STAND Sustain. Transform. Authenticate. North Dakota.

Tax Policy and Energy Economics

A 20-year Forecast for CO_2-Enhanced Oil Recovery in North Dakota

January 28, 2025

Executive Summary

North Dakota CO_2-EOR Financial Analysis
North Dakota Tax Commissioner

North Dakota CO_2-EOR Forecast
Energy & Environmental Research Center

STAND

Disclaimer

This executive summary presents a combined analysis of insights from two key reports—*North Dakota CO_2-EOR Financial Analysis* and *North Dakota 20-Year CO_2 EOR Forecast*. Drawing from the expertise of the North Dakota Tax Commissioner, and Energy & Environmental Research Center, this synthesis reflects findings current as of December 31, 2024. Each contributing organization has applied its own independent methodologies, data sources, and objectives, resulting in analyses that remain distinct. Consequently, this document should not be viewed as a unified endorsement or exhaustive analysis by any single entity.

Readers should exercise independent judgment and consult the original reports for more detailed information on specific findings. This executive summary is intended solely for informational purposes and does not constitute financial, legal, or professional advice.

List of Abbreviations and Definitions

BBL	Barrel of crude oil
BND	Bank of North Dakota
Brent Crude	Light, sweet crude oil used as one of three global benchmarks for oil prices
CCUS	Carbon capture, utilization and storage
CI	Carbon intensity refers to the amount of CO_2 or greenhouse gases emitted per unit of activity
CO_2`	Carbon Dioxide
CO_2-EOR	Injection of CO_2 into the reservoir rock of an existing oil field to recover more oil than would otherwise have been produced
EERC	Energy & Environmental Research Center
EOR	Enhanced oil recovery
ESG	Environmental, Social and Governance
Extraction Tax	North Dakota state tax rate of 5% applied to the gross value at the point of extraction of oil from the earth
GHG	Greenhouse gas
LCFS	Low carbon fuel standard
MMbbl	Million barrels
Restimulated Well	Existing oil well that undergoes additional treatment to boost production
Stripper Well	Low-production oil well
Tonne	Metric ton
WTI	West Texas Intermediate is a light sweet oil used as one of three global benchmarks for oil prices
45Q	Federal IRS incentive tax credit that provides a monetary credit for CO_2 that is geologically stored permanently ($85/tonne), stored through enhanced oil recovery or via other utilization ($65/tonne)
45Q Differential	$25 differential to incentivize CO_2 storage ($85) over CO_2 utilization ($60)

Research Question

Do current North Dakota state tax policies incentivize infrastructure investment from the private sector to utilize carbon dioxide (CO_2) for enhanced oil recovery (EOR)?

Research Assessment

North Dakota's tax policy, which reduces the federal 45Q tax credit $25 differential between carbon storage ($85) and utilization ($60) to less than $10, makes the state a more attractive choice for CO_2 utilization in EOR compared to other oil-producing states. By lowering the economic barrier for CO_2-EOR, North Dakota enhances the viability of carbon capture and utilization, encouraging investment and growth in both oil production and carbon storage. Current state tax policy not only boosts oil recovery rates but also positions the state as a leader in energy production and global-market environmental standards. As a result, North Dakota offers a more favorable business environment for CO_2-EOR projects, creating a competitive advantage for the state's oil, lignite and agriculture sectors.

Background

House Bill 1429, Section 5, enacted by the 68th Legislative Assembly of North Dakota, directed Bank of North Dakota (BND) to examine environmental, social, and governance (ESG) trends, laws, and policies impacting the state's energy and production agriculture sectors. During this study, additional analysis was requested to evaluate current state tax policies related to EOR using CO_2 in North Dakota.

To fulfill this request, Energy & Environmental Research Center (EERC) was retained to model a 20-year forecast for incremental oil production associated with CO_2-EOR in both unconventional and conventional reservoirs in western North Dakota. EERC's forecast includes various CO_2 supply scenarios, predicting incremental oil production and CO_2 demand. Next, the North Dakota Tax Commissioner reviewed the forecast to assess financial implications for CO_2-EOR, including current state and federal tax policies, and potential cross-sector synergies.

The intent of both studies is to provide insights into the potential for future Co_2-EOR oil production and evaluate how current tax policy may create a favorable business environment, encouraging oil producers to invest in the necessary EOR infrastructure. Before new tax policies are considered, it's important to assess the effectiveness of current policies.

A key factor in this analysis is the federal 45Q tax credit, enacted in 2008 and amended by the Inflation Reduction Act of 2022. The 45Q credit offers a dollar amount per metric tonne of qualified CO_2 captured and utilized. Specifically, $85 per metric tonne is provided for CO_2 permanently stored underground, while $60 per metric tonne applies to CO_2 used in EOR—a difference known as the "$25 differential." The tax analysis evaluated whether North Dakota's current policies shrink the differential.

The reports *North Dakota CO_2-EOR Financial Analysis* and *North Dakota CO_2 EOR Forecast* are included in the appendices following the executive summary.

Executive Summary

In 2024, after nearly six decades of drilling, the Bakken Formation achieved a significant milestone surpassing 5 billion barrels of oil produced. With continued technological advancements and favorable market conditions, experts predict the Bakken could yield an additional 5 to 8 billion barrels over the next 30 to 50 years. Achieving this potential, however, depends on securing adequate carbon dioxide (CO_2) supplies for enhanced oil recovery (EOR), which could significantly increase recovery rates. Without EOR, as much as 90% of the remaining oil in the Bakken may go untapped.[1]

North Dakota state tax policies, paired with federal incentives like the 45Q tax credit, may be key to unlocking the Bakken Formation's remaining oil potential by enabling CO_2-EOR and driving private investments in necessary infrastructure.

With its diverse energy resource portfolio, North Dakota is strategically positioned to implement CO_2-EOR compared to other oil-producing states, thanks to the proximity and volume of multiple industrial energy sectors—oil, lignite, and agriculture—all vital to the state's economy. The potential to sustain and increase oil production, thereby supporting and boosting revenue from carbon capture and EOR, is significant; however, realizing this potential requires that CO_2-EOR's economic benefits exceed those of sequestration, with a supply chain capable of meeting demand. It is also important to recognize that CO_2 is becoming a valuable operational tool and commodity, driving growth across multiple industries and extending beyond state lines.

Federal Tax Credit Incentives

The 45Q tax credit, established under Section 45Q of the U.S. Internal Revenue Code, offers financial incentives for carbon capture, utilization, and storage (CCUS) by offering a per-metric-tonne credit for CO_2 that is either permanently stored or used in industrial applications. Specifically, 45Q is structured to promote the reduction of greenhouse gas (GHG) emissions by capturing CO_2 from industrial or power generation facilities that would otherwise be released into the atmosphere. 45Q has become a policy tool for incentivizing CCUS, especially as industries and energy sectors seek to reduce emissions and offset costs of carbon capture and injection.[2]

Federal Tax Credit - 45Q Credit Structure

CO_2 Storage: The 45Q tax credit provides $85 per metric tonne for CO_2 that is captured and then permanently stored underground. This typically involves injecting CO_2 into deep geological formations, such as saline aquifers or depleted oil and gas reservoirs, where the CO_2 is stored in rock formations that trap it and prevent it from entering the atmosphere. This method is often referred to as geologic sequestration.

CO_2 Utilization: When CO_2 is captured and used in EOR or other commercial applications (such as converting it into building materials), 45Q offers a lower credit of $60 per metric tonne that is

---

[1] Thompson, Dave. "Oil Production in North Dakota Will Soon Reach a New Milestone." *Prairie Public Newsroom*, 29 Dec. 2023.

2 "The Section 45Q Tax Credit for Carbon Sequestration." Congressional Research Service, 25 Aug. 2023.

permanently stored and removed from the atmosphere during the course of utilization. In EOR, CO_2 is injected into oil fields to increase the pressure in the reservoir, making it easier to extract additional oil. The injected CO_2 can either remain underground as part of the production process or be separated and re-injected, depending on the field's geology and operation.

The "$25 differential" between the 45Q tax credits for CO_2 storage and utilization underscores the federal government's preference for permanent sequestration. Decreasing this gap would likely result in greater CO_2 removal from the atmosphere, while simultaneously producing lower carbon intensity oil.

North Dakota State Tax Incentives

Currently, North Dakota offers tax incentives to promote CO_2-EOR and carbon capture projects. Key provisions under NDCC § 57-51.1-02 include exemptions for incremental oil production from qualifying oil recovery projects, with different durations depending on location and CO_2 source. For projects outside the Bakken or Three Forks formations that inject over 50% CO_2 produced from coal, the exemption lasts 20 years, while projects within these formations are exempt for 10 years.

Additionally, North Dakota provides tax incentives for low producing "stripper" wells, exempting them from oil extraction tax, and reduces the extraction tax rate for restimulated wells.

The state also incentivizes infrastructure for CO_2-EOR by offering sales and use tax exemptions for materials involved in CO_2 transportation, storage, or injection for enhanced oil recovery or geological storage. CO_2 pipeline projects are exempt from property taxes during construction and for the first 10 years of operation, and sales of CO_2 used for EOR or geological storage are exempt from sales tax.

These incentives collectively support the development of CO_2-EOR projects, enhance carbon capture efforts, and promote infrastructure investment in the state.

As North Dakota evaluates a path forward, it is important to recognize other oil and gas producing states including Texas, Oklahoma, New Mexico, and in proximity to North Dakota, Wyoming, are also actively positioning and competing to attract the same CO_2 supplies and capital investment dollars necessary to advance CO_2-EOR projects within their respective geographies.

CO_2-EOR Fiscal Impact

North Dakota's diverse energy portfolio makes it uniquely well-suited for implementing CO_2-EOR compared to other oil-producing states. The close proximity and abundance of key resources—oil, lignite, and agriculture—form the backbone of the state's economy and offer significant strategic advantages. Although infrastructure challenges remain in transporting CO_2 from capture sites to oil fields, these hurdles can be mitigated by the relatively short distances between in-state CO_2 sources and their applications. Additionally, North Dakota's favorable geology offers a distinct advantage for the permanent sequestration of CO_2.

Developing CO_2-EOR in North Dakota presents significant economic opportunities, warranting a closer evaluation of existing policies and incentives to optimize pricing models. Key discussions include addressing the $25 tax credit gap between CO_2-EOR and permanent sequestration, exploring policy-driven solutions to reduce the 45Q disparity, and recognizing major industry expenses such as CO_2 acquisition, transportation, distribution, and well surface costs. Understanding these financial factors is critical to supporting effective, large-scale CO_2-EOR implementation and ensuring its economic viability.

The cost model estimate below is based on the following criteria:

- Well development and surface costs represent approximately two-thirds of total project cost
- CO_2 supply expense equaling approximately one-third of total project cost
- No additional CO_2 compression costs
- Limited cost associated with filtration systems, waste fluid injection and electricity

CO_2-EOR Production Cost Model (Single Well) [3]

Expense/Savings Centers	Cost per bbl	Tax savings/bbl	Tax savings/tonne CO_2	Net Cost/bbl
CO_2 Transportation [1,2]	$5.00	$0	$0	$5.00
CO_2 price/bbl ($30/t = 3 bbl) [2]	$10.00	$0.50	$1.50	$9.50
Royalty payment est. (19% of $80/bbl)	$15.20	$0	$0	$15.20
Well and surface (taxable) [3]	$17.50	$0.88	$2.63	$16.63
Well and surface (non-taxable)[4]	$7.50	$0	$0	$7.50
Extraction tax savings - $80/bbl*5%	$0	$4.00	$12.00	($4.00)
Totals	**$55.20**	**$5.375**	**$16.13**	**$49.83**

[1]Primary distribution delivery cost est.=$15/tonne. [2] Per bbl based on $30/tonne CO_2 and 3:1 bbl oil/tonne CO_2. [3] Includes well, distribution infrastructure & production costs. [4] Labor costs.

While North Dakota current state tax policy doesn't eliminate the "$25 differential", it offsets approximately 64.5% of the 45Q tax credit differential per tonne of CO_2 for utilization.

North Dakota's 20-Year CO2-EOR Forecast

The potential for CO_2-EOR in North Dakota is closely tied to establishing a stable CO_2 supply, which could enable longer-term investments in the Bakken Formation and coal and ethanol industries. North Dakota's industrial landscape, encompassing oil, lignite, and agriculture, may benefit from leveraging in-state CO_2 sources, particularly from coal-fired plants and the Dakota Gasification Company, due to their strategic proximity to oil fields. Unlike states reliant on importing CO_2, North Dakota's existing infrastructure and energy resources place it in a position to integrate CO_2-EOR more effectively, potentially supporting its energy and economic objectives. However, securing additional long-term CO_2 sources to maximize EOR will depend significantly on state land management policies, state tax policies and federal incentives to address the capital and logistical challenges involved.

[3] Kroshus, B. "*North Dakota CO2-EOR Financial Analysis*." Table 8. Office of North Dakota Tax Commissioner, 15 Nov. 2024.

The North Dakota 20-Year CO_2-EOR Forecast focused on EOR in the Bakken and Three Forks Formations using a sample of 271 grids across McKenzie, Mountrail, and Dunn counties, representing about 10,000 existing wells. Over 20 years, the modeled EOR suggest potential incremental oil recovery from 300 million barrels (MMbbl) under low-CO_2 injection (5 million tonnes/year) to 1100 MMbbl under high-CO_2 injection (15 million tonnes/year), with an average scenario yielding 700 MMbbl (10 million tonnes/year). CO_2 requirements vary from 90 to 300 million tonnes, with additional CO_2 potentially increasing recovery if operated at higher rates. The analysis does not include around 10,000 forecasted new wells or expansions beyond the Bakken core, which could substantially raise oil recovery and CO_2 storage estimates.[4]

Comparison of Total Bakken EOR Incremental Oil and Purchased (stored) CO_2 Utilization over the 20 years for the Baseline Case Assuming a Low-CO_2 Constraint (5 million tonnes of CO_2 per year), Baseline CO_2 Constraint (10 million tonnes of CO_2 per year), and High-CO_2 Constraint (15 million tonnes of CO_2 per year) [5]

Case	Incremental Oil, MMbbl	% Change[1]	Purchased/ Stored CO_2, million tonnes	% Change[1]	No. of EOR Grids	% Change[1]
Low CO_2	337	−51	93	−51	55	−60
Baseline	694	N/A	190	N/A	137	N/A
High CO_2	1076	+55	294	+55	255	+86

1 The percentage change from baseline was calculated as (Case X – Baseline)/Baseline.

From a state perspective, CO_2-EOR provides a considerably greater economic return in comparison to permanent geological storage, with no incremental oil production and associated benefits. Mineral owners, shareholders and North Dakota citizens benefit as well whether in the form of royalty payments, dividends or tax-related collections used to fund state priorities.

Using the single well production model provided by EERC's North Dakota 20-year CO_2-EOR Forecast, incremental tax revenues generated on a per well basis range from $502,149 to $714,812 over the initial 10-year period of production following commencement of CO_2-EOR, depending on various pricing scenarios for crude oil.[6]

[4,5] Peck, W., Azzolina, N., and Guillot, S. "*North Dakota 20-Year CO_2 EOR Forecast*." Energy & Environmental Research Center, University of North Dakota. 29 Dec. 2024.

[6] Kroshus, B. "North Dakota CO2-EOR Financial Analysis." Table 6. *Office of North Dakota Tax Commissioner*, 15 Nov. 2024.

Single Well CO_2-EOR – Revenue Model Comparisons[7]			
Single Well Revenue Model	**Incremental Production Tax Revenue**	**Incremental Extraction Tax Revenue**	**Total – Single Well**
EOR 10-year model - EIA Pricing	$502,149	$0	$502,149
EOR 10-year model - $80.00 WTI	$661,696	$0	$661,696
EOR 5-year model - EIA Pricing	$502,149	$46,248	$548,396
EOR 5-year model - $80.00 WTI	$661,696	$53,116	$714,812

Applying the single well model to the estimated 271 grids and 5,744 associated EOR wells targeted in the EERC study, under the high-case scenario and current stripper well count in North Dakota as of July 2024 (12,515), in conjunction with U.S. Energy Information Administration (EIA) price estimates for Brent Crude at $80/bbl., generate an additional $2.9 billion to $9 billion in incremental revenue to the state, alone.[8]

Overall CO_2-EOR Incremental Revenue Model – North Dakota[9]		
Single Well Revenue Model	**Total - 5,744 Wells**	**Total - 12,515 Wells* (*Stripper Well Count - 7-24)**
EOR 10-year model - EIA Pricing	$2,884,341,547	$6,284,389,704
EOR 10-year model - $80.00 WTI	$3,800,781,824	$8,281,125,440
EOR 5-year model - EIA Pricing	$3,149,988,103	$6,863,179,163
EOR 5-year model - $80.00 WTI	$4,105,880,128	$8,945,872,180

**As indicated, if every certified, low-producing or stripper well currently identified in North Dakota is targeted for CO_2-EOR, the economic benefit is significantly higher in comparison to the low estimate, even with low-producing wells in the state being exempted from extraction tax for the life of the well under current statute. Conversely, the opportunity cost or potential revenue loss absent CO_2-EOR as demonstrated, equates to billions of dollars in unrealized collections.*

High-end oil production estimates exceed the currently available supply of CO_2 required to achieve production estimates, but nonetheless demonstrate the economic potential of CO_2-EOR from an incremental oil production and associated tax revenue perspective.

---

[7] Kroshus, B. "North Dakota CO2-EOR Financial Analysis." Table 6. *Office of North Dakota Tax Commissioner*, 15 Nov. 2024.
[8] Kroshus, B. "North Dakota CO2-EOR Financial Analysis." Tables 3, 5, and 7. *Office of North Dakota Tax Commissioner*, 15 Nov. 2024.
[9] Kroshus, B. "North Dakota CO2-EOR Financial Analysis." Table 7. *Office of North Dakota Tax Commissioner*, 15 Nov. 2024.

North Dakota Potential for Low-Carbon Energy to Meet Global Market and Regulatory Mandates

Driven by both global market forces and regulatory shifts, the energy industry is increasingly focused on producing low-carbon intensity (CI) energy. CI represents the GHG emissions associated with each unit of energy produced, offering a quantitative measure of a product's environmental footprint; a metric gaining importance as global and national markets prioritize low-emission sources and policies like the federal 45Q tax credit incentivize carbon capture and storage (CCS) to reduce overall emissions.

For the Bakken Formation, this presents a unique opportunity to produce low-CI oil by integrating carbon-reducing technologies and CO_2-EOR, aligning with global environmental standards while maintaining or even increasing production. Similarly, lignite, often challenged by its higher emissions profile, faces mounting pressure to adopt CCS technologies to remain viable in an increasingly carbon-conscious market. Efforts to capture and sequester emissions from lignite power plants could secure its role in the energy mix while addressing regulatory demands.

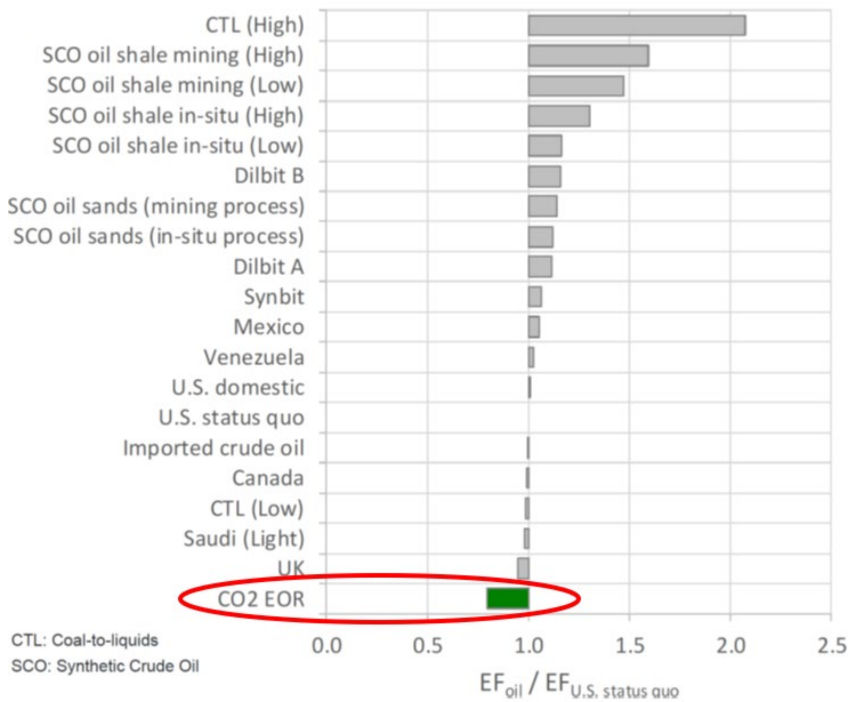
Ethanol production is also under pressure to lower its carbon footprint, especially as states like California enforce stringent CI standards for fuels under programs such as the Low Carbon Fuel Standard (LCFS). By integrating carbon capture and adopting innovative production practices, North Dakota's ethanol industry has the potential to enhance its competitiveness and meet both market demands and regulatory requirements. Together, these efforts position North Dakota’s energy industries to thrive in a low-carbon future while capitalizing on evolving market opportunities.

Understanding Carbon Intensity and CO_2-EOR

The growing demand for low-emission oil is driven by global efforts to meet carbon reduction goals, meet regulatory mandates, and align with market preferences for sustainable energy sources. As consumers, investors, and governments prioritize reducing carbon footprints, oil producers face increasing pressure to lower CI of their products. Low-emission oil not only meets evolving environmental standards but also enhances market competitiveness.

North Dakota is uniquely positioned to produce low-emission oil due to its integration of innovative technologies and abundant resources. The Bakken Formation offers opportunities to adopt CCS technologies and CO_2-EOR, reducing emissions associated with extraction and production. By capturing CO_2 from in-state sources like lignite and ethanol facilities and using it for EOR, North Dakota can both lower its CI and increase oil recovery efficiency.

CO_2-EOR Significantly Lowers GHG Emissions in Oil Production by Approx. 20%[10]



The chart compares the emission factors (EF) of various crude oil blends based on their source, listed in the left-hand column, which includes nations or industrial production types. The "EFoil/EFU.S. status quo" column shows the ratio of each crude oil blend's emission factor (EFoil) to the baseline emission factor for U.S. oil production in 2004, normalized to a value of 1 and referred to as the "U.S. status quo," as defined by Mangmeechai (2009). This ratio highlights how the emissions of each crude oil source compared to the U.S. benchmark.

Conclusion

North Dakota's tax policy, which reduces the federal 45Q tax credit $25 differential between carbon storage ($85) and utilization ($60) to less than $10, makes the state a more attractive choice for CO_2 utilization in EOR compared to other oil-producing states. By lowering the economic barrier for CO_2-EOR, North Dakota enhances the viability of carbon capture and utilization, encouraging investment and growth in both oil production and carbon storage. Current state tax policy not only boosts oil recovery rates but also positions the state as a leader in energy production and global market environmental standards. As a result, North Dakota offers a more favorable business environment for CO_2-EOR projects, creating a competitive advantage for oil, lignite and agriculture sectors.

---

[10] Adapted from: Mangmeechai, A., 2009, Life cycle greenhouse gas emissions, consumptive water use and levelized costs of unconventional oil in North America: Dissertation, Pittsburgh, Pennsylvania, Carnegie Mellon University.
Azzolina, N.A., Peck, W.D., Hamling, J.A., Gorecki, C.D., Ayash, S.C., Doll, T.E., Nakles, D.V., and Melzer, L.S. How green is my oil? A detialed look at greenhouse gas accounting for CO2-enhanced oil recovery (CO2-EOR) sites. Inernational Journal of Greenhouse Gas Control, v.51, p0. 369-379.

STAND Sustain. Transform. Authenticate. North Dakota.

Appendix A

Report: North Dakota CO_2-EOR Financial Analysis

Authored by: North Dakota Tax Commissioner

North Dakota CO_2-EOR Financial Analysis

November 15, 2024

Summary

The following document explores and evaluates various financial considerations related to CO2-EOR in North Dakota, potential synergies across multiple energy-sectors, and the influence policy will have on future CO2-based tertiary efforts in the state.

The U.S. Geological Survey estimates that up to 3.3 billion barrels of undiscovered, technically recoverable oil are in the Bakken formation, with much of that oil in North Dakota. CO2-EOR can play a central role in the recovery of these untapped resources.

By: Brian Kroshus
North Dakota Tax Commissioner

Table of Contents

Introduction

Enhanced oil recovery (EOR) development in North Dakota utilizing CO_2, particularly from CO_2 feedstocks sourced from in-state coal conversion facilities, biofuel plants and synfuels production, represents a significant economic opportunity.

Supporting and further enhancing an already favorable economic and regulatory environment to encourage CO_2-EOR versus CO_2 sequestration and permanent, geologic storage, will require evaluating both existing and new policy offerings to mitigate the current $25 differential between two of the three primary 45Q tax credit incentives currently available.

These incentives and economics on the surface favor sequestration over enhanced oil recovery. However, state policy from both a tax and regulatory perspective at least in part, holds the potential to offset the monetary gap and positively influence adoption of CO_2-EOR within our borders, promoting new, long-term capital investment in North Dakota.

From an industry perspective, beyond production-related economics, CO_2-EOR can play a key role in addressing and meeting corporate sustainability objectives, serving as a valuable extension of existing ecocentric practices.

Both internal and external factors will invariably influence CO_2 usage patterns. They include commodity pricing, other investment and capital deployment opportunities, and the regulatory and tax policy environment at the federal, state and local levels.

Further, recognizing the importance of fostering an environment that supports effective public-private partnerships and working collaboratively with tribal interests, is essential.

Arguably, CO_2-EOR in conjunction with existing energy resources in the state signifies the next chapter of oil production in North Dakota. For industry and public sector alike, there exists the potential to further monetize current oil, lignite, and biofuel energy infrastructure.

As North Dakota evaluates a path forward, it is important to recognize other oil and gas producing states including Texas, Oklahoma, New Mexico, and in proximity to North Dakota, Wyoming, are also actively positioning and competing to attract the same CO_2 supplies and capital investment dollars necessary to advance CO_2-EOR projects within their respective geographies.

To counter that reality, new incentive opportunities from a tax policy perspective to complement existing mechanisms and encourage CO_2-EOR and supporting infrastructure development, may be required to attract in-state capital investment for conventional and unconventional oil production alike, where CO_2-EOR is deemed economically viable and applied.

Further, supporting the development of critical CO_2 transportation infrastructure necessary to move feedstock from point-of-capture to application in North Dakota oil fields, will also play an important role in advancing CO_2-EOR efforts in the state.

The ability to establish greater CO_2 supply assurances necessary for industry to justify capital investment within and outside the Bakken, will be an essential element in the level of success experienced. Potential in-state supplies of CO_2 are optimal in the sense they support multiple industrial energy segments including oil, lignite, and agriculture, each playing an important role in the state's economy.

In essence, state regulatory and tax policy as previously mentioned will play a key role in advancing CO_2-EOR in what can best be described as a rapidly developing and highly competitive landscape.

It is important to emphasis that the benefits of CO_2-EOR are not exclusive to the production of oil. North Dakota's fleet of coal-fired plants in proximity to the Bakken and lone synfuels plant, Dakota Gasification, are also strategically positioned to benefit from the application of CO_2-EOR as suppliers and sellers of CO_2. That in turn supports the advancement of carbon capture technology and ultimately, implementation of CO_2-EOR.

North Dakota, with its diverse energy resource portfolio, is arguably more strategically positioned to implement CO_2-EOR in comparison to other oil-producing states, again in large part due to proximity and volume of interrelated energy resources.

While CO_2 transport challenges from an infrastructure placement standpoint currently exist, the ability to move feedstock from point-of-capture to actual use, while not entirely removed, is arguably less pronounced due to the relatively short distance between in-state supplies of CO_2 and oil field application.

North Dakota is in a unique position in that it also has very favorable geology for the sequestration and permanent storage of CO_2. Still, an equally compelling if not stronger argument to support CO_2-EOR can be made, the latter providing a broader and in effect, more favorable long-term economic platform to support incremental production in the Bakken. That in turn provides an attractive return on investment not only in the state, but nation from an energy production and security perspective.

Ultimately, the potential to sustain and increase oil production in North Dakota and subsequently, support and bolster associated revenue collections resulting from carbon capture and EOR, is significant. However, for that to become a reality, it is essential that the economic potential of CO_2-EOR exceeds sequestration.

Conversely, the opportunity cost and loss in potential revenue if sequestration instead displaces CO_2-EOR, particularly in oil-producing states like North Dakota, cannot be overlooked as the following analysis explains.

CO_2 EOR Incentives and Infrastructure by State

As previously noted, effectively competing for investment dollars targeted for carbon capture and transportation, whether from existing industry reserves or venture capital groups, will be paramount in determining the level of success experienced in North Dakota.

In many respects, North Dakota already heavily incentivizes utilizing CO_2 for EOR development. Numerous tax incentives currently exist to support CO_2-EOR, including as specified in NDCC § 57-51.1-02:

- Incremental production from a qualifying tertiary recovery project is exempt for a period of 10 years.
- Incremental production from a qualifying tertiary recovery project located outside the Bakken or Three Forks formations and that injects more than fifty percent carbon dioxide produced from coal, is exempt for twenty years from the date incremental production begins.
- Incremental production from a qualifying tertiary recovery project located within the Bakken or Three Forks formations and that injects more than fifty percent carbon dioxide produced from coal, is exempt for ten years from the date incremental production begins.

Beyond CO_2-EOR incentives, North Dakota exempts low-producing or marginal wells from the oil extraction tax. These wells, often referred to as "stripper wells," can qualify for tax-reduction incentives based on production and location criteria and then be exempt from the state's oil extraction tax for the remaining life of the well, once designated as a stripper well by the North Dakota Industrial Commission. While not necessarily a direct CO_2-EOR incentive, the net effect is still the same through elimination of the extraction tax obligation.

Additionally in North Dakota, the oil extraction tax rate for restimulated wells, identified as previously completed and producing oil and subsequently treated with an application of fluid under pressure for the purpose of creating additional fractures in a targeted geological formation outside the Bakken and Three Forks formations, is reduced from 5% to 2%, effective for the first 75,000 barrels (bbl) or 18 months, whichever occurs first, after restimulation is complete.

To encourage carbon capture projects and development of infrastructure to support EOR, state policy provides a sales and use tax exemption for materials used in compressing, gathering, collecting, storing, transporting, or injecting carbon dioxide for secure geological storage or use in enhanced recovery of oil or natural gas (NDCC § 57-39.2-04.14) The incentive is broad-based in nature, applying not only to primary pipeline transportation projects but oilfield distribution networks as well.

For projects to be exempt under NDCC § 57-39.2-04.14, tangible personal property must be incorporated into a system used to compress, gather, collect, store, transport, or inject carbon dioxide for secure geologic storage or use in enhanced recovery of oil or natural gas.

Tangible personal property to replace an existing system to compress, gather, collect, store, transport, or inject carbon dioxide for secure geologic storage or use in enhanced recovery of oil or natural gas qualifies as sales tax exempt if the replacement creates an expansion of the original system.

Additionally, a CO_2 pipeline project exemption as specified in NDCC § 57-06-17.1, exempts property, not including land, from taxation during construction and for the first 10 full taxable years following initial operation. Associated equipment necessary for the transportation or storage of CO_2 for secure geological storage or for use in enhanced recovery of oil or natural gas, is also exempt.

Finally, under NDCC § 57-39.2-04.49, Gross receipts from sales of carbon dioxide used for enhanced recovery of oil or natural gas, or secure geologic storage, are exempt from sales tax.

Similarly, other oil-producing states in the U.S. are also aggressively positioning and engaging in policy discussions to incentivize CO_2-EOR within their borders and capture market share.

Virtually all oil producing states in the U.S. currently have mechanisms in place to address low-price cycles for crude oil, similar to previous North Dakota statute which established a low-price trigger and subsequent suspension of the oil extraction tax during market downturns to protect oil producers in the state. While the low-price trigger protection was repealed by North Dakota lawmakers in exchange for a permanent reduction in the extraction tax rate, from 6% to 5%, that same concept is still applicable in other states.

In Texas, the Texas Railroad Commission, the counterpart to North Dakota Public Service Commission, has the authority to incentivize CO_2-EOR projects. Under their current incentive, the producer of oil recovered through a CO_2-EOR project that qualifies, is entitled to an additional 50% reduction in the oil tax rate in Texas if in the recovery of the oil the EOR project uses CO_2 that:

- Is captured from an anthropogenic source in this state;
- Would otherwise be released into the atmosphere as industrial emissions;
- Is measurable at the source of capture; and
- Is sequestered in one or more geological formations as part of the enhanced oil recovery process

Other states, like Wyoming, continue to actively pursue new legislation to support CO_2-EOR development, to effectively compete for regional supplies of CO_2.

In some cases, CO_2 transportation infrastructure designated for CO_2-EOR is already operational, including the Kinder Morgan Cortez Pipeline, delivering approximately 800 million cubic feet or 22,654 metric tonnes of naturally occurring CO_2 daily from the McElmo Dome site in southwest Colorado to oil fields in the Permian Basin in New Mexico and West Texas. Incremental oil production attributed to that project is approximately 50,000 barrels per day (bbl/d).

Active CO_2-EOR projects in North Dakota include the Denbury CO_2 pipeline, stretching 105 miles from Wyoming to Southeast Montana and Southwest North Dakota, targeting the Cedar Creek Anticline.

Additionally, Dakota Gasification Company, a subsidiary of Basin Electric Power Cooperative, has been transporting CO_2 since October 2000 from the Great Plains Synfuels Plant through a 205-mile pipeline operated by Souris Valley Pipeline, Ltd. to the Weyburn-Midale oil fields in Canada, currently shipping up to 155 million cubic feet, or 4,389 tonnes of CO_2 daily for EOR.

In 2022, Red Trail Energy located outside of Richardton began operating North Dakota's first CO_2 storage well in June of 2022. Preceding that effort, test wells were drilled in Mercer and Oliver counties located in North Dakota, in 2018 to study the geologic potential for CO_2 sequestration sourced from North Dakota coal-conversion facilities.

While CO_2-EOR production accounts for only a small fraction of oil currently produced in the U.S. and even globally, new CO_2-EOR policy and projects as previously mentioned continue to be actively explored both in North Dakota and throughout the U.S.

While advancements in carbon capture technology and associated capital investment are rightfully at the forefront of the discussion, the ability to secure, transport and distribute economically viable volumes of CO_2 necessary to support large-scale CO_2-EOR is equally important, particularly from a North Dakota perspective given the opportunity to link multiple energy industry segments to one another.

In summary, North Dakota energy resources and current policy, will serve as a benchmark for future discussions supporting the advancement and application of CO_2-EOR in the state.

Economic Analysis – Current Oil and Gas Collections

Economic estimates are often constructed from a direct or linear, incremental gains' perspective, with limited focus placed on opportunity cost. In evaluating the application and potential economic benefit of CO_2-EOR in North Dakota, it not only has the potential to provide incremental benefits to the state as referenced, but equally important, help preserve existing production levels and associated revenue streams.

That latter aspect or preservation will be particularly evident during periods of oil price declines, whether cyclical or due to unanticipated market conditions, unfavorable supply and demand dynamics, or consequential geopolitical events.

The North Dakota Legislature, recognizing the finite nature of oil resources in the state, has established various reserve funds, most notably the Legacy Fund, intended to benefit future generations by protecting revenue streams should production levels drop below the current range.

Until that time, however, oil production and associated revenue collections in the state can be better optimized through strategic initiatives intended to improve recovery rates in western North Dakota, including CO_2-EOR.

As an energy producing state, North Dakota relies heavily on oil-related revenue to fund state and local government both within and beyond oil producing counties. Oil production and extraction tax collections alone are substantial, most recently exceeding $3 billion in FY2023 and FY2024 respectively, as illustrated in Figure 1. Beyond those collections, associated economic activity plays a vital role in supporting the state's economy, covered later in this document.

As shown on the following graph, oil revenue collections in aggregate over just the past decade, equate to $23 billion.

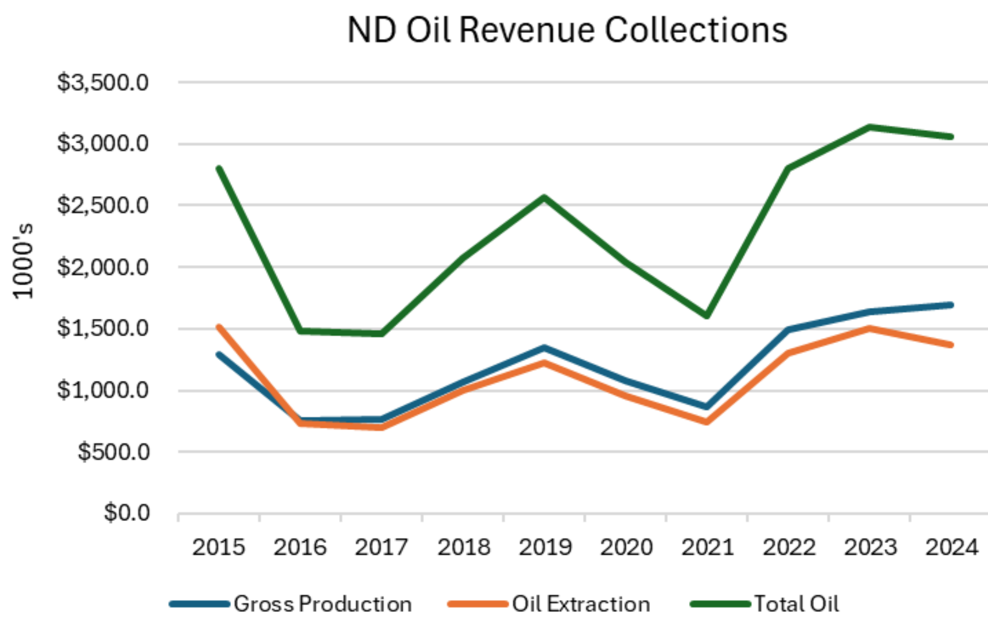


Figure 1

Figure 1 underscores the financial significance associated with oil production in North Dakota and illustrates the impact cyclical pricing, particularly price spikes and declines at various times (Figure 2), predictably has on revenue collections. This is most pronounced during the 2016-2017, 2020 and 2022 timeframes.

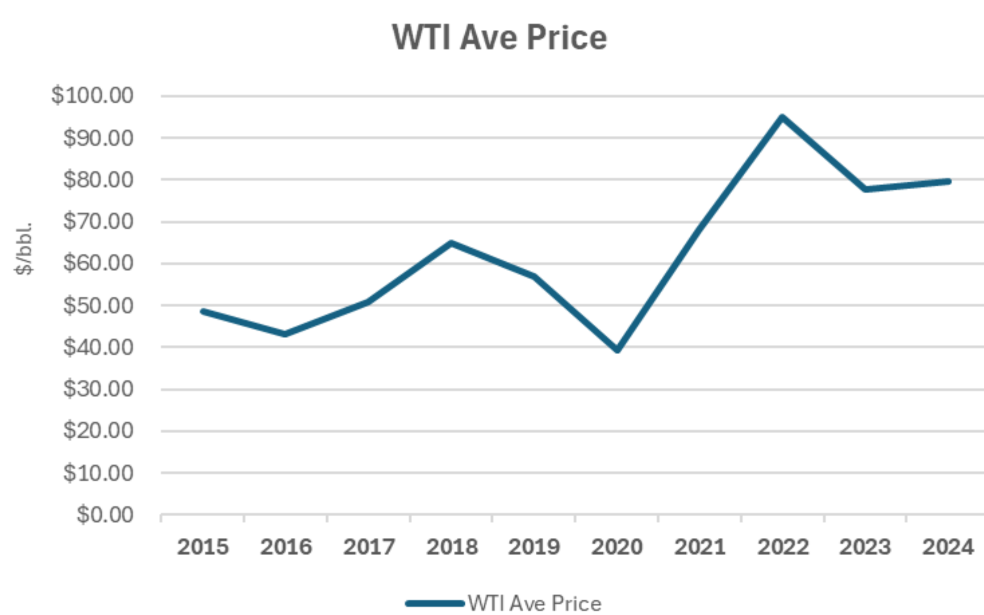


Figure 2

As noted, CO_2-EOR efforts have the potential to increase revenue collections, but equally importantly, preserve existing revenue streams by mitigating market-influenced price declines that inhibit drilling activity and subsequently, negatively impact production.

Historically, the ability to increase or maintain oil production levels in North Dakota has predominately correlated to drilling activity and the introduction of new wells. Absent that, output predictably declines due to high depletion rates experienced by wells drilled in shale plays like the Bakken, often exceeding 50% during the first year of production and falling below 10% of initial production, within 5 to 7 years.

Figure 3 illustrates shifts in economic value or revenue collected from a production and extraction tax standpoint, between 2014 and 2023, for every 100,000 bbl produced. The economic impact shown underscores the importance of maintaining production, particularly when oil prices are depressed over prolonged periods of time.

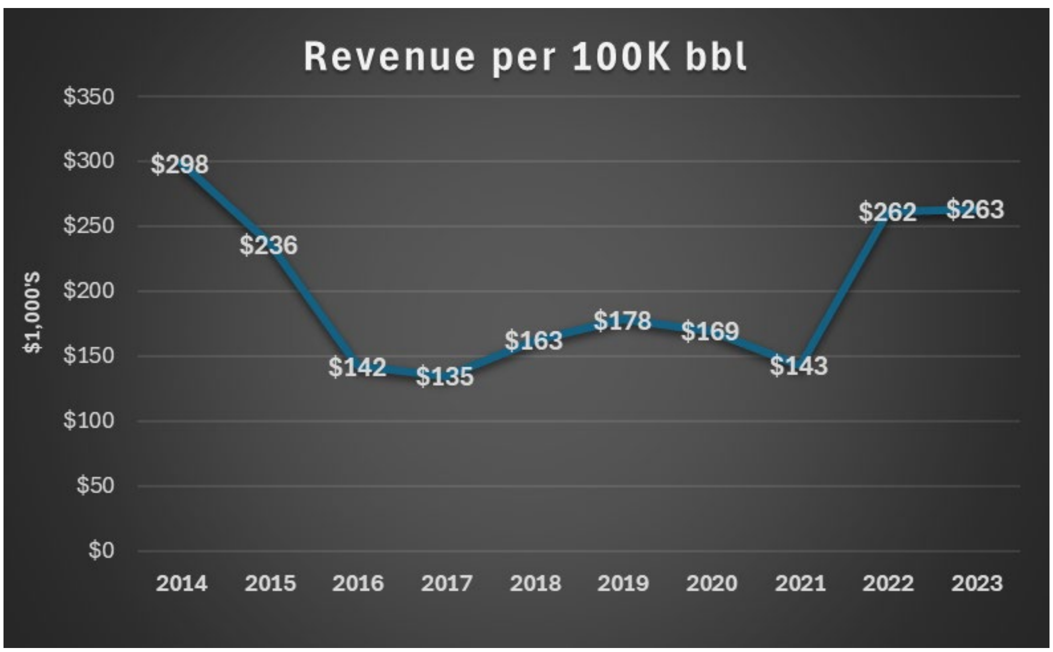


Figure 3

CO_2-EOR Fiscal Impact

Future commodity pricing combined with input costs including the cost of CO_2 itself, will significantly influence the degree of opportunity producers have to pursue CO_2-EOR. Unlocking additional crude oil from existing wells in inventory, reflected in the CO_2-EOR single well revenue models shown in Tables 2-5 to follow, demonstrate the revenue potential to the state, primarily from oil production tax collected on incremental barrels produced, based on different incentive scenarios including:

- 5-year extraction tax exempt models
- 10-year extraction tax exempt models

Models are formulated using the same, single well production estimates over the first 10 years following initiation of CO_2-EOR. Twenty-year and low producing, or stripper well models, are not calculated due to relatively immaterial, residual oil output and respective collections beyond the 10-year mark, resulting from rapid depletion rates associated with and prevalent in shale plays.

The following calculations (Tables 2-5) are based on oil pricing estimates over both 5-year and 10-year timeframes, using the U.S. Energy Information Administration (EIA) price outlook for Brent Crude as of June 2024 (Table 1) for the years 2028-2037 and for comparative purposes, applying an average net price of $80.00/bbl for Bakken crude.

U.S EIA Price Estimates/bbl – June 2024

Year range	Brent crude price projections (ave.)*	WTI after discount to Brent (3%)	Bakken discount to WTI ($3.75-$2.65)	Net price to Bakken producers
2025-2029	$61.00	$59.17	$3.20	$55.97
2030-2034	$73.00	$70.81	$3.20	$67.61
2035-2039	$80.00	$77.60	$3.20	$74.40
2040-2044	$87.00	$84.39	$3.20	$81.19
2045-2049	$91.00	$88.27	$3.20	$85.07
2050	$95.00	$92.15	$3.20	$88.95

Table 1

Net prices reflected in Table 1 and received by Bakken producers are extrapolated from EIA Brent price projections, applying a 3% discount to approximate the price for West Texas Intermediate and assuming an additional average discount rate of $3.20/bbl for Bakken crude, to determine net price.

Single Well CO_2-EOR – 10 yr. extraction tax exempt

Based on EIA 2028-2037 Price Estimates (Table 1)

	Total Annual Production bbl	Legacy Production bbl	Incremental Production bbl	Ave. price Bakken Crude	Incremental Production Tax Revenue	Incremental Extraction Tax Revenue	Total Incremental Revenue
yr 1	71,781	9,211	62,570	$55.97	$175,102	$0	$175,102
yr 2	45,192	7,375	37,817	$55.97	$105,831	$0	$105,831
yr 3	33,222	5,905	27,317	$67.61	$92,345	$0	$92,345
yr 4	20,043	4,728	15,315	$67.61	$51,772	$0	$51,772
yr 5	12,911	3,785	9,126	$67.61	$30,850	$0	$30,850
yr 6	8,719	3,030	5,689	$67.61	$19,232	$0	$19,232
yr 7	6,016	2,426	3,590	$67.61	$12,136	$0	$12,136
yr 8	4,148	1,943	2,205	$74.40	$8,203	$0	$8,203
yr 9	3,010	1,555	1,455	$74.40	$5,413	$0	$5,413
yr 10	1,732	1,392	340	$74.40	$1,265	$0	$1,265
Total	**206,774**	**41,350**	**165,424**		**$502,149**	**$0**	**$502,149**

Table 2

Single Well CO_2-EOR - 10-yr. extraction tax exempt

Based on 10 yr. average price of $80

	Legacy Production bbl	Incremental Production bbl	Total Annual Production bbl	Ave. price Bakken Crude	Incremental Production Tax Revenue	Incremental Extraction Tax Revenue	Total Incremental Revenue
yr 1	9,211	62,570	71,781	$80.00	$250,280	$0	$250,280
yr 2	7,375	37,817	45,192	$80.00	$151,268	$0	$151,268
yr 3	5,905	27,317	33,222	$80.00	$109,268	$0	$109,268
yr 4	4,728	15,315	20,043	$80.00	$61,260	$0	$61,260
yr 5	3,785	9,126	12,911	$80.00	$36,504	$0	$36,504
yr 6	3,030	5,689	8,719	$80.00	$22,756	$0	$22,756
yr 7	2,426	3,590	6,016	$80.00	$14,360	$0	$14,360
yr 8	1,943	2,205	4,148	$80.00	$8,820	$0	$8,820
yr 9	1,555	1,455	3,010	$80.00	$5,820	$0	$5,820
yr 10	1,392	340	1,732	$80.00	$1,360	$0	$1,360
Total	**41,350**	**165,424**	**206,774**		**$661,696**	**$0**	**$661,696**

Table 3

Single Well – CO_2-EOR – 5 yr. extraction tax exempt

Based on EIA 2028-2037 Price Estimates (Table 1)

	Total Annual Production bbl	Legacy Production bbl	Incremental Production bbl	Ave. price Bakken Crude	Incremental Production Tax Revenue	Incremental Extraction Tax Revenue	Total Incremental Revenue
yr 1	71,781	9,211	62,570	$55.97	$175,102	$0	$175,102
yr 2	45,192	7,375	37,817	$55.97	$105,831	$0	$105,831
yr 3	33,222	5,905	27,317	$67.61	$92,345	$0	$92,345
yr 4	20,043	4,728	15,315	$67.61	$51,772	$0	$51,772
yr 5	12,911	3,785	9,126	$67.61	$30,850	$0	$30,850
yr 6	8,719	3,030	5,689	$67.61	$19,232	$19,232	$38,463
yr 7	6,016	2,426	3,590	$67.61	$12,136	$12,136	$24,272
yr 8	4,148	1,943	2,205	$74.40	$8,203	$8,203	$16,405
yr 9	3,010	1,555	1,455	$74.40	$5,413	$5,413	$10,825
yr 10	1,732	1,392	340	$74.40	$1,265	$1,265	$2,530
Total	**206,774**	**41,350**	**165,424**		**$502,149**	**$46,248**	**$548,396**

Table 4

Single Well CO_2-EOR– 5-yr. extraction tax exempt

Based on 10 yr. average price of $80.00

	Total Annual Production bbl	Legacy Production bbl	Incremental Production bbl	Ave. price Bakken Crude	Incremental Production Tax Revenue	Incremental Extraction Tax Revenue	Total Incremental Revenue
yr 1	71,781	9,211	62,570	$80.00	$250,280	$0	$250,280
yr 2	45,192	7,375	37,817	$80.00	$151,268	$0	$151,268
yr 3	33,222	5,905	27,317	$80.00	$109,268	$0	$109,268
yr 4	20,043	4,728	15,315	$80.00	$61,260	$0	$61,260
yr 5	12,911	3,785	9,126	$80.00	$36,504	$0	$36,504
yr 6	8,719	3,030	5,689	$80.00	$22,756	$22,756	$45,512
yr 7	6,016	2,426	3,590	$80.00	$14,360	$14,360	$28,720
yr 8	4,148	1,943	2,205	$80.00	$8,820	$8,820	$17,640
yr 9	3,010	1,555	1,455	$80.00	$5,820	$5,820	$11,640
yr 10	1,732	1,392	340	$80.00	$1,360	$1,360	$2,720
Total	**206,774**	**41,350**	**165,424**		**$661,696**	**$53,116**	**$714,812**

Table 5

Using the single well production model provided by the Energy & Environmental Research Center (EERC) North Dakota 20-year CO_2-EOR Forecast, incremental tax revenues generated on a per well basis range from $502,149 to $714,812 (Table 6) over the initial 10-year period of production following commencement of CO_2-EOR, depending on various pricing scenarios for crude oil.

Single Well CO_2-EOR - Revenue Model Comparisons

Single Well Revenue Model	Incremental Production Tax Revenue	Incremental Extraction Tax Revenue	Total - Single Well
EOR 10-year model - EIA Pricing	$502,149	$0	$502,149
EOR 10-year model - $80.00 WTI	$661,696	$0	$661,696
EOR 5-year model - EIA Pricing	$502,149	$46,248	$548,396
EOR 5-year model - $80.00 WTI	$661,696	$53,116	$714,812

Table 6

Applying the single well model to the estimated 271 grids and 5,744 associated EOR wells targeted in the EERC study, under the high-case scenario and current stripper well count in North Dakota as of July 2024 (12,515), in conjunction with EIA price estimates for Brent crude as illustrated in Tables 2 and 4 and average price of $80/bbl (Tables 3 and 5), generates approximately $2.9 to $9 billion in incremental revenue (Table 7) to the state, alone.

It's worth noting that high-end estimates exceed the available supply of CO_2 required to achieve production estimates, but nonetheless demonstrate the economic potential of CO_2-EOR from an incremental oil production and associated tax revenue perspective.

Overall CO_2-EOR Incremental Revenue Model - North Dakota

Single Well Revenue Model	Total - 5,744 Wells	Total - 12,515 Wells* (*Stripper Well Count - 7-24)
EOR 10-year model - EIA Pricing	$2,884,341,547	$6,284,389,704
EOR 10-year model - $80.00 WTI	$3,800,781,824	$8,281,125,440
EOR 5-year model - EIA Pricing	$3,149,988,103	$6,863,179,163
EOR 5-year model - $80.00 WTI	$4,105,880,128	$8,945,872,180

Table 7

As indicated, if every certified, low-producing or stripper well currently identified in North Dakota is targeted for CO_2-EOR, the economic benefit is significantly higher in comparison to the low estimate, even with low-producing wells in the state being exempted from extraction tax for the life of the well under current statute. Conversely, the opportunity cost or potential revenue loss absent CO_2-EOR as demonstrated, equates to billions of dollars in unrealized collections.

Associated Fiscal Impact – Oil Producing Counties in North Dakota

Beyond direct benefits resulting from incremental oil production, associated economic impacts for CO_2-EOR extend exponentially beyond revenues generated from production and oil extraction tax levied on oil produced in North Dakota.

Target energy sectors including oil and coal, support state and local economies through employment opportunities, sales and use tax collections, property tax or equivalent of, and a plethora of other economic benefits.

Over the most recent five-year period roughly $10 billion in purchases, with associated state sales tax collections totaling approximately $500 million, can be attributed to oil-induced economic activity in the state's four largest oil and gas producing counties comprised of McKenzie, Dunn, Mountrail and Williams.

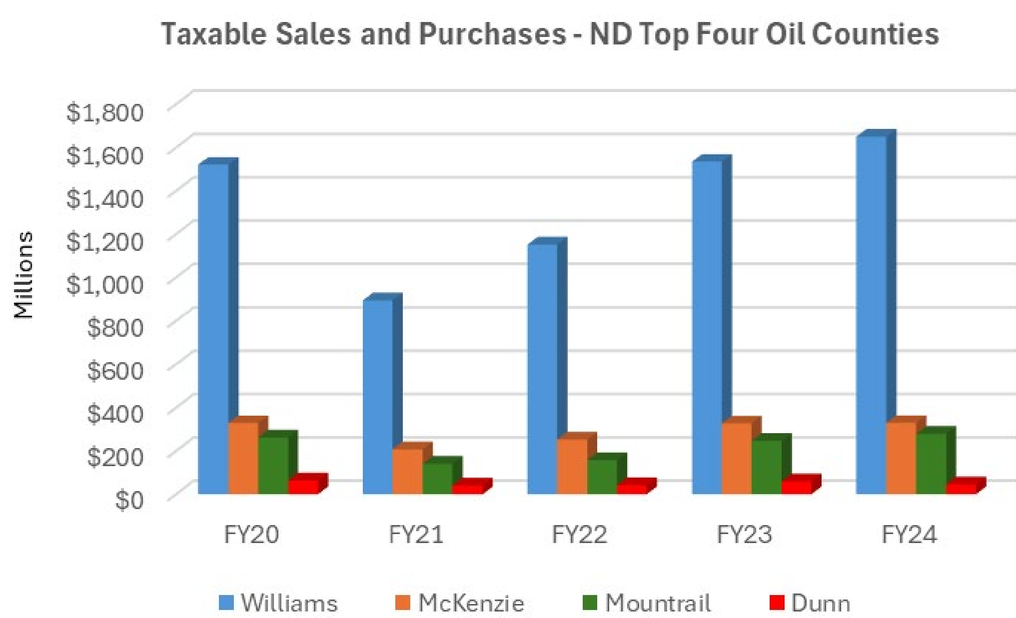


Figure 4

As shown in Figure 4, Williams County, including the city of Williston, continues to be an economic powerhouse in the region with approximately $7 billion in taxable purchases taking place over the past five fiscal years (FY20-FY24). While seemingly overshadowed by their larger economic cousin, the counties of McKenzie, Mountrail and Dunn combined still represent significant economic activity, approaching $3 billion in taxable sales and purchases over the same timeframe.

In addition to the 5% state sales and use tax rate, both cities and counties can levy and collect local sales and use tax in addition to the state requirement, with funds collected channeling directly back to the respective political subdivision.

While rates vary depending on location, the additional local options tax on qualifying purchases yields incremental collections equal to approximately one-third of the amount collected by the state, or $160-$170 million during the same 5-year period.

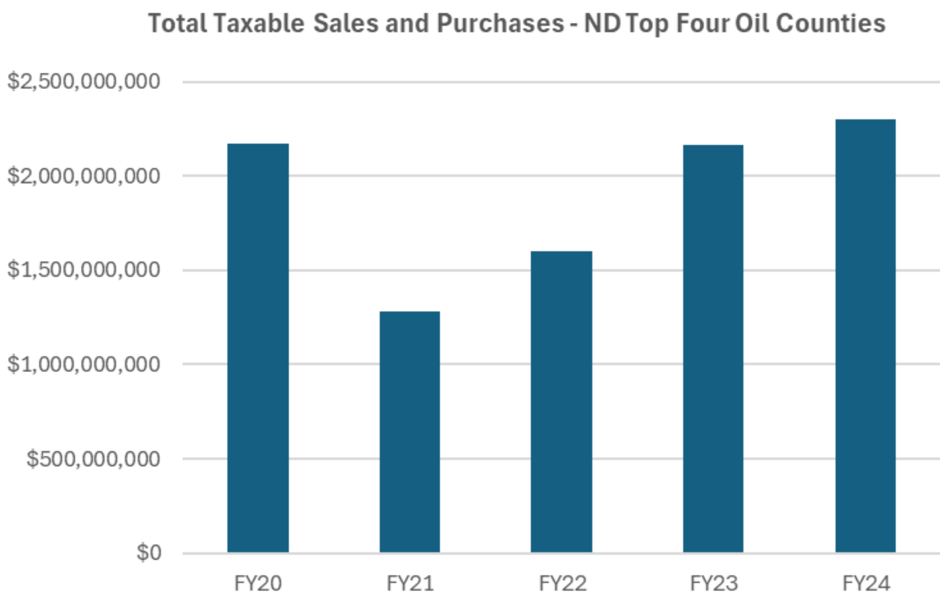


Figure 5

In aggregate, economic activity for North Dakota's four largest oil producing counties (Figures 4 and 5) is significant, despite challenges within the reflected period due to the effects of the pandemic, negatively impacting purchasing activity in FY20, FY21 and FY22.

While the agriculture sector throughout the state including in northwestern North Dakota continues to serve as the foundation of the state's economy, a predominant driver of the forementioned economic activity in the referenced region is energy, or more specifically oil-related, further supporting the case to advance CO_2-EOR in North Dakota.

Addressing the 45Q Incentive Gap

Given the significant economic opportunity related to CO_2-EOR development in North Dakota, ongoing discussions to evaluate and where applicable, improve upon existing policies and incentives to accentuate their influence on pricing models, are warranted.

Gaining a better understanding of the plethora of financial considerations and decisions industry is faced with, including addressing the $25 tax credit incentive differential between CO_2-EOR and permanent sequestration, and how policy-driven incentives and offsets can reduce the 45Q delta, will also be an important part of the conversation.

Production and infrastructure costs associated with CO_2-EOR and incurred by industry should also be recognized as key points of discussion, as prominent expense categories.

Specifically, primary expense centers include CO_2 acquisition cost, associated transportation and distribution costs, and well surface costs to support effective, large-scale implementation of CO_2-EOR, each an equally important factor in determining the financial outlook for tertiary recovery projects utilizing CO_2.

The cost model estimate below (Table 8) is based on the following criteria:

- Well development and surface costs represent approximately two-thirds of total project cost
- CO_2 supply expense equaling approximately one-third of total project cost
- No additional CO_2 compression costs
- Limited cost associated with filtration systems, waste fluid injection and electricity

CO_2-EOR Production Cost Model (Single Well)

Expense/Savings Centers	Cost per bbl	Tax savings/bbl	Tax savings/tonne CO_2	Net Cost/bbl
CO_2 Transportation [1,2]	$5.00	$0	$0	$5.00
CO_2 price/bbl ($30/t = 3 bbl) [2]	$10.00	$0.50	$1.50	$9.50
Royalty payment est. (19% of $80/bbl)	$15.20	$0	$0	$15.20
Well and surface (taxable) [3]	$17.50	$0.88	$2.63	$16.63
Well and surface (non-taxable)[4]	$7.50	$0	$0	$7.50
Extraction tax savings - $80/bbl*5%	$0	$4.00	$12.00	($4.00)
Totals	**$55.20**	**$5.375**	**$16.13**	**$49.83**

Table 8

[1] Primary distribution delivery cost est. = $15/tonne
[2] Per bbl based on $30/tonne CO2 and 3:1 bbl oil/tonne CO_2
[3] Includes well, distribution infrastructure & production costs
[4] Labor cost

Numerous price projection models for CO_2 exist with some in the $10-20 per tonne range. However, like other commodities, CO_2 pricing will vary by region and be influenced by a variety of factors including transportation capacity, available supply, industry demand, and proximity to end use whether geological storage or oil fields targeted for CO_2-EOR. Based on what is anticipated to be a highly competitive landscape for CO_2 acquisition in North Dakota, a $30/tonne estimate is used and reflected in Table 8.

Compression costs as previously noted are determined to be relatively inconsequential based on the assumption that CO_2 transportation projects, i.e. pipelines required to move CO_2 from point-of-origin to oil field distribution networks and ultimately targeted wells, will be accomplished with new infrastructure placement and not through the repurposing of existing facilities, which may be pressure limited.

A high percentage of project cost impacting economic performance is expected to originate from three primary areas including well and surface costs, royalty payments, and CO_2 acquisition costs. While not absent from the equation, filtration system, waste fluid injection, and electricity costs are anticipated to be relatively limited in scope compared to overall project costs and embedded in the "well and surface" cost category.

As demonstrated, tax savings resulting from various state-supported incentives are reflected in the cost model, representing an estimated savings of $5.375 per bbl of incremental oil produced, and based on a bbl of oil produced per tonne CO_2 ratio of 3:1, $16.13 in tax-related incentives per tonne of CO_2 acquired and deployed.

While the $25 credit differential for 45Q as described is not entirely removed through available North Dakota state tax incentives, current exemptions whether direct or indirect are nevertheless material from an economic standpoint, in the sense they offset approximately 64.5%, or almost two-thirds, of the 45Q tax credit differential per tonne of CO_2.

In aggregate, the model (Table 8) equates to $889,000 in tax-related savings, on a per well basis, assuming 165,424 bbl in incremental production over the immediate 10-year period following commencement of CO_2-EOR.

From a state revenue collection perspective using the same production estimates, taxes levied on incremental oil production generate an additional $502,000 to $715,000 (Table 6) in new revenue per well through production and extraction taxes levied, funds that would otherwise not materialize.

Summary

Encouraging industry to pursue CO_2-EOR, sets the stage to further monetize North Dakota energy resources in the Bakken and southwestern portion of the state, well into the future.

From a state perspective, CO_2-EOR certainly provides a considerably greater economic return in comparison to permanent geological storage, with no incremental oil production and associated benefits. Mineral owners, shareholders, and North Dakota citizens benefit as well whether in the form of royalty payments, dividends, or tax-related collections used to fund state priorities.

Similar to the introduction of new wells in unconventional shale plays like the Bakken, CO_2-EOR can serve as a profit center and help mitigate risk for producers, particularly during an oil price downturn, if large volumes of CO_2 can be effectively secured and transported to distribution networks and targeted oil plays.

Producers, in order to justify significant upfront capital investment needed to support CO_2-EOR, will require long-term CO_2 supply contracts structured in a manner that ensures acceptable pricing, whether pricing is fixed or as a percentage of WTI, and the reliable delivery of economic viable quantities of CO_2.

Effectively addressing the 45Q incentive gap between CO_2-EOR and sequestration or permanent storage, will again require adequately incentivizing industry to pursue CO_2-EOR by:

- Funding research to advance technology
- Supporting the development of new energy infrastructure
- Maintaining a reasonable and consistent regulatory environment
- Promoting existing and exploring new CO_2-EOR tax-related policy deemed mutually beneficial to industry and state alike

As emphasized, CO_2-EOR development in states like North Dakota can assist energy producers in addressing increasingly rigid social and environmental standards, challenging federal emissions requirements and aggressive, self-identified sustainability targets.

Even though a federal carbon tax is not currently in place, discussion surrounding that topic will undoubtedly continue but even absent that, a growing number of states have either adopted or are considering cap-and-trade systems and regulations. California has a cap-and-trade program and Washington, a cap-and-invest program.

Eleven northeastern states have organized and participate in a program referred to as the Regional Greenhouse Gas Initiative (RGGI) including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia.

Under RGGI, which was established in 2005 as the first market-based regulatory program in the United States, CO_2 emissions from power plants operating in that region are capped and the regulated power plants, participate in a program to auction or trade emission allowances, with each "allowance" permitting the holder to emit one short ton (2,000 lbs.) of CO_2.

Although these programs are beyond North Dakota's borders, state-driven greenhouse gas reduction initiatives arguably pose a future challenge from a trade standpoint. Subsequently, if not effectively countered, they create long-term risk to both industry and the state's ability to continue as a major exporter of energy and agriculture products, key contributors to the North Dakota economy.

CO_2-EOR as a mechanism to permanently store CO_2 in the reservoir, does not entirely remove those concerns, but holds the potential to certainly lessen the potential impact and reduce CO_2 intensity levels across multiple energy sectors operating in North Dakota.

Despite sequestration appearing to hold an economic advantage over CO_2-EOR due to the $25 dollar tax credit differential, CO_2-EOR nonetheless presents a unique and attractive opportunity for industry to further monetize existing holdings and more effectively distribute previously established costs over new, incremental barrels produced within the same geographic footprint.

While a degree of uncertainty exists regarding the direction federal policy will take long-term and future of the 45Q tax credit program, there remains an exceptional opportunity to pursue CO_2-EOR in North Dakota, given a current construction deadline date of January 1, 2033, and subsequent 12-year timeframe in which tax credits can be received under the program.

In closing, CO_2-EOR presents a significant opportunity to monetize existing resources, create new synergies among critical energy sectors in the state, and act as a catalyst to effectively enhance and extend the life of the Bakken for decades to come.

Appendix B

Report: North Dakota CO_2 EOR Forecast

Authored by: Energy & Environmental Research Center, UND

NORTH DAKOTA 20-YEAR CO_2 EOR FORECAST

Final Report

Prepared for:

Kayla Ver Helst

Bank of North Dakota
Economic Development and Government Programs
1200 Memorial Highway, PO Box 5509
Bismarck, ND 58506-5509

Prepared by:

Wesley D. Peck
Nicholas A. Azzolina
Stephen N. Guillot

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

2024-EERC-11-06 November 2024

EERC DISCLAIMER

LEGAL NOTICE: This research report was prepared by the Energy & Environmental Research Center of the University of North Dakota (UND EERC) as an account of work sponsored by the North Dakota Industrial Commission (NDIC) (SPONSOR). To the best of UND EERC's knowledge and belief, this report is true, complete, and accurate; however, because of the research nature of the work performed, neither UND EERC, nor any of their directors, officers, or employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the use of any information, apparatus, product, method, process, or similar item disclosed or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by UND EERC. NDIC (SPONSOR) understand and accept that this research report and any associated deliverables are intended for a specific project. Any reuse, extensions, or modifications of the report or any associated deliverables by SPONSOR or others will be at such party's sole risk and without liability or legal exposure to UND EERC or to their directors, officers, and employees.

NDIC DISCLAIMER

LEGAL NOTICE: This research report was prepared by UND EERC as an account of work sponsored by NDIC. To the best of UND EERC's knowledge and belief, this report is true, complete, and accurate; however, because of the research nature of the work performed, neither UND EERC, NDIC, nor any of their directors, officers, or employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the use of any information, apparatus, product, method, process, or similar item disclosed or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by UND EERC or NDIC. NDIC understands and accepts that this research report and any associated deliverables are intended for a specific project. Any reuse, extensions, or modifications of the report or any associated deliverables by NDIC or others will be at such party's sole risk and without liability or legal exposure to UND EERC or to their directors, officers, and employees.

TABLE OF CONTENTS

LIST OF FIGURES

Continued . . .

LIST OF FIGURES (continued)

LIST OF TABLES

NORTH DAKOTA 20-YEAR CO_2 EOR FORECAST

EXECUTIVE SUMMARY

The Bank of North Dakota retained the Energy & Environmental Research Center (EERC) to forecast incremental oil production associated with carbon dioxide (CO_2) enhanced oil recovery (EOR) in North Dakota's unconventional and conventional reservoirs. The forecast targets potential development scenarios over 20 years and predicts incremental oil production and CO_2 supply demand. In addition, the EERC provided output to support the North Dakota Office of State Tax Commissioner companion study to understand the economic implications of the modeled scenarios. These economic results are reported in a separate document. Section 5 of House Bill 1429 of the 68th Legislative Assembly of North Dakota directed the Bank of North Dakota to study environmental, social, and governance (ESG) trends, laws, and policies that impact the state's businesses and industries, specifically those that impact the state's energy and production agriculture industries.[1] The study may identify industry-specific public policy strategies for immediate and long-term implementation to help the state remain a global leader in energy and agriculture. This CO_2 EOR study is part of the Bank of North Dakota's broader sustainability market analysis.

The unconventional reservoirs included in the study were the Bakken and Three Forks Formations of the Bakken Petroleum System (Bakken). A stratified sampling approach subdivided the Bakken into 1147 standardized EOR grids. Each grid was approximately three 1280-acre drilling spacing units (DSUs) wide (east–west) and two 1280-acre DSUs tall (north–south). Only 271 grids contained 20 or more wells. These were mainly in the Bakken core areas in McKenzie, Mountrail, and Dunn Counties. The modeled EOR development focused on these 271 grids, representing nearly 10,000 existing wells.

The modeling work in this study suggests incremental oil recoveries from the Bakken over 20 years could range from around 300 million barrels (MMbbl) under a low-CO_2 Bakken scenario (5 million tonnes of CO_2 per year) to 1100 MMbbl under a high-CO_2 Bakken scenario (15 million tonnes of CO_2 per year), with an average of 700 MMbbl under the baseline CO_2 Bakken scenario (10 million tonnes of CO_2 per year). The CO_2 supply demands range from ~90 million to ~300 million tonnes, depending on the assumed Bakken constraint.

Additional sensitivity analysis cases showed that CO_2 supplies above 15 million tonnes per year would be needed to process more grids within the same time frame if the cyclic gas EOR was operated to maintain higher CO_2 utilization rates or improved oil recovery (IOR) ratios. In addition, approximately 10,000 new wells will likely be drilled and completed in the Bakken core areas and adjacent acreages. These forecast new wells were not included in this analysis. Development of the Bakken beyond the timelines considered here, which would expand beyond the core area and include recently drilled and completed wells, would exceed these estimates and yield significantly greater incremental oil recovery and volumes of stored CO_2 estimated in this analysis.

---

[1] Bank of North Dakota study – environmental, social, and governance trends: Report to Legislative Management, https://ndlegis.gov/assembly/68-2023/regular/documents/23-0990-05000.pdf (accessed May 2024).

Twenty-one fields/units were chosen as prime candidates for conventional CO_2 EOR. The modeling work in this study suggests incremental oil recoveries from these fields/units of 105 MMbbl and a CO_2 supply demand of 88 million tonnes.

Key drivers of the modeling results include the number of cycles used for cyclic gas injection in the Bakken, the IOR ratios assumed for Bakken and conventional EOR, and the CO_2 rate constraints imposed on the analysis. Bakken incremental oil results were proportional to the CO_2 supply; therefore, CO_2 supply significantly impacts Bakken incremental oil recovery.

DOCUMENT SUMMARY

The Bank of North Dakota retained the Energy & Environmental Research Center (EERC) to forecast incremental oil production associated with carbon dioxide (CO_2) enhanced oil recovery (EOR) in North Dakota's unconventional and conventional reservoirs. The forecast targets potential development scenarios over 20 years and predicts incremental oil production and CO_2 supply demand. In addition, the EERC provided output to support the North Dakota Office of State Tax Commissioner companion study to understand the economic implications of the modeled scenarios. These economic results are reported in a separate document.

Section 5 of House Bill 1429 of the 68th Legislative Assembly of North Dakota directed the Bank of North Dakota to study environmental, social, and governance (ESG) trends, laws, and policies that impact the state's businesses and industries, specifically those that impact the state's energy and production agriculture industries.[2] The study may identify industry-specific public policy strategies for immediate and long-term implementation to help the state remain a global leader in energy and agriculture. This CO_2 EOR study by the EERC is part of the Bank of North Dakota's broader sustainability market analysis.

CO_2 Supply

The modeling conducted in the study used a baseline case CO_2 supply rate of 10 million metric tons (tonnes) per year. While there are currently three coal-related CO_2 capture projects in various stages of development in North Dakota that, once operational, could together capture over 15 million tonnes per year (Coal Creek, Dakota Gasification Company [DGC], and Milton R. Young), the rate of 10 million tonnes per year was chosen as a conservative theoretical baseline case illustrating a scenario where modest adoption of CO_2 capture, transportation, and field infrastructure has occurred. Sensitivity cases of 5 million tonnes and 15 million tonnes per year were also examined.

The modeled scenarios assumed that competitive business cases were developed and that CO_2 infrastructure (e.g., well preparation, field unitization, flowlines, recycle facilities, compression equipment) was entirely in place at the start of the simulation period. This highly simplified approach to infrastructure development enabled the study to focus on deriving estimates of the maximum economic potential of CO_2 EOR in North Dakota. EOR infrastructure takes time to finance, procure, and build out. Establishing the CO_2 infrastructure to support the broad deployment of EOR is a long game that will most likely occur stepwise. The full potential of EOR in North Dakota may require a decade or more.

Because the development of widespread EOR infrastructure will take many years to mature, policy actions in the near-term may significantly bolster North Dakota's ability to harvest the maximum financial benefits in the decades to come. Both within industry operating budgets and Wall Street, financing competes with other oil plays (e.g., Permian Basin of Texas and New Mexico, Texas Eagle Ford), not just EOR. Policies that support EOR in North Dakota can strongly signal that investment in North Dakota is attractive.

[2] Bank of North Dakota study – environmental, social, and governance trends: Report to Legislative Management, https://ndlegis.gov/assembly/68-2023/regular/documents/23-0990-05000.pdf (accessed May 2024).

The federal 45Q tax credit provides an incentive for CO_2 capture of \$60/tonne for CO_2 utilized in EOR and storage, \$85/tonne for CO_2 sequestered in saline storage, and up to \$180/tonne for CO_2 captured and stored from a direct air capture facility. Eligible facilities can claim the 45Q tax credit for 12 years after being placed in service. Current law limits eligibility to carbon capture facilities that begin construction no later than January 1, 2033. The \$25 differential between saline storage and EOR storage 45Q tax credits drives investment toward saline storage projects, which will limit the near-term availability of CO_2 for EOR in North Dakota. This limit will likely continue to be the case until either the 45Q tax credits sunset (currently 12 years) or other incentives are put in place that close the differential and pull EOR development/production forward in time.

To encourage the development of EOR in the state, the North Dakota Century Code (NDCC) provides several exemptions[3] from the oil extraction tax[4] for EOR:

1) Incremental production associated with EOR is exempt for 10 years.
2) Incremental production from EOR from a horizontal well drilled and completed within the Bakken and Three Forks Formations is exempt for 5 years.
3) Incremental production from EOR that injects more than 50% CO_2 from coal, located outside the Bakken and Three Forks Formations, is exempt for 20 years.
4) Incremental production from EOR that injects more than 50% CO_2 produced from coal and is within the Bakken and Three Forks Formations is exempt for 10 years.

To compare the value of 45Q and North Dakota extraction tax exemption, at current Bakken crude prices of \$70/barrel (bbl), a 5% extraction tax exemption provides an approximately \$3.50/bbl incentive. Assuming an average of 2–4 bbl of incremental oil per tonne of CO_2 injected, the incentive equals approximately \$7–\$14/tonne of CO_2. The amount of the 45Q tax credit for EOR storage versus saline storage represents a significant disparity in the economic value of CO_2 for EOR despite the tax exemption provided by NDCC and not including the additional incremental production costs of EOR. Barring some other policy, regulatory, or market driver, this disparity creates significant uncertainty regarding the total CO_2 available for EOR through 2045 (12 years following the 2033 deadline for eligibility) and the potential for EOR deployment and associated economic benefits. For this forecast, the CO_2 quantities modeled represent theoretical cases to illustrate EOR scenarios once modest adoption of CO_2 capture, transportation, and field infrastructure (flowlines, compression, recycle) is in place and operational.

Unconventional Reservoirs – The Bakken Petroleum System

Conventional reservoirs have reservoir characteristics that allow for production from wells that do not require hydraulic fracturing, most often vertical wells. CO_2 EOR in conventional reservoirs has been happening in Texas since the 1970s; at the Weyburn Field in Saskatchewan using CO_2 from DGC since 2000; and in the Cedar Hills Field in Bowman County, North Dakota, since 2022 using CO_2 from a gas plant in Wyoming. Most conventional reservoirs in North Dakota were developed before 2010 using vertical wells. In contrast, unconventional reservoirs require the use of long horizontal wells and hydraulic fracturing to enable economical production. The Bakken is a world-class example of these types of unconventional reservoirs.

---

[3] NDCC § 57-51.1-03.
[4] 5% of the gross value at the well of the oil extracted (NDCC § 57-51.1-02).

The unconventional reservoirs included in the study were the Bakken and Three Forks Formations of the Bakken Petroleum System (Bakken). A stratified sampling approach subdivided the Bakken into 1147 standardized EOR grids. Each grid was approximately three 1280-acre drilling spacing units (DSUs) wide (east–west) and two 1280-acre DSUs tall (north–south). Only 271 grids contained 20 or more wells. These were mainly in the Bakken core areas in McKenzie, Mountrail, and Dunn Counties. The modeled EOR development focused on these 271 grids, representing nearly 10,000 wells. The grid size used in this study was used to simplify the estimates and is not meant to imply an ideal EOR development size. Furthermore, the current study did not include future new wells. Approximately 10,000 additional wells may be drilled, completed, and produced in this region over the study time frame. Those new wells would be produced via primary production for some duration, at which point they would be amenable to CO_2 EOR. Therefore, the estimates of incremental oil production and CO_2 demand have the potential to significantly exceed the numbers derived herein.

Forecast models were developed to predict oil production from implementing cyclic gas CO_2 EOR. The basis for these models was the dimensionless production curve method commonly used in conventional EOR. Each cycle was assumed to last 24 weeks, comprising 6 weeks of injection, 1 week of soaking, and 17 weeks of production. The development scenarios used seven cycles for each grid for 168 weeks, or 3.2 years, of EOR development. Wells in a grid were scheduled to be staggered to hold the forecast incoming CO_2 supply rate as constant as possible. Weekly forecasts were generated for each well. The model outputs were upscaled or downscaled to each grid's number of wells and primary estimated ultimate recovery (EUR). The scaled curves for the 271 grids were summed over 20 years to generate time-series estimates of Bakken EOR incremental oil production and purchased (stored) CO_2. The cyclic gas CO_2 EOR design used in this study was informed by EOR that has occurred in other unconventional resources around the United States and pilot studies conducted in the Bakken.

Starting EOR in all 271 grids simultaneously would be impracticable, requiring nearly 350,000 tonnes of CO_2 per day (almost 128 million tonnes of CO_2 per year) at the start of CO_2 injection and extensive infrastructure to deliver CO_2 to wells across the Bakken. Instead, a development scenario limiting the Bakken to 10 million tonnes of CO_2 per year (27,400 tonnes of CO_2 per day) was examined as a baseline estimate. Sensitivity cases of 5 million tonnes and 15 million tonnes of CO_2 per year were also evaluated. Grids in the core areas of the Bakken were developed first, moving from the highest well densities and EURs in the core areas and westward, northward, and southward of an approximate centerline through the Bakken.

The modeling results showed the maximum daily oil rate for the baseline case was 134,000 bbl/day, the average oil rate was 95,000 bbl/day, and the cumulative incremental oil production over 20 years was 694 million barrels (MMbbl). For the low-CO_2 case, the maximum daily oil rate was 64,000 bbl/day, the average oil rate was 46,000 bbl/day, and the 20-year cumulative incremental oil production was 337 MMbbl, a 51% reduction from the baseline. The maximum daily oil rate for the high-CO_2 case was 206,000 bbl/day, the average oil rate was 148,000 bbl/day, and the 20-year cumulative incremental oil production was 1076 MMbbl, a 55% increase from the baseline (Table DS-1).

Under the baseline case, the maximum net CO_2 utilization was 27,400 tonnes of CO_2 per day, a constraint imposed on the analysis. The average net CO_2 utilization was 26,100 tonnes of CO_2 per day, which was less than the maximum because of variations in developing EOR grids while simultaneously remaining below the constraint. The cumulative purchased CO_2 was 190 million tonnes. The maximum net CO_2 utilization for the low-CO_2 case was 13,700 tonnes of CO_2 per day, and the cumulative purchased (stored) CO_2 was 93 million tonnes, a 51% reduction from the baseline. The maximum net CO_2 utilization for the high-CO_2 case was 41,100 tonnes of CO_2 per day, and the cumulative purchased CO_2 was 294 million tonnes, a 55% increase from the baseline (Table DS-1).

Table DS-1. Comparison of Total Bakken EOR Incremental Oil and Purchased (stored) CO_2 Utilization over the 20 years for the Baseline Case Assuming a Low-CO_2 Constraint (5 million tonnes of CO_2 per year), Baseline CO_2 Constraint (10 million tonnes of CO_2 per year), and High-CO_2 Constraint (15 million tonnes of CO_2 per year)

Case	Incremental Oil, MMbbl	% Change[1]	Purchased/ Stored CO_2, million tonnes	% Change[1]	No. of EOR Grids	% Change[1]
Low CO_2	337	−51	93	−51	55	−60
Baseline	694	N/A	190	N/A	137	N/A
High CO_2	1076	+55	294	+55	255	+86

[1] The percentage change from baseline was calculated as (Case X – Baseline)/Baseline.

One hundred thirty-seven grids initiated EOR before the end of the 20-year time frame for the baseline case, representing 5744 wells. Therefore, of the 271 grids, 134 (roughly 50% representing 4251 wells) did not initiate EOR because of the CO_2 constraint and the inability to begin cyclic gas injection within the time frame without exceeding 10 million tonnes of CO_2 per year. Fifty-five grids representing 2513 wells initiated EOR for the low-CO_2 case. This was a 60% reduction from the baseline. Conversely, 255 grids initiated EOR for the high-CO_2 case, representing 9543 wells. This was an 86% increase from the baseline (Table DS-1). At the end of 20 years, large portions of the Bakken remain available for EOR under the low-CO_2 and baseline cases, whereas most grids initiated EOR under the high-CO_2 case. These results suggest a constant CO_2 supply of 10 million–15 million tonnes of CO_2 per year may be appropriate for broad EOR implementation across the Bakken.

Additional cases were included to evaluate the effects of a higher CO_2 utilization rate and increased oil recovery (IOR) ratios on the results. These cases showed that CO_2 supplies above 15 million tonnes per year would be needed to process more grids within the same time frame if the cyclic gas EOR was operated to maintain the higher CO_2 utilization rate or IOR performances. However, these cases are considered end-members that would require significant incentives or operational modifications.

Conventional Reservoirs

The conventional reservoirs included in the study were 21 fields representing approximately 28% of conventional oil in place identified by Peck and others (2019): Cedar Creek Anticline (four fields), Nesson Anticline area (12 fields), and Billings Nose area (five fields).[5]

Forecast models were developed to predict oil production from conventional CO_2 EOR. The basis for these models was the dimensionless production curve method commonly used in conventional EOR. Projected incremental tertiary recovery factors were calculated for each field using available data. The forecasting method was applied to only 80% of the original oil-in-place (OOIP) values to account for acreage around the edges of the fields that may never be flooded because of concerns about CO_2 migration outside the unit boundaries.

Scheduling CO_2 floods in each of the 21 fields was not done at the pattern level as the data required to do so were not readily available. An appropriate level of precision could be achieved by splitting the field into phases representing fractions of each field's OOIP. These phases could then be manually scheduled, resulting in a reasonably constant CO_2 storage rate with fluctuations within the expected variation due to operational activity. Phases and then whole fields were scheduled in this manner to provide a reasonably constant CO_2 storage rate for the entire group of fields. Once CO_2 injection was scheduled by phase, oil production could be calculated (by phase) using the dimensionless curve, individual dimensionless field injection rate, and specific phase start date.

The modeling results showed the maximum daily oil rate was 23,000 bbl/day, the average oil rate was 14,000 bbl/day, and the cumulative incremental oil production was 105 MMbbl. The maximum and average net CO_2 utilization were 17,000 and 12,000 tonnes of CO_2 per day, respectively, and the cumulative purchased and stored CO_2 over the 20-year time frame was 88 million tonnes.

Summary

The Bank of North Dakota retained the EERC to forecast incremental oil production associated with CO_2 EOR in North Dakota's unconventional and conventional reservoirs. The forecast targets potential development scenarios over 20 years and predicts incremental oil production and CO_2 supply demand.

The modeling work in this study suggests incremental oil recoveries from North Dakota's unconventional reservoirs over 20 years could range from 337 MMbbl under a low-CO_2 Bakken scenario (5 million tonnes of CO_2 per year) to 1076 MMbbl under a high-CO_2 Bakken scenario (15 million tonnes of CO_2 per year), with an average of 694 MMbbl under the baseline CO_2 Bakken scenario (10 million tonnes of CO_2 per year). The CO_2 supply demands range from 93 million to 294 million tonnes, depending on the assumed Bakken constraint. Additional sensitivity analysis cases showed that CO_2 supplies above 15 million tonnes per year would be needed to process more

[5] Peck, W., Azzolina, N., Barajas-Olalde, C., Burton-Kelly, M., Kalenze, N., Feole, I., Glazewski, K., Ayash, S., Hurley, J., Jensen, M., Gorecki, C., Harju, J. Bangsund, D., and Cook, B., 2019, Subtask 1.4 – Techno-economic assessment of regional carbon utilization scenarios and attendant monitoring technology.

grids within the same time frame if the cyclic gas EOR was operated to maintain higher CO_2 utilization rates or IOR ratios. Development of the Bakken beyond the timelines considered here, which would expand beyond the core area and include recently drilled and completed wells, would exceed these estimates and yield more incremental oil recovery and larger volumes of stored CO_2.

Twenty-one fields/units were chosen as prime candidates for conventional CO_2 EOR. The modeling work in this study suggests incremental oil recoveries from these fields/units of 105 MMbbl and a CO_2 supply demand of 88 million tonnes.

Key drivers of the modeling results include the number of cycles used for cyclic gas injection in the Bakken, the IOR ratios assumed for Bakken and conventional EOR, and the CO_2 rate constraints imposed on the analysis. The Bakken incremental oil results were proportional to the CO_2 supply; therefore, the CO_2 supply, or lack thereof, significantly affects the Bakken incremental oil recovery rate.

NORTH DAKOTA 20-YEAR CO_2 EOR FORECAST

1.0 INTRODUCTION

The Bank of North Dakota retained the Energy & Environmental Research Center (EERC) to forecast incremental oil production associated with carbon dioxide (CO_2) enhanced oil recovery (EOR) in North Dakota's unconventional and conventional reservoirs. The forecast targets potential development scenarios over 20 years and predicts incremental oil production and CO_2 supply demand.

Section 5 of House Bill 1429 of the 68th Legislative Assembly of North Dakota directed the Bank of North Dakota to study environmental, social, and governance (ESG) trends, laws, and policies that impact the state's businesses and industries, specifically those that impact the state's energy and production agriculture industries.[1] The study may identify industry-specific public policy strategies for immediate and long-term implementation to help the state remain a global leader in energy and agriculture. This CO_2 EOR study by the EERC is part of the Bank of North Dakota's broader sustainability market analysis.

Because widespread EOR infrastructure will take many years to develop, policy actions in the near-term may significantly bolster North Dakota's ability to harvest the maximum financial benefits in the decades to come. Both within industry operating budgets and Wall Street, financing competes with other oil plays (e.g., Permian Basin of Texas and New Mexico, Texas Eagle Ford), not just EOR. Policies that support EOR in North Dakota can strongly signal that investment in North Dakota is attractive.

The unconventional reservoirs included in the study were the Bakken and Three Forks Formations of the Bakken Petroleum System (Bakken). The conventional reservoirs included in the study were 21 fields representing approximately 28% of conventional oil in place identified by Peck and others (2019):

- Cedar Creek Anticline (CCA) – four fields (Ordovician)
  - Cedar Creek
  - Cedar Hills South (CO_2 injection started January 2022)
  - Horse Creek
  - Medicine Pole Hills

- Nesson Anticline area (along Dakota Gasification Company [DGC] pipeline) – 12 fields
  - Antelope (Devonian and Madison)
  - Beaver Lodge (Devonian and Madison)
  - Blue Buttes (Silurian and Madison)
  - Charlson (Silurian and Madison-North)
  - Clear Creek Madison
  - Hawkeye Madison

[1] Bank of North Dakota study – environmental, social, and governance trends: Report to Legislative Management, https://ndlegis.gov/assembly/68-2023/regular/documents/23-0990-05000.pdf (accessed May 2024).

- Stoneview Stonewall
- Tioga Madison

- Billings Nose Area – five fields (Madison)
  - Big Stick
  - Little Knife
  - T.R.
  - Tree Top
  - Whiskey Joe

The remainder of this document describes the methods used to generate the forecasts and summarizes the results.

2.0 METHODS

The methods differ between the Bakken and conventional EOR models and are therefore described separately. The Bakken and conventional EOR results were independently derived and aggregated to generate a complete summary of CO_2 EOR performance across North Dakota's unconventional and conventional reservoirs.

2.1 Bakken EOR

Conventional reservoirs have reservoir characteristics that allow for production from wells that do not require hydraulic fracturing, most often vertical wells. CO_2 EOR in conventional reservoirs has been happening in Texas since the 1970s; at the Weyburn Field in Saskatchewan using CO_2 from DGC since 2000; and in the Cedar Hills field in Bowman County, North Dakota, since 2022 using CO_2 from a gas plant in Wyoming. Most conventional reservoirs in North Dakota were developed before 2010 using vertical wells. In contrast, unconventional reservoirs have characteristics that require long horizontal wells and hydraulic fracturing to enable economical production. The Bakken is a world-class example of these types of unconventional reservoirs. CO_2 EOR performance in the Bakken is still in the early stages of development, with several pilot studies conducted or ongoing and many open research questions about EOR performance. The approach outlined here was adopted to balance data availability and lessons learned from the literature and pilot studies.

2.1.1 Bakken Well Data

The list of Bakken horizontal wells by producing zone was obtained from the North Dakota Department of Mineral Resources (DMR) (2024). The study included 14,066 wells imported to ArcGIS (Esri, 2024) for mapping onto a standardized set of EOR grids.

2.1.2 Bakken EOR Grids

Overlaid onto the Bakken were standardized EOR grids of 3 miles wide (east–west) by 2 miles tall (north–south), approximately three 1280-acre drilling spacing units (DSUs) wide by two 1280-acre DSUs tall. There were 31 columns and 37 rows for 1147 grids. Three hundred and twenty grids with zero wells were removed from the analysis. Among the remaining 827 grids with one or more wells, 66% had fewer than 20 wells (Figure 1). Only 271 grids contained 20 or more wells. These were mainly in the Bakken core areas of McKenzie, Mountrail, and Dunn Counties (Figure 2). The modeled EOR development focused on these 271 grids, representing nearly 10,000 wells. The grid size used in this study was used to simplify the estimates and is not meant to imply an ideal EOR development size. Furthermore, the current study did not include future new wells. Approximately 10,000 additional wells may be drilled, completed, and produced in this region over the study time frame. Those new wells would be produced via primary production for some duration, at which point they would be amenable to CO_2 EOR. Therefore, the estimates of incremental oil production and CO_2 demand have the potential to significantly exceed the numbers derived herein.

2.1.3 Bakken Production Performance Assessment

2.1.3.1 Grid Primary Estimated Ultimate Recoveries

Production data for each well were obtained by matching the well API (American Petroleum Institute) numbers from the DMR list to a dataset accessed from Enverus/DrillingInfo (Enverus, 2024). The DrillingInfo estimated ultimate recoveries (EURs) for primary production for each well were summed to generate total EURs for each grid.[2] Across all 827 grids, the EURs ranged from <0.1 to 53.2 million barrels (MMbbl), with a median of 3.5 MMbbl. For the 271 grids with 20 or more wells, the EURs ranged from 3.8 to 53.2 MMbbl, with a median of 16.1 MMbbl (Figure 3).

[2] DrillingInfo provides two types of EURs: full fit and segmented fit. The full-fit solution uses the entire oil production decline curve (Oil EUR Full), while the segmented fit evaluates possible changes in the oil production decline curve and refits a new EUR to the curve segment after the change (Oil EUR BE). The Oil EUR BE was used in this study because it provides a more conservative EUR given the nonlinear oil production decline curves observed in the Bakken.

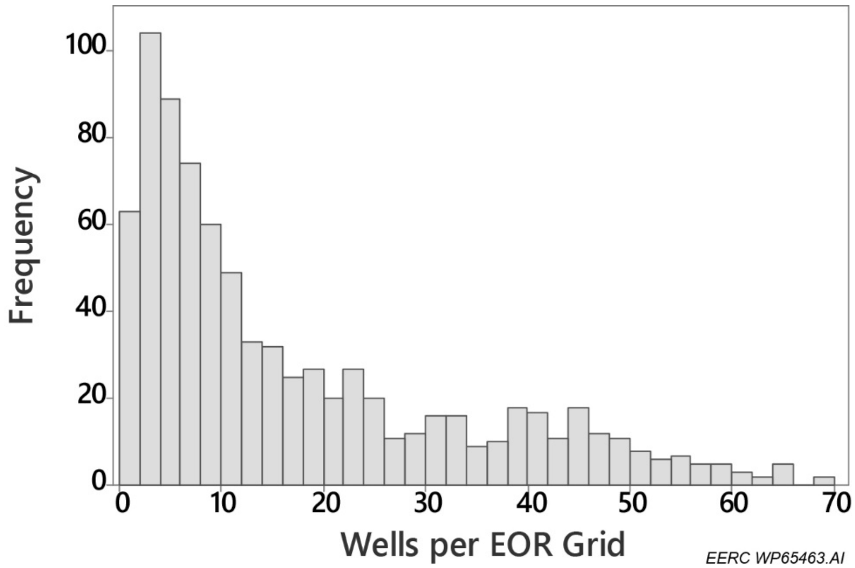


Figure 1. Histogram of well counts per EOR grid.

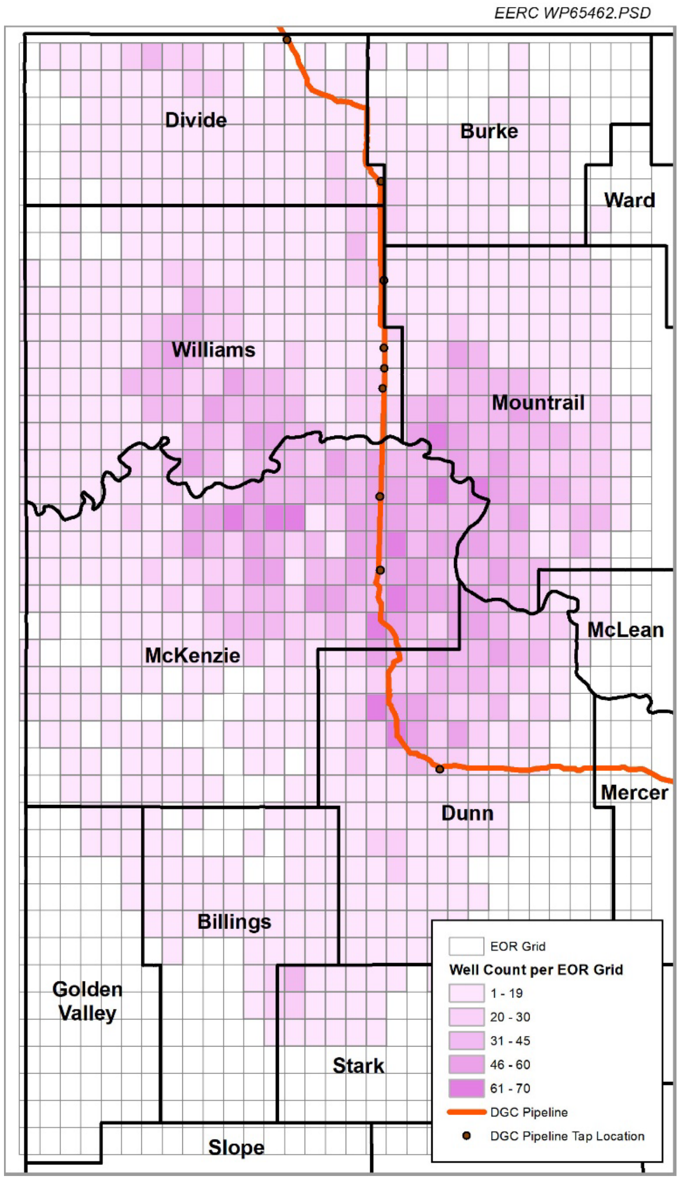


Figure 2. Heat map of well counts per EOR grid. Grids with zero wells are white.

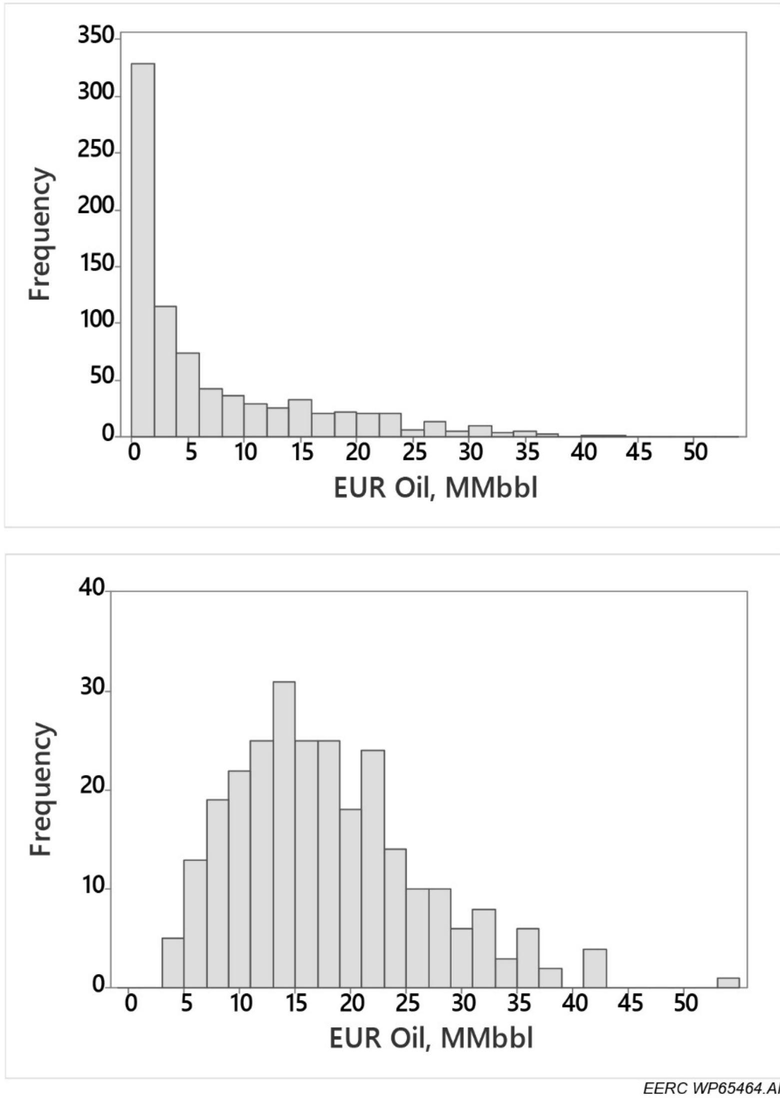


Figure 3. Histograms of primary production EUR oil per EOR grid showing all 827 grids with one or more wells (top) and only the 271 grids with 20 or more wells (bottom).

Like the spatial distribution of wells, the grid EURs were greatest in the Bakken's core areas of McKenzie, Mountrail, and Dunn Counties (Figure 4). These areas represent the most developed portion of the Bakken and the most likely EOR targets in the next 20 years.

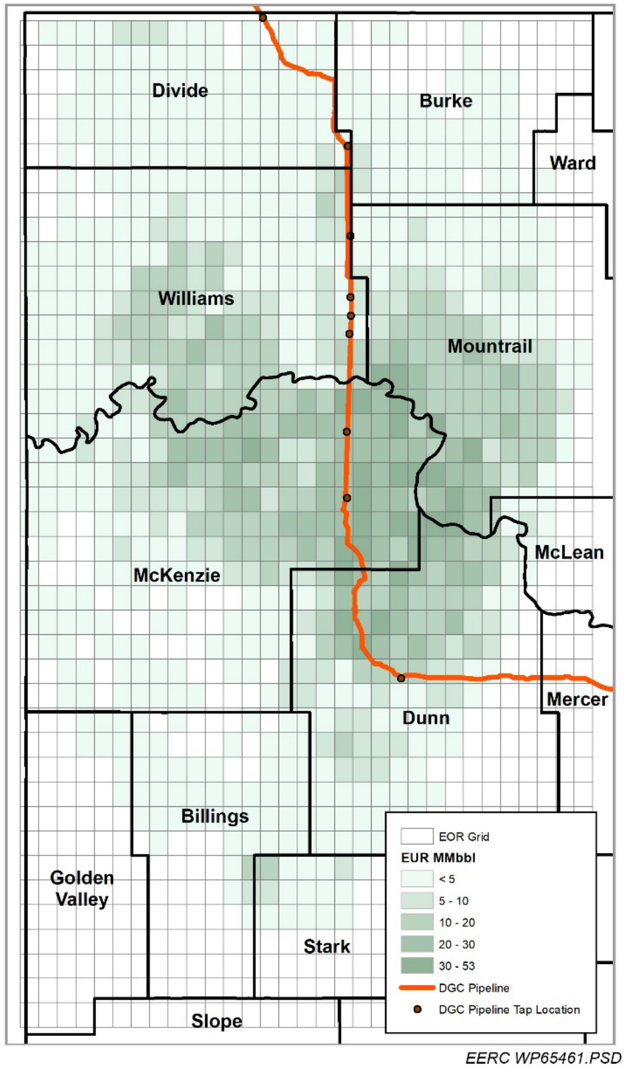


Figure 4. Heat map of primary production EURs per EOR grid. Grids with zero primary production EUR are white.

2.1.3.2 Derived Relationship Between Grid Well Counts and Primary EUR

A power law relationship was derived between the EOR grid well counts and primary production EURs. The power law relationship described 88.9% of the variation in the data and was used to define the average response between grid well count and EUR. Seven grids were selected for detailed cyclic gas EOR modeling to represent grids with 20, 30, 35, 40, 44, 50, and 60 wells (yellow diamonds in Figure 5).

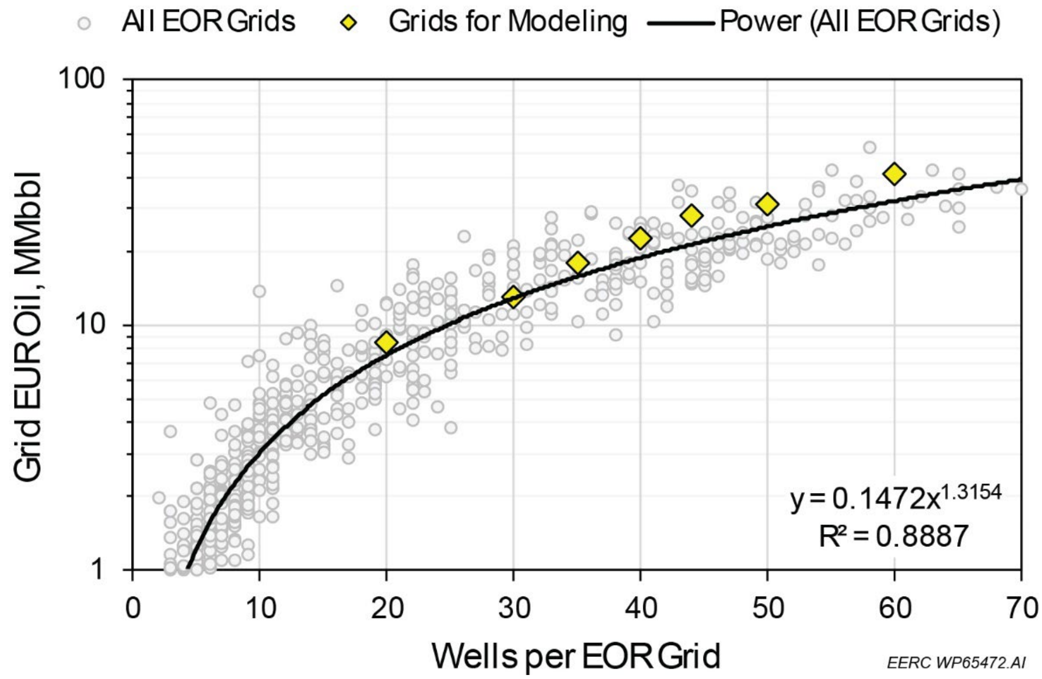


Figure 5. Crossplot between EOR grid well counts and primary production EURs showing the power law relationship (black dashed line) and the seven grids selected for detailed cyclic gas EOR modeling.

2.1.4 Cyclic Gas EOR Modeling

2.1.4.1 Basis for Expected Bakken EOR Performance Metrics

EOG Resources, Inc. (EOG) Eagle Ford EOR operations were used as an analog to inform Bakken EOR modeling. This was done because it is the most data-rich EOR operation in an unconventional oil reservoir and recent small-scale EOR pilots in the Bakken combined with laboratory- and modeling-based investigations also suggest that the Eagle Ford may be a reasonable analog to the Bakken for EOR.

The first significant cyclic gas EOR projects in unconventional plays were done by EOG in the Eagle Ford Shale (Texas), with the first of these projects initiated in 2012. This activity has expanded to include over 30 leases and six different operators. EOG did not make this work available in the public domain for the first few years. However, by February 2017, its results were sufficiently promising to warrant mention in that month's earnings report, at which time Figure 6 was presented, which was later published by Hoffman (2018).

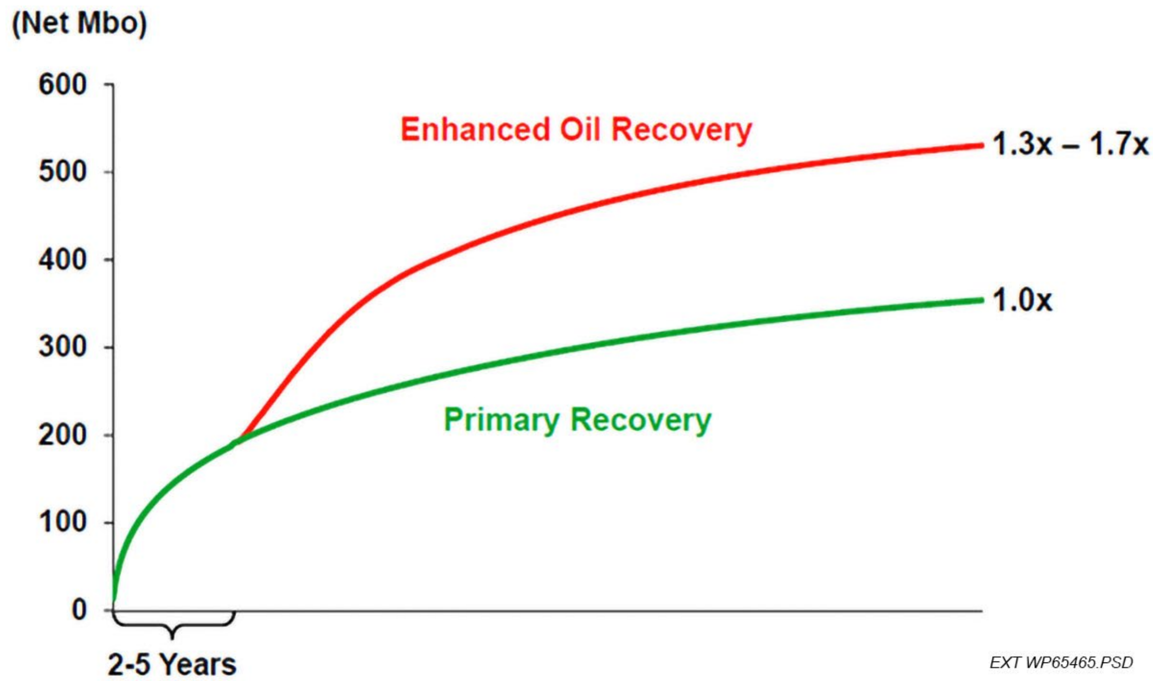


Figure 6. Eagle Ford generalized recovery curves showing net thousand barrels of oil (Mbo, y-axis) versus time for primary depletion (green curve) and with cyclic gas EOR (red curve) and associated increased oil recovery (IOR) ratios (Hoffman, 2018).

EOG predicted that recovery from an Eagle Ford well could be improved by 30%–70% (1.3× to 1.7×) by applying cyclic gas EOR (EOG Resources, Inc., 2017). There was no question about a significant uplift in oil production. Still, the projects had not reached anything approaching depletion, so this conclusion was reached with simulation-based extrapolation and given a sufficiently large range of uncertainty. At the time of this prediction, EOG claimed its pilots were in areas with certain favorable characteristics that maximize confinement of injected gas; therefore, cyclic gas EOR may not be successful in other areas. No further information or analysis of this assertion has ever been produced; nevertheless, confinement issues should be a high priority for further study.

Complete datasets that would aid the evaluation of these projects are not available. The Railroad Commission of Texas requires that production be reported monthly on a lease basis and not by individual wells, so intervals of zero production mask the response in responding wells during the injection phase. In the beginning, it was not even clear whether EOG injected lease gas, pure methane, or enriched lease gas, but over time, it became clear that the company was using lease gas. Monthly reporting is too granular to provide much insight into where wells switch from injection to production only days apart. In addition, EOG could proceed until recently with not filing H-12 forms for its injectors since the injection phase was intermittent and did not require permits to reclassify the wells as injectors; in these cases, no injection volumes are available in the public domain. Without well production volumes and injection data, it is difficult to glean sufficient information to use EOG's projects as analogs for future ones.

Two groups conducted independent analyses confirming significant oil production uplift from cyclic gas EOR in the Eagle Ford. Dr. Todd Hoffman of Montana Technological University led an effort to review four pilot studies. The results of his analysis of data from projects that remain active and are poised to continue significant additional recovery showed that the pilot studies had already produced between 17% and 30% additional oil above the projected primary production at the same point in time. The cyclic gas EOR process had at least doubled the production rate in each case. Estimates of the ultimate IOR ratio (the ratio of oil recovery after cyclic gas EOR process to oil recovery from primary depletion only) range from 1.3 to 1.7 (Hoffman, 2018). Results from these pilot studies are shown in Figure 7. Based on the decline curve extrapolation, the lowest purple line represents a standardized lease production on primary production (no-injection case). Based on reported estimates, the red-shaded area indicates improved production due to gas injection of 30%–70% over primary production (Hoffman, 2018).

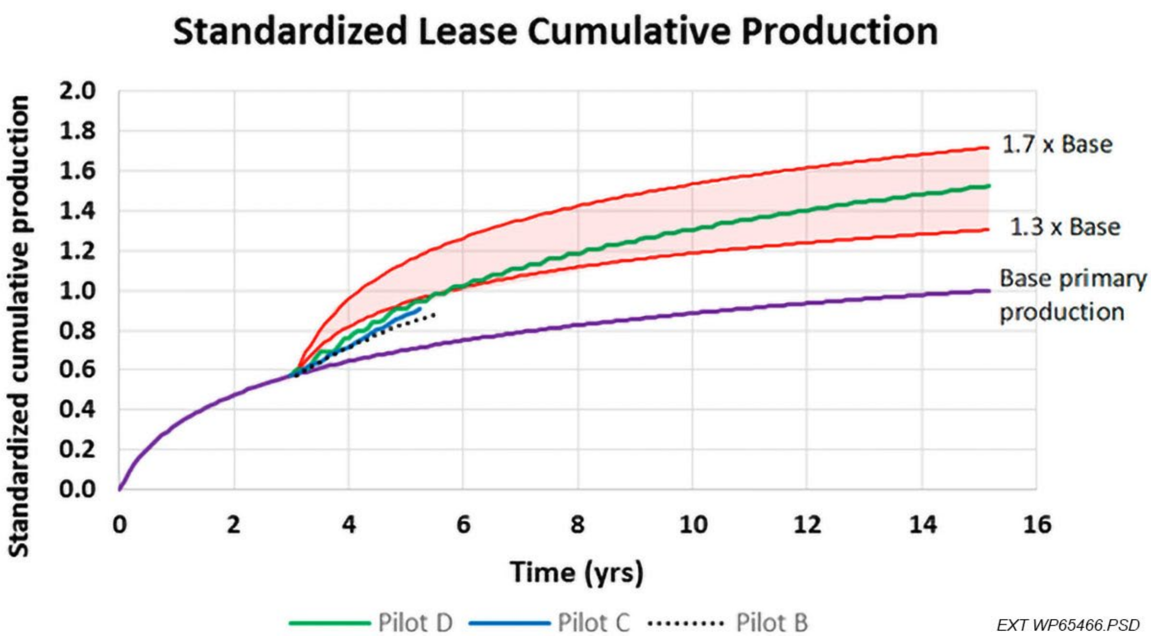


Figure 7. Eagle Ford incremental oil recoveries with cyclic gas EOR (Hoffman, 2018).

Another analysis of Eagle Ford cyclic gas EOR pilot studies was presented by RS Energy Group at the 2019 Unconventional Resources Technology Conference (Malo and others, 2019). The team analyzed 11 pilot studies and calculated IOR ratios of 1.12 to 1.49, averaging 1.30. This analysis may be conservative, as the more mature projects tended to have recoveries of over 30% (i.e., IOR ratios of 1.3 or greater). Figure 8 shows projections for these cyclic gas EOR pilot studies. The IOR ratios, derived from the difference between the primary depletion (green line) and EOR prediction (blue line), were higher for pilot studies with longer EOR durations at the time of the analysis.

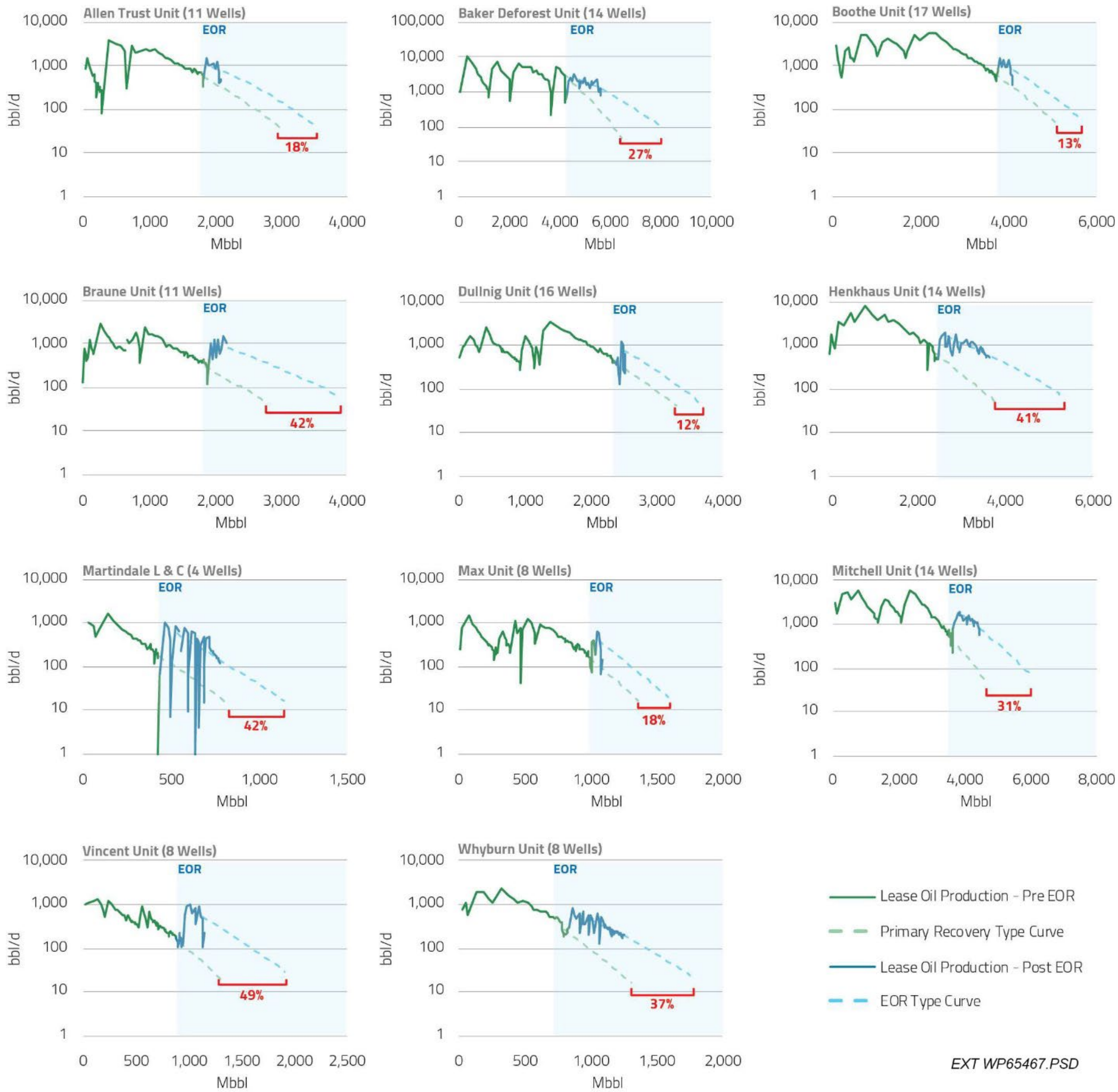


Figure 8. Individual Eagle Ford cyclic gas EOR project recovery curves (Malo and others, 2019).

Shale IOR LLC (Shale IOR) consultants presented a further analysis at the 2020 Society of Petroleum Engineers Improved Oil Recovery Conference (Grinestaff and others, 2020). They analyzed four of the EOG pilots in detail, predicted the future performance of one of these four pilots using a history-matched simulation, and calculated project economics for each. All four of these projects were also included in Malo and others (2019). Grinestaff and others (2020) suggested that IOR ratios could be as high as 1.8–2.0 using rate-cumulative extrapolation to forecast future performance, while a cumulative recovery versus time extrapolation based on simulation results for the Martindale project showed that the IOR ratio for that project would be approximately 1.4. Some skepticism is warranted since their upper range is significantly higher than any other forecast IOR ratios for shale cyclic gas EOR projects.

In the current study, the interpretation of the published rate versus cumulative oil production curves, without considering simulation results, is that the worst case for the IOR ratio ranges from 1.3 to 1.4, while the most likely ratios are 1.4 and higher. Shale IOR accounted for some of these projects' most recent production data, stopping after a limited number of cycles to move the compressor to another project. In contrast, the Malo and others (2019) analysis did not account for this. Instead, it projected IOR ratios based on extrapolating the terminal declines of the last extended production cycle after the compressors were moved. Malo and others (2019) calculated the IOR ratios for the same four projects, which ranged from 1.27 to 1.42, which should be improved by continuing the cyclic gas injection. This interpretation does not imply confidence in the same recoveries in the Bakken; it is meant to show success at a similar operation in a similar reservoir setting and considerable recovery from cyclic gas EOR in unconventional plays.

The Shale IOR analysis also provided data that could be used to calculate the net gas utilization ratio experienced in some of the Eagle Ford cyclic gas EOR projects. Using available data on costs for gas purchases and dividing by an estimated price for unprocessed gas at the lease that was gleaned from published gas price data from that point in time, the net gas utilization factor was estimated to be about 4 thousand cubic feet (Mcf) of gas per incremental barrel recovered. Given that CO_2 is 50% denser at reservoir conditions (on a molar basis), 6 Mcf of CO_2 would occupy the same reservoir volume as 4 Mcf of lease gas, so utilization of 6 Mcf/bbl would be used as a basis for CO_2 EOR in the Bakken. With incentives to store CO_2 in oil reservoirs, EOR projects would be operated to maximize the utilization factor rather than the current economic regime, which calls for minimizing CO_2 usage to control costs. Therefore, CO_2 utilization is highly uncertain at this point.

Additional estimates of the IOR ratio based on CO_2 injection and not hydrocarbon gas injection come from Yu and others (2014), which predicted a range of 1.30–1.47 based on simulations of cyclic CO_2 injection in the Bakken and a ratio of 1.26, which was a simulation-based extrapolation of the results of Liberty Resources LLC's Bakken EOR test that ran from July 2018 to April 2019 (Sorensen and others, 2020).

Based on these results and predictions, an IOR ratio of 1.3 was set as the baseline target for oil recovery using a CO_2 net utilization factor of 6 Mcf (0.3 tonnes) per incremental barrel. Because of the complexity of calculations, revisions to assumed operating parameters, and the construction of the predictive model, model output may deviate slightly from these values. Additional cases were evaluated to examine the effect of these parameters on the results (see Sensitivity Analysis section).

2.1.4.2 Construction of the Bakken Predictive Model

A tool was created using Microsoft Excel to forecast oil production for any scenario implementing cyclic gas CO_2 EOR. The basis for this tool is the dimensionless production curve method commonly used in conventional EOR. In this case, the tool does not create a genuinely dimensionless curve. Instead, it describes cumulative incremental oil production (in barrels) versus the dimension of time, with one curve representing the production of a well to depletion and a second curve describing the uplift from cyclic gas CO_2 EOR.

Typically, a dimensionless curve plots oil recovery (in terms of percentage hydrocarbon pore volume recovered) against hydrocarbon pore volumes of fluid injected. However, this tool was designed for a displacement process where pore volume could be determined for a specific gross rock volume, be it lease, pattern, section, or some area developed with injectors and producers. In the case of cyclic EOR, this volume is not readily identifiable, so the method is not directly transferable. The technique is applied because the shape of a shale well's cumulative production-versus-time curve is similar and can be similarly described by the dimensionless curve equation (Equation 1).

$$y = a\left(1 - e^{-b(x-c)^d}\right) \qquad \text{[Eq. 1]}$$

Where:

a = the horizontal asymptote representing the maximum theoretical oil recovery.
b = shape coefficient that controls the initial upward slope.
c = initial time lag/*x*-intercept of the curve.
d = shape coefficient controlling character of the curve where a value greater than one produces an s-shaped curve as observed in conventional EOR projects; a value of one indicates an immediate exponential decline; and a value less than one produces an early-peak, immediately hyperbolic decline as observed in an unconventional well.
x = independent variable; pore volume injected for an EOR dimensionless curve or time in this application to unconventional wells.
y = oil recovery in terms of pore volume or actual barrels.

Cumulative oil production type curves were created using historical production data from all Bakken wells. These were grouped into three vintages (well completion years) in which wells performed similarly: 2014 and prior, 2015–2016, and 2017 and later (Figure 9). These groups correspond to periods where significant improvements in completion technology accelerated oil recovery relative to older wells after production started.

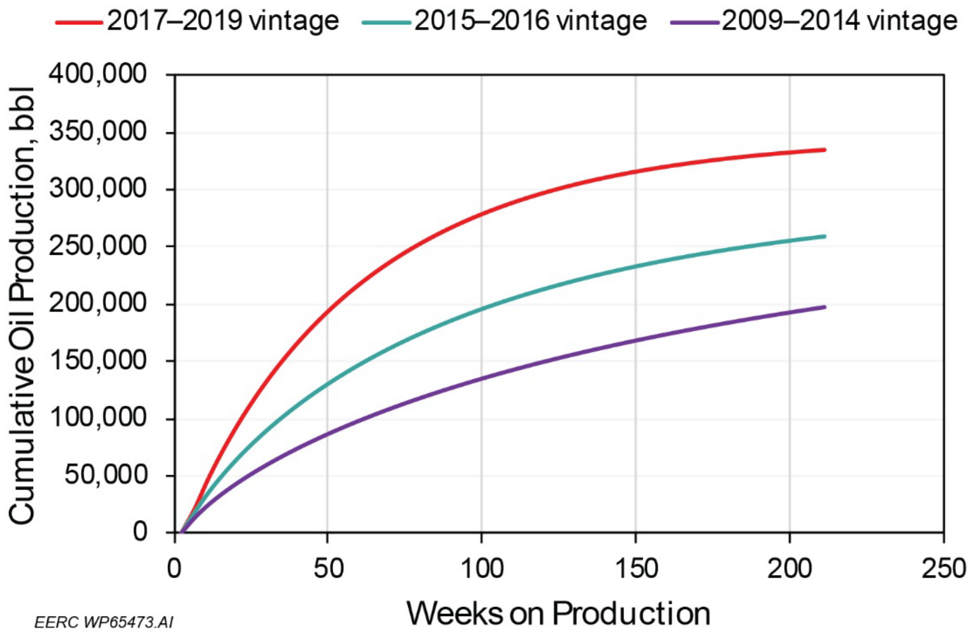


Figure 9. Cumulative production type curves by well vintage that were used in the projections.

Each well was classified by vintage, and the corresponding type curve was linearly adjusted to match that well's actual primary EUR. The second curve (depicted in Figure 10) was created to model the EOR uplift, where a new type curve was initiated at the week of the initial EOR response. The curve shown in Figure 10 represents a 30% (1.3×) ultimate IOR ratio and depicts a response like that shown in Figure 6.

The change in slope of the EOR (dashed) curve above, at the initiation of the EOR process, represents the magnitude and speed of the EOR response. The total departure of the dashed EOR curve from the primary production curve represents the cumulative incremental EOR response. The uncertainty around this response is high. Two constraints were applied: 1) the initial EOR production rate could not be higher than the initial production rate and 2) assuming an IOR ratio of 1.25–1.30, most of that oil would be recovered by the seventh cycle.

A similar method was used to predict CO_2 retention and production, which would be recycled as injection gas in another well. Given the constraint of a fixed CO_2 supply volume, this recycled gas must be estimated to determine the scheduling of subsequent wells for cyclic injection. In this process, CO_2 production was adjusted to achieve a net CO_2 utilization of approximately 6 Mcf (0.3 tonnes)/bbl of incremental oil.

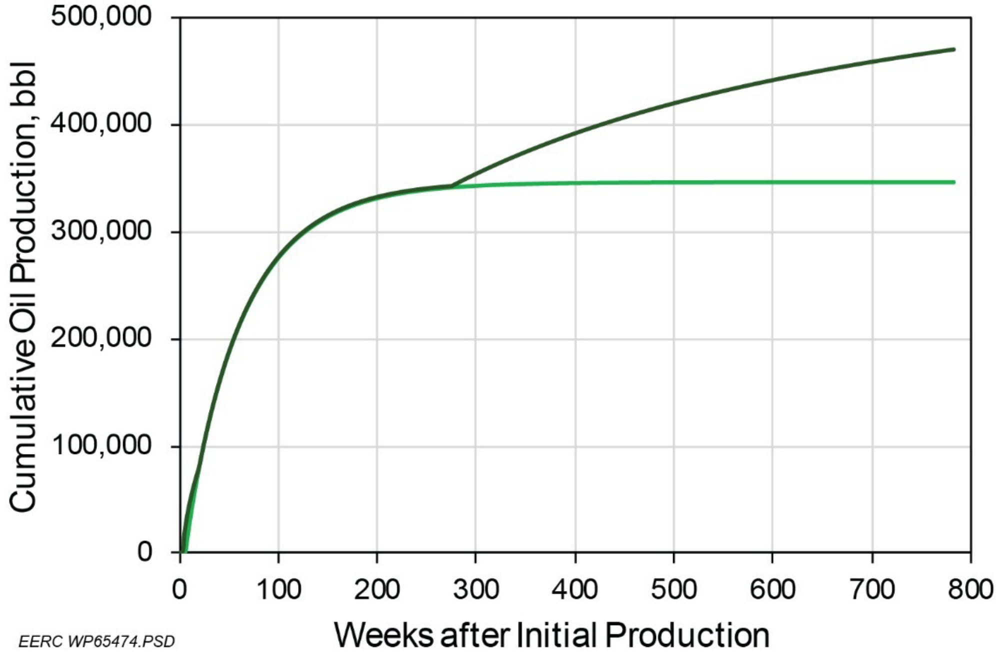


Figure 10. Example curve showing primary production (solid line) and cyclic gas CO_2 EOR projection (dashed line) for a typical Bakken well of the most recent vintage.

Each cycle is assumed to last 24 weeks, comprising 6 weeks of injection, 1 week of soaking, and 17 weeks of production. The schedules for wells in an EOR grid were staggered to hold the forecast incoming CO_2 supply rate as constant as possible. Accordingly, the schedule was created to generate a weekly forecast for each well.

For seven different scenarios where an EOR grid would be developed with a different number of wells (ranging from 20 to 60 wells per grid—the yellow diamonds shown in Figure 5), cyclic EOR was scheduled on a well-by-well basis in a manner intended to maintain a reasonably constant CO_2 storage rate. The result of one of these prototypical scheduled EOR grids is shown in Figure 11, which was scheduled to maintain a near-constant storage rate of approximately 35 million cubic feet per day (MMcfd) over seven 24-week EOR cycles (3.2 years). Figure 12 shows the incremental oil produced over the same period. These time-series CO_2 and incremental oil curves were exported for each of the seven modeled grids for input to the scaling and extrapolation for the Bakken-wide EOR assessment.

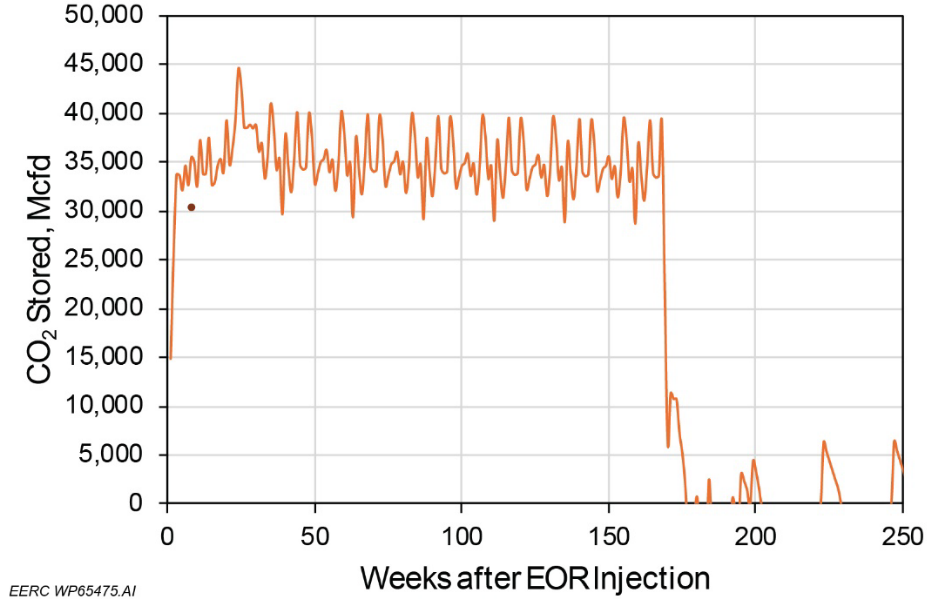


Figure 11. Graph depicting the result of scheduling EOR cycles to maintain a near-constant CO_2 storage rate of approximately 35 MMcfd for one of the prototypical scheduled EOR grids. The solid line is the modeled CO_2 storage, and the dotted line is a moving average.

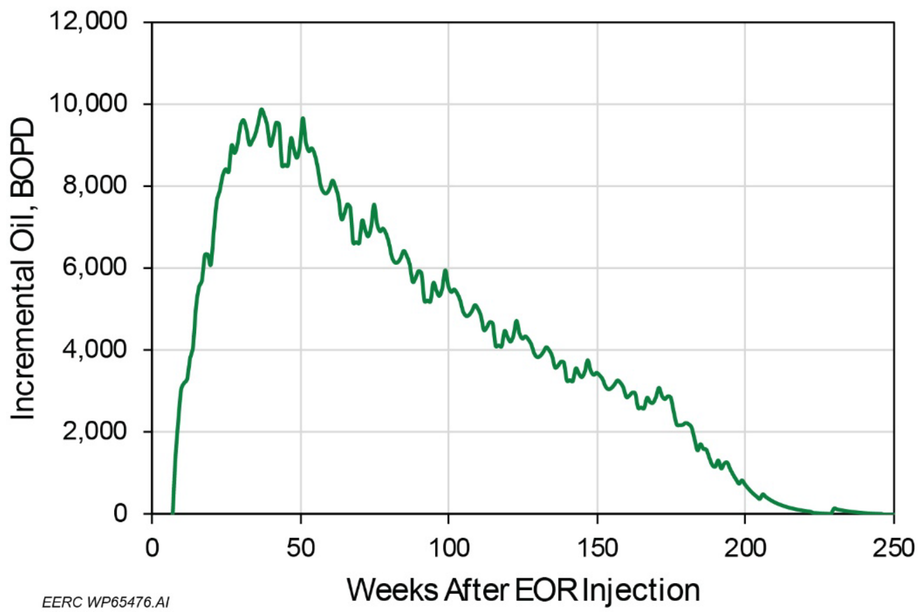


Figure 12. Graph depicting the incremental oil production response from the cyclic gas EOR process for one of the prototypical scheduled EOR grids.

2.1.5 Bakken Scaling

Outputs from the detailed cyclic gas EOR modeling representing grids with 20, 30, 35, 40, 44, 50, and 60 wells were used to generate scaled CO_2 and incremental oil curves for each of the 271 grids. The curves were first scaled to the number of wells and then scaled up from the detailed model.[3] Figure 13 shows the resultant scaled CO_2 and incremental oil curves for grids with 20–70 wells in ten-well increments (curves were generated for all 51 configurations from 20–70 wells). Exponential fits of the scaled curves were used for the Bakken-wide modeling to smooth the CO_2 and incremental oil responses.

The base-case cyclic gas EOR modeling used seven 24-week cycles, yielding 168 weeks (3.2 years). Therefore, as shown in the time-series curves, purchased (stored) CO_2 declines to zero from approximately Weeks 169–176 (3.4 years). Likewise, incremental oil declines roughly 7% per week beginning in Week 184 and declines to essential zero before Week 260 (5 years).

After scaling each grid to the number of wells per grid, each grid was scaled to its primary production EUR (see Section 2.3.1) using the ratio of the grid EUR to the EUR of the scaled curve. Therefore, grids with higher EURs than the mean response were scaled up, and grids with lower EURs than the mean response were scaled down. For example, the mean EUR response for a grid with 20 wells was 7.6 MMbbl. If another 20-well grid had an EUR of 10 MMbbl, the curve was scaled by the ratio of 10/7.6, or 1.32 (scaled up). Conversely, if another 20-well grid had an EUR of 6 MMbbl, the curve was scaled by the ratio of 6/7.6, or 0.79 (scaled down). The net result of this process was a set of scaled CO_2 and incremental oil curves for 271 grids based on their well count and primary production EUR.

[3] The 20-well model was used to scale grids with 20–29 wells, the 30-well model was used to scale grids with 30–34 wells, the 35-well model was used to scale grids with 35–39 wells, the 40-well model was used to scale grids with 40–43 wells, the 44-well model was used to scale grids with 44–49 wells, the 50-well model was used to scale grids with 50–59 wells, and the 60-well model was used to scale grids with 60–70 wells.

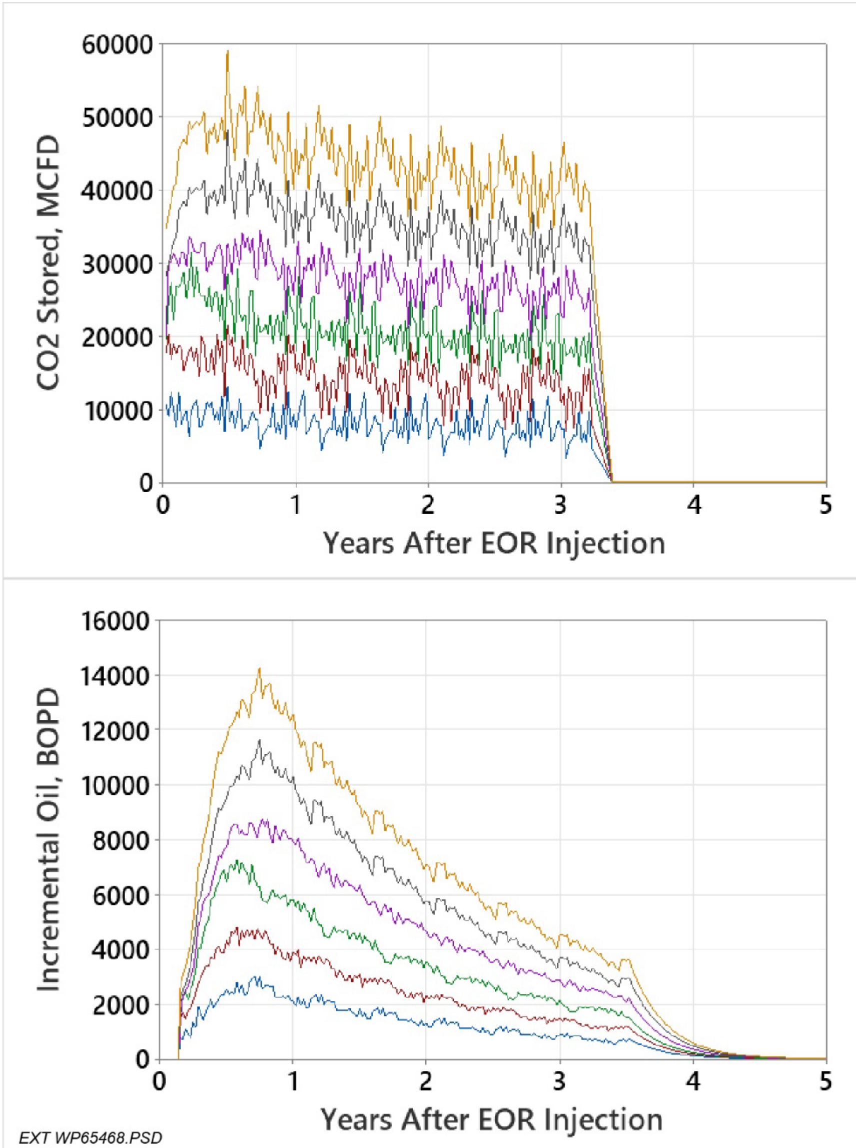


Figure 13. Scaled CO_2 (top) and incremental oil (bottom) curves for grids with 20 wells (blue line) to 70 wells (yellow line), which were scaled from the detailed cyclic gas EOR modeling representing grids with 20, 30, 35, 40, 44, 50, and 60 wells. To improve visualization, the curves are shown in ten-well increments (20, 30, 40, 50, 60, and 70 wells per grid); however, curves were generated for all 51 configurations from 20–70 wells.

2.1.6 Bakken EOR Estimates

The scaled curves for the 271 grids were summed over 20 years to generate time-series estimates of Bakken EOR production, assuming a broad, Bakken-wide EOR implementation. Starting EOR in all 271 grids simultaneously would be impracticable, requiring nearly 350,000 tonnes of CO_2 per day (almost 128 million tonnes of CO_2 per year) at the start of CO_2 injection and extensive infrastructure to deliver CO_2 to wells across the Bakken. Instead, a development scenario limiting the Bakken to 10 million tonnes of CO_2 per year (27,400 tonnes of CO_2 per day) was examined as a baseline estimate of near-term (20 years) Bakken EOR potential. The modeled scenario assumes competitive business cases have been developed. The scenario also assumes that CO_2 infrastructure (e.g., well preparation, field unitization, flowlines, recycle facilities, compression equipment, etc.) is entirely in place at the start of the simulation period. This highly simplified approach to infrastructure development enabled the study to focus on deriving estimates of the maximum economic potential of CO_2 EOR in North Dakota. EOR infrastructure takes time to finance, procure, and build out. Establishing the CO_2 infrastructure to support the broad deployment of EOR is a long game that will most likely occur stepwise. The full potential of EOR in North Dakota may require a decade or more.

Grids in the core areas of the Bakken were developed first, moving from the highest well densities and EURs in the core areas and westward, northward, and southward of an approximate centerline through the Bakken. Fourteen grids were initiated in the first week of the first year, representing 671 wells. Successive grids were added by staggering their start dates to keep the CO_2 utilization across all grids at less than 27,400 tonnes of CO_2 per day. For example, the 15th grid started on Week 26, the 16th grid on Week 36, etc., through the set of grids.

The outputs from this development scenario were time-series curves of incremental oil and purchased (stored) CO_2 utilization. These outputs were summarized and used as inputs to the economic modeling.

2.2 Conventional EOR Modeling

2.2.1 Basis for Conventional EOR Forecast

Twenty-one fields/units were chosen as prime candidates for CO_2 EOR (Table 1 and Figure 14). Although several screening efforts in the past have presented economics at the field level, simpler criteria were used to select these fields. Fields had to be near enough to the existing DGC CO_2 pipeline or the Cedar Creek pipeline owned by Exxon Mobil Corporation (formerly Denbury Inc.) or be part of a large enough tertiary oil target to justify new pipelines connecting to the existing pipeline network. Using these screening criteria, 21 conventional reservoirs were identified and included in the study. These fields account for approximately 28% of the conventional original oil in place (OOIP) identified by Peck and others (2019) and 44% of the cumulative oil production of all conventional oil reservoirs in North Dakota.

Table 1. List of Fields Included in the Prediction of Incremental Oil CO_2 EOR

Group	Field/Unit	Reservoir
Nesson Anticline	Charlson	Silurian
Nesson Anticline	Antelope Madison Unit	Madison
Nesson Anticline	Blue Buttes Madison Unit	Madison
Nesson Anticline	Charlson N. Madison Unit	Madison
Nesson Anticline	Blue Buttes	Silurian
Nesson Anticline	Hawkeye Madison Unit	Madison
Nesson Anticline	Charlson S. Madison Unit	Madison
Nesson Anticline	Antelope Devonian Unit	Devonian
Nesson Anticline	Clear Creek Madison Unit	Madison
Nesson Anticline	Antelope	Silurian
Nesson Anticline	Stoneview Stonewall Unit	Stonewall
Nesson Anticline	Tioga Madison Unit	Madison
Nesson Anticline	Beaver Lodge Madison Unit	Madison
Nesson Anticline	Beaver Lodge Devonian Unit	Devonian
Billings Nose	Little Knife	Madison
Billings Nose	Whiskey Joe	Madison
Billings Nose	Big Stick Madison Unit	Madison
Billings Nose	T.R. Madison Unit	Madison
Billings Nose	Tree Top	Madison
CCA	Cedar Hills South Unit	Ordovician
CCA	Cedar Creek Ordovician Unit	Ordovician

In developing this study's screening criteria, it was determined that less than 100% of fields would be CO_2-flooded. The development of the 21 fields would provide infrastructure that could be used to flood adjacent fields. No fields in the Northern Tier were included in this analysis. While certain fields in that area have attributes that make them attractive for CO_2 flooding from a technical standpoint, the Northern Tier lacked large fields that would anchor CO_2 development, and its fields are farther from existing CO_2 pipeline infrastructure than the ones in the study.

EOR performance was forecast via dimensionless curves. Two curves define a CO_2 EOR project. Both use dimensionless injection as the *x* variable, defined as the total injection of water and gas in hydrocarbon pore volumes (HCPVs) units. On the y-axis, one curve plots cumulative incremental oil production volume as a fraction of OOIP volume. The second plots the reservoir volume of cumulative CO_2 production in terms of the reservoir volume of the OOIP. In both cases, the numerator and denominator are volume. Therefore, the resulting ratio is dimensionless.

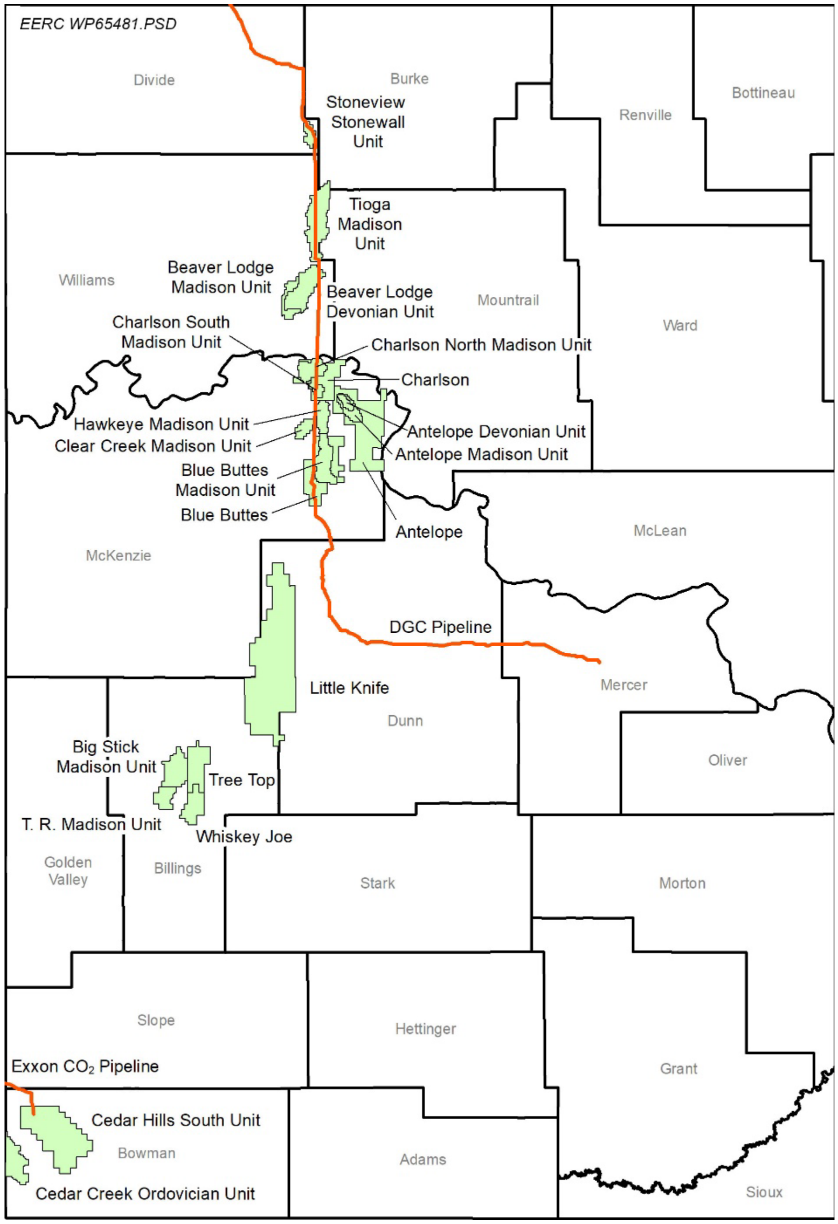


Figure 14. Target conventional fields used to calculate CO_2 EOR potential in the current study.

These values are calculated and plotted at various points in an EOR project's life. The following equation generated a curve that closely fits these calculated data points (Equation 2).[4]

$$y = a\left(1 - e^{-b(x-c)^d}\right) \qquad \text{[Eq. 2]}$$

Where:

a = the horizontal asymptote representing the maximum theoretical oil recovery.
b = shape coefficient that controls the initial upward slope.
c = initial time lag/x-intercept of curve.
d = shape coefficient controlling character of curve where a value greater than one produces an s-shaped curve as observed in conventional EOR projects; a value of one indicates an immediate exponential decline; and a value less than one produces an early-peak, immediately hyperbolic decline as observed in an unconventional well.
x = independent variable: cumulative HCPV injected (HCPVI).
y = oil recovery in terms of HCPV.

The Wasson Field in the Permian Basin was one of the first fields where CO_2 was injected after developing three CO_2 source fields in Colorado and New Mexico in the early 1980s and constructing a pipeline network to transport the CO_2 to the Permian Basin. The primary operator in the field was Shell, which operated the Denver Unit, the largest enhanced recovery unit. Shell reported that a certain part of the Wasson Field had been operated optimally compared with earlier flood phases, particularly where the water-alternating-gas (WAG) scheme had been optimized using past performance and reservoir simulations as guides. Using actual performance until approximately 0.7 HCPV had been injected and performance projected using simulation beyond that, a set of dimensionless curves was created for this optimized area. The oil curve is solid in Figure 15. The dashed curve in the figure was created by the best fit of these data to Equation 2.

The Denver Unit was projected to achieve an ultimate tertiary recovery factor of 17.7% of OOIP. It is a dolomite formation from a depositional environment analogous to Williston Basin formations. The Weyburn and Midale Fields near Midale, Saskatchewan, are perhaps even better analogs, and their ultimate recovery factors were 11% and 17%, respectively (Whittaker, 2015; Weyburn, 2024). The general shape of this curve provided the basis for forecasting. The ultimate recovery factor was estimated for each Williston Basin reservoir by multiplying the ratio of each field's specific EUR factor to the Denver Unit factor of 17.7%.

[4] Equation 2 is the same as Equation 1, used for the Bakken predictive model, except that the x variable for the conventional models was cumulative HCPV injected instead of time.

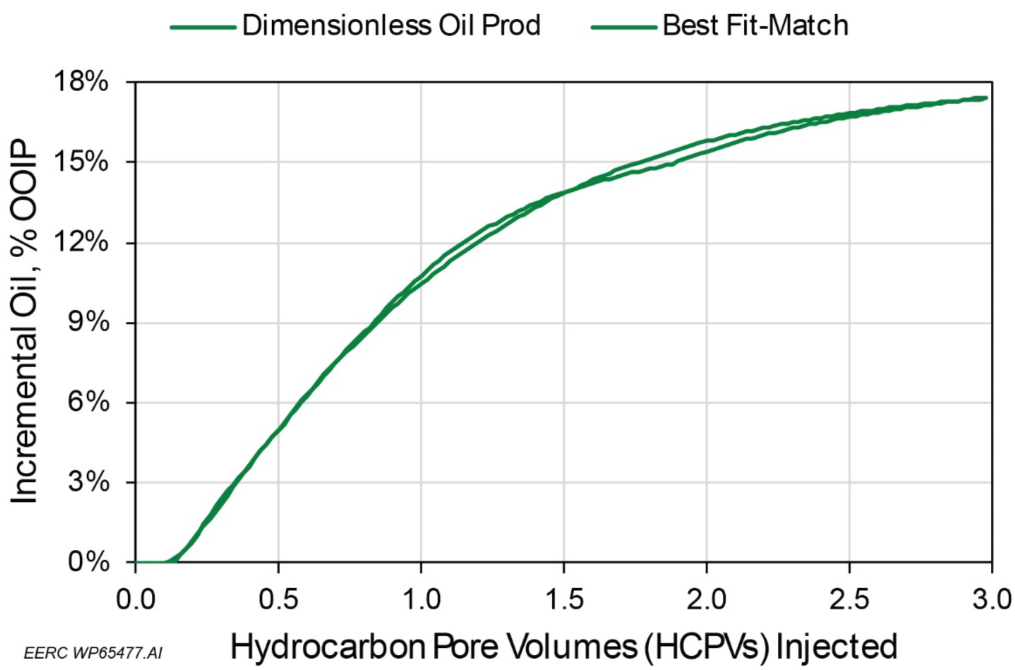


Figure 15. Denver Unit optimized EOR oil recovery curve and best-fit match.

The field-specific calculation was done using the following equation (Equation 3):

$$RE_{CO2} = \left[\left(\frac{1}{C}\right) * \frac{RE_{wf} * S_{oi}}{S_{oi} - S_{orw}}\right] * \left[1 - RE_{wf} - \frac{S_{orm}}{S_{oi}}\right] \quad \text{[Eq. 3]}$$

Where:

RE_{CO2} = Incremental CO_2 EOR recovery factor, %OOIP.
C = Waterflood volumetric sweep efficiency/CO_2 EOR volumetric sweep efficiency.
RE_{wf} = Recovery factor at the end of the waterflood, %OOIP.
S_{oi} = Initial oil saturation, fraction of pore space.
S_{orw} = Residual oil saturation in water-swept volume after waterflood.
S_{orm} = Residual oil saturation in CO_2-swept volume after CO_2 flood.

Equation 3 is derived from classical equations that calculate oil recovery efficiency in a displacement process (Dykstra and Parsons, 1950; Craig, 1971). High volumetric sweep efficiency in a waterflood indicates high oil recovery efficiency, suggesting a more efficient CO_2 flood. However, a lower residual oil saturation to water will result in higher waterflood recovery, but this also means less oil left behind in the swept volume to be mobilized by CO_2, resulting in lower recovery through CO_2 injection of the oil originally in place. This equation was created to account for those factors when predicting CO_2 flood recovery efficiency.

While OOIP data are available by field from prior EERC reports, particularly Peck and others (2019), production data for the fields is readily available from DMR. Data for the initial water saturation or initial oil saturation and for the residual oil saturations to water at the field level were sparse. The primary reference for these was the 1984 version of the Tertiary Oil Recovery Information System (TORIS) database created in conjunction with the 1984 National Petroleum Council Study on Enhanced Oil Recovery (TORIS Database, 1984; Long, 2016). However, the initial and residual oil saturations (to water) were available only for a few fields. These were applied to the other fields for which no values were available, as deemed appropriate. In all cases, the residual oil saturation to the miscible process was assumed to be 10%. The value of the C coefficient was, in most cases, assumed to be 2.5, which has been used in calculations for Permian Basin reservoirs. In cases with no waterflood or a poorly executed one, the value was lowered to 2.2 to account for reservoir portions that would be swept by CO_2 but that had not been swept by water.[5] Table 2 shows the projected incremental tertiary recovery factors (TRFs) calculated for each field using these data. The forecasting method was applied to only 80% of the OOIP values listed to account for acreage around the edges of the fields that may never be flooded because of concerns about CO_2 migration outside of the unit boundaries.

Table 2. Summary of Input Data Used to Calculate CO_2 EOR Incremental Oil Recovery for the 21 Fields in This Study

Field	Reservoir	S_{orw}	S_{wi}	S_{orm}	WFRF*	C	OOIP, MMbbl	Cum. Oil, MMbbl	TRF
Charlson	Silurian	0.38	0.32	0.1	0.179	2.2	106.0	19.0	0.124
Antelope Madison Unit	Madison	0.32	0.32	0.1	0.175	2.2	100.0	17.5	0.102
Blue Buttes Madison Unit	Madison	0.32	0.32	0.1	0.376	2.5	93.0	35.0	0.136
Charlson N. Madison Unit	Madison	0.38	0.32	0.1	0.300	2.5	80.0	24.0	0.150
Blue Buttes	Silurian	0.38	0.25	0.1	0.176	2.2	74.0	13.0	0.112
Hawkeye Madison Unit	Madison	0.32	0.36	0.1	0.341	2.5	44.0	15.0	0.137
Charlson S. Madison Unit	Madison	0.38	0.32	0.1	0.469	2.5	9.6	4.5	0.163
Antelope Devonian Unit	Devonian	0.38	0.32	0.1	0.390	2.5	16.3	6.4	0.164
Clear Creek Madison Unit	Madison	0.38	0.32	0.1	0.367	2.5	27.0	9.9	0.162
Antelope	Silurian	0.38	0.25	0.1	0.197	2.2	23.4	4.6	0.121
Stoneview Stonewall	Stonewall	0.38	0.25	0.1	0.187	2.2	30.0	5.6	0.117
Tioga	Madison	0.32	0.25	0.1	0.277	2.5	216.0	59.9	0.114
Beaver Lodge	Madison	0.32	0.25	0.1	0.330	2.5	172.0	56.7	0.124
Beaver Lodge	Devonian	0.38	0.32	0.1	0.435	2.5	172.0	74.8	0.165
Little Knife	Madison	0.32	0.40	0.1	0.323	2.5	294.0	95.0	0.141
Other Billings Nose Area	Madison	0.32	0.32	0.1	0.295	2.5	333.9	98.5	0.124
CCA Area	Ordovician	0.32	0.25	0.1	0.288	2.5	456.5	131.3	0.120

* Water flood recovery factor.

[5] This coefficient assumes that volumetric sweep efficiency in CO_2 flooding is proportional to waterflooding. A case could be made that modifications such as conformance modifications, pattern realignments, infill drilling, or completion of horizontal laterals done as part of the CO_2 development program could lower this ratio and, in turn, improve volumetric sweep and, consequently, incremental EOR oil recovery.

For forecasting EOR injection, a WAG scheme that closely resembles Shell's was used. This scheme continues CO_2 injection further into the future at a higher, or "wetter," WAG ratio. It is based on the numbers in the table below but is defined by a power law equation to provide smooth transitions to progressively wetter WAGs (Table 3).

Table 3. Summary of WAG Schedule Used to Forecast CO_2 Injection Rates over Life of Projects

HCPVI at Start	0.00	0.10	0.20	0.30	0.39	0.69	1.50	1.80	1.95	2.30
HCPVI at End	0.10	0.20	0.30	0.39	0.69	1.50	1.80	1.95	2.30	2.50
WAG Ratio	100% CO_2	0.25	0.67	0.80	1.00	1.25	1.50	2.00	2.50	3.00

The dimensionless curve method was also used to predict CO_2 production. The CO_2 production curve used was derived from the above WAG schedule and assumed that CO_2 stored in the reservoir would occupy 40% of the HCPV at the end of the project life (Azzolina and others, 2015). This is shown graphically in Figure 16, where the blue area represents water injected and the red and orange areas represent CO_2 injection either from the external CO_2 supply (stored volume – red) or CO_2 produced and reinjected into the reservoir (recycled – orange).

The WAG scheme and recycle curve shown represent what happens at the level of individual injection well-centered patterns. The curve will look different when plotted at the field level because of additional patterns phasing in to optimize CO_2 utilization and required capital investment.

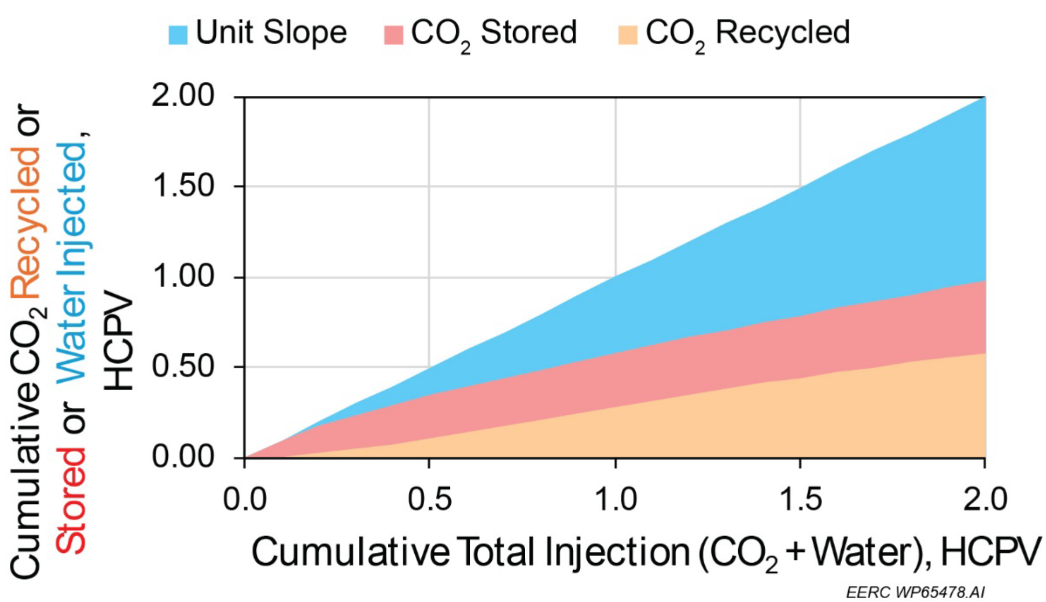


Figure 16. Graph showing the disposition of cumulative injection volumes as a function of dimensionless time (HCPVI). The sum of the red and orange areas represents the total CO_2 injected from all sources.

2.2.2 Construction of the Conventional Predictive Model

Scheduling CO_2 floods in each of the 21 fields was not done at the pattern level as the data required to do so were not readily available and an appropriate level of precision could be achieved by splitting the field into phases that represent fractions of each field's OOIP. These phases could then be manually scheduled, resulting in a reasonably constant CO_2 storage rate with fluctuations within the expected variation due to operational activity. Phases and then whole fields were scheduled in this manner to provide a reasonably constant CO_2 storage rate for the entire group of fields. Once CO_2 injection was scheduled by phase, oil production could be calculated (by phase) using the dimensionless curve, individual dimensionless field injection rate, and specific phase start date.

The lone exception to this scheduling to achieve constant CO_2 storage is the CCA area, where since early 2022, Denbury has been injecting its CO_2 sourced from the Shute Creek gas plant in southwestern Wyoming and transporting it by its pipeline to the CCA. We attempted to match the injection and production of the company's nascent CO_2 flood based on the short available injection and production history. Denbury's project was not scheduled in a manner that generated a flat CO_2 supply profile, as was done in the remaining fields where industrial sources will likely be employed and will require assurance of a specific daily storage rate. Each field was scheduled so the start date of CO_2 injection could be moved, shifting the entire projection so that the overall CO_2 storage for all fields (excluding the CCA) could be maintained at a constant rate.

Injection rates are difficult to predict given the time allotted for this evaluation, but those used were inferred from the study of each field's production and injection history. These rates ranged from 6% to 15% HCPV injected annually, representing the expected range of dimensionless injection rates achieved in Permian Basin CO_2 EOR projects. A graph of the projected CO_2 stored, CO_2 recycled, and incremental oil production for the Beaver Lodge Madison Unit is shown in Figure 17 as an example of the scheduling output for one field.

The Nesson Anticline field group was scheduled assuming CO_2 injection would begin in some fields in 2028. These fields were scheduled so a constant rate of approximately 150 MMcfd, or approximately 3 million tonnes per day, could be stored daily for 14 years. The first few years of this storage plateau start in 2028 in Figure 18 (see brown curve). The Billings Nose field group was scheduled to begin injection in 2033 and scheduled aggressively since this region would require a payout on a significant pipeline investment. It would provide a constant storage rate of 100 MMcfd, or approximately 2 million tonnes per day, for 4 years before declining. The individual fields' oil production projections from this implementation schedule were aggregated to create a statewide conventional CO_2 EOR projection.

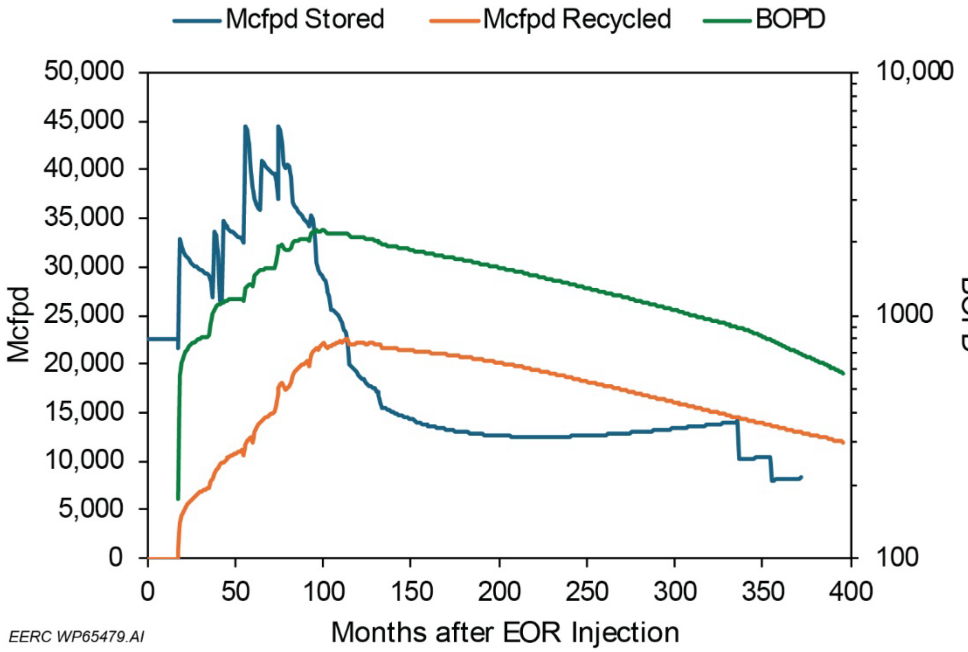


Figure 17. Example graph showing flow streams as scheduled for the Beaver Lodge Madison Unit plotted against the months after initial CO_2 injection (BOPD: barrels of oil per day).[6]

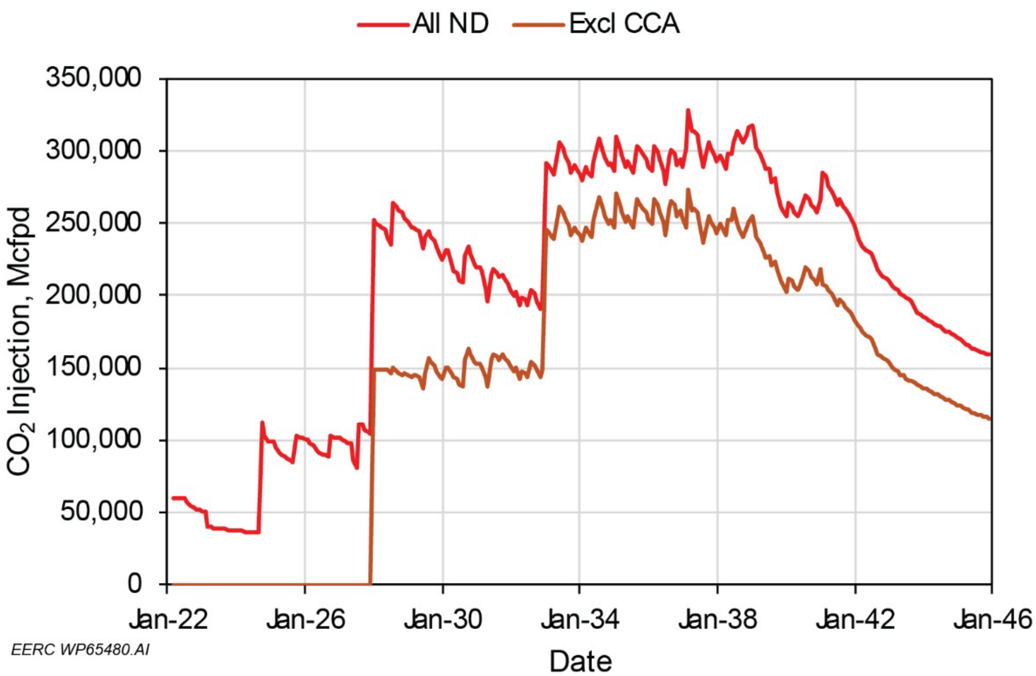


Figure 18. Projected CO_2 storage rates for all 21 fields and excluding CCA fields (Excl. CCA).

[6] While the Bakken cyclic gas EOR modeling was done on a weekly basis to accommodate the seven 24-week injection, soak, and production cycles, the conventional EOR modeling was done monthly to conform with standard practice and the monthly reported oil volumes.

2.3 Sensitivity Analysis

The baseline Bakken case considered a development scenario limited to 10 million tonnes of CO_2 per year (27,400 tonnes of CO_2 per day). Two additional sensitivity cases were considered using 50% less CO_2 (5 million tonnes of CO_2 per year, or 13,700 tonnes of CO_2 per day) and 50% more CO_2 (15 million tonnes of CO_2 per year, or 41,100 tonnes of CO_2 per day). Since the baseline conventional EOR forecast was not CO_2-constrained, no additional sensitivity analyses were conducted for those fields.

Two additional Bakken cases were examined to evaluate the effects of a higher CO_2 utilization rate and a higher IOR on the results. The high CO_2 utilization rate considered a scenario where the Bakken reservoir pressure was increased to 6000 psia and 100% fluid replacement after accounting for oil, excess gas, and water production. The high CO_2 utilization rate maintained the IOR at 1.3 and used 17.3 Mcf (0.9 tonnes) per incremental barrel. The high-IOR case increased the IOR to 1.6 and used 9.6 Mcf (0.5 tonnes) per incremental barrel to maintain 100% fluid replacement. To achieve the high CO_2 utilization and IOR rates, the cyclic gas EOR model was adapted to eleven 16-week cycles comprising 6 weeks of injection, 1 week of soaking, and 9 weeks of production. Therefore, the total EOR time of 176 weeks (3.4 years) was slightly longer than the baseline cases (168 weeks, or 3.2 years). The high-CO_2-utilization and high-IOR cases are considered end-members that would require significant incentives or operational modifications.

The three CO_2 constraints and three IOR and CO_2 utilization rate cases resulted in a matrix of seven outcomes. The high-CO_2-utilization-rate and high-IOR cases were not examined for the 5-million-tonnes-of-CO_2-per-year scenario (Table 4).

Table 4. Case Matrix for Bakken EOR Showing the Three CO_2 Constraints and Three IOR and CO_2 Utilization Rate (UR) Cases Resulting in a Matrix of Seven Outcomes

5 MMt CO_2 per Year	10 MMt CO_2 per Year	15 MMt CO_2 per Year
IOR = 1.3 CO_2 UR = 0.3 tonnes/bbl	IOR = 1.3 CO_2 UR = 0.3 tonnes/bbl	IOR = 1.3 CO_2 UR = 0.3 tonnes/bbl
N/A	IOR = 1.3 CO_2 UR = 0.9 tonnes/bbl	IOR = 1.3 CO_2 UR = 0.9 tonnes/bbl
N/A	IOR = 1.6 CO_2 UR = 0.5 tonnes/bbl	IOR = 1.6 CO_2 UR = 0.5 tonnes/bbl

3.0 RESULTS

3.1 Bakken EOR Assessment

Figure 19 shows the time-series estimates of Bakken EOR incremental oil and purchased (stored) CO_2 for the baseline case, assuming a constraint of 10 million tonnes of CO_2 per year (27,400 tonnes of CO_2 per day).

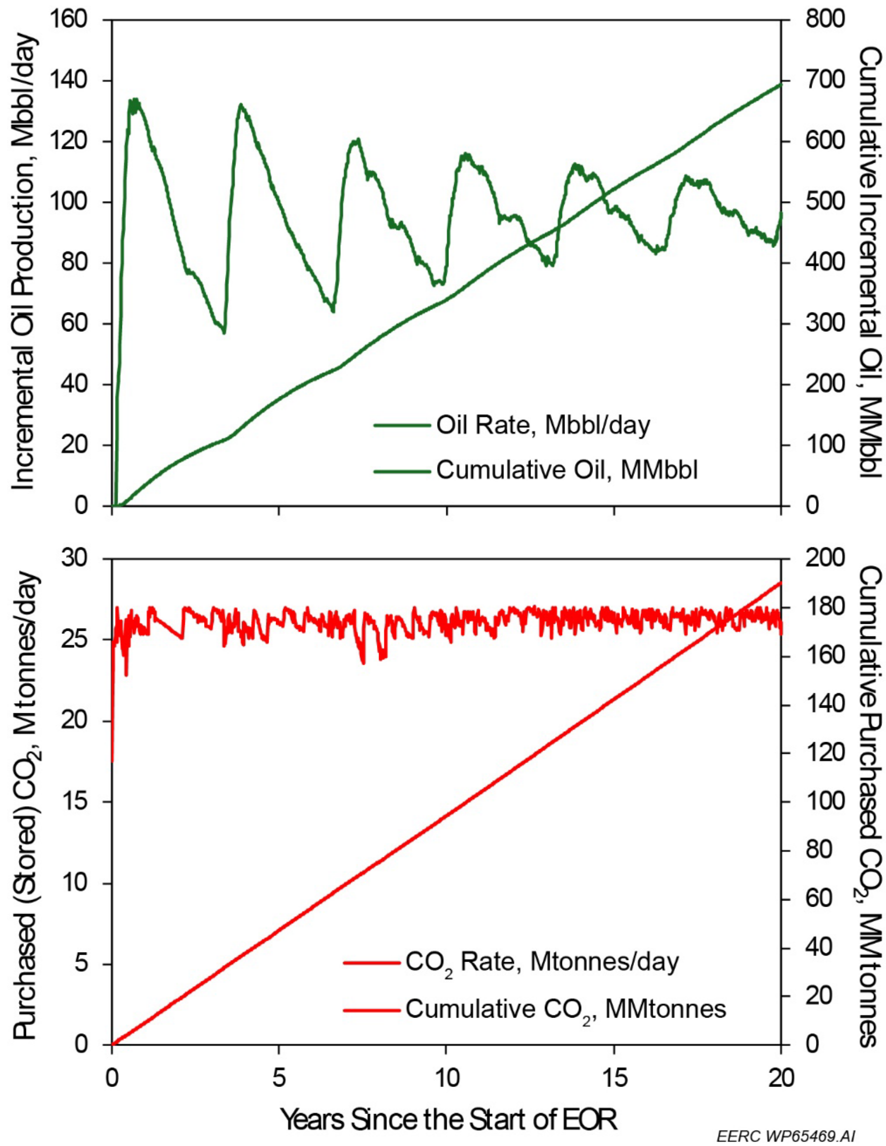


Figure 19. Time-series plots of Bakken EOR incremental oil (top) and purchased (stored) CO_2 utilization (bottom) for the baseline case, assuming a constraint of 10 million tonnes of CO_2 per year (27,400 tonnes of CO_2 per day).

The maximum daily oil rate was 134,000 bbl/day, with an average oil rate over the 20-year time frame of 95,000 bbl/day. The cyclic oil rate peaks have a periodicity of approximately 3.2 years, corresponding to the underlying assumption of cyclic gas injection performed over seven 24-week cycles, or 3.2 years per grid. Therefore, as sets of grids begin EOR, the incremental oil rate increases and then declines before the next set begins EOR. The cumulative incremental oil production over the 20 years was 694 MMbbl.

The maximum net CO_2 utilization was 27,400 tonnes of CO_2 per day, a constraint imposed on the analysis. The average net CO_2 utilization was 26,100 tonnes of CO_2 per day, which was less than the maximum because of variations in developing EOR grids while remaining below the constraint. The cumulative purchased CO_2 over the 20-year time frame was 190 million tonnes.

One hundred and thirty-seven grids initiated EOR before the end of the 20-year time frame, representing 5744 wells. Therefore, of the 271 grids, 134 (roughly 50%, representing 4251 wells) did not initiate EOR because of the CO_2 constraint and the inability to begin cyclic gas injection within the time frame without exceeding 10 million tonnes of CO_2 per year. Only grids in the core areas of the Bakken were developed, moving from the highest well densities and EURs in the core areas and westward, northward, and southward of an approximate centerline through the Bakken. Therefore, at the end of 20 years, large portions of the Bakken remain available for EOR.

3.2 Bakken Sensitivity Analysis

Table 5 and Figure 20 compare the Bakken baseline case (10 million tonnes of CO_2 per year, 27,400 tonnes of CO_2 per day) to the low-CO_2-sensitivity case (5 million tonnes of CO_2 per year, 13,700 tonnes of CO_2 per day) and high-CO_2-sensitivity case (15 million tonnes of CO_2 per year, 41,100 tonnes of CO_2 per day).

Table 5. Comparison of Total Bakken EOR Incremental Oil and Purchased (Stored) CO_2 over the 20 years for the Baseline Case, Assuming a Constraint of 10 million tonnes of CO_2 per Year, Low-CO_2 Case (5 million tonnes of CO_2 per year), and High-CO_2 Case (15 million tonnes of CO_2 per year)

Case	Incremental Oil, MMbbl	% Change[1]	Purchased/ Stored CO_2, MMt	% Change[1]	No. of EOR Grids	% Change[1]
Low CO_2	337	−51	93	−51	55	−60
Baseline	694	N/A	190	N/A	137	N/A
High CO_2	1076	+55	294	+55	255	+86

[1] The percentage change from baseline was calculated as (Case X – Baseline)/Baseline.

The maximum daily oil rate for the low-CO_2 case was 64,000 bbl/day, with an average oil rate over the 20-year time frame of 46,000 bbl/day. The cumulative incremental oil production over the time frame was 337 MMbbl, a 51% reduction from the baseline (694 MMbbl). The maximum daily oil rate for the high-CO_2 case was 206,000 bbl/day, with an average oil rate over the 20 years of 148,000 bbl/day. The cumulative incremental oil production over the 20-year timeframe was 1,076 MMbbl, a 55% increase from the baseline.

The maximum net CO_2 utilization for the low-CO_2 case was 13,700 tonnes of CO_2 per day, a constraint imposed on the analysis. The average net CO_2 utilization was 12,700 tonnes of CO_2 per day, which was less than the maximum because of variations in developing EOR grids while simultaneously remaining below the constraint. The cumulative purchased (stored) CO_2 over the 20-year time frame was 93 million tonnes, a 51% reduction from the baseline (190 million tonnes). The maximum net CO_2 utilization for the high-CO_2 case was 41,100 tonnes of CO_2 per day, a

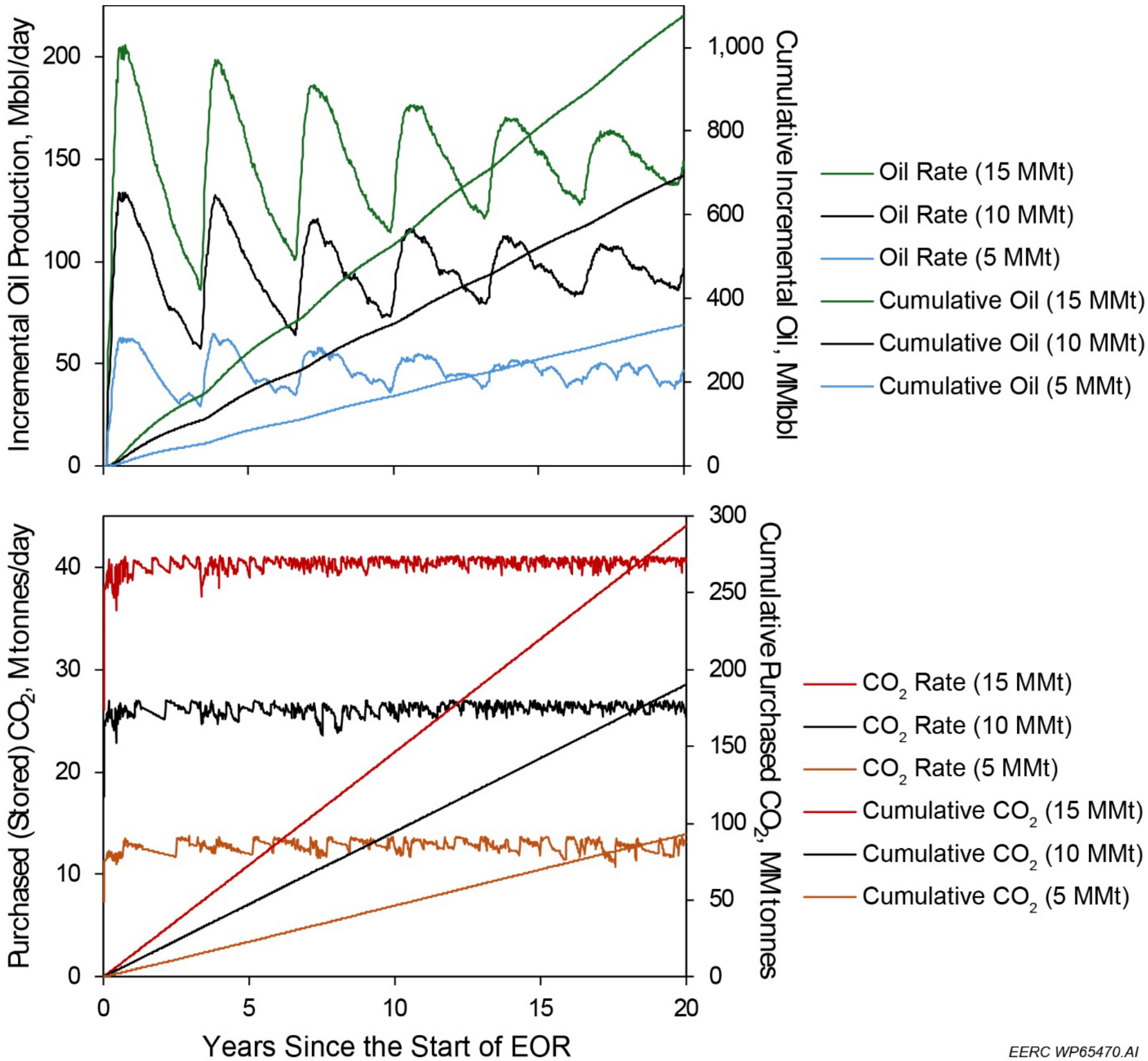


Figure 20. Comparison of time-series plots of Bakken EOR incremental oil (top) and net CO_2 utilization (purchased or stored CO_2, not total CO_2 injection) (bottom) for the baseline case (10 million tonnes of CO_2 per year, 27,400 tonnes of CO_2 per day), low-CO_2 case (5 million tonnes of CO_2 per year, 13,700 tonnes of CO_2 per day), and high-CO_2 case (15 million tonnes of CO_2 per year, 41,100 tonnes of CO_2 per day).

constraint imposed on the analysis. The average net CO_2 utilization was 40,300 tonnes of CO_2 per day. Like the previous case, the average utilization was less than the maximum because of variations in developing EOR grids while remaining below the constraint. The cumulative purchased CO_2 over the 20-year time frame was 294 million tonnes, a 55% increase from the baseline.

Fifty-five grids representing 2513 wells initiated EOR for the low-CO_2 case before the end of the 20-year time frame. This was a 60% reduction from the baseline (137 grids). Of the

271 grids with 20 or more wells, 216 (roughly 80%, representing 7482 wells) did not initiate EOR because of the CO_2 constraint and the inability to begin cyclic gas injection within the time frame without exceeding 5 million tonnes of CO_2 per year. Conversely, 255 grids initiated EOR for the high-CO_2 case before the end of the time frame, representing 9543 wells. This was an 86% increase from the baseline. Only 16 grids (roughly 6%, representing 452 wells) did not initiate EOR because of the CO_2 constraint of 15 million tonnes of CO_2 per year. Figure 21 shows the spatial arrangement and incremental oil recoveries for the 55 grids for the low-CO_2 case, 137 grids for the baseline case, and 255 grids for the high-CO_2 case that initiated EOR before the end of the 20-year time frame. At the end of 20 years, large portions of the Bakken remain available for EOR under the low-CO_2 and baseline cases, whereas most grids initiated EOR under the high-CO_2 case. These results suggest that a constant CO_2 supply of 10 million–15 million tonnes of CO_2 per year may be appropriate for broad EOR implementation across the Bakken under the stated assumptions of an IOR of 1.3 and a CO_2 utilization rate of 0.3 tonnes per incremental barrel.

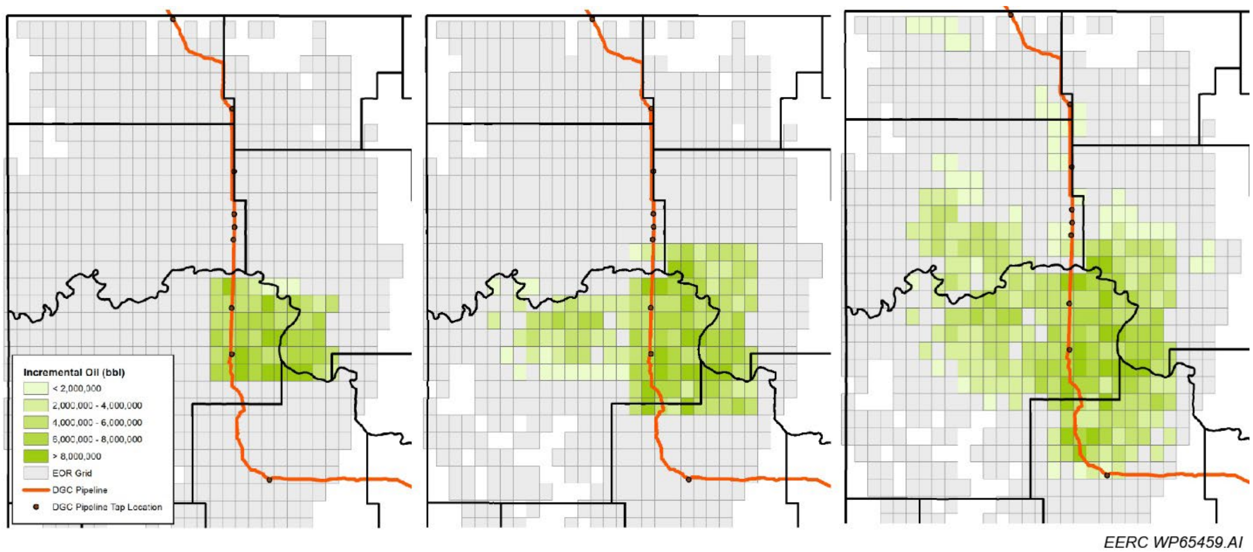


Figure 21. Heat map of EOR incremental oil production within the 20-year time frame for the 55 grids under the low-CO_2 case (left, 5 million tonnes of CO_2 per year), 137 grids under the baseline case (middle, 10 million tonnes of CO_2 per year), and 255 grids under the high-CO_2 case (right, 15 million tonnes of CO_2 per year).

Table 6 and Figure 22 show the two additional Bakken sensitivity analysis cases assuming the high CO_2 utilization case (1.3 IOR and 0.9 tonnes per incremental barrel) and the high IOR case (1.6 IOR and 0.5 tonnes per incremental barrel) for the baseline CO_2 constraint (10 million tonnes of CO_2 per year; 27,400 tonnes of CO_2 per day) and high CO_2 constraint (15 million tonnes of CO_2 per year; 41,100 tonnes of CO_2 per day).

Table 6. Comparison of Total Bakken EOR Incremental Oil and Purchased (Stored) CO_2 over the 20 years for the Baseline Case (1.3 IOR and 0.3 tonnes of CO_2 per incremental barrel), High-CO_2-Utilization Case (1.3 IOR and 0.9 tonnes of CO_2 per incremental barrel), and High-IOR Case (1.6 IOR and 0.5 tonnes of CO_2 per incremental barrel) Assuming Constraints of 10 million or 15 million tonnes of CO_2 per year

CO_2 Constraint, MMt CO_2/year	IOR	CO_2 Utilization, tonnes/bbl	Incremental Oil, MMbbl	% Change[1]	Purchased/Stored CO_2, MMt	% Change[1]	No. of EOR Grids	% Change[1]
10	1.3	0.3	694	N/A	190	N/A	137	N/A
10	1.3	0.9	184	−73	168	−12	25	−82
10	1.6	0.5	352	−49	172	−10	23	−83
15	1.3	0.3	1076	N/A	294	N/A	255	N/A
15	1.3	0.9	295	−73	278	−5	42	−84
15	1.6	0.5	513	−52	269	−8	36	−86

[1] The percentage change from baseline was calculated as (Case X – Baseline)/Baseline.

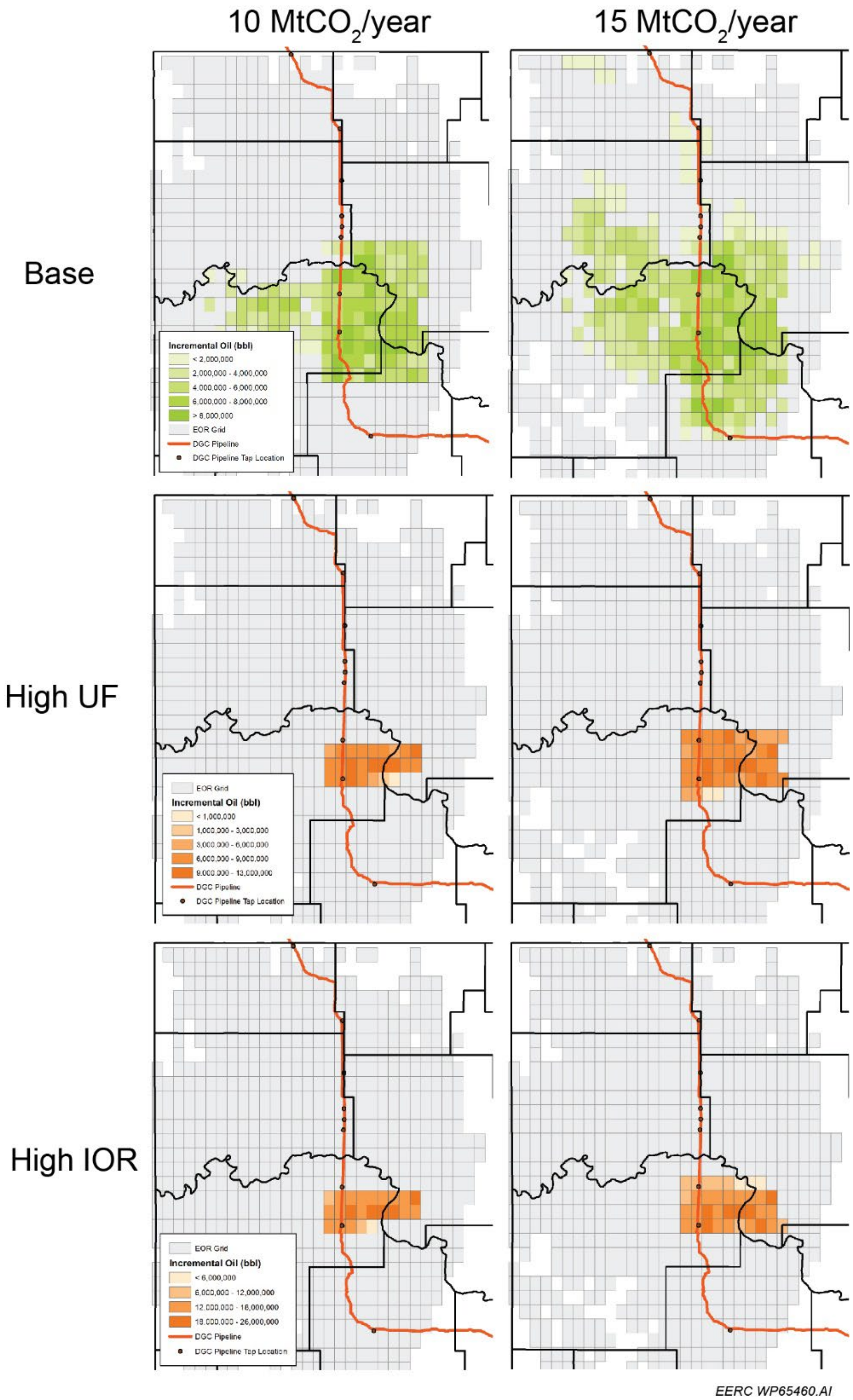


Figure 22. Heat map of EOR incremental oil production within the 20-year time frame under the 10 million tonnes of CO_2 per year constraint (left column) and 15 million tonnes of CO_2 per year constraint (right column) for the baseline EOR performance case (top row, 1.3 IOR and 0.3 tonnes of CO_2 per incremental barrel), high-CO_2-utilization case (middle row, 1.3 IOR and 0.9 tonnes of CO_2 per incremental barrel), and high-IOR case (bottom row, 1.6 IOR and 0.5 tonnes of CO_2 per incremental barrel).

Over 20 years, the high-CO_2-utilization cases flooded significantly fewer grids than the baseline. For example, under the 10-million-tonnes-per-year CO_2 constraint, the high-CO_2-utilization case reached only 25 grids, 82% less than the baseline case of 137 grids. This is because the CO_2 injection schedule for each grid included an initial period of rapid CO_2 injection to increase reservoir pressure and achieve the 0.9-tonnes-per-incremental-barrel CO_2 utilization rate. Consequently, to maintain the CO_2 supply at or below the threshold, fewer grids could initiate EOR within 20 years. Because of the fewer grids flooded in the 20 years, the high-CO_2-utilization case generated only 184 MMbbl of incremental oil, 73% down from the baseline case of 694 MMbbl. Similar results were observed for the 15-million-tonnes-per-year CO_2 constraint. The high-CO_2-utilization case flooded 91% fewer grids (23 versus 255 grids) and generated 67% less incremental oil (352 versus 1076 MMbbl) than the comparable baseline case (Table 6).[12] As shown in Figure 22, only a small portion of the Bakken was flooded in 20 years under the high-CO_2-utilization-rate cases. Therefore, if the EORs were operated to maintain higher CO_2 utilization rates or IOR ratios, greater than 15 Mt CO_2/year would be needed.

The high-IOR cases also flooded significantly fewer grids than the baseline. For example, under the 10-million-tonnes-per-year CO_2 constraint, the high-IOR case reached only 42 grids, a 69% reduction from the baseline case of 137 grids. The high-IOR case generated only 295 MMbbl of incremental oil, a 58% reduction from the baseline's 694 MMbbl. Similar results were observed for the 15-million-tonnes-per-year CO_2 constraint. The high-IOR case flooded 86% fewer grids (36 versus 255 grids) and generated 52% less incremental oil (513 versus 1076 MMbbl) than the comparable baseline case (Table 6). As shown in Figure 22, only a small portion of the Bakken was flooded in 20 years under the high-IOR cases. Analogous to the high-CO_2-utilization-rate cases, CO_2 supplies above 15 million tonnes per year would be needed to process more grids within the same time frame if the cyclic gas EOR was operated to maintain a higher IOR of 1.6 and a higher CO_2 utilization rate of 0.5 tonnes per incremental barrel.

3.3 Conventional EOR Assessment

Figure 23 shows the time-series estimates of conventional EOR incremental oil and the associated purchased (stored) CO_2 for the baseline case. The maximum daily oil rate was 23,000 bbl/day, with an average oil rate over the 20-year time frame of 14,000 bbl/day. The cumulative incremental oil production over the 20-year time frame was 105 MMbbl. The maximum and average net CO_2 utilization were 17,000 and 12,000 tonnes of CO_2 per day, respectively. The cumulative purchased CO_2 over the 20-year time frame was 88 million tonnes.

---

[12] Subtle differences in the CO_2 scheduling between the development constraints of 10 million and 15 million tonnes of CO_2 per year resulted in the counterintuitive result of processing slightly fewer grids under the 10-million-tonnes-of-CO_2-per-year scenario (25 grids) than the 15-million-tonnes-of-CO_2-per-year scenario (23 grids). This results from combining multiple nonlinear curves through time while honoring the CO_2 constraint. The same phenomenon occurred with the high-IOR cases, which processed 42 grids under the 10-million-tonnes-of-CO_2-per-year scenario and 36 grids under the 15-million-tonnes-of-CO_2-per-year scenario.

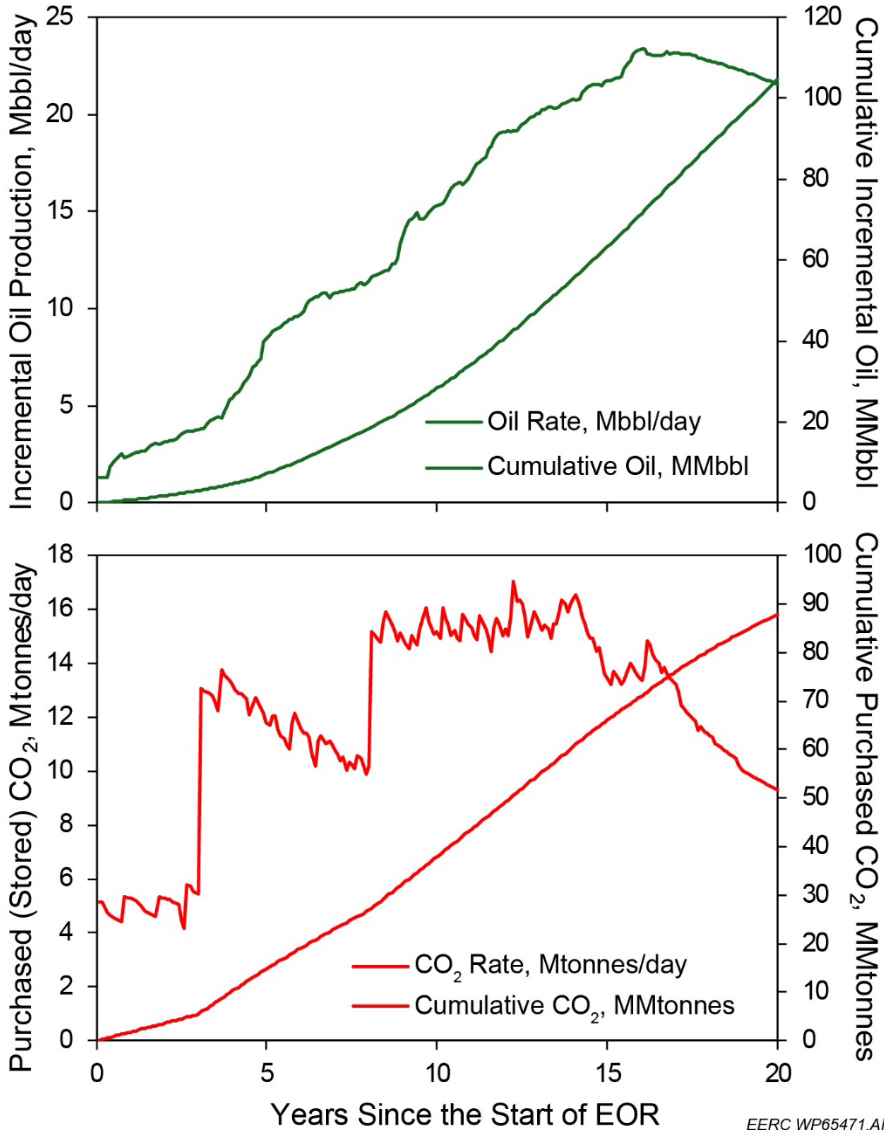


Figure 23. Time-series plots of conventional EOR incremental oil (top) and net CO_2 utilization (purchased or stored CO_2, not total CO_2 injection) (bottom) for the baseline case.

3.4 Discussion

3.5.1 Key Drivers of Bakken EOR Performance

The operation of cyclic gas injection EOR and the CO_2 constraint imposed on the scheduling of EOR grids significantly affected the study results. This study used seven 24-week cycles (168 weeks, or 3.2 years) to estimate the baseline Bakken EOR performance. Fewer cycles would accelerate the rate of grid development (i.e., more grids would begin EOR in the same time frame); however, fewer cycles would lower oil recovery from each grid. Conversely, more cycles would slow grid development (i.e., fewer grids would begin EOR in the same time frame); however, more cycles would increase oil recovery from each grid. Exploratory analyses of different cycle lengths showed that more cycles consumed significant quantities of CO_2 without the commensurate oil recovery response. Therefore, cycles beyond the seventh cycle constrained new grid development without producing large amounts of incremental oil. This study did not attempt to optimize the number of cycles in the cyclic gas EOR process, which could be less than or greater than seven cycles.

Constraints of 5 million (low), 10 million (baseline), or 15 (high) million tonnes of CO_2 per year were imposed on the rate of Bakken EOR development. These constraints significantly impacted the grid development rate, with the number of grids initiating EOR in the 20-year time frame increasing from 55 to 137 to 255 for the low-CO_2, baseline, and high-CO_2 cases, respectively. Therefore, the CO_2 supply constraint is important in estimating Bakken EOR incremental oil and purchased (stored) CO_2. While three coal-related CO_2 capture projects are in various stages of development in North Dakota that, once operational, could together capture over 15 million tonnes per year (Coal Creek, DGC, and Milton R. Young), the rate of 10 million tonnes per year was chosen as a conservative theoretical baseline illustrating modest adoption of CO_2 capture, transportation, and field infrastructure.

This study did not attempt to overlay infrastructure considerations onto the CO_2 constraints. The low, baseline, and high cases were selected to explore a range of CO_2 supply from the baseline and ±50% of the baseline. The modeled scenarios assumed that competitive business cases were developed and that CO_2 infrastructure (e.g., well preparation, field unitization, flowlines, recycle facilities, compression equipment) was entirely in place at the start of the simulation period. This highly simplified approach to infrastructure development enabled the study to focus on deriving estimates of the maximum economic potential of CO_2 EOR in North Dakota. EOR infrastructure takes time to finance, procure, and build out. Establishing the CO_2 infrastructure to support the broad deployment of EOR is a long game that will most likely occur stepwise. The full potential of EOR in North Dakota may require a decade or more.

Industry experience and published studies informed the cyclic gas EOR modeling. An IOR ratio of 1.3 was set as the target for oil recovery, based on a net CO_2 utilization factor of 6 Mcf (0.5 tonnes) per incremental barrel. However, Bakken EOR is immature, and true performance metrics could vary from these assumptions. Alternative cases explored a high CO_2 utilization rate (1.3 IOR and 0.9 tonnes of CO_2 per incremental barrel) and a high IOR (1.6 IOR and 0.5 tonnes of CO_2 per incremental barrel), which showed that CO_2 supplies above 15 million tonnes per year would be needed to process more grids within the same time frame if the cyclic gas EOR was operated to maintain the higher conditions. However, these cases are considered end-members that would require significant incentives or operational modifications.

3.5.2 Static Snapshot of the Bakken

This analysis assumes that the number of Bakken wells per grid is static based on the synoptic snapshot collected at the time of the study. However, DSUs in the core area (Tier 1 and Tier 2 acreage) may drill child wells until each DSU has approximately nine to eleven wells (five to six Middle Bakken and four to five Three Forks wells within each 1280-acre DSU). Since an EOR grid was defined as six DSUs, grids with 54–66 wells would be considered fully drilled and ready to begin EOR. This is a significantly greater number of wells than the 20-well cutoff in the study.

At the time of the analysis, 38 grids had 50 or more wells and only two had 60 or more wells. This analysis did not consider the time required to drill new wells and produce them through primary production until starting EOR. Therefore, additional incremental oil production is possible, especially within the core area, and this analysis is conservative in this aspect. Upscaling to 60-well grids increases the estimated incremental oil production and purchased CO_2 by approximately 43% over the baseline case (33% for the low-CO_2 case and 58% for the high-CO_2 case). However, the time needed to drill new wells and produce them through primary production could range from 5 to 10 years (or longer), delaying the EOR production significantly.

3.5.3 Fiscal Incentives for EOR in North Dakota

Because the development of widespread EOR infrastructure will take many years to accomplish, policy actions in the near-term may significantly influence North Dakota's ability to harvest the maximum financial benefits in the decades to come. Both within industry operating budgets and Wall Street, financing competes with other oil plays (e.g., Permian Basin of Texas and New Mexico, Texas Eagle Ford), not just EOR. Policies that support EOR in North Dakota can strongly signal that investment in North Dakota is attractive.

The federal 45Q tax credit provides an incentive for CO_2 capture of \$60/tonne for CO_2 utilized in EOR and storage, \$85/tonne for CO_2 sequestered in saline storage, and up to \$180/tonne for CO_2 captured and stored from a direct air capture facility. Eligible facilities can claim the 45Q tax credit for 12 years after being placed in service. Current law limits eligibility to carbon capture facilities that begin construction no later than January 1, 2033. The \$25 differential between saline storage and EOR storage 45Q tax credits drives investment in saline storage projects, which will limit the near-term availability of CO_2 for EOR in North Dakota. This will likely continue to be the case until either the 45Q tax credits sunset (currently 12 years) or other incentives are put in place that close the differential and pull EOR development/production forward in time.

To encourage the development of EOR in the state, the North Dakota Century Code (NDCC) provides several exemptions[13] from the oil extraction tax[14] for EOR:

1) Incremental production associated with EOR is exempt for 10 years.
2) Incremental production from EOR from a horizontal well drilled and completed within the Bakken and Three Forks Formations is exempt for 5 years.
3) Incremental production from EOR that injects more than 50% CO_2 from coal outside the Bakken and Three Forks Formations is exempt for 20 years.
4) Incremental production from EOR that injects more than 50% CO_2 produced from coal and is within the Bakken and Three Forks Formations is exempt for 10 years.

To compare the value of 45Q and North Dakota extraction tax exemption, at current Bakken crude prices of \$70/bbl, a 5% extraction tax exemption provides an approximately \$3.50/bbl

[13] NDCC § 57-51.1-03.
[14] 5% of the gross value at the well of the oil extracted (NDCC § 57-51.1-02).

incentive. Assuming an average of 2–4 barrels of incremental oil per tonne of CO_2 injected, the incentive equals approximately $7–$14/tonne of CO_2. The amount of the 45Q tax credit for EOR storage versus saline storage represents a significant disparity in the economic value of CO_2 for EOR despite the tax exemption provided by NDCC and not including the additional incremental production costs of EOR. Barring some other policy, regulatory, or market driver, this disparity creates significant uncertainty regarding the total CO_2 available for EOR through 2045 (12 years following the 2033 deadline for eligibility) and the potential for EOR deployment and associated economic benefits. For this forecast, the CO_2 quantities modeled represent theoretical cases to illustrate EOR scenarios once modest adoption of CO_2 capture, transportation, and field infrastructure (flowlines, compression, recycle) is in place and operational.

3.5.4 Future Studies to Address Key Data Gaps

For the Bakken cyclic gas EOR, an IOR ratio of 1.3 was set as the baseline target for oil recovery using a CO_2 net utilization factor of 6 Mcf (0.3 tonnes) per incremental barrel. Additional cases were evaluated to examine the effect of these parameters on the results. Further studies are needed to reduce the uncertainty around these performance parameters. Simulation, pilot, and larger-scale pilot studies (e.g., multiple DSUs) are needed to understand the ranges and expected values for these performance parameters in the Bakken.

The modeled scenarios assumed that CO_2 infrastructure (e.g., well preparation, field unitization, flowlines, recycle facilities, compression equipment) was entirely in place at the start of the simulation. Additional studies are needed to quantify the infrastructure development required to transport CO_2 from capture sources to the Bakken and conventional reservoirs and the interplay between those infrastructure challenges and the rate of EOR development.

This study focused solely on CO_2 EOR. Natural gas liquids (NGLs) produced in the Bakken could be used as an injectate with CO_2 for EOR. Additional studies are needed to quantify the interactions among NGL production, gas processing and other infrastructure needs, and EOR performance under NGL–CO_2 EOR.

4.0 CONCLUSIONS

The Bank of North Dakota retained the EERC to forecast incremental oil production associated with CO_2 EOR in North Dakota's unconventional and conventional reservoirs. The forecast targets potential development scenarios over 20 years and predicts incremental oil production and CO_2 supply demand.

The modeling work in this study suggests incremental oil recoveries from North Dakota's unconventional reservoirs over 20 years could range from 337 MMbbl under a low-CO_2 Bakken scenario (5 million tonnes of CO_2 per year) to 1076 MMbbl under a high-CO_2 Bakken scenario (15 million tonnes of CO_2 per year), with an average of 694 MMbbl under the baseline CO_2 Bakken scenario (10 million tonnes of CO_2 per year). The CO_2 supply demands range from 93 million to 294 million tonnes, depending on the assumed Bakken constraint. Additional sensitivity analysis cases showed that greater CO_2 supplies above 15 million tonnes per year would be needed to process more grids within the same time frame if the cyclic gas EOR was operated to maintain higher CO_2 utilization rates or IOR ratios. Development of the Bakken beyond the timelines considered here, which would expand beyond the core area and include recently drilled and completed wells, would exceed these estimates and yield more incremental oil recovery and larger volumes of stored CO_2.

Twenty-one fields/units were chosen as prime candidates for conventional CO_2 EOR. The modeling work in this study suggests incremental oil recoveries from these fields/units of 105 MMbbl and a CO_2 supply demand of 88 million tonnes.

Key drivers of the modeling results include the number of cycles used for cyclic gas injection in the Bakken, the IOR ratios assumed for Bakken and conventional EOR, and the CO_2 rate constraints imposed on the analysis. The Bakken incremental oil results were proportional to the CO_2 supply; therefore, CO_2 supply significantly impacts Bakken incremental oil recovery. Additional studies are needed to quantify the infrastructure development required to transport CO_2 from capture sources to the Bakken and conventional reservoirs and the interplay between those infrastructure challenges and the rate of EOR development.

5.0 REFERENCES

Azzolina, N.A., Nakles, D.V., Gorecki, C.D., Peck, W.D., Ayash, S.C., Melzer, L.S., and Chatterjee, S., 2015, CO_2 storage associated with CO_2 enhanced oil recovery—a statistical analysis of historical operations: International Journal of Greenhouse Gas Control, v. 37, p. 384–397. ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2015.03.037.

Craig, F.F., 1971, Reservoir engineering aspects of waterflooding: Richardson, Texas, Society of Petroleum Engineers Monograph Series, v. 3.

Department of Mineral Resources, 2024, Bakken horizontal wells by producing zone: from www.dmr.nd.gov/oilgas/bakkenwells.asp (accessed January 2024).

Dykstra, H., and Parsons, R.L., 1950, Secondary recovery of oil in U.S.: American Petroleum Institute publication, p. 160–174.

Enverus, 2024, DrillingInfo website, from https://app.drillinginfo.com/production/#/default (accessed March 2024).

EOG Resources, Inc., 2017, EOG Resources quarterly earnings report: February 2017, from https://investors.eogresources.com/2018-02-27-EOG-Resources-Reports-Fourth-Quarter-and-Full-Year-2017-Results-and-Announces-2018-Capital-Program?pagetemplate=widgetpopup (accessed March 2024).

Esri, 2024, ArcGIS Desktop: Release 3.2. Redlands, California, Environmental Systems Research Institute.

Grinestaff, G., Barden, C., Miller, J., Franklin, W., Barden, C., and Eric D., 2020, Evaluation of Eagle Ford cyclic gas injection EOR—field results and economics: Paper presented at the

Society of Petroleum Engineers Improved Oil Recovery Conference, Virtual, August 2020. doi: https://doi-org.ezproxy.library.und.edu/10.2118/200427-MS.

Guillot, S., 1995–1996, Personal records from Denver Unit Working Interest Owners Meetings.

Hoffman, B., 2018, Huff-n-puff gas injection pilot projects in the Eagle Ford: Paper presented at the Society of Petroleum Engineers Canada Unconventional Resources Conference, Calgary, Alberta, Canada, March 2018. doi: https://doi.org/10.2118/189816-MS.

Long, R., 2016. TORIS: an integrated decision support system for petroleum E&P policy evaluation: 2016-09-29, https://edx.netl.doe.gov/dataset/toris-an-integrated-decision-support-system-for-petroleum-e-p-policy-evaluation (accessed May 2024).

Malo, S., McNamara, J., Volkmer, N., and Ehsan A., 2019, Eagle Ford – introducing the big bad wolf: Paper presented at the Society of Petroleum Engineers/American Association of Petroleum Geologists/Society of Exploration Geophysicists Unconventional Resources Technology Conference, Denver, Colorado, July 2019. doi: https://doi-org.ezproxy.library.und.edu/10.15530/urtec-2019-624.

Peck, W., Azzolina, N., Barajas-Olalde, C., Burton-Kelly, M., Kalenze, N., Feole, I., Glazewski, K., Ayash, S., Hurley, J., Jensen, M., Gorecki, C., Harju, J. Bangsund, D., and Cook, B., 2019, Subtask 1.4 – Techno-economic assessment of regional carbon utilization scenarios and attendant monitoring technology.

Sorensen, J.A., Pekot, L.J., Jin, L., Jiang, T., Hawthorne, S.B., Bosshart, N.W., Burton-Kelly, M.E., Kurz, B.A., Gorecki, C.D., Harju, J.A., and Steadman, E.N., 2020, Enhanced oil recovery in the Bakken – key observations and lessons learned from laboratory studies, modeling and field testing: 2020-EERC-06-16, June.

TORIS Database, 1984, U.S. Department of Energy – National Energy Technology Laboratory.

Weyburn, 2024, Weyburn regional economic development: from https://weyburneconomicdevelopment.com/invest/current-sectors/oil-gas/ (accessed March 2024).

Whittaker, S., 2015, CO_2 EOR and carbon storage with case examples from Weyburn Field: from www.ccop.or.th/ccsm/data/23/docs/ccop_whittaker_eor_june%203_final.pdf (accessed March 2024).

Yu, W., Lashgari, H., and Sepehrnoori, K., 2014, Simulation study of CO_2 huff-n-puff process in Bakken tight oil reservoirs: Paper presented at the Society of Petroleum Engineers Western North American and Rocky Mountain Joint Meeting, Denver, Colorado, April 2014. doi: https://doi.org/10.2118/169575-MS.