the permitting requirements for temporary produced gas storage. Meetings were held between the EERC, XTO, and DMR to better understand the existing regulatory requirements for temporary produced gas storage and to suggest areas in which regulatory clarity was needed. In addition, because the location of interest for produced gas storage in the Minnelusa Group was owned by the N.D. Department of Trust Lands, the EERC and XTO participated in several meetings and discussions to negotiate a pore space easement. Meetings were also held with the North Dakota Office of the State Tax Commissioner to better understand the tax structure related to temporary storage of produced gas prior to leaving the well pad at a point of sale.

The EERC and XTO were quickly advancing toward implementation of a field pilot project when the COVID-19 pandemic hit. Unfortunately, given the rapid decline in oil prices and the associated pause in oil and gas development, XTO decided not to proceed with implementation of the project. The following sections describe the detailed modeling and simulation efforts performed by the EERC to better understand temporary gas storage and recovery in the Minnelusa Group as well as produced gas EOR in the Bakken. The results of assessments performed with XTO illustrated the technical feasibility of geologic storage and recovery of produced gas as well as the potential increase in oil production that could be achieved using produced gas EOR in the Bakken. The following sections summarize key learnings of work reported in Kurz and others (2020).

6.3.1 Broom Creek Gas Storage Evaluation

The evaluation of temporary produced gas storage and recovery in the Minnelusa Group was focused on the Broom Creek and Amsden Formations. XTO was interested in this concept because it had a well pad in the core Bakken production area with eight drilled and completed wells with no gas takeaway capacity. Because of XTO's commitment to North Dakota's and its own internal (and more stringent) gas capture requirements, XTO planned on keeping the wells shut in until it had a means of handling the produced gas other than flaring.

A geomodel of the Broom Creek and Amsden Formations was developed for a 6×7-mile area centered on an existing Bakken well to be used as a vertical injector. The model properties were based on well data from within the model area to capture porosity and permeability for the sandstones and shale of the Broom Creek and dolostones of the Amsden. Relative permeabilities were calculated based on the Bakken gas composition and the brine of the Broom Creek. Injection

BHP was controlled by a maximum allowable pressure gradient 0.63 psi/ft, 90% of Broom Creek fracture gradient, making the BHP limit 4588 psi. The maximum WHP constraint was set at 5000 psi based on the surface facility assessment and the specifications from potentially available compression units.

A variety of constant produced gas injection rates, Cases 1–12, (ranging from 8 to 16 MMscf/d), injection durations (1, 2, and 5 years), and storage periods (1, 2, 5, and 10 years) were evaluated using reservoir simulation to test produced gas storage in saline formation (Table 3). Figure 13 shows the resulting lateral extent of the injected gas plume for Cases 1, 3, and 4 with 8 vs. 16 MMscf/d. Variable injection rates were also tested (Cases 13, 14, 15), beginning at 10 MMscf/d or 17 MMscf/d and reducing over the 2-year injection period with variable storage periods (1, 2, and 5 years).

Recovery factor results ranged from 43% to 63%, requiring the optimization of injection rates, injection period, storage period, and gas and water recovery rates. Shorter-duration gas storage periods, coupled with higher gas extraction rates (16 MMscf/d), resulted in higher estimated recovery factors (63%). Injecting at a variable rate, storing the gas for 5 years, and limiting the gas extraction rate to 5 MMscf/d caused lower recovery factors (43%).

Table 3. Primary Cases Investigated for Evaluating the Produced Gas Injection Pilot Project. Cases in Bold Selected for Sensitivity Analysis.

Case	Injection Time, Year	Postinjection Shut-In Period, Year
1	1	1
2		2
3		**5**
4		10
5	2	1
6		2
7		**5**
8		10
9	5 years	1
10		2
11		**5**
12		10
13	2, varying surface gas rate	**5**
14		1
15		2

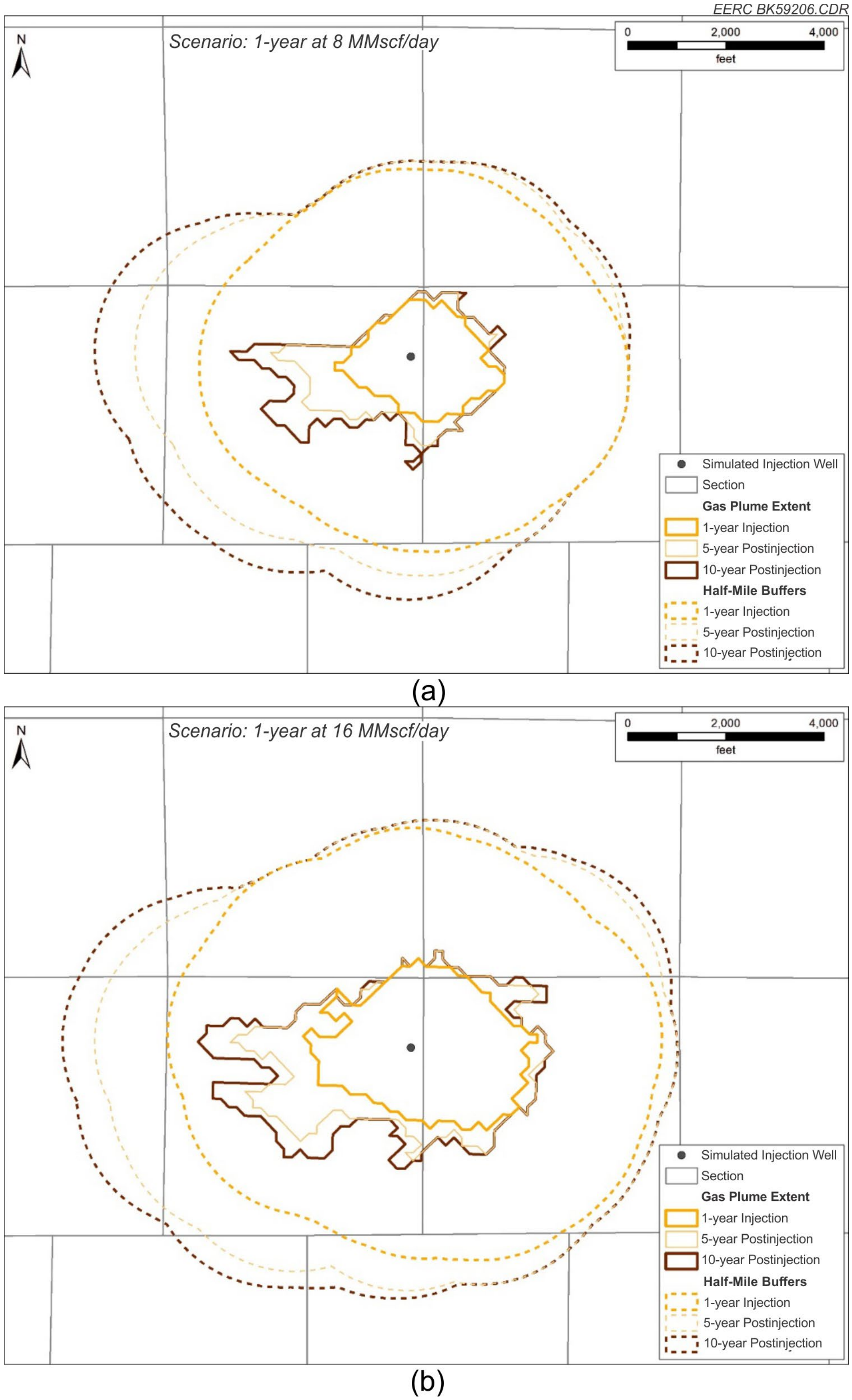

Figure 14. Estimated injected gas plume extent after a) 1 year of gas injection at a rate of 8 MMscf/d; b) 1 year of gas injection at a rate of 16 MMscf/d (Kurz and others, 2020).

The surface facility evaluation indicated that compressor frames capable of more modest flow rates (5-MMscf/d flow) are more readily available than compressor frames capable of handling the maximum estimated flow rate of 16 MMscf/d. Using multiple smaller compressors over a single large compressor allowed for flexibility with time and three to four compressors when handling high initial gas flow rates then allowing individual units to go offline as gas production rate declines. Prior to compression, produced gas would require treatment to remove NGLs and other impurities that could damage compression equipment. Trailer-mounted mechanical refrigeration units (MRUs) capable of 1-MMscf/d gas treatment are typically available and would allow for flexibility in reducing the number of compression units needed as gas volumes decline over time. The cost to lease the required number of MRUs was not evaluated and would have to be negotiated with appropriate service providers.

The gas storage scenarios evaluated for this study included only a single cycle of gas injection and recovery based on anticipated XTO operational scenarios. Kurz and others (2018) demonstrated that gas recovery rates could be increased from 50% to 63% after three cycles of gas injection and recovery into the same storage facility. For simulations, recovery factors are sensitive to fluid and formation properties (e.g., gas saturation and relative permeability), and additional laboratory testing of samples reduces uncertainties for planned injection sites and can be used as inputs to revise simulation results.

6.3.2 XTO Bakken EOR Investigation

XTO also partnered with the EERC to evaluate produced gas EOR in the BPS. Produced gas has been employed to enhance oil recovery in numerous pilot projects in several unconventional plays, and successful cases have been reported in the Eagle Ford play (Zhao and Others, 2022). Although theoretical studies and field tests have shown that better oil recovery is possible in unconventional reservoirs using produced gas injection, this technique has not yet been widely tested in the BPS. To evaluate the feasibility of produced gas injection for EOR in the BPS, systematic modeling and simulation activities were conducted by the EERC to support XTO objectives for EOR development of BPS resources. Specific objectives included implementing a pilot assessment to demonstrate the technical feasibility of increasing oil production through EOR from the Bakken pool utilizing produced gas as well as optimizing injection, soaking, and production strategies to improve gas injection/production performance and maximize achievable EOR benefits. This section summarizes key learnings of work reported in Jin and others (2022).

The proposed EOR pilot evaluation location was a drill spacing unit (DSU) in Dunn County, North Dakota. Produced gas to be used as an injectant was from producing pads near the proposed location. The expected injection rates were predicted to be up to 8 MMscfd into injection wells based on the available gas sources. The maximum allowable WHP was 5000 psi, and BHP was constrained to not exceed the formation fracture pressure gradient (~7500 psi). The EOR pilot duration was for 2 years with around 5 Bscf of produced gas to be injected. The surveillance plan included:

- Daily monitoring and recording of oil, gas, and water rates; GOR; and water cut trends in wells at the pilot DSU.

- Monitoring WHP data for all wells with some injection wells equipped with bottomhole gauges to record bottomhole flowing pressure during injection, soaking, and production cycles.

- Monitoring and recording of operational and production data from nearby offset pads (all operated by XTO for the pilot location).

A 3D geologic model for the EOR study was created from available well data. The zone of interest for the modeling effort included the Lodgepole, Bakken, and Three Forks Formations of the Williston Basin. Data from wells in the area around the pilot were collected from the NDIC database and analyzed for geologic and reservoir properties. The core porosity, permeability, and water saturation measurements from 17 wells in the study area were extracted from well files. A geologic model was built for the pilot site and its offset area using petrophysical well log data within SLB's Petrel software (SLB, 2022). Based on the geologic model, a simulation model with seven wells was developed to reproduce the historical data and predict the possible EOR response in the field.

Interwell fluid communication was observed in the production history of the pilot site, and a multiple-well, multiple-fracture reservoir model was developed to test well performance for the simulated EOR process. The model was designed to evaluate the response of oil production to gas injection and simulate hydraulic communication between formations and production/injection interference between wells for the EOR simulation. The multiple-well setting enabled the simulation model to more accurately mimic actual EOR operations over a model with only one well included.

An approach called "embedded discrete fracture modeling (EDFM)" was employed to represent fractures in the numerical simulation model. The multiple-well, multiple-fracture model developed in this study was able to simulate interference between wells more efficiently than other fracture modeling approaches (shorter computation time). This effect is especially important in the gas injection process as the injected gas will easily flow from the injection well(s) to offset production wells when the fractures are connected. The EDFM method enables modeling of complex fracture geometry using structured grids with a traditional reservoir simulator with complex fracture settings like CMG's software package (Xu, 2015; Xu et al., 2017).

An eight-component EOS or PVT model was developed based on PVT input data provided by XTO to calculate phase behavior in the reservoir. MMP measurements were conducted for two oil samples collected from the Middle Bakken (MB) and Three Forks (TF) units. The composition of the injection gas included about 65-mol% methane, 25-mol% ethane, and 15-mol% propane based on the main gas components observed in the field. MMP was determined to give an indication of the conditions needed for interfacial tension (or capillary pressure) between oil and gas to become negligible, enabling miscibility and viscosity reduction. Results showed the MMP varied between 2200 and 2300 psi for both MB and TF oil samples at reservoir conditions. Swelling tests were also performed for the TF oil sample using the same injection gas composition, demonstrating that injection gas can swell the oil volume up to 18% at reservoir conditions. The PVT and MMP data helped match the simulation model to production history of the wells within the model.

A successful produced gas EOR case in the Eagle Ford was analyzed to design reasonable EOR parameters for the pilot in this study (Zhao and others, 2022). The simulation model with seven wells, including HnP, offset, and monitoring, was employed to design the EOR pilot considering well interference/fluid communication effects in the reservoir. A series of simulation cases was designed to predict the EOR performance in the pilot wells and to study the sensitivity of the oil production response to EOR operations. Key designing parameters included injection rate, injection time, soaking time, production time, HnP well configuration, and gas fill-up. 50 cases were simulated to identify the range of oil recovery after 2 years of HnP operations for the target EOR wells.

Produced gas was found to interact effectively with oil in the reservoir to reach miscible EOR conditions, provided the injection rate was high enough. HnP gas injection EOR lead up to 60% more incremental oil production over pressure depletion-only operation for the same production period using gas injection rates of 17 MMscf/d or higher, as shown in Figure 15. Production performance of offset wells depended on the SRV around each of these wells. An offset well with a large SRV close to the primary HnP well simulated to have a maximum of 58% incremental oil production when the gas injection rates reached 17 MMscf/d or higher. A negative EOR effect was also observed in offset wells with small SRVs. The chance of success for an EOR project increases by optimizing design parameters as listed below:

- Well selection – consider current production and pressure levels of wells and completion details, including the number of fracture stages and SRV extent.

- Timing of EOR initiation – incremental oil production from EOR should offset the lost production during periods of produced gas injection and soaking.

- Injection rate –optimal gas injection rates for oil miscibility and maximizing oil recovery for potential EOR sites need to be determined.

- Cycle design – numerical simulation can identify injection, soaking, and production period combinations to yield optimized EOR with injection rates and pressures.

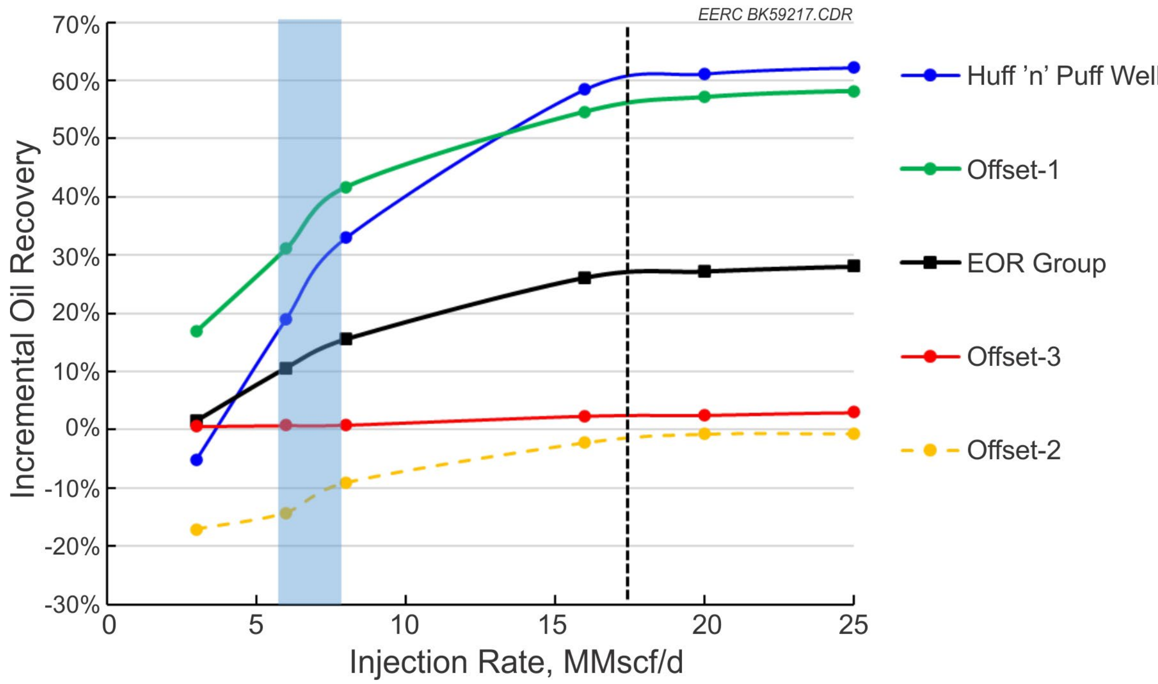

Figure 15. Effect of gas injection rate on EOR. The blue band represents the range of injection rates proposed by XTO. The EOR group includes the HnP well and three offset wells as these wells were completed on or before 2015 and were grouped together in the field. The Offset-1 well has the largest SRV, while the Offset-2 well has the smallest SRV.

6.4 Liberty East Nesson Bakken Produced Gas EOR Pilot Test

6.4.1 Background

In September of 2021, the EERC worked closely with Liberty Resources to deploy an EOR pilot project via a single HnP well in a 2560-acre Bakken spacing unit (Kaitlyn-Haley DSU) in Mountrail County, North Dakota (Figure 16). The primary goal of the project was to demonstrate the economic viability of EOR using produced gas with water and surfactant in an area referred to as the East Nesson. The pilot was designed, permitted, and conducted by Liberty in partnership with the EERC and EOR ETC, with funding provided through this project as well as through the Bakken Production Optimization Program, an NDIC-funded program in partnership with several oil and gas companies. The objectives of the pilot were to 1) repressure the reservoir above the MMP, 2) prove the concept of using water coinjection to build hydrostatic pressure to inject gas at low surface pressures and to improve gas conformance, and 3) evaluate the performance of a surfactant to enhance oil recovery through rock wettability alteration and interfacial tension reduction.

This program provided support toward the pilot to better understand the viability of using produced gas for EOR in the Bakken and to evaluate an alternative gas injection technology

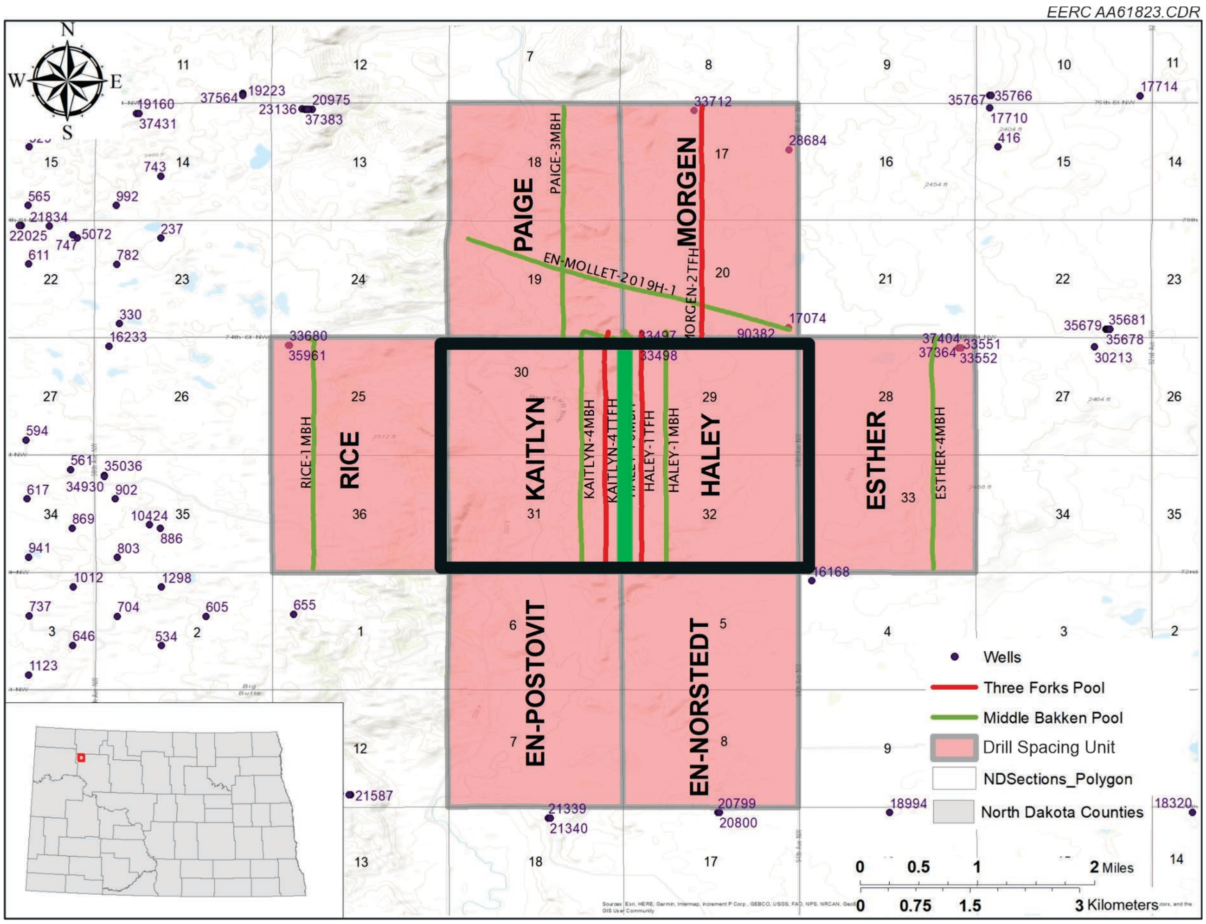

Figure 16. Map view of the East Nesson area and pilot DSU layout. Injection well: Haley-10MBH; monitor wells: Kaitlyn-4TFH and Haley-1TFH; and boundary wells: Kaitlyn-4MBH and Haley-1MBH (Pospisil and others, 2022).

developed by EOR ETC that requires significantly less surface pressure for gas compression than typical compression technologies. The technology is commonly referred to as coinjection but is formally the RSSS system. The RSSS system differs from conventional water alternating gas (WAG) injection techniques by rapidly (in seconds and minutes) switching between liquid and gas injection to create a stacked slug flow regime in the injection path. The weight of the coinjected water boosts downhole pressures while providing for a significant reduction in surface injection pressure compared to traditional gas compression options (800–1300 psi compared to ~3000–4000 psi). The coinjection of water also allows for the injection of surfactant into the reservoir. Using this technology eliminates certain equipment and reduces compression requirements by a factor of up to 10, which greatly reduces power utilization and greenhouse gas impacts.

The following section of this report summarizes the results of the pilot project. The details of the project can be found in Pospisil and others (2022).

6.4.2 *Pilot Project Summary*

Static and dynamic modeling work was conducted by the EERC with support from CMG and direction from Liberty regarding scenarios to optimize design parameters. Several reservoir simulation case studies were conducted to explore methods for characterizing the recovery mechanism and assessing EOR performance, including single-phase injection, coinjection of produced gas and water, single- and multiwell injection, and scenarios with and without surfactant. The model was designed to capture matrix and fracture communication and interference between the wells in the MB and TF intervals that exist on the 7-well DSU (Figure 17).

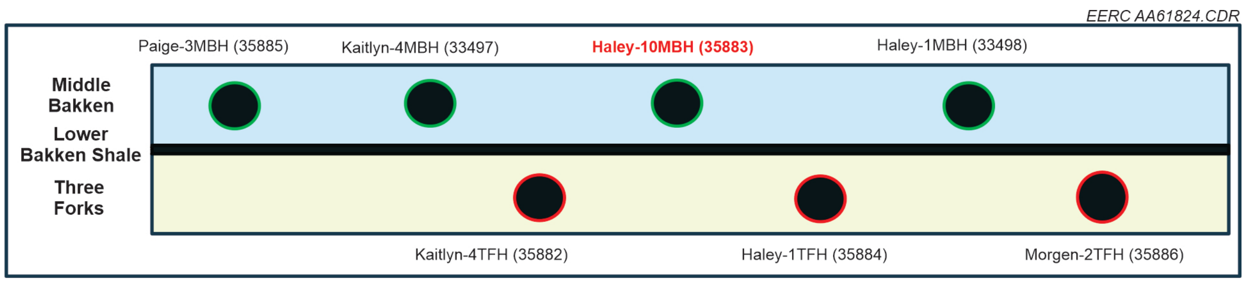

Figure 17. Schematic of the pilot DSU cross section (Pospisil and others, 2022).

Water coinjected with gas simulation results indicated significant pressure buildup with water in the injection process and incremental oil production up to 12.500 Mbbl for the full DSU compared to 4.5 Mbbl for the gas-only injection results. For all cases, injection gas composition was assumed to be rich, high in ethane and propane, and miscible with oil at expected operational pressures. Additionally, in coinjection cases, the water provided a higher BHP at lower surface pressure and improved conformance along the wellbore and within the formation. Adding surfactant was predicted to improve incremental oil production up to 50% in 3 years with two cycles of gas injection of 3 MMscf/d and water of 3000 bpd.

Simulations indicated that increasing gas and water injection rates yields higher pressure buildup and higher oil production. However, a higher gas injection rate showed higher incremental oil compared to increased water injection rate. Additionally, higher injection rates led to higher injected fluid flowback volume that could burden facility capacity and increase water-handling costs. Increasing to four cycles of injection demonstrated higher oil volumes compared to two cycles. Adding soaking or increasing production time did not show a significant improvement in oil production.

The simulated coinjection technology allowed for a relatively low (<1300 psi) surface injection pressure while achieving a significantly high reservoir pressure of >4500 psi (a net pressure increase of 3500 psi), well above the estimated MMP of 2450 psi. Also, adding water to the injection process enhances conformance and reduces gas breakthrough.

The gas injection rate targeted was 3 MMscfd, with cumulative volume of 180 MMscf. The water coinjection rate targeted was 2 Mbpd with cumulative volume of 130 Mbbl of fresh water.

The maximum allowable surface injection pressure was 1400 psi. The injection scheme used coinjection of gas and water into the Haley-10MBH well with two injection stimulation cycles for the well over 4–6 months.

The field injection operation commenced on September 10, 2021. The surveillance plan included continuous injection rate and surface pressure measurements, BHP gauges in monitoring wells, and fluid rates (oil, water, and gas) in monitoring/boundary wells. Periodic produced water and gas sampling was conducted in the injection and monitor wells. Offset DSUs were also monitored for oil, water, and gas rates and pressures continuously (operated wells) and daily (non-operated wells).

Coinjection of gas and water laden with surfactant proceeded in the well until October 11, 2021. The injection was alternated between water and gas to control the WHP and not exceed the approved maximum allowable operating pressure (1400 psi). As the BHP increased, the gas injection rate was reduced below the target rate and the water injection rate was increased to keep the WHP under a working target of 1300 psi. A total of 46 MMscf of produced gas and 40 Mbbl of fresh water laden with 2400 gallons of surfactant were injected within 31 days, with some operational shutdowns related to equipment maintenance and cold weather conditions. Figure 18 is a photo of the pad location with the production facilities and equipment for gas injection. Figures 19 and 20 show gas and water injection rates and cumulative volumes during the injection cycle, respectively.

The East Nesson EOR injection-monitoring data are summarized in Table 4.

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Figure 18. Photo of the pad location with the production facilities and equipment for gas injection (Pospisil and others, 2022).

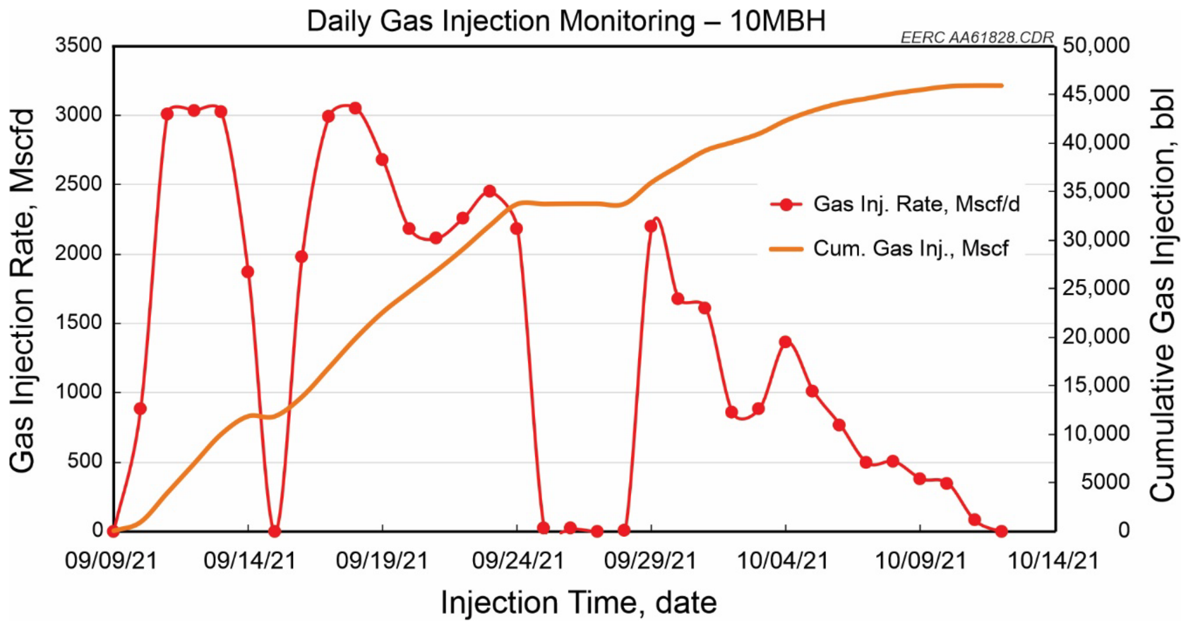

Figure 19. Daily gas injection rate and cumulative gas injected into Haley-10MBH (Pospisil and others, 2022).

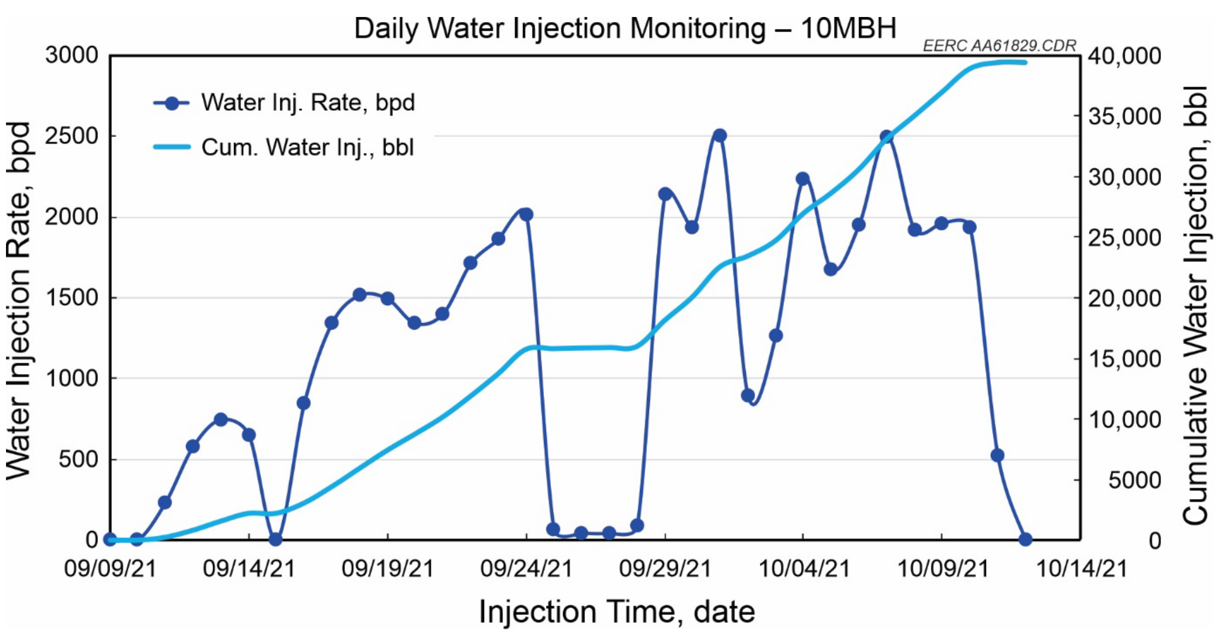

Figure 20. Daily water injection rate and cumulative water injected into Haley-10MBH (Pospisil and others, 2022).

Table 4. Summary of East Nesson Pilot EOR Injection Data (Pospisil and others, 2022)

Pilot Injection Start Date	10-Sep-21
Pilot Injection End Date	11-Oct-21
Number of Cycles	One
Pilot Production Start Date	12-Oct-21
Rich Gas Injected Volume	46 MMscf
Water Injected Volume	40 Mbbl
Surfactant Injected	2 gpt (2400 gallons)
Daily Average Gas Injection Rate	1.5 MMscf/d
Daily Average Water Injection Rate	1.3 Mbpd
Formation Pressure Buildup Achieved	4500 psi
Wellhead Injection Pressure	1300 psi

Key observations and results:

- Although the target gas injection volume was not achieved because of equipment limitations, the key objectives were accomplished. The RSSS coinjection technology allowed for a relatively low (<1300 psi) surface injection pressure while achieving a significantly high reservoir pressure of >4500 psi (a net pressure increase of 3500 psi), well above the estimated MMP of 2450 psi.

- Injectivity was readily established, and no related issues were observed.

- A minor gas breakthrough at one of the adjacent wells (Haley-1TFH) was observed but was apparently controlled by increasing the water injection ratio.

- After the initial spikes in gas and water, the oil rate increased to 68.3 bpd (30-day average), with the simulated baseline production at 55 bpd for the same period had the pilot injection not occurred.

- The oil rate suggested an EOR response in which gas/water/surfactant invaded the matrix to improve oil recovery. In addition, the production rates for gas and water were noticeably higher following the injection cycle. This was associated with the injection rates, the addition of the surfactant with the water, and the increase seen in the BHP from the injection of the water and gas volumes. Ultimately, the water and gas rates resumed the normal declines preceding the injection period in approximately 9 months for water and approximately 6 months for gas. Total EOR recoveries are estimated at ~6500 BO, ~50 MMscf, and ~46,000 bbl.

- Gas hydrates formed in the injection lines during a short downtime because of cold ambient conditions; this was remediated with insulation of the injection lines.

- No gas or pressure response was observed in the surrounding DSUs during pilot operations.

- This pilot demonstrated that unconventional EOR can be performed at reduced surface pressures and at lower compression requirements through the use of a water–gas coinjection system. These results can inform the future development of full-field EOR methods in the BPS.

7.0 COMPRESSION AND SURFACE FACILITIES

7.1 Background

A key component required for subsurface produced gas injection is the surface facility required for handling, conditioning, and compression of the unprocessed gas generated from a well pad. Prior to compression, the gas will require partial treatment to remove condensable NGL, CO_2, water vapor, and other constituents that can damage compressors and pipelines.

Several different options for NGL removal are available based on volume, gas quality, and conditioning requirements. MRUs use compressed refrigerant, typically propane, to chill gas to subzero temperatures, causing the heavier portions of the gas to condense out. The clean, chilled gas can then be reheated through exchange with incoming warm gas to reduce the cooling load on the raw gas stream. Other options for gas treatment include Joule–Thomson (JT) plants, which use pressure drop to induce a cooling effect without any moving parts but require relatively lean gas and sufficient supply pressure as well as cryogenic plants, which reach very low temperatures and can selectively recover products as light as ethane.

Once gas is treated, it must be compressed. Reciprocating compressors are generally preferred for variable-volume field sites and large pressure ratios (the ratio of outlet to inlet pressure). A large pressure ratio requires several compressor stages with interstage cooling to prevent excessive heat buildup. Reciprocating compressors for gas compression often include multiple throws that can be configured with different cylinders and configurations. The cylinders are plumbed together through interstage coolers to allow multistage compression within a single compressor package.

For applications such as EOR where gas recovery is not the driving concern, gas could also be compressed by coinjecting with water to reduce surface delivery pressures. This is the RSSS approach used at the East Nesson pilot injection test site. The economics of this approach depend on a number of factors specific to a given application, and it is worth comparing estimated costs for RSSS or similar technologies to the costs for traditional gas injection.

The EERC investigated the economics and logistics of several different applications through its work with XTO, Marathon, and Liberty. Each unique project offered a different set of insights into the potential for underground storage of produced gas. The results are summarized below in a set of case studies, giving a sense of the variability in how gas storage might be approached for different applications throughout the state of North Dakota. A more detailed discussion of each project is provided in Appendix A.

7.2 Compression and Surface Facility Scenarios

Each project had unique characteristics that would affect the optimum compressor scenario. For the Marathon project looking to inject in the Broom Creek Formation, the goal was to combine the gas from multiple producing pads to inject at a single injection well over a long duration, with peak injection rates of up to 19 MMscfd at wellhead pressures of 3500 psig. In this case, to sustain gas injection over a period of 9 or more years, the most favorable option is likely to purchase a single purpose-built compressor package while leasing one or more smaller compressors to provide trim during peak gas flow. Using a single centralized compressor at the injection well avoids the cost and logistics of moving smaller compressors between wellsites, though some gas boosting would likely be required to push gas from production wells to the centralized injection site. However, some consideration would need to be given to gas injection or shut-in during periods of compressor maintenance. Depending on the relative importance of needs for continuous operation (favored by multiple smaller compressors) versus reduced maintenance and operational costs (favored by a single larger compressor), it may be desirable to install several smaller compressors to provide redundancy during maintenance periods.

For the XTO project, the goal was to inject and temporarily store all gas from a single pad over a short duration, so there would be no need to transport produced gas to a centralized injection facility. Because the goal was short-term gas storage, leasing would make more sense than purchasing. Compressor frames capable of 5-MMscfd flow at 3500-psig delivery pressure were more readily available for lease than compressor frames capable of handling the maximum estimated flow rate of 16 MMscfd that would be observed if all wells were brought online at the same time. Three to four of these smaller compressors operating in parallel would be desirable during initial injection, with individual units coming offline as the gas production rate declines. Trailer-mounted MRUs capable of 1 MMscfd were also readily available for a project of this scale. The logistics of leasing and operating 16 initial MRUs for the initial production phase would need consideration if less stringent gas conditioning were acceptable during the early gas production peak. Alternatively, well development could be staggered to eliminate the large peak associated with bringing all wells online at once, reducing the need to only one or two compressor trains and a smaller number of MRUs.

The Liberty East Nesson project was unique in that gas was to be used for oil recovery rather than storage and gas was pressurized using RSSS rather than traditional gas injection. With the RSSS approach, the injection well has alternating slugs of water and gas, and the high density of water creates head pressure in the vertical well that pressurizes gas as it travels downhole. Comparison of the RSSS process against traditional gas injection shows similar total cost for a 60-day injection project: RSSS would reduce energy costs for compression and would allow use of cheaper rental compressors, but these savings are estimated to be offset by added storage and consumable costs for the water needed to operate an RSSS system. Although RSSS may not result in direct cost savings for the injection facility, there may be other benefits to consider: leased compressors capable of 1400-psig delivery pressure for RSSS are likely to be more readily available than compressors capable of 4500 psig for traditional gas injection, allowing EOR projects to start sooner, and RSSS could potentially lead to higher oil yields. Further study would be needed to better assess the overall economics of the RSSS process as compared to traditional gas injection.

For all studies, compressor lead time may be a concern. Compressors operating up to roughly 3000 BHP or requiring discharge pressures below 3500 psig at flow rates of 5000 MMscfd are used for gas lift and could be procured or leased from existing inventory. High-pressure, large-capacity compressors tend to be custom-built to specific requirements. Compressors operating above 4000 BHP or requiring pressure ratings of 5000 psig or above would likely require a 12- to 24-month lead time. This may not affect an operator who is planning to develop a new site more than a year out, but it would be a major consideration when trying to develop a site more quickly.

For projects spanning multiple years (such as the Marathon Broom Creek study), the cost to buy a single compressor package can be lower than the cost to lease multiple purpose-built boosted compressor packages to achieve the same flow rate. However, these advantages for a single large compressor would come at the cost of longer lead times and less flexibility if gas injection volumes decline. For short-term projects, the option to lease multiple gas lift compressors would be preferable in terms of cost and performance. Further study would be needed to determine a breakeven point at which compressor purchase becomes more favorable for a full-field, multiyear injection program.

In all projects, it was assumed that gas treatment and compressor configurations would remain unchanged throughout the project duration. However, as produced gas flow rates decline, the wellhead pressure at an injection site would also decline because less pressure is required to deliver the smaller flow rate of gas. Gas composition might also become richer and/or sourer, leading to greater treatment requirements. Future studies on gas storage should assess whether changes in the process conditions would warrant changes in MRU or compressor configurations.

8.0 CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

To better understand the viability of temporary produced gas storage and recovery as a potential mechanism to reduce flaring, industry partners collaborated with the EERC to evaluate the technical and economic feasibility of produced gas injection into porous and permeable saline formations for temporary storage and into oil-bearing formations for the purpose of EOR. The EERC worked closely with XTO, Marathon, Liberty, and Maroon Bells on the assessment of six conceptual pilot projects: 1) two produced gas storage efforts in the Broom Creek Formation, 2) an investigation into produced gas storage potential in the Duperow Formation, 3) an evaluation of the potential for produced gas storage in the Inyan Kara Formation, and 4) two assessments of produced gas injection for EOR in the BPS. Key lessons learned from the various investigations include the following:

- North Dakota has established a complete and comprehensive statutory and regulatory framework for geologic storage of oil or gas. Three analogs, oil and gas unitization, UIC Class II permitting, and CO_2 storage facility permitting, form the framework for a produced gas storage facility permit template.

- Well location has a large effect on gas recovery potential. Proximity to operating injection or production wells affects pressure responses during injection and production. Structural features can affect gas recovery potential with domes or anticlines, possibly retaining injected gas in a smaller footprint and potentially enabling greater gas recovery.

- A lower operating bottomhole producing pressure is beneficial for gas recovery. The downside to operating at a lower BHP is that water production also increases, leading to greater costs for water disposal.

- Simulation results indicated that a shorter soaking time improves gas recovery.

- Shorter-duration gas storage periods, coupled with higher gas extraction rates, resulted in higher estimated recovery factors; however, this also required adequate gas handling and takeaway capacity.

- With respect to gas and water coinjection into saline formations, the predicted gas recoveries were much lower than dedicated gas injection strategies.

- Using multiple smaller compressors over a single large compressor would allow for flexibility, allowing individual units to go offline as gas production rate declines. Multiple smaller compressors can assist with redundancy and continuous operations at the cost of more maintenance and operational costs. Trailer-mounted MRUs capable of 1-MMscf/d gas treatment are typically available and would allow for flexibility in reducing the number of compression units needed as gas volumes decline over time.

- As produced gas flow rates decline, the WHP at the injection site will also decline because less pressure is required to deliver the smaller gas injection rates. Gas composition may also become richer and/or sourer, leading to greater treatment requirements. Future studies on gas storage should assess whether changes in the process conditions would warrant changes in MRU or compressor configurations.

- The novel RSSS coinjection technology has demonstrated an ability to significantly reduce the surface compression requirements needed for gas injection into the subsurface and provide a mechanism to more effectively build reservoir pressure for gas-based EOR in the Bakken.

- The results of the produced gas Bakken EOR evaluation suggest that huff-n-puff gas injection could result in significant increases in incremental oil recovery. The promising results of this work suggest that produced gas EOR pilot tests in the Bakken using higher gas injection rates are warranted.

While the concepts evaluated by the EERC and reported here were aimed at providing a potential gas handling option at a smaller scale (i.e., individual well pads), these concepts are also viable for larger volumes of gas. As previously discussed, the subsurface storage of produced gas in saline formations, depleted oil and gas reservoirs, and salt domes at commercial-scale volumes is widely practiced across the United States. NDPA forecasts suggest that unless additional gas processing plants are built or existing plant capacity is increased, North Dakota will have insufficient gas processing capacity beginning as early as 2026. Temporary subsurface storage of large volumes of gas may be a mechanism to help manage produced gas and/or NGLs in locations where there is insufficient processing capacity and/or large-scale export capacity. North Dakota's geology is conducive for large volumes of subsurface gas storage, and if a single location is used for repeated cycles of gas injection and recovery, gas recovery factors improve with each subsequent storage and retrieval cycle until a gas cushion is fully developed.

Minimizing waste and extracting value from the associated gas of the BPS in the Williston Basin of central North America requires the reduction of gas flaring and preserving gas volumes until sufficient capacity of gas-gathering infrastructure is available to production wells. Preserving as much of the value as possible of the produced gas not currently being collected by gas-gathering pipelines for marketable products requires alternative means of temporary storage or investigating means of other beneficial use of the produced gas. Overall, the pilot studies reported here have shown that geologic storage in North Dakota is a promising and viable means to store and recover produced gas.

9.0 PARTNERS AND FINANCIAL INFORMATION

The project is sponsored by NDIC through its Oil and Gas Research Program and partners XTO Energy, MRO, Maroon Bells, Liberty, and EOR ETC. Table 5 shows the expenses through April 28, 2023. The project end is June 30, 2023. It should be noted that the EERC received an amendment to the NDIC agreement indicating that, on August 4, 2022, NDIC accepted the recommendation of the Oil and Gas Research Council to reallocate $2,500,000 from Contract No. G-049-092 (Underground Storage of Produced Natural Gas) and provide additional funding of $2,500,000 for the project under Contract G-054-104 (Field Study to Determine the Feasibility of Developing Salt Caverns for Hydrocarbon Storage in Western North Dakota). Therefore, the budget for this project was reduced from $6,000,000 to $3,500,000, as reflected in Table 5. In addition, on December 20, 2022, NDIC voted to grant a variance from the Oil and Gas Research Council Policy 3.02 to allow the project to be completed with a 57% match from NDIC. Paragraphs 2 and 3 of Contract No. G-049-092 were amended to reflect the project cost reallocation to complete the project. This third amendment to the contract was officially executed in early January of 2023.

Table 5. Budget and Expenses to Date

Sponsors	Budget	Expended	Balance
NDIC	$3,500,000	$3,320,529	$179,471
Industry Share – In-Kind	$2,611,339		$(0)
XTO	–	$1,028,120	–
MRO	–	$734,813	–
Maroon Bells	–	$252,656	–
Liberty	–	$395,678	–
EOR ETC	–	$200,073	–
Total	**$6,111,339**	**$5,931,868**	**$179,471**

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