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CO_2 EOR Potential in North Dakota

Challenges, policy solutions, and contribution to economy and environment

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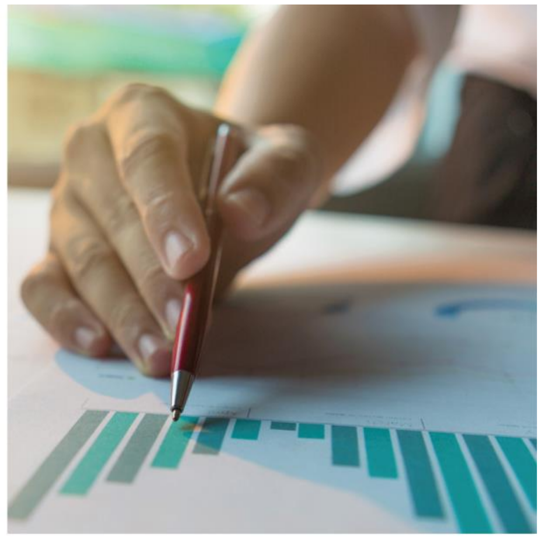

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Contents

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Executive summary

The carbon dioxide (CO_2) enhanced oil recovery (EOR) technologies have the potential to bring 1.2–1.8 billion bbl of incremental production to North Dakota over the next 20 years. However, there is a wide range of uncertainty associated with the EOR technologies for unconventional plays. We will not know the true potential of the EOR technologies in the Bakken until the development of the technology moves from the early stages of proof of concept to commercial deployment in the field. Major technology developments usually require significant level of collaboration between the government, industry, and research organizations, and policy support to enable technological breakthrough. Currently there is a wide gap between technical and economic recovery of CO_2 EOR in the Bakken. Only 22% to 27% of the estimated technical recovery potential could be economically recovered during the 2017–36 time frame. Realization of this potential will depend on a number of factors:

- The ability of the industry to narrow down the range of uncertainty currently associated with CO_2 EOR technologies for shale plays and tight oil formations within a relatively short period of time, and move from the laboratory and single well testing to multiwell pilots and ultimately to commercial deployment in the field.

- Breakthrough in carbon capture technologies that will bridge the gap between the cost of capture and the price EOR operators are willing to pay for CO_2, which is largely contingent on the success of the US Department of Energy (DOE) research and development and demonstration program, reaching critical mass and efficiency in moving projects developed under the Clean Coal Research Program (CCRP) from laboratory/bench to commercial large-scale demonstration.

- Access to economical and abundant supplies of CO_2, as the development of the CO_2 supply sources within the state will depend largely on statewide policies that will be adopted to comply with Clean Power Plan or other federal policy that may take its place.

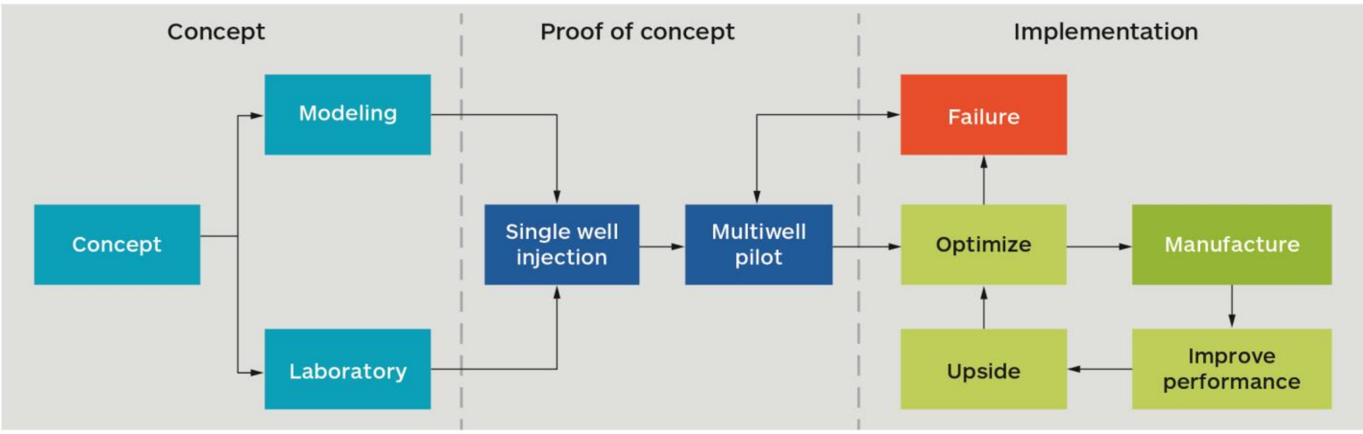
- Development of fiscal incentives that encourage the utilization of CO_2 for EOR while acknowledging the benefits to the economy and the environment.

Narrowing down the range of uncertainty

The technology for CO_2 EOR in tight oil plays is still in the early stages of development. Every technology usually goes through three main stages—from concept, to proof of concept, and then to commercial deployment. At present the technologies associated with EOR in the Bakken are in the early phase of the "proof of concept" stage. Similar to the primary recovery for tight oil resources, proof of concept requires more than single well pilots (see Figure E.1). This process has been well established for primary production in the Bakken.

Figure E.1

Unconventional EOR road map



Source: IHS

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A considerable amount of modelling and laboratory work related to the Bakken EOR has been performed, which has been encouraging thus far. However, such results need to be viewed with cautious optimism for the following reasons:

- Modeling programs have been developed primarily for conventional reservoirs, and may not adequately address the additional complexities of a "tight oil" reservoir.

- Models, by their very nature, rely on a relatively simple set of input variables and assumptions; thus generally failing to capture the multiple phases, complexities, and heterogeneities of a "real world" reservoir situation. CO_2 EOR modeling in "tight oil" reservoirs such as the Bakken requires additional "hard to measure and obtain" variables to adequately address the complexities of the reservoir.

- The results of various modeling exercises viewed for this study were highly variable.

Several injection tests were conducted in the Bakken between 2008 and 2014, but did not produce the same robust results as some of the modeling exercises and laboratory work. While the industry has gained some insight from field tests, injection test results are variable and the sampling is extremely small. Multiwell pilot programs may be able to give us additional insights. There have been no multiwell pilot tests in the Bakken to date. A multiwell pilot program conducted in the Eagle Ford "tight oil" play in Texas using cyclic gas injection gives us more insight and reason to be cautiously optimistic about the potential application of EOR technologies in "tight oil" plays. However, each play has its own characteristics, and a proof of concept and commercial deployment of the EOR technologies in the Bakken will help narrow the range of uncertainty.

Bridging the gap between CO_2 cost and price

CO_2 EOR has been successfully used in the United States for around 40 years. The injection of CO_2 into aging oil fields to produce residual oil has helped extend the producing life of some fields by more than 25 years. The key enabler of this success has been the availability of large volumes of low-cost, naturally occurring CO_2 that provides regular supply for EOR projects. Many more potential EOR projects could be implemented if they had access to supplies of CO_2. Access to economical and abundant supplies of CO_2 is the primary driver of successful EOR in projects with optimal development conditions. The success of CO_2 EOR in the United States can be attributed to the following unique conditions:

- **Affordable CO_2:** There is ample supply of low-cost CO_2 from naturally occurring deposits and, to a lesser extent, natural gas–processing facilities.

- **Oil price indexation:** Many EOR projects benefit from variable purchase agreements that adjust for oil prices to maintain the affordability of CO_2 at lower oil prices.

- **Proximity to source:** Existing EOR projects tend to be located within a reasonable distance of CO_2 sources, minimizing transport costs for CO_2 providers.

- **Vertical integration:** A handful of operators control the entire supply chain, from CO_2 source to pipeline transport and EOR operations, giving them the flexibility to use CO_2 that is already linked by pipeline to oilfields.

Unlike the carbon sequestration process, in which the primary goal is to reduce CO_2 emissions from industrial facilities, the development of natural CO_2 fields occurs for the sole purpose of supplying CO_2 to EOR projects. These projects have had the advantages of lower prices and more flexible contract structure since long-term contract prices have historically been a function of the oil price. In 2014, the contracted CO_2 price for EOR projects associated with natural CO_2 fields in certain regions ranged from $17 to $27/metric ton for crude oil prices ranging between $30 and $70/bbl. That is significantly lower than the 2012 estimate by the US Energy Information Administration (EIA) of the CO_2 capture and transportation cost of $115/ton for power plants, resulting in an effective gap of over $80/ton of CO_2. CO_2 captured from power plants is the highest cost supply alternative for EOR projects. The price for other sources of supply ranges between $37/ton in the case of natural gas processing plants to $83/ton for cement plants.

Given the highly localized nature and limited sources of natural CO_2 fields, the growth of CO_2 supply for EOR in the United States is expected to come from industrial sources. If the Bakken is to realize its full EOR potential, the CO_2 EOR projects in North Dakota will have to rely primarily on anthropogenic sources of CO_2 supply.

Deployment of large scale commercial CO_2 EOR projects could create an opportunity for North Dakota to lower carbon emissions and at the same time offset some of the costs associated with carbon capture and sequestration. Power plants in North Dakota emit 30 MMt of CO_2 equivalent (CO_2e) per year, about 83% of total greenhouse gas (GHG) emissions from industrial sources in the state. Coal generation accounts for 74% of electricity generation in the state. Carbon capture and storage (CCS) for EOR enables fossil fuels, such as coal and natural gas, to remain part of the energy mix in the state by limiting the emissions from their use. In order to capture one third of the annual CO_2 emissions from power plants in the state, investments of $7.5 billion may be required for CCS technology. The extent to which power plants will deploy CCS technology for EOR will depend on the commercial viability of these technologies and targeted state and federal government policies enabling CCS and carbon capture utilization and storage (CCUS) from power plants. Recent setbacks faced by several CCS/CCUS projects in the United States reflected poor economics and insufficient policy support.

The development of CO_2 EOR in the Bakken will require about 35 MMt of CO_2 per year by 2035. That would require a combination of sources of supply within the state and from states nearby. North Dakota has the potential to supply about one-third of the CO_2 supply, provided technological advances narrow the gap between the cost of CO_2 capture and transportation and the CO_2 price EOR projects are willing to pay. The gap may need to be reduced to below $10/ton for such projects to move ahead. Federal and state policies related to CCS and EOR will play a significant role in bridging that gap.

Federal and state policies promoting CCS and EOR

While CO_2 has been successfully used for EOR in the United States, typically increasing recoveries 5–18% in conventional reservoirs, the expansion of CO_2 for EOR to include anthropogenic sources of supply is heavily dependent on carbon policies designed to affect the capture and utilization of CO_2 for EOR. The federal government has supported CCS and CO_2 EOR activity by funding research and development (R&D) of new processes and technologies.[1] The purpose of the R&D funding is to facilitate the development of more effective tools and methods to enhance the efficiencies of CCS and CO_2 EOR processes, reduce the negative environmental impact of fossil fuel-related activities, and increase the overall supply of energy resources in the United States.

The federal government has also provided assistance to CCS projects across the United States through the American Recovery and Reinvestment Act (ARRA) and DOE's coal program activities within the Office of Fossil Energy.[2] The overall goal of the DOE is to develop technologies that would allow for commercial-scale demonstration in both new and retrofitted power plants and industrial facilities by 2020. The program, however, has not reached the critical mass necessary for commercialization of CCS technologies. A lot more CCS and CCUS projects may be needed for commercialization of the technology.

Other programs sponsored by the federal government include loan guarantees, federal tax credits, and EOR tax credit. In fiscal years 2007 and 2008, Congress authorized $8 billion for loan guarantees through appropriations; however, no CCS projects have received any loan guarantees. There is no public information related to the interest the solicitations garnered from the industry, therefore it is hard to pinpoint the reasons why no loan guarantees have been made by the DOE for CCS.

As far as federal income tax credits are concerned not every project is able to benefit from credits associated with CCS or EOR. They are either tied to oil prices (Section 43 of the Internal Revenue Code) and do not apply once a certain price threshold is reached, or expire after a certain volumetric cap of stored CO_2 is reached (Section 45Q of the Internal Revenue Code), or are issued to a limited number of projects on a competitive bidding process (Sections 48A and 48B of the Internal Revenue Code). Credits under Sections 48A and B have been cancelled for projects that have failed to be placed in service within five years. For CCS and EOR projects to get off the ground, they need the certainty that such credits are going to be available for them in the future. None of the current systems offers such certainty.

At the state level, North Dakota offers various incentives including:

- Offering grants, loans, or other forms of financial assistance to support the development of CO_2 pipelines for EOR operations

- Offering temporary exemption from extraction tax for tertiary recovery projects (five years in the Bakken and 10 years for non-Bakken EOR)

- Property tax exemption for tangible property used to construct or expand a system used to compress, gather, collect, store, transport, or inject CO_2 for use in enhanced oil recovery or CO_2 capture system installed at a coal conversion facility in the state

- Exempting the sale of CO_2 to be used for enhanced oil recovery from sales tax

While there is no lack of incentives at the state level, no EOR projects have occurred in the state to date. Most conventional production units that are candidates for CO_2 EOR face significant cost challenges associated with the amount of new wells needed to be drilled for EOR. For most of them there is no amount of incentives that can enable

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[1] USASpending.gov; The Catalog of Federal Domestic Assistance (CFDA).
[2] Peter Folger, "Carbon Capture and Sequestration: Research and Development, and Demonstration at the U.S. Department of Energy," Congressional Research Service, 10 February 2014.

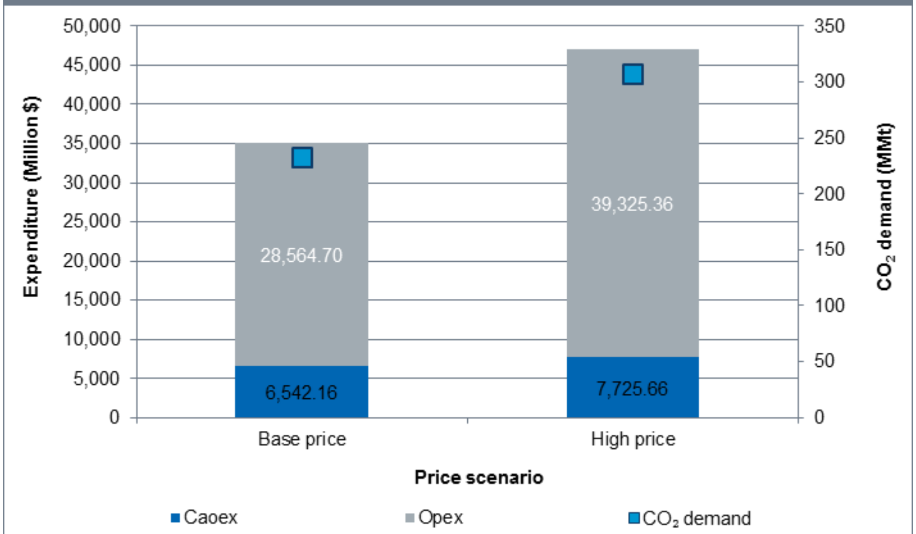
economic recovery of incremental production—the costs are prohibitively high. The Bakken, however, can benefit significantly from tax incentives either at the federal or state level.

The Bakken CO_2 EOR economic impact and policy solutions

Economic recovery of incremental production associated with CO_2 injection in the Bakken is expected to yield 254 million bbl to 473 million bbl of oil during 2017–36. The full scale development of CO_2 EOR projects in the Bakken is expected to start in 2023 with significant impact continuing beyond the 20-year time frame for this study. Direct revenues to the state via production and extraction taxes, income tax, and royalties on state land are expected in the order of 4.7 to 7.4 billion. CO_2 EOR activities in the play have the potential to result in injection of 233 MMt to 307 MMt of CO_2 during the study period. Depending on the government's and industry's commitment to curb carbon emission, 56% of the CO_2 supply could be met by anthropogenic sources of CO_2 captured in North Dakota. The capital investment is expected to be in the order of \$6.5 billion to \$7.7 billion for EOR projects in the Bakken. The highest expenditure and perhaps the biggest challenge will be operating costs. Such costs are expected to be in the order of \$28.5 billion to \$39.3 billion during the study period (see Figure E.2). Costs associated with the purchase of CO_2 are expected to make up 30% of the operating expenditure.

Figure E.2

Bakken EOR Case 1—Expenditure and CO_2 demand



Source: IHS

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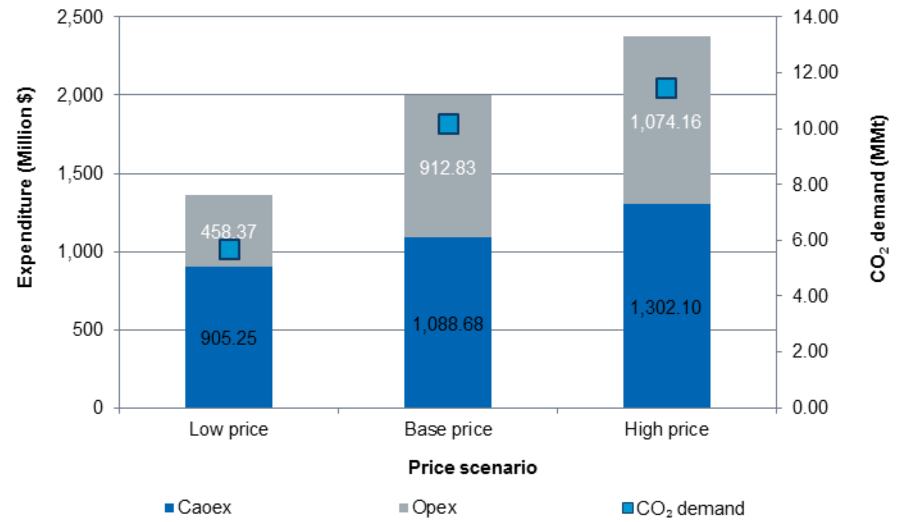
The impact of CO_2 EOR for conventional projects is expected to be much smaller by comparison—about 7% of the incremental production potential of the Bakken in the same period (18 MMbbl to 35 MMbbl)—with projected direct revenues to the state ranging between \$139 million and \$439 million. The incremental production is expected to add about 7,500 b/d by 2026. The CO_2 demand for conventional EOR is expected to be between 5.7 and 11.5 MMt during the 20-year time frame. Total spend by the industry on capital and operating costs combined is expected to range between \$1.3 billion and \$2.3 billion (see Figure E.3).

Figure E.3

Conventional EOR—Expenditure and CO_2 demand



Source: IHS

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The EOR activities in the Bakken and conventional oil fields in North Dakota are expected to have a significant impact on the state and the nation in terms of employment, labour income, value added, and direct revenues to the state and the federal government. On average, about 50% of the overall economic contribution benefits the state of North Dakota, with the remaining 50% leaking to other states and the federal government in tax revenues.

The combined EOR activities in the Bakken and conventional fields have the potential to contribute on average about 6,000 jobs annually at the state level and 4,300 jobs nationally during 2022–36. By 2036, the CO_2 EOR activities in the Bakken are expected to add over 10,000 jobs in the state (see Table E.1). Employment is not the only impact of the EOR activities in the Bakken. The state is going to experience a steady increase in labour income. The Bakken EOR activity will contribute on average $470 million per year, starting at $47 million in 2023 and contributing $917 million in 2036. Under the high oil price scenario, the contribution is even greater: $590 million on average and reaching almost one billion ($988 million) by 2036 within the state (see Table E.2). The total value-added to the state economy is on average $918 million per year. By the end of the study period in 2036, the yearly additions to the economy will reach 1.8 billion at the state level and 1.7 billion at the national level, making for a combined $3.5 billion in total.

Table E.1

Economic impact of CO_2 EOR in the Bakken case 1—Base price case

	2017–22	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Employment (number of workers)															
North Dakota	-	762	1,699	1,610	3,431	4,116	4,366	5,344	6,284	7,191	8,078	8,927	9,624	10,080	10,372
Other states	-	1,095	2,165	1,515	3,627	3,762	3,164	3,710	4,234	4,739	5,233	5,706	6,093	6,344	6,502
Labor income (million $)															
North Dakota	-	47	109	109	235	292	324	406	488	571	656	741	816	872	917
Other states	-	94	188	130	322	336	280	333	386	440	494	549	597	634	663
Gross value added (million $)															
North Dakota	-	76	185	203	423	545	629	793	959	1,125	1,294	1,464	1,614	1,728	1,816
Other states	-	129	280	241	547	636	640	790	940	1,092	1,246	1,401	1,538	1,642	1,723
Output (million $)															
North Dakota	-	130	310	330	695	885	1,007	1,268	1,530	1,794	2,063	2,332	2,570	2,751	2,891
Other states	-	420	852	620	1,503	1,607	1,405	1,687	1,971	2,257	2,548	2,840	3,099	3,295	3,449

Source: IHS

Table E.2

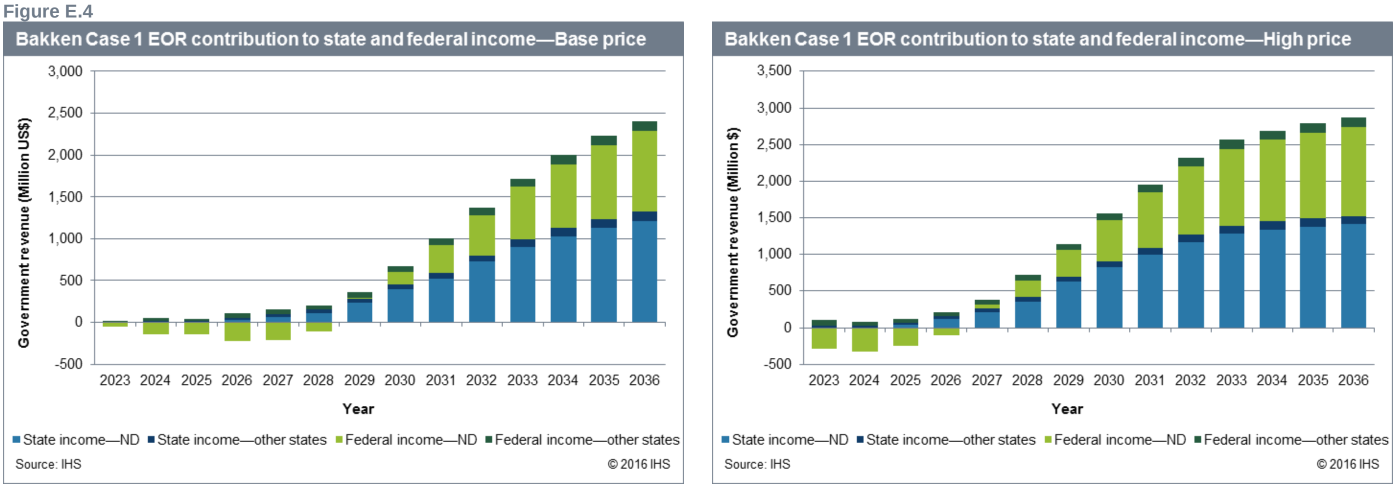
Economic impact of CO_2 EOR in the Bakken case 1—High price case

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Employment (number of workers)															
North Dakota	816	3,904	3,408	3,729	4,835	5,874	6,877	7,859	8,819	9,757	10,652	11,343	11,535	11,360	11,174
Other states	1,173	5,316	3,497	2,870	3,486	4,066	4,625	5,172	5,708	6,230	6,728	7,112	7,213	7,106	6,994
Labor income (million $)															
North Dakota	49	242	225	259	344	428	513	599	687	777	867	943	979	984	988
Other states	98	454	297	241	296	350	405	460	517	575	633	682	705	709	713
Gross value added (million $)															
North Dakota	80	402	408	498	669	837	1,007	1,180	1,357	1,536	1,716	1,868	1,940	1,950	1,958
Other states	136	647	515	523	679	833	987	1,145	1,306	1,469	1,633	1,771	1,837	1,847	1,855
Output (million $)															
North Dakota	136	681	669	800	1,071	1,339	1,608	1,882	2,162	2,447	2,731	2,973	3,087	3,103	3,115
Other states	440	2,043	1,394	1,192	1,486	1,776	2,067	2,365	2,668	2,976	3,285	3,546	3,672	3,693	3,710

Source: IHS

The Bakken EOR has the potential to contribute between $11.4 billion to $18.6 billion to the states and the federal government under the IHS base and high price assumptions. The direct revenues to the state of North Dakota are expected to range between $6.3 billion and $9.7 billion during the study period. In 2036 alone the contribution to state and federal government revenue reaches $2.4 billion to $2.8 billion.

Figure E.4



While the impact on the economy of the CO_2 EOR in the Bakken is undeniably significant, this activity is constrained not only by the uncertainty surrounding the technology but also by the current fiscal system that pushes the breakeven prices above $100/bbl, thus delaying the onset of EOR activities in the Bakken. IHS considered various policy alternatives that would not only improve recovery, but would also bring forward the timeline for the development of CO_2 EOR in the Bakken. Most policy solutions had only a moderate impact on breakeven prices. Two alternative policies that specifically targeted the use of CO_2 for EOR were found to mitigate, to some extent, the cost associated with these activities.

The most impactful policy alternative, by far, is an alternative to the current federal income tax credit for use of CO_2 for EOR that is set to expire once a statutory cap of 75 MMt of captured and sequestered CO_2 is reached. This alternative is based on the assumption that Congress could perhaps take action to make the credit permanent and increase the current $10/ton credit to $20/ton over a 10-year period.[3] This alternative will bring forward the timeline for development of EOR projects in the Bakken from 2023 to 2019, resulting in 77% increase of incremental production and revenues to the state of North Dakota compared with current fiscal system. The impact of increased incremental production on the economy of the state under this alternative policy is 30% higher with respect to jobs, employment income, and gross value added versus current terms. While this policy solution is the most attractive option, it is not clear whether there will be enough support for such a solution both in the House of Representatives and the Senate of the United States.

An alternative policy solution at the state level assumes an allowance for operating costs associated with CO_2 for EOR against extraction tax, while eliminating the current five-year holiday for tertiary recovery in the Bakken. Overall this policy solution has the potential to enable an increase in the recovery of incremental production in the Bakken from 353 million to 473 million bbl during the study period. The direct government revenue under this policy declines 8% compared with the status quo and is outweighed by the overall benefits to the economy of the state. The economic contribution to the state via employment, labour income, and value added is 20% higher than under the current fiscal system.

Policies similar to the ones analyzed in this study have the potential not only to incentivize incremental production of oil from the Bakken but also to contribute toward narrowing the gap between the CO_2 price and the cost of CCS from anthropogenic sources of supply. The projected amounts of CO_2 to be captured and ultimately stored during the EOR process will help the state of North Dakota make significant progress toward curbing carbon emissions and ensuring that fossil fuels continue to be part of its energy mix in the future.

[3] The federal income tax credit alternative is based on a proposed amendment of section 45Q. The proposed bill in the House of Representatives intends to increase the credit from $10/ton to $30/ton over 10 years. That proposal could have a greater impact on the potential EOR activities in the Bakken if it were to become law.

CHAPTER ONE

1.Introduction

This study was commissioned by the North Dakota Legislative Management to study the technical aspects of the use of CO_2 for EOR in North Dakota and the likely impact of such developments over a 20-year time frame on the oil industry, economy, and environment in the state. The objective of the study is to provide a clear picture of the current and future landscape of the oil and gas industry and economic climate in North Dakota with an emphasis on carbon capture technologies and EOR to allow for comprehensive legislative evaluation of existing, alternative, and potential future tax incentives that would best serve the interests of the state, political subdivisions, the environment, and the energy industry.

The research conducted under this study:

- Offers insights on the current regulatory landscape governing development of carbon capture technologies and CO_2 EOR projects at the federal and state level, and the impact—if any—they have had in promoting these activities

- Examines the current market and sources of CO_2 supply in the United States in general and specifically in North Dakota, and develops a potential supply outlook and an assessment of investments needed for capture of CO_2 from anthropogenic sources of supply within the state

- Conducts an analysis of the potential deployment of CO_2 EOR technologies in the Bakken and conventional fields, and provides an assessment of the technically recoverable resources in the next 20 years through application of these technologies

- Provides an economic analysis of the CO_2 EOR projects in the Bakken/Three Forks play and conventional fields under projected price and cost outlooks through 2036, as well as the potential impact such projects could have on the environment owing to incidental and ultimate storage of CO_2

- Provides direct, indirect, and induced economic impact analysis on jobs, labor income, value-added, and revenues accruing to the state under various price outlooks and policy solutions

This research will inform on policy solutions and lay the foundation for comprehensive legislative evaluation of tax policy alternatives by the legislature of North Dakota.

1.1 Economic modeling approach

In performing the economic analysis for this study and generating results for the economic impact of various development scenarios under distinct market conditions and fiscal policy alternatives, IHS relied on two proprietary economic models: the upstream economics model and the economic impact analysis model. The outputs of the upstream economics model such as upstream spending and revenues generated via royalties, extraction and production taxes, and state and federal income taxes—generated by county—serve as inputs to the economic impact model that analyses the direct, indirect, and induced impact of the CO_2 EOR activities in North Dakota over the study period.

1.1.1 Upstream economics model

The basic inputs to the upstream economics model fall largely into four categories. The model relies on the field development input generated by the analysis of applicable technologies and the study of CO_2 EOR potential of the Bakken and conventional fields in North Dakota; the capital and operating costs generated through proprietary IHS models and databases as well as specific research performed for this project; the price and cost outlook based on IHS global and regional scenarios; and the fiscal model that incorporates the fiscal terms that currently apply to CO_2 EOR upstream projects in North Dakota and incorporation of alternative solutions for the fiscal policy analysis.

1.1.1.1 Field development

The study of the CO_2 EOR potential for North Dakota followed two different approaches regarding the evaluation of technically recoverable resources under CO_2 EOR for conventional and unconventional fields in North Dakota. This is largely due to two factors: the degree of knowledge and uncertainty surrounding the CO_2 EOR developments for conventional and unconventional resources is not the same—there has been no commercial scale CO_2 EOR project to date; and unconventional projects will most likely require the application of unconventional EOR technologies—unlike conventional projects, they will most likely not undergo waterflooding. Thus, the assessment of the potential for CO_2 EOR incremental recovery, which is supported by a 40-year oil industry record in the United States, as well as international experience, is based on widely accepted project screening criteria and more predictable modeling approaches. IHS relied on the numerical modeling approach to estimate incremental oil recovery rates for the 19 conventional production units that passed the screening criteria developed for this study.

The approach developed to estimate incremental recovery rates for the Bakken/Three Forks play in North Dakota is based on the current level of knowledge and understanding by the industry and takes into account the wide range of uncertainty surrounding the viability of CO_2 EOR projects in tight oil and shale formations. Hence, the estimate of incremental oil recovery rates was based on knowledge gained to date from laboratory work and single well tests in the Bakken as well as certain assumptions related to areal extent and sweet spots, well completion design and spacing, and producing zones based on our knowledge of the primary production in the Bakken. To account for the degree of uncertainty, two potential scenarios were developed with different drilling configurations and well spacing.

A detailed description of the approach and methodology used for the estimate of incremental recovery rates for conventional fields and the Bakken is provided in Chapter 4 of this study. The drilling and production profiles and CO_2 injection volumes generated by the conventional reservoir modeling and the Bakken development scenarios served as inputs for the upstream economic model. Also, reservoir data related to depth and pressure were used as inputs for well cost estimation.

IHS relied on data from the North Dakota Industrial Commission (NDIC) and IHS proprietary databases. The IHS US proprietary exploration and production databases were used to provide field information related to cumulative production, recoverable reserves, geological formation, reservoir and water depth, well flow rates, pressure, oil/gas ratio, distance from existing facilities and infrastructure, and other inputs. The following data sets were used:

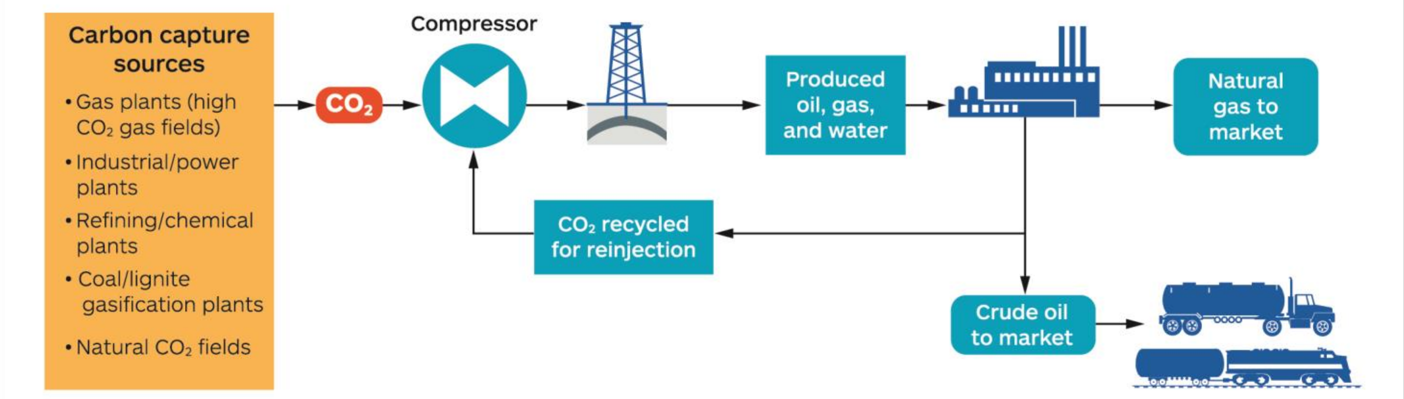
- IHS Well database provides comprehensive information on more than 4 million current and historical well records in the United States, accounting for virtually every well drilled and produced back to 1859. It goes far beyond state regulatory data through collection of information from operators and drilling contractors.
- IHS Oil & Gas Production database in its many forms contains production data that we receive from various sources. The production database includes 30 million well test records with initial potential and production capacity tests.
- The Bakken Community Database includes:
    - Well data:
        - Daily production data and flowing pressures
        - Petrophysical and fluid properties
        - Wellbore and completion details
    - Individual well analysis—interpretations gathered and analyzed using a common workflow and platform (IHS Harmony)
    - Specialized reservoir engineering studies including multilayer analysis, well spacing, drawdown management, inter-well communication using bottom-hole pressures

1.1.1.2 Cost modeling

This study encompasses upstream field development and operating cost models to illustrate the typical flow of CO_2 EOR projects (see Figure 1.1). IHS assessed the current status of wells in each conventional project area to determine the number of reusable wells that would only receive a workover and the number of new, infill wells to drill. Some conventional reservoir projects will require drilling many new infill wells while other projects may require mostly workovers of existing wells. IHS considers any production or injection well that is currently active or temporarily abandoned to be reusable. The unit cost of the project improves when the ratio of new wells versus workovers skews toward more workovers. In the case of the Bakken CO_2 EOR, the use of well workover versus new injection wells depends on the drilling configuration and well spacing development scenarios (see Chapter 4).

Figure 1.1

CO_2 EOR development schematic



Source: IHS © 2016 IHS: 1677874

Determining the costs to develop and operate an incremental EOR project using CO_2 flooding also requires considering the development area location relative to the CO_2 resources, oil offtake points, and oil transportation routes. A project that is farther away from key access points or production that is farther away from the destination market will result in higher development costs. IHS utilized a geographical information system software to measure the distances from the center of the conventional production units to the nearest CO_2 source and the nearest accessible pipeline or rail terminal. The offtake locations determine the final destination for the oil, which was assumed to be the LHS Gulf Coast, WTI Cushing, ANS West Coast, or East Coast Brent. Based on marketing arrangements of each producing unit and operator in the Bakken, IHS determined the offtake location for each CO_2 EOR project modeled for this study.

Detailed cost models were developed for the cost of facilities, particularly compression costs, separation of produced CO_2 for re-injection in the reservoir, the cost of purchasing and transporting CO_2, gathering systems, well maintenance, energy costs, and general administrative costs. IHS modeled the cost of transporting CO_2 to the project site by determining the distance from the field to the nearest CO_2 source, considering the sources that are expected to be available under the various CO_2 supply scenarios developed for this study.

Pipeline costs were determined using a rate of $93,250 per inch-mile based on researched pipeline costs for recently constructed or proposed CO_2 pipeline systems throughout the United States and adjusted to reflect current costs.[4]

[4] US DOE, Office of Fossil Energy, "A Review of the CO2 Pipeline Infrastructure in the U.S.," *21* April 2015*;* 2015 Denbury and Kinder Morgan Financial and Investor Materials; Riding, J B., Rochelle, C A., "The IEA Weyburn CO2 Monitoring and Storage Project: Final report of the European research team," British Geological Survey, RR/05/03, 2005. All costs not reported in 2015–16 have been adjusted to 2016 values using the IHS Capital Cost Index.

1.1.1.3 Price and cost outlook

Our price and cost outlooks for this study are based on IHS scenarios, which are based on the underlying behavior of consumers, governments, businesses, and nongovernmental organizations (see Table 1.1).

Table 1.1

Key scenario characteristics

Scenario	Core behavior(s)	Impacts
Rivalry	Heightened competition	• Historically dominant sources of energy in North America face increasingly greater competition from other energy sources, i.e., their "rivals". • This results in growing role of natural gas as a power fuel, rapid growth in renewable energy, the evolution of energy technology and environmental regulations, and the decline of the US coal industry
Autonomy	The "millennial shift" and the focus on regional activism	• Desire to reduce urban externalities and increase regional control of energy motivates technology advancements in transportation, energy storage, and renewable energy. • At the same time the derive for more local energy control drives a reduction in "aboveground" restrictions to the wider spread of unconventional oil and gas production outside the United States. • Global Climate Accord of 2030.
Vertigo	Risk aversion	• Consumers are increasingly anxious about job security (both job losses and reduced earning potential owing to automation). • Businesses are increasingly reluctant to make capital investments until they see demand and prices increase. • Governments and central banks find traditional fiscal and monetary tools have limited ability to manage the economy. • The result is exacerbated fiscal cyclicality with asset and commodity price bubbles, lower growth, and higher inflation.

Source: IHS

Rivalry is used as our base price scenario in this study. It reflects WTI reaching \$100/bbl in nominal terms in 2023, and remaining above \$100/bbl for the forecast period to 2036. Over the study period, the WTI averages \$111/bbl under Rivalry. In Autonomy, which reflects our high-price scenario in this study, the WTI averages \$125/bbl in nominal terms over the study period. Under Vertigo, the WTI averages \$74/bbl. We have not applied this price scenario to the Bakken EOR outlook since EOR projects in the Bakken would require a higher crude oil price than the one reflected in Vertigo to break even at 10% rate of return. Costs were likewise adjusted based on IHS Upstream Capital Costs Index for each of the above scenarios (see Table 1.2).

Table 1.2

Commercial scenarios

Scenario	Costs variance	Crude oil price variance	CO_2 purchase price (\$/ton)
Low price	-3%	-33%	30.06
Base price	0%	0%	31.20
High price	+6%	+13%	32.95

Notes: The base case for costs reflects 2016 costs. The variance for the low and high case is based on IHS UCCI outlook for each scenario.

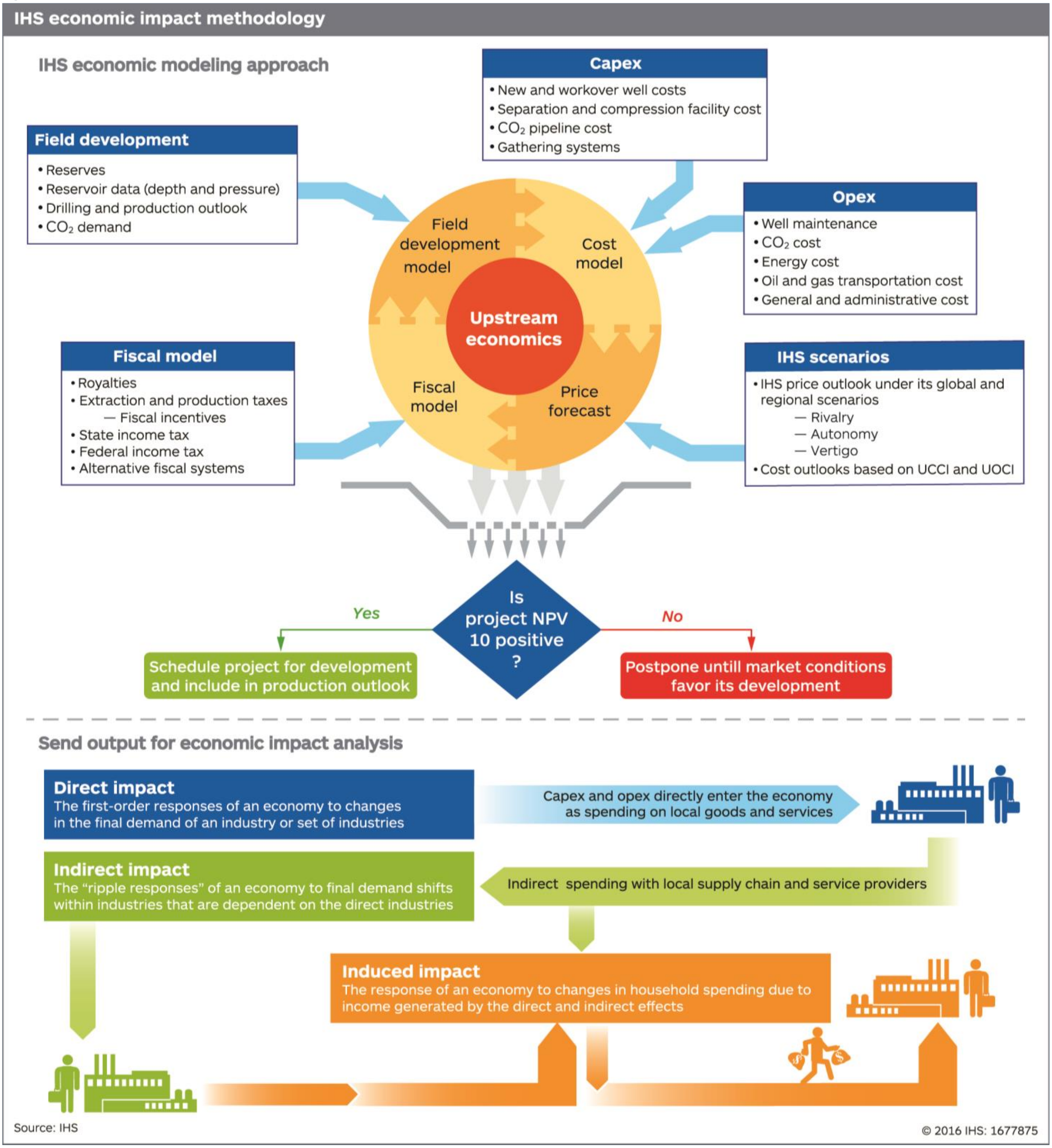
Source: IHS

1.1.1.4 Fiscal model

IHS modeled the currently applicable fiscal terms for North Dakota CO_2 EOR projects accounting for all applicable levies such as royalties payable to the owner of mineral rights, state and federal income taxes, extraction and production taxes, taking into account all applicable allowances and incentives at the state and federal level. Alternative fiscal models were built to consider project economics under potential policy solutions.

The economic analysis conducted for CO_2 EOR projects considered the viability of these projects identified in the technical analysis under various market prices and fiscal policies. Based on the assumption that projects would need to achieve a positive net present value (NPV) at a discount of 10%, projects were scheduled to commence when market conditions were such that they would meet the threshold. Projects that failed to meet the NPV 10 threshold were excluded from the economic impact analysis (see Figure 1.2).

Figure 1.2


IHS economic impact methodology
IHS economic modeling approach
Capex
• New and workover well costs
• Separation and compression facility cost
• CO2 pipeline cost
• Gathering systems
Field development
• Reserves
• Reservoir data (depth and pressure)
• Drilling and production outlook
• CO2 demand
Opex
• Well maintenance
• CO2 cost
• Energy cost
• Oil and gas transportation cost
• General and administrative cost
Field development model
Cost model
Upstream economics
Fiscal model
Price forecast
Fiscal model
• Royalties
• Extraction and production taxes
— Fiscal incentives
• State income tax
• Federal income tax
• Alternative fiscal systems
IHS scenarios
• IHS price outlook under its global and regional scenarios
— Rivalry
— Autonomy
— Vertigo
• Cost outlooks based on UCCI and UOCI
Is project NPV 10 positive ?
Yes
No
Schedule project for development and include in production outlook
Postpone untill market conditions favor its development
Send output for economic impact analysis
Direct impact
The first-order responses of an economy to changes in the final demand of an industry or set of industries
Capex and opex directly enter the economy as spending on local goods and services
Indirect impact
The "ripple responses" of an economy to final demand shifts within industries that are dependent on the direct industries
Indirect spending with local supply chain and service providers
Induced impact
The response of an economy to changes in household spending due to income generated by the direct and indirect effects
Source: IHS
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1.1.2 Economic impact model

The resulting economic activity can be measured by examining the transactions between businesses, wages paid to employees, and headcount required to realize each project's objectives. There are also economic benefits from tax transfers to the government.

Input-output analysis measured how these direct impacts flow through the economy. Input-output accounting describes commodity flows from producers to intermediates and final consumers. The total industry purchases of commodities, services, employment compensation, value added, and imports are equal to the value of the commodities produced. Indirect impacts describe the extent to which the ripple effect result from linkages to other businesses and induced impacts capture the spending that occurs by employees and owners of these businesses.

To accurately estimate the indirect economic impact of these projects, it is necessary to know the input requirements—the types, sources, and quantities of goods and services needed to develop and operate a CO_2 EOR project. The input-output tables summarize these flows between businesses to describe the economy of North Dakota and its counties. Induced impacts are estimated by applying wage and dividends generated by the firm to an average household expenditure pattern (i.e., destination and quantity of expenditure), and then by estimating the ways in which these expenditures produce further economic activity.

For this study, IHS forecast the upstream capital, operating expenditures, royalties, and direct tax payment projections from each scenario model. The forecast figures were then inputted into the economic impact analysis model.

IHS also sourced data from IMPLAN to serve as the foundation for quantifying the economic impacts of the CO_2 EOR project activity forecasts in North Dakota. The IMPLAN model closely follows the accounting conventions such as those used in the US Bureau of Economic Analysis[5] and is flexible enough to evaluate changes via the value of output or employment from the source industry. Using data from our World Industry Service, World Economic Service, and other IHS proprietary data assets, we customized and refined the modeling environment.

The model's results are reported in terms of three economic indicators—employment, value added, and government revenues—as defined below:

- Employment is the number of jobs needed to support the additional output in the economy. It includes all wage or salaried jobs and those self-employed within an economy.
- Total value added, also described as contribution to gross state product (GSP), is the difference between the production cost of products or services and the sales price (i.e., total value added is revenue less outside purchases of material and services). The frequently cited GDP or GSP figure is simply the sum of values added across all products and services produced within an economy. GDP is generally considered the broadest measure of the health of an economy.
- Government revenues are the personal and corporate tax transfers to federal, state, and local governments.

[5] Bureau of Economic Analysis, US Department of Commerce, "Input-Output Accounts Data," *www.bea.gov/industry/io_annual.htm*.

CHAPTER TWO

2.Federal and state policies

Carbon capture and storage (CCS) has been singled out by the federal government's Climate Action Plan as one of the means to reduce US GHG emissions.[6] Though associated with the need to reduce power and industrial sector GHG emissions, CCS development in the United States has been driven by the prospect of revenues from EOR. To date, the vast majority of projects sequestering CO_2 have been outside of the power sector. Upstream oil production has been the source of greatest CCS activity in the United States; 9 of the 10 large-scale CCS projects either in operation (7) or under construction (3) have an EOR component.

While CO_2 has been successfully used for EOR in the United States for about 40 years, typically increasing recoveries by 5% to 18% in conventional reservoirs, the expansion of CO_2 for EOR to include anthropogenic sources of supply is heavily dependent on carbon policies designed to affect the capture and utilization of CO_2 for EOR. Such policies fall largely into three main categories: policies that regulate CCS projects, policies that promote CCS technology, and policies that enable commercial deployment of CCS.[7] We will discuss in this section the extent to which these policies have been efficient in reducing the cost and risk gap between the projects with and without CCS in the industries in which they operate.[8]

2.1 Federal policies that promote CCS

2.1.1 Financial support at federal level

2.1.1.1 Research and development

The federal government has supported CCS and CO_2 EOR activity by providing funding for research and development (R&D) of new processes and technologies.[9] The purpose of the R&D funding is to facilitate the development of more effective tools and methods to enhance the efficiencies of CCS and CO_2 EOR processes, reduce the negative environmental impact of fossil fuel–related activities, and increase the overall supply of energy resources in the United States.

While CCS research has been funded by the DOE since 1997, in recent years the DOE has increased its focus on carbon utilization to reflect the growing importance of beneficial uses of CO_2. The utilization of CO_2 for EOR is the most significant utilization opportunity at present. The CCRP, administered by the Office of Fossil Energy, is gathering data, building the knowledge base, and developing advanced technology platforms needed to prove that CCS can be a viable strategy for reducing GHG emissions and ensuring that coal remains a viable source to power a sustainable economy.[10] The overall program consists of four subprograms: Advanced Energy Systems, Carbon Capture, Carbon Storage, and Crosscutting Research. These four subprograms are further divided into numerous technology areas (see Figure 2.1). The DOE's technology readiness assessment report for 2014 found that all four technology areas are represented within 53 active technology projects representing the laboratory/bench scale through pilot stages.[11]

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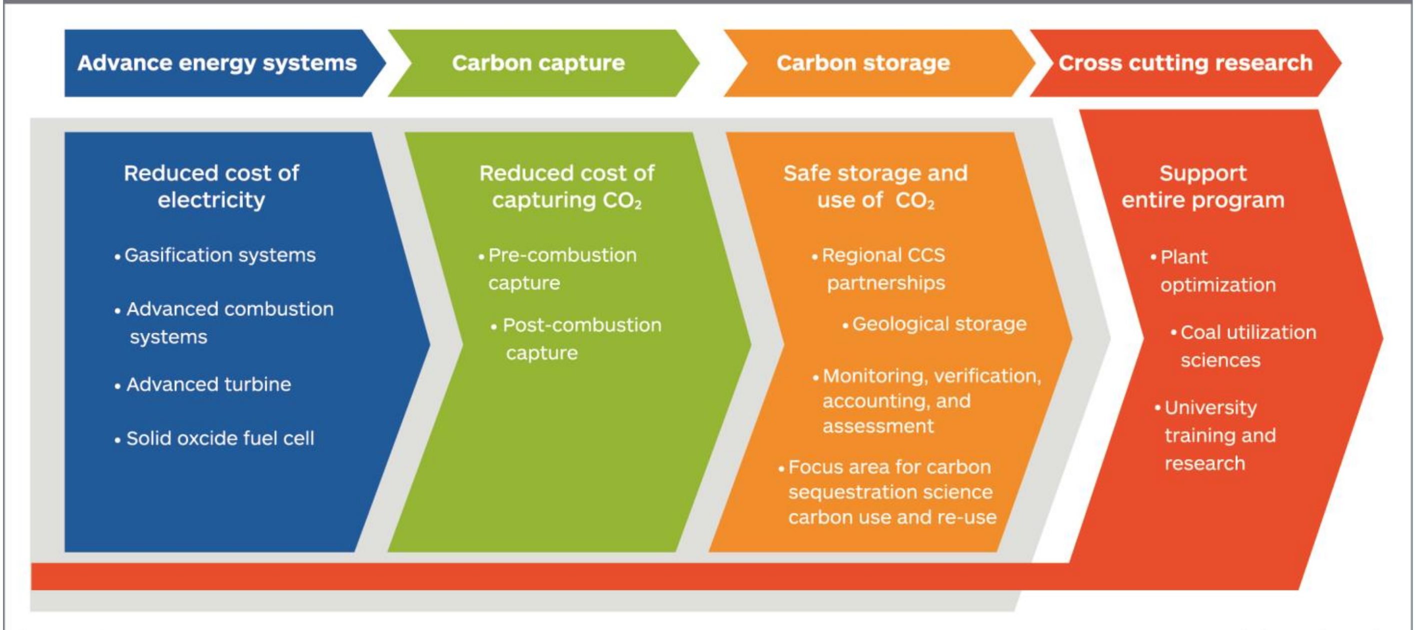
[6] The White House: Office of the Press Secretary, "Fact Sheet: President Obama to Announce Historic Carbon Pollution Standards for Power Plants," *www.whitehouse.gov/the-press-office/2015/08/03/fact-sheet-president-obama-announce-historic-carbon-pollution-standards*, retrieved 4 May 2016.
[7] Clean Air Task Force, "Existing CCS Policies," *www.fossiltransition.org/pages/existing_ccs_policies/101.php*, retrieved 30 May 2016.
[8] J. Price, *Effectiveness of Financial Incentives for Carbon Capture and Storage*, Bluewave Resources, Virginia, December 2014.
[9] USASpending.gov; Catalog of Federal Domestic Assistance (CFDA).
[10] Carbon Capture Technology Program Plan, DOE Office of Fossil Energy, January 2013
[11] 2014 Technology Readiness Assessment, Clean Coal Research Program, DOE/NETL, 2015.

Figure 2.1

CCS and power systems R&D subprograms



Source: IHS

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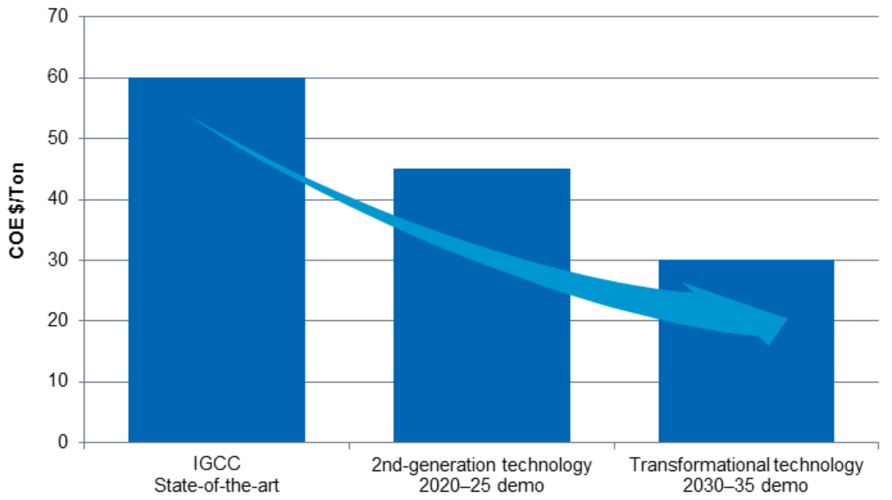
The DOE R&D program has three specific demonstration and deployment targets and cost of electricity (COE) reduction expectations (see Figure 2.2). The first relates to demonstration of state-of-the-art first-generation technologies. The COE for these technologies is expected to be about \$60/ton of CO_2. The second target is development of second-generation technologies ready for demonstration in 2020–25 with commercial deployment beginning in 2025. Costs for these technologies are expected to go down to \$40/ton for integrated gasification combined cycle (IGCC) and post-combustion for new plants. In the case of post-combustion retrofit the COE is expected to be about \$45/ton. The third target is the development and deployment of transformational technologies ready for demonstration in 2030–35, and commercial deployment beginning in 2035. The target for this phase is to bring down the COE below \$40/ton. The expectation is to achieve a COE of \$10/ton for IGCC and post-combustion for new plants, and about \$30/ton for post-combustion retrofits.[12]

[12] *Carbon Capture Technology Program Plan*, DOE Office of Fossil Energy, January 2013.

Figure 2.2

US DOE cost reduction target—Post-combustion retrofit



Source: IHS

© 2016 IHS

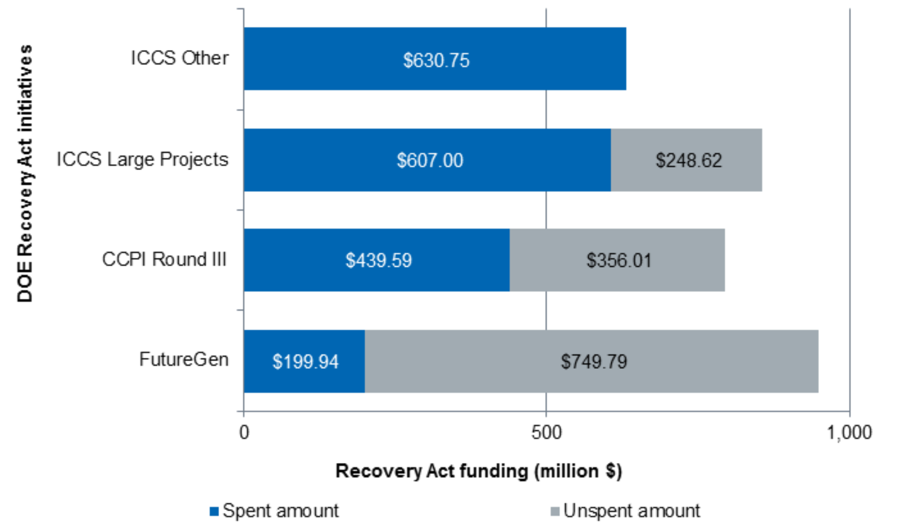
2.1.1.2 Funding of large-scale demonstration projects

Since 2009 the federal government has provided assistance to CCS projects across the United States through the American Recovery and Reinvestment Act (ARRA) that designated $3.4 billion for CCS programs through 2015. In addition to the ARRA, the DOE has appropriated approximately $2.3 billion over the same period to CCS-related activities from annual appropriations under its coal program activities within the Office of Fossil Energy.[13] Major demonstration projects received DOE funding through the Clean Coal Power Initiative (CCPI), the Industrial Carbon Capture and Storage (ICCS) programs, and the FutureGen project under the ARRA. While CCPI Round III focused on large scale demonstration of CO_2 capture from power plants, FutureGen was intended to provide funding for the full CCS spectrum—capture, transportation, and storage—in one facility.[14] The ICCS initiative on the other hand targets the demonstration of CCS technology for the nonpower plant industrial sector.

[13] Peter Folger, "Carbon Capture and Sequestration: Research and Development, and Demonstration at the U.S. Department of Energy," Congressional Research Service, 10 February 2014.
[14] Peter Folger, "Recovery Act Funding for DOE Carbon capture and Sequestration Projects," Congressional Research Service, 18 February 2016.

Figure 2.3

DOE CCS project funding under Recovery Act



Source: IHS, DOE © 2016 IHS

The overall goal of the DOE with the cash infusion by the ARRA and annual appropriations under its coal program has been to develop technologies that would allow for commercial-scale demonstration in both new and retrofitted power plants and industrial facilities by 2020. In its 2011 strategic plan, the DOE set a target to bring at least five commercial-scale CCS projects online by 2016. Under DOE's 2014 strategic plan, the timeline to bring five commercial-scale CCS projects online was pushed to 2019.[15] The coal power plant large-scale demonstration projects have proven very challenging. Out of the eight power plant projects funded by the DOE under the CCPI and FutureGen initiatives, only one project—the NRG Petra Nova Project in Texas—is currently active. The other seven have been withdrawn from the program with 63% of the funds from both programs being returned to the DOE. As of 30 September 2015—the deadline for ARRA funding—approximately 42% of the ARRA funds were unspent (see Figure 2.3). The cancelled or suspended projects faced significant challenges such as cost overruns, delays, and regulatory uncertainty.

Table 2.1

Major power plant CCS projects funded by the DOE

Project	Status	State	Capture capacity (MMt/y)	Original DOE funding[16] (million $)	Capex estimate (million $)	DOE funding share of total cost
Hydrogen Energy California	Withdrawn (2015)	CA	2.6	408	4,028	10%
AEP Mountaineer	Withdrawn (2011)	WV	1.5	334	668	50%
Southern Company Plant Barry	Withdrawn (2010)	AL	1.0	295	665	44%
Basin Electric Beulah	Withdrawn (2010)	ND	1.0	100	387	26%
Kemper County Energy Facility	Withdrawn (2015)	MI	3.0	270	6,600	4%
FutureGen 2.0	Withdrawn (2015)	IL	1.0	1,000	1,650	61%
Texas Clean Energy	Suspended (2016)	TX	1.1	450	3,980	11%
Petra Nova	Active	TX	1.4	167	1,000	17%

Note: As of end of 2015.

Source: DOE CCPI Initiative © 2016 IHS

[15] Id.

[16] Petra Nova is the only power plant CCS project that was able to spend 100% for the funding allocated by the DOE.

The DOE share of contribution toward the total costs for the eight large-scale power plant demonstration projects has varied between 10% and 60% of the original cost estimate.[17] FutureGen 2.0 was slated to receive the highest level of funding from the DOE both in terms of committed amount ($1 billion) and in terms of share of the estimated project cost (61%). This flagship project was also expected to benefit from Illinois state incentives for liability assumption and purchases of electricity.[18] While the status of projects such as the Hydrogen Energy California (HECA), Kemper County Energy Facility, and Texas Clean Energy is not clear yet, the withdrawal of federal funding makes their future viability less certain. Critics of the DOE CCS program argue that the program has not reached the critical mass necessary for commercialization of CCS technologies. A lot more CCS and CCUS demonstration and pilot projects are needed for commercialization of the technology.[19]

2.1.1.3 Loan guarantees

The federal government has made available loan guarantees to support investment in "clean coal" under Energy Policy Act of 2005. Section 1703 of the act authorized the secretary of energy to make loan guarantees for up to 80% of the total costs for projects that avoid, reduce, or sequester air pollutants or anthropogenic emissions of GHGs, and employ new or significantly improved technologies. The guaranteed loan authority for CCS under Section 1703 of the act is $8 billion, authorized by the US Congress through appropriations in fiscal years 2007 and 2008. The loan guarantee authorization is subject to the condition that the costs of guaranteed loans are provided by the borrowers.[20] The DOE has since then offered two solicitations for clean coal project loan guarantees—the first one in 2008 and the second in 2013—however, no CCS projects have received loan guarantees.[21] There is no public information related to the interest the solicitations garnered from the industry, therefore it is hard to pinpoint the reasons why no loan guarantees have been made by the DOE for CCS. By contrast, the DOE's loan guarantees have been used by renewable energy projects. Unlike the CCS loan guarantee program, the renewable energy program does not place the burden for credit subsidy costs on the borrowers. Under those programs, the Congress appropriated funds to pay for some or all of the loan guarantee credit costs. The substantial fees required to be paid for loan guarantee applications under the CCS program combined with the uncertainty of getting the loan application approved could have deterred applications by CCS developers.[22]

2.1.1.4 Federal tax credits

Throughout the value chain, CO_2 EOR projects can benefit under three different sections of the Internal Revenue Code. The extent to which such projects could benefit from the federal; tax credits vary depending on the price of crude oil for purposes of Section 43 credit, on the cap of sequestered CO_2 for purposes of Section 45Q, and whether the CO_2 is sourced from a qualifying advanced coal project for purposes of Section 48A, or gasification project for purposes of Section 48B.

2.1.1.4.1 EOR tax credit

Section 43 of the Internal Revenue Code provides a 15% credit for qualified EOR costs—qualified tangible, intangible, and tertiary injectant costs—incurred in a given tax year. This credit, which has been applied since 1991, is reduced if the reference price for the preceding calendar year is greater than $28/bbl multiplied by the inflation adjustment factor for that year. When the crude oil reference price for the preceding taxable year exceeds $28/bbl—as adjusted for inflation—by at least $6, the credit is phased out. The adjustment factor for the preceding calendar year is published no

[17] The original share of DOE funding for Kemper County Energy Facility was 12% of the project cost at the time the funding was approved. The project cost has however skyrocketed from the original $2.2 billion to an estimate of $6.6 billion as of May 2016.
[18] J. Price, note 8 supra.
[19] National Coal Council, "Fossil Forward: Revitalizing CCS Bringing Scale and Speed to CCS Deployment," p. 130, January 2015.
[20] Loan guarantee costs include the loan guarantee credit subsidy cost, which is the estimated long-term amount that a direct loan or loan guarantee will cost the federal government, calculated on a net present value basis, excluding administrative costs. See Peter Folger and Molly F. Sherlock, "Clean Coal Loan Guarantees and Tax Incentives: Issues in Brief," Congressional Research Service, 19 August 2014.
[21] Id.
[22] Id.

later than 1 April of any calendar year by the secretary of commerce.[23] The EOR tax credit had been phased out for the past 10 years (2006–15 taxable years). With the significant drop in oil prices in 2015, the EOR projects will likely be able to apply the credit towards qualifying EOR expenditure for fiscal year 2016.

Table 2.2

Inflation adjustment factors and phase-out amounts

Calendar year	Adjusted threshold price	Phase-out amount
1991	28.00	0%
1992	29.02	0%
1993	29.98	0%
1994	30.78	0%
1995	31.25	0%
1996	32.16	0%
1997	32.82	0%
1998	33.60	0%
1999	33.68	0%
2000	33.84	0%
2001	34.59	0%
2002	3537	0%
2003	35.80	0%
2004	36.27	0%
2005	37.14	0%
2006	38.48	100%
2007	39.82	100%
2008	41.06	100%
2009	42.01	100%
2010	42.57	100%
2011	42.91	100%
2012	43.92	100%
2013	44.71	100%
2014	44.73	100%
2015	45.49	100%

Source: IHS, data from Internal Revenue Bulletin 2015–40

2.1.1.4.2 CO_2 sequestration credit

As part of the Energy Improvement and Extension Act of 2008, the federal government introduced Section 45Q that provides credits for capture and sequestration of CO_2 as well as for utilization of CO_2 for EOR. Under section 45Q of the Internal Revenue Code, a \$20/metric ton credit, adjusted for inflation, may be claimed for qualifying domestic CO_2 that is captured and sequestered. CO_2 that is captured and sequestered from an industrial source, which would otherwise have been released as an industrial GHG emission, qualifies for the CO_2 sequestration credit. The credit for CO_2 utilization in EOR operations is \$10/metric ton, adjusted for inflation. Both the CO_2 sequestration and the EOR utilization credits under Section 45Q are scheduled to terminate after 75 million metric tons (MMt) of qualified CO_2 have been captured and taken into account for the purposes of the credit.

As of 1 June 2014, 27 MMt of CO_2 had been taken into account in claiming credit under Section 45Q. However, the cap of 75 MMt does not offer developers the certainty they need to obtain financing for carbon capture projects. Given the 8–10 year lead times for IGCC projects to achieve commercial deployment, projects at the permitting or front-end

[23] 26 USC §43(b)(3)(B). The adjustment factor is a fraction the numerator of which is the GNP implicit price deflator for the preceding calendar year and the denominator of which is the GNP implicit price deflator for 1990.

engineering and design stage cannot count on the credit being available for them. The uncertainty associated with credit availability in the future could act as a deterrent to commercial-scale deployment of large CCS projects.

2.1.1.4.3 Investment credits for advanced coal projects

Investment tax credits under Sections 48A and 48B of the Internal Revenue Code are awarded to certified projects, with certifications issued in a competitive bidding process by the secretary of the treasury in consultation with the secretary of energy. Section 48A applies to IGCC and other advanced coal projects that capture and sequester 65% of the CO_2 emissions and are placed in service within five years. Since 2009, $1.772 billion in tax credits have been awarded in IGCC and other advanced coal projects under Section 48A of the Internal Revenue Code. Section 48B credits apply to gasification projects that capture and sequester at least 74% of the CO_2 emissions and are placed in service within seven years. The tax credit rate for Sections 48A and 48B is 30% of the qualified investments.

Table 2.3

Section 48: Investment tax credit allocation (Phases II and III allocations)

Code section	Project name		Credit awarded
2009–10 allocation round			
26 USC §48A	Christian County Generation, LLC		$417,000,000
	Summit Texas Clean Energy, LLC		$313,436,000
	Mississippi Power Company		$279,000,000
		Total	**$1,009,436,000**
26 USC §48B	Faustina Hydrogen Products		$121,660,000
	Lake Charles Gasification, LLC		$128,340,000
		Total	**$250,000,000**
2011–12 allocation round			
26 USC §48A	Hydrogen Energy California, LLC		$103,564,000
		Total	**$103,564,000**
2012–13 allocation round			
26 USC §48A	STCE Holdings, LLC		324,000,000
	SCS Energy California, LLC		$334,500,000
		Total	**$650,500,000**
Total			**$2,021,500,000**

Source: Data from IRS compiled by Peter Folger[24]

2.2 Incentives at state level

More than 10 states have adopted a wide range of approaches when it comes to direct and indirect financial support offered for CCS and CO_2 EOR projects. State support is typically found in the form of state programs that provide direct expenditures of state funds to subsidize CCS and CO_2 EOR projects or research, securing or guaranteeing long-term agreements for the offtake of CO_2, utility cost recovery mechanisms, financing incentives and tax incentives in the form of income tax abatement, tax credits, property or severance tax allowances, exemptions, or rate reductions. The financial incentives adopted by each jurisdiction vary with the financial needs of the intended CCS application and the financial and economic practices of the jurisdiction where the project is undertaken.[25] Some are targeted at specific applications such as use of CO_2 for EOR or power generation, others have broader applicability. Table 2.4 groups the various state approaches into five broad categories. The incentives within each category vary widely from one jurisdiction to another and often several approaches apply within the same jurisdiction.

[24] Peter Folger and Molly F. Sherlock, note 20 supra.
[25] Jeffrey Price, note 8 supra.

Table 2.4

State incentives for CCS and CO_2 EOR

State	Grants & loan guarantees	Offtake agreements	Utility cost recovery	Financing incentives	Tax incentives			
					Income/franchise tax	Severance tax	Property tax	Sales tax
Colorado	x		x					
Florida			x					
Illinois	x	x	x	x	x			
Indiana		x	x					
Kansas					x		x	
Kentucky	x							
Louisiana				x				
Minnesota	x							
Mississippi			x		x			x
Montana							x	
New Mexico					x			
North Dakota	x		x			x		x
Rhode Island				x				
Texas	x				x	x	x	x
Virginia			x					
Wyoming	x							x

Source: IHS

2.2.1 Grants and loan guarantees

Of the various states that offer grants for CO_2-related projects, the states of North Dakota and Wyoming are among the ones that have authorized grants or loan guarantees for CO_2 EOR projects. The funding in most states has been focused on clean coal technologies. Direct state financial support in CO_2 EOR projects has taken the form of developing infrastructure such as pipelines and storage facilities through their respective public commissions, boards, and authorities. In North Dakota, the legislature has authorized the ND Pipeline Authority to make grants, loans, or other forms of financial assistance to support the development of CO_2 pipelines for EOR operations.[26] Similarly, the Wyoming Pipeline Authority can provide grants, loans, and bonding authority to CO_2 pipeline projects.

Table 2.5

Grants and loan guarantees at state level

State	Incentive description	Target
Colorado	Financial support for study, engineering, and development from a clean energy fund	IGCC power plants of <350 MW
Illinois	Grants and funding for projects and research	Power plants with CCS
Minnesota	Grant of $2 million/year for five years	CCS facilities
Texas	$22 million in grants for low-emissions projects (introduced in 2005)	FutureGen-type projects
	$20 million grants biannually for advanced clean energy projects (introduced in 2007)	
	$10 million in loan guarantees biannually for advanced clean energy projects (introduced in 2007)	Clean coal energy program
Wyoming	Grant for studies and evaluation of technologies	CCS

Source: IHS

[26] North Dakota Pipeline Authority Annual Report, 2015.

2.2.2 Offtake agreements

Offtake agreements provide a mechanism for a guaranteed buyer of output from a CCS project. Indiana and Illinois provide different frameworks that designate certain entities as purchasers of production or require utilities to enter long-term purchasing agreements.[27] The Illinois Clean Coal Portfolio Standard mandates that utilities must enter long-term purchasing agreements with certain new clean coal plants. In 2009, the Indiana legislature implemented a law that provided an offtake purchaser to a particular coal-to-natural gas plant near Rockport, Indiana. These incentives provide a guaranteed revenue stream to allow CCS projects to obtain financing and move forward with their projects.

Failure to secure offtake agreements can derail CCS projects entirely. Long-term offtake agreements provide the certainty investors need to move from one stage of the project financing to the next. The HECA project is an example where failure to secure an offtake agreement led to project suspension. This project was designed to demonstrate 90% carbon capture efficiency from an advanced gasification power plant and store 2.6 MMt of CO_2 per year. The total project costs were approximately $4 billion. The DOE's share under the CCPI equated to $408 million. The California State Public Utilities Commission also awarded the project $30 million. The project anticipated EOR use for the captured carbon; however, the project was suspended in March 2016 after numerous delays in establishing an offtake agreement.[28]

2.2.3 Utility cost recovery

Utility cost recovery is the most widely used incentive in the United States after tax credits. Cost recovery is a financial mechanism that is used to shift the costs associated with developing infrastructure from the utility company to the consumer through the increase in rates charged to the consumer. This type of financial incentive can substantially improve a project's economics for the company since it would be able to recoup millions of dollars invested in the project. While a company may be able to recoup significant amounts of investment dollars, the drawback is that approval from a public utility commission (PUC) for cost recovery of CCS technology is far from guaranteed. A PUC may deny a company's cost recovery for CCS technology because of the technology's relatively high cost compared with alternative technologies and electricity-generating fuels. Also, even with a PUC's approval for cost recovery, this type of financial incentive may still be unattractive because the process of recovering costs can be lengthy and administratively burdensome.

Mississippi implemented a cost recovery mechanism for the Kemper IGCC power project. The Mississippi Public Service Commission authorized the Kemper IGCC power project to recover certain costs from rate payers. As stated previously, the Kemper IGCC power project is encountering numerous issues related to project delays and increased costs despite a combination of incentives supporting the project. Colorado, Florida, and West Virginia are among the states with utility cost recovery mechanisms. Colorado implemented the mechanism in 2006 for IGCC power plants with 350 MW or less that use coal from specified sources to produce electricity and demonstrate capture and sequestration of CO_2 emissions. Cost recovery support is provided for various aspects of the project, including financial support for study, engineering, and development and operating costs.[29] Florida implemented cost recovery legislation in 2007 to allow cost recovery for IGCC power plants. West Virigina passed utility cost recovery regulations in 2007 and allows utilities to recover particular investment costs related to CCS projects. It is unclear how much of an impact cost recovery mechanisms have on CCS project investment decisions, given the lack of large-scale commercial projects to have benefited from such programs.

[27] Patrick Falwell, "State Policy Actions to Overcome Barriers to Carbon Capture and Sequestration and Enhanced Oil Recovery," Center for Climate and Energy Solutions, 2013.
[28] MIT, Carbon Capture & Sequestration Technologies, "Hydrogen Energy California Project (HECA) Fact Sheet: Carbon Dioxide Capture and Storage Project," *sequestration.mit.edu/tools/projects/heca.html*.
[29] Center for Climate and Energy Solutions, "Financial Incentives for CCS," *www.c2es.org/us-states-regions/policy-maps/ccs-financial-incentives*.

2.2.4 Tax incentives

Tax incentives, which include credits, deductions, deferrals, exemptions, and special preferential tax rates, are a well-recognized form of indirect financial measures used to support the development of CCS and CO_2 EOR through the reduction of the tax burden on corporate and individual taxpayers.[30, 31] The reduction of taxes can foster the development of CCS and CO_2 EOR projects by reducing project financial risks and improving project economics. Additional advantages of tax incentives versus other financial incentive mechanisms include a lower administrative burden on the government and the private developer; a shift of responsibility from the government to the private developer to claim the tax incentives for which they are qualified; and the relative ease of claiming tax incentives versus qualifying for a loan, claiming cost recovery, or applying for a grant. The following are some of the major tax incentives offered by various states.

2.2.4.1 Severance or production tax incentives

Production tax relief provides operational incentives through reduction of state taxes on EOR production. This could apply to the entire production from an EOR project or the incremental production associated with a new project or extension of an existing project. Such projects are usually subject to certification by designated agencies within the state before they can claim the benefits of a reduced tax or credit. North Dakota provides a temporary exemption from the extraction tax for CO_2 EOR projects (10-year non-Bakken, 5 year within Bakken).[32] North Dakota's tax reduction is consistent with other oil-producing states. Mississippi reduces the production tax from 6% to 3% for oil recovered using CO_2 EOR. Mississippi also assesses no production tax on CO_2 sold for the purposes of EOR.[33] Louisiana grants a severance tax exemption until the well reaches payout, then provides a 50% severance tax reduction for CO_2 EOR production.[34] In Texas, oil produced from an approved new EOR project or an expansion of an existing project is eligible for a special EOR tax rate of 2.3% of the productions market value (one-half the standard rate of 4.6%) for 10 years. In the case of expansion projects, the reduced rate is applied only to the incremental increase in production after certification. The severance tax rate is reduced by an additional 50% of the applicable rate for EOR projects (resulting in an effective rate of 1.15%) in the case of EOR projects using anthropogenic sources of CO_2 for a 30-year period from certification of the project.[35] In Oklahoma, CO_2 EOR projects receive a gross production tax credit for incremental capital costs and incremental operating expenses for a period of 10 years.[36]

2.2.4.2 Property tax

Relief for property taxes may be granted to qualified expenditure associated with equipment and or facilities used for CO_2 EOR projects. North Dakota offers a tax exemption for tangible property used to construct or expand a system used to compress, gather, collect, store, transport, or inject CO_2 for use in EOR. The same relief applies to coal conversion facilities and any CO_2 capture system installed at a coal conversion facility in North Dakota.[37] In Texas, "components of tangible personal property used in connection with an advanced clean energy project … are exempted from property taxes."[38] Montana provides for up to 50% property tax abatement for new investment in CCS equipment and facilities.

2.2.4.3 Sales tax

Some states incentivize the sale and purchase of CO_2 by exempting the application of or lowering the sales tax on the sale of CO_2. In North Dakota, the sale of CO_2 to be used for enhanced recovery of oil or natural gas is exempt from

30 Joint Committee on Taxation, "Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014," *JCS-3-10*, Washington, DC, December 2010.
31 Joint Committee on Taxation, "Estimates of Federal Tax Expenditures for Fiscal Years 2012-2017," *JCS-1-13*, Washington, DC, February 2013.
32 NDCC 57-51.1.
33 Miss. Code Ann. Sections 27-25-703, 27-25-503; Mississippi Department of Revenue, *www.dor.ms.gov/Business/Pages/Miscellaneous-Taxes.aspx*.
34 LA Rev Stat § 47:633.4.
35 Texas Tax Code, Chapter 202.
36 Oklahoma Tax Commission Title 710:45-9-32.1(c).
37 NDCC 57-60-06.
38 Texas Tax Code § 151.334.

sales and use tax.[39] Louisiana reduces sales tax on CO_2 sold for EOR by 50%.[40] Mississippi establishes a low-income tax rate (1.5%) for income from sales of naturally occurring or anthropogenic CO_2 used for EOR or permanent sequestration in a geologic formation.[41] Likewise, Wyoming provides a sales tax exemption for CO_2 sold for EOR.[42]

2.2.4.4 Income/franchise tax

Relief for CCS projects can come in the form of income or franchise tax credits. Texas provides up to $100 million in franchise tax credits for three in-state projects that sequester at least 70% of CO_2 emissions and a 50% reduction in the recovered oil tax rate for EOR projects that use anthropogenic CO_2. Such projects may claim franchise tax credits equal to 10% of a project's capital costs. In 2013, House Bill 2446 extended the eligibility for franchise tax credits to natural gas electricity-generation projects, meeting the previously adopted requirements for CO_2 capture. New Mexico established $60 million in income tax credit for power plants that capture and sequester CO_2 so that less than 1,100 pounds per megawatt-hour of CO_2 is emitted into the atmosphere.[43]

Other methods of lowering income tax liability have been used. One example is Kansas, which allows for accelerated amortization of CO_2 sequestration–related costs by allowing 55% of amortizable costs to be deducted in the first year of the project with 5% allowable in subsequent years.[44] Specifically targeting the FutureGen CCS Project, the state of Illinois established investment and employment criteria and issued tax exemptions on electrical-generation units based on FutureGen meeting those requirements.[45]

2.3 Policies that regulate CO_2

2.3.1 US power sector CO_2 policy

The US Environmental Protection Agency (EPA) has been on a five-year path to regulate CO_2 emissions from US power plants, dating back to the last attempt to pass federal climate change legislation in 2010.[46] The agency reached a milestone in August 2015 when it issued two final rules. The Carbon Pollution Standards (CPS) regulates CO_2 emissions from new, modified, and reconstructed power plants. The Clean Power Plan (CPP) regulates CO_2 emissions from existing power plants.

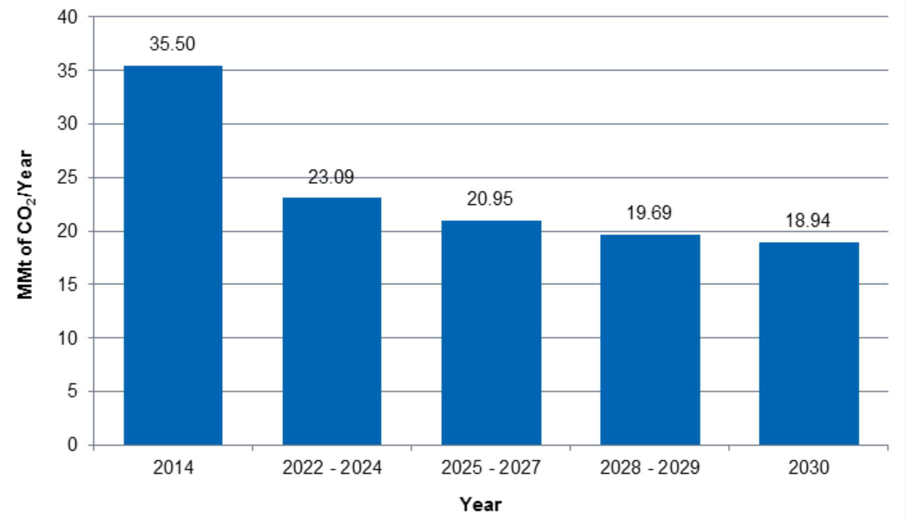
The CPP requires a significant reduction in an EPA-defined adjusted CO_2 emission rate for existing US fossil fuel–fired power plants over 2022–30 relative to a 2012 baseline.[47] It does so by requiring power plant owners to rely partly on emission reduction measures that are located outside the power plant fence line, including shifting from coal to natural gas–fired generation and deploying new renewables.

[39] NDCC §§ 57-39.2-04(49), and 57-40.2-04(24).
[40] Id.
[41] Patrick Falwell, note 27 supra.
[42] Wyoming Statutes 39-15-105.
[43] New Mexico SB 994 (2007).
[44] Kansas House Bill No. 2419 (2007).
[45] Illinois SB 1704 (2007 Illinois Public Act 095-0018).
[46] The Waxman-Markey bill passed by the House would have established a national cap-and-trade scheme but failed to be taken up for vote by Senate.

[47] The CPP's adjusted emission rate comprises the emissions and generation from existing fossil fuel–fired power plants covered by the rule plus emission rate credits (ERCs) attributable to generation from new renewables and new nuclear, as well as avoided generation from new demand-side energy efficiency measures. It is defined as follows: $CPP\ adjusted\ emmission\ rate = \frac{CO_2 emissions\ from\ affected\ existing\ fosil\ generation\ (lb)}{affected\ existing\ fossil\ generation\ (MWh) + ERCs\ (MWh)}$

Figure 2.4

EPA CPP North Dakota's CO_2 emission goals



Source: IHS © 2016 IHS

In February 2016, the US Supreme Court stayed the CPP just weeks after the District of Columbia Circuit Court of Appeals, which is first in line to hear arguments against the CPP, opted not to stay the rule. The Supreme Court stay puts the rule on hold, including the requirement that states submit plans, until both courts vet the CPP's legal merits. A final ruling from the Supreme Court is not likely until sometime during the term that lasts from October 2017 through June 2018. Even if the CPP is upheld, its fate is also tied to the CPS, which legal proceedings are moving more slowly. Under Section 111 of the Clean Air Act, a rule that covers existing source emissions (i.e., the CPP) cannot be finalized unless a rule addressing new source emissions (i.e., the CPS) is already in place.

Even if CPP is upheld by the Supreme Court it is hard to predict what role, if any, it will play to incentivize CCS. Unlike the CPS, which contains prescriptive, unit-level CO_2 emission rate standards, the CPP sets state-level targets that give states flexibility in developing compliance plans. There is flexibility not only in how the targets will be met but also in the metrics of compliance that are used. Many states have already expressed an interest in allowing power plants to comply via interstate trading. In the case of North Dakota, the state is facing an overall 45% GHG reduction target in 2030 relative to a 2012 baseline (see Figure 2.4). The response of electric power utilities in the state will depend largely on the statewide policies that will be adopted to comply with CPP.

2.3.2 Regulation of CO_2 storage

Underground injection and storage of CO_2 in the United States is administered by the EPA under two complimentary but not fully integrated programs: the Underground Injection Control (UIC) program, designed to protect drinking-water resources; and the Greenhouse Gas Reporting Program (GHGRP), related to monitoring and reporting of GHG emissions.

The EPA permits underground injection under six designated classes.[48] "Class II wells are used only to inject fluids associated with oil and natural gas production."[49] Class II covers CO_2 EOR and the more recent Class VI classification is for saline storage of CO_2.[50] Class VI requirements are much more rigorous in terms of well construction, operational and mechanical integrity testing, well plugging, and post-injection site care. In the event of "increased risk" to underground sources of drinking water, or if the "primary purpose" of the operation becomes CO_2 storage, Class II operators would need

[48] Tim Dixon, Sean McCoy, Ian Havercroft. "Legal and Regulatory Developments on CCS," *International Journal of Greenhouse Gas Control* 40:431–448.
[49] US EPA, "Class II Oil and Gas Related Injection Wells," *www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells*, retrieved 18 May 2016; Dixon, et. al.
[50] The Class VI classification was introduced in 2010.

to obtain a Class VI permit. CO_2 injected into Class VI are conditionally exempt from hazardous waste classification, but the CO_2 EOR operators remain liable for Post Injection Site Care (PISC) for up to 50 years (negotiable) after closure.[51]

The initial guidance related to Class VI wells created a lot of uncertainty in the CO_2 EOR industry. While operators could still operate CO_2 EOR wells under Class II permits, they could not claim storage credit under the Class II permit.[52] In a statement released in 2015 to clarify its previous guidance on the issue of transition from Class II EOR wells to Class VI storage wells, the EPA stated that CO_2 EOR does indeed store CO_2 while producing oil during EOR operations and that CO_2 injection under Class II rules could recognize the incidentally stored volumes under subpart PR of GHGRP that relates to the more stringent reporting requirements and verification plans for Class VI wells.[53] However, if operators use standard reporting under subpart UU of the GHGRP program that applies to Class II wells, and has been used by EOR facilities, they will not be able to claim credit. The EPA went further to clarify that the 50-year liability by the operator under Class II permit could be avoided as long as the endangerment finding was acceptable to the regulator.

Under the UIC program, states may apply for primacy to administer the program within their state. A total of 41 states have or share primacy with the EPA over Class II well permits. Only five Class VI permits have been granted to date. North Dakota was the first state to apply for primacy on 23 June 2013; however, EPA's decision on North Dakota's application is still pending.[54]

To address the significant liability period imposed by the EPA PISC requirements, many oil-producing states have passed legislation that shifts liability from the CO_2 EOR operator to the state at some period after operations cease. State regimes typically leave CO_2 EOR operators liable for wells during operations and for a statutorily defined period post-closure.[55] States that assume liability for CO_2 storage wells also gain ownership of the CO_2 itself and benefit from any future economic and environmental proceeds, credits, or other benefits of the well.[56] Examples of states that assume liability include the following: Illinois and Texas (offshore) have provisions assuming liability immediately upon well closure; however, the specificity of the legislation in these states limits applicability to future underground CO_2 storage.[57] North Dakota and Louisiana assume CO_2 ownership and liability 10 years after injection ceases and the state certifies well integrity.[58] Montana assumes liability after 30 years.[59] Operators must get certification of well integrity from the state of Montana 15 years after closure, and then the state assumes liability after certification.[60] Kansas denies liability for CO_2 storage wells outright.[61]

The states that do assume liability for post CO_2 EOR monitoring typically establish trust funds to handle long-term monitoring and necessary remediation efforts for post-closure CO_2 storage wells.[62] The trust funds receive money from per ton injection fees, licensing fees, and specific long-term storage fund fees. States with established CO_2 well funds include Kansas, Louisiana, Mississippi, Montana, North Dakota, Texas, and Wyoming.[63]

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[51] Lupion, M., et. al., "Challenges to Commercial Scale Carbon Capture and Storage: Regulatory Framework," working paper, Massachusetts Institute of Technology, Carbon Capture and Sequestration Technologies Program, 2015, p. 9, *sequestration.mit.edu/pdf/2015_WorkingPaper_CCS_Regulations_Lupion.pdf*; Dixon, et. al., at 446.
[52] Id.
[53] US EPA, "Class VI – Wells used for Geologic Sequestration of CO_2," *water.epa.gov/type/groundwater/uic/class6/upload/class2eorclass6memo.pdf*, retrieved June 2016.
[54] North Dakota Department of Mineral Resources, "Class VI Primacy Application for the authority to regulate the Geologic Storage of Carbon Dioxide," *www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp*, retrieved June 2016.
[55] Patrick Falwell, note 27 supra.
[56] Illinois SB 1704 (2007); Texas HB 1796 (2009); Louisiana HB 661 (2009); North Dakota SB 2095 (2009); *www.ccsreg.org/bills.php?id=50*.
[57] Holly Javedan, "Regulation for Underground Storage of CO_2 Passed by U.S. States," working paper, Massachusetts Institute of Technology, Carbon Capture and Sequestration Technologies Program, 2013, p. 5, *sequestration.mit.edu/pdf/US_State_Regulations_Underground_CO2_Storage.pdf*; Jacobs, Wendy B. and Stump, Debra L., "Proposed Liability Framework for Geological Sequestration of Carbon Dioxide," Harvard Law School, Cambridge, Massachusetts, October 2010.
[58] Id.
[59] Id.
[60] Id.
[61] Id.
[62] Glen Andersen, "Advances in technology could make 'clean coal' a reality, but can we afford it?" National Conference of State Legislatures, 2011, *www.ncsl.org/research/energy/capturing-co2.aspx*, retrieved 18 May 2016; CCS Reg, "State CCS Policy," *www.ccsreg.org/bills.php?policy=S_LTS*, retrieved 18 May 2016.
[63] CCS Reg, State CCS Policy; Falwell at 10–11; Javedan at 6–7.

CHAPTER THREE

3. CO_2 supply costs and sources

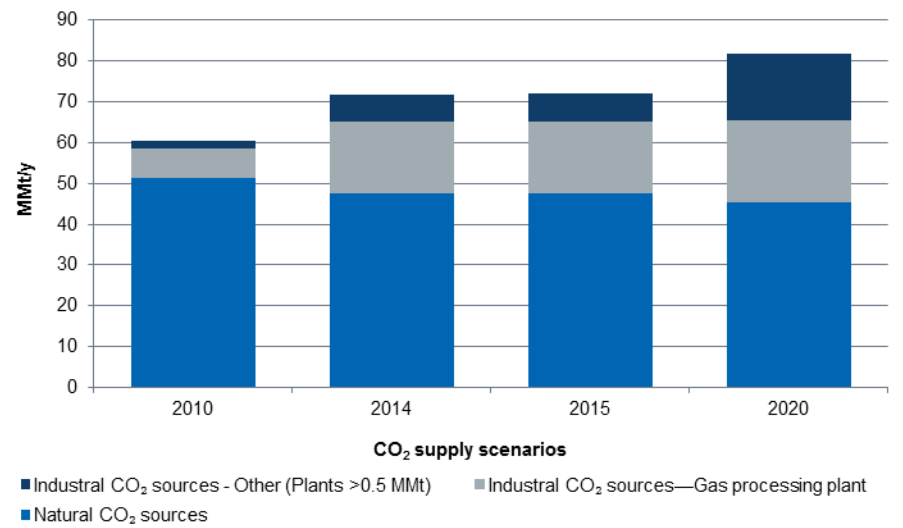
CO_2 EOR has been successfully used in the United States for about 40 years. The injection of CO_2 into aging oil fields to produce residual oil has helped extend the producing life of some fields by more than 25 years. The key enabler of this success has been the availability of large volumes of low-cost, naturally occurring CO_2 that provides a regular supply for EOR projects. Many more potential EOR projects could be implemented if they had access to supplies of CO_2. The primary driver of successful EOR in projects with optimal development conditions will continue to be access to economical and abundant supplies of CO_2. This holds true in the Permian Basin, but CO_2 supply may not be the only important driver for North Dakota.

Proximity to CO_2 is important for the success of EOR projects. New pipeline construction costs about $75,000–100,000 per mile per inch.[64] This is due to the highly corrosive nature of CO_2 that requires heavy-duty stainless steel construction, and requires transportation under relatively high pressures. For example, a 20-inch, 100-mile pipeline would cost about $150–200 million to construct. While there are many opportunities for EOR projects in North Dakota, particularly with the emergence of the Bakken/Three Forks oil play, successful realization of EOR recovery will largely hinge on the ability of operators to economically capture, transport, and inject large sources of CO_2.

Historically, within the United States, CO_2 EOR projects have been supplied from three primary sources: naturally occurring underground accumulations or fields where the produced gas is primarily CO_2 (90% or higher); CO_2 derived from natural gas processing, where CO_2 is captured as a byproduct at a natural gas–processing plant; and other industrial sources where CO_2 is captured from either power plants or other industrial sources such as hydrogen production (e.g., heavy-oil refineries), coal gasification (e.g., synfuel production), or other industrial separation processes that remove the CO_2 during the production of iron and steel, fertilizer, and chemicals.

Figure 3.1

Committed operational sources of CO_2 for EOR in the US and Canada



Source: IHS © 2016 IHS

[64] KLJ, "Evaluation of near-term (5-year) potential for carbon dioxide enhanced oil recovery in conventional oil fields in North Dakota," North Dakota Oil and Gas Industry Impacts Study, 2014; Carbon Dioxide Enhanced Oil Recovery, NETL, March 2010.

In 2010, naturally occurring CO_2 accounted for nearly 85% of all CO_2 used for EOR in Canada and the United States. As more industrial and gas processing capacity came on stream, the share of CO_2 from natural fields being used for EOR dropped to 66% in 2015. Our research indicates that future production from natural sources will decline slightly, with anthropogenic sources of CO_2 driving the future CO_2 supply growth. We anticipate that by 2020, CO_2 production will reach 20.2 million metric tons per year (MMt/y) from gas processing plants and 16.2 MMt/y from other industrial sources, thus reducing the relative contribution from natural sources to about 57% (see Figure 3.1).

An analysis of drivers and challenges associated with CO_2 EOR development across the United States is instrumental in developing CO_2 supply and cost outlook for potential EOR projects in North Dakota. This section of the report will also address the supply cost for natural and anthropogenic sources of CO_2 and the prevailing market prices of CO_2 for EOR. Availability of continuous reliable supply of CO_2 and the price of CO_2 for EOR will play an important role in the commercial viability of potential EOR projects in North Dakota.

3.1 CO_2 supply drivers and challenges

CO_2 EOR currently accounts for 3–4% of total US annual domestic production: roughly 300,000 b/d of crude oil in 2015 (up from 200,000 b/d in 2005). To produce this volume, the oil industry injects roughly 67 MMt of CO_2 annually. That is equivalent to 3% of the country's CO_2 emissions from power generation in 2015.

The success of CO_2 EOR in the United States can be attributed to the following unique conditions:

- **Affordable CO_2.** There is ample supply of low-cost CO_2 from naturally occurring deposits and to a lesser extent natural gas–processing facilities.

- **Oil price indexation.** Many EOR projects benefit from variable purchase agreements that adjust for oil prices to maintain the affordability of CO_2 at lower oil prices.

- **Proximity to source.** Existing EOR projects tend to be located within a reasonable distance from CO_2 sources, minimizing transport costs for CO_2 providers.

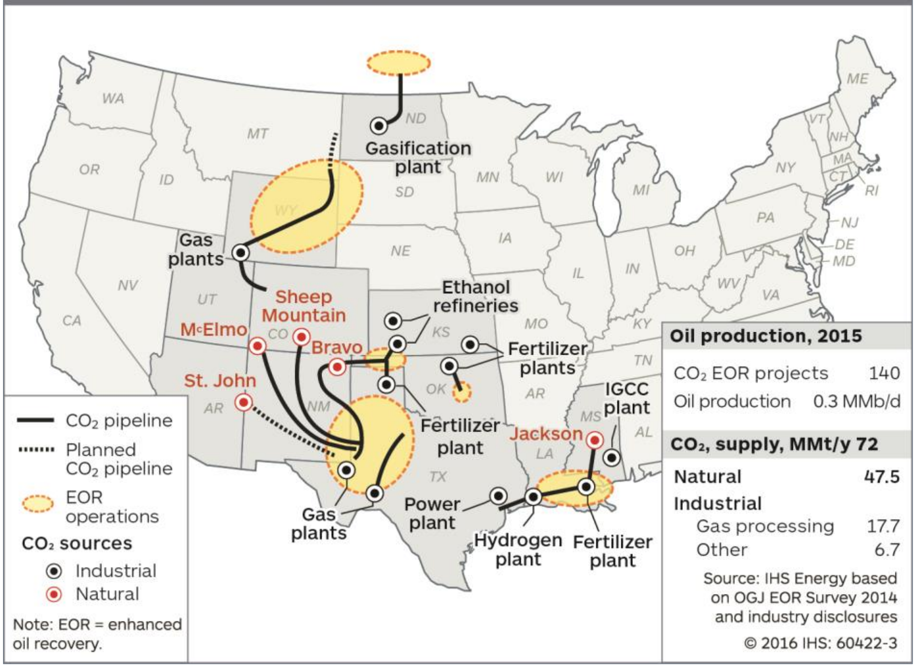
- **Vertical integration.** A handful of operators control the entire supply chain, from CO_2 source to pipeline transport and EOR operations, giving them the flexibility to use CO_2 that is already linked by pipeline to oilfields.[65]

However, EOR projects relying on low-cost natural sources of CO_2 are restricted geographically because of high pipeline construction and transportation cost. CO_2 EOR operations are concentrated around three major CO_2 supply centers—Permian Basin, Gulf Coast, and Wyoming—which account for 92% of active CO_2 EOR projects in Canada and the United States (see Figure 3.2).

[65] They include Occidental Petroleum, Denbury Resources, Kinder Morgan, and to a lesser extent ExxonMobil and ConocoPhillips.

Figure 3.2

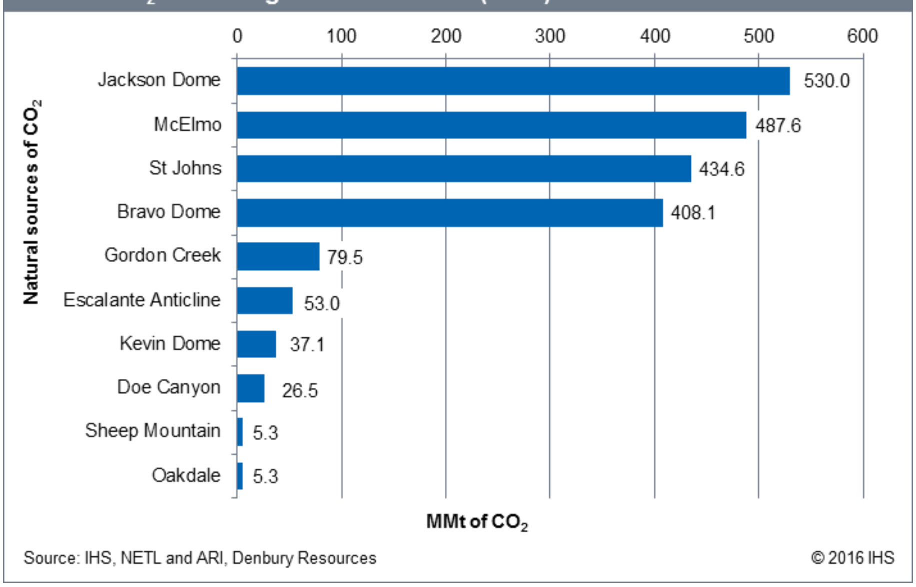
Major CO_2 EOR operations, CO_2 sources: 2015



Natural CO_2 fields are expected to continue to play a significant role in CO_2 EOR developments in the United States for the next decade. The reserve estimates for the naturally occurring reservoirs are 2.067 billion tons, which is expected to last approximately 43 years at current production rate.[66] Nearly 99% of natural supplies of CO_2 in recent years have come from Colorado, Mississippi, and New Mexico (see Figure 3.3).

Figure 3.3

Natural CO_2 remaining reserve estimate (2015)



66 P. DiPietro, P. Balash, and M. Wallace, "A Note on Sources of CO_2 for Enhanced-Oil-Recovery Operations," SPE Economics and Management, April 2012.

Projects relying on CO_2 from natural fields are usually vertically integrated—the same companies controlling the CO_2 supply chain and EOR operations—thus ensuring a secure and reliable source of supply for their operations. Unlike the carbon sequestration process where the primary goal is reducing CO_2 emissions from industrial facilities, the development of natural CO_2 fields occurs for the sole purpose of supplying CO_2 to EOR projects. These projects have had the advantages of lower prices and more flexible contract structure, since long-term contract prices have historically been a function of the oil price. Table 3.1 shows indicative CO_2 purchase prices by region in 2014.

Table 3.1

Price of CO_2 from natural fields

	Colorado, New Mexico, Texas, Wyoming		Louisiana		Other states	
Oil price ($/bbl)	CO_2 price ($/Mcf)	CO_2 price ($/ton)	CO_2 price ($/Mcf)	CO_2 price ($/ton)	CO_2 price ($/Mcf)	CO_2 price ($/ton)
30	0.89	17	1.11	21	1.78	34
40	1.20	20	1.28	25	2.04	39
50	1.15	22	1.44	28	2.30	44
60	1.28	25	1.60	31	2.56	49
70	1.41	27	1.76	34	2.80	54
	$0.89–1.41	**$17–27**	**$1.11–1.76**	**$21–34**	**$1.78–2.80**	**$34–54**

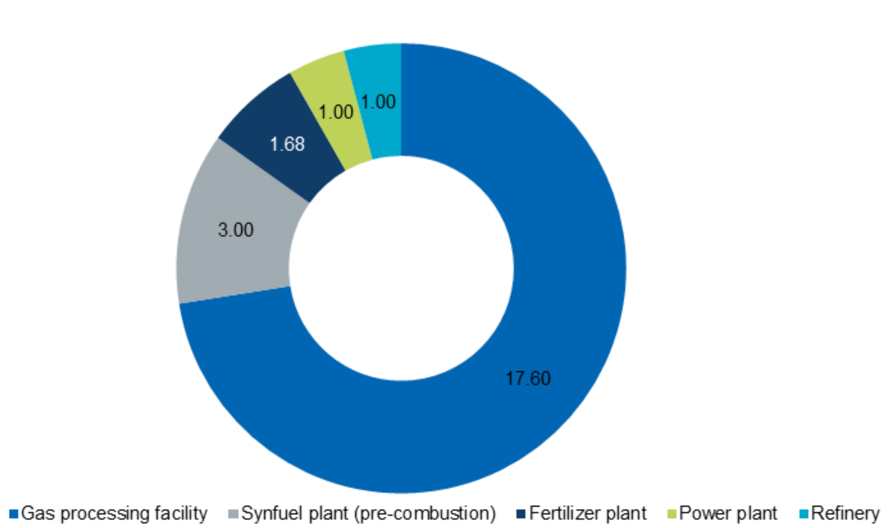
Notes: Sample prices based on public disclosures in 2014. May not reflect current structure.

Source: IHS Energy, EIA OGSM 2014

Given the highly localized nature and limited sources of natural CO_2 fields, the growth of CO_2 supply for EOR is expected to come from industrial sources. In 2015, 24.3 MMt/y (1.3 Bcf/d) of CO_2 came from industrial sources, nearly three quarters of which was captured at major gas processing plants. In addition to CO_2 captured from gas processing plants, a total of 6.7 MMt/y (350 MMcf/d) of CO_2 captured and used for EOR was sourced from large-scale industrial CCS projects in Canada and the United States, such as gasification, fertilizer, chemical, and power plants (see Figure 3.4).

Figure 3.4

Operational US/Canada large CCS projects used for EOR (MMt/y)



Source: IHS

Unlike natural CO_2 fields in the case of industrial sources of carbon, the cost of CO_2 to the producer includes the cost of capturing, compressing, and transporting CO_2 via pipeline within the region. Inter-regional transportation adds about $7.7/metric ton for every region crossed. Natural gas processing appears to be the lowest cost option among the industrial sources of supply at $37/metric ton, matching the natural-field CO_2 price when crude oil is $110/bbl in regions such Colorado, New Mexico, Texas, and Wyoming.

Table 3.2

Industrial CO_2 capture and transportation costs by region ($/metric ton)

Region	Hydrogen	Ammonia	Ethanol	Cement	Refineries	Natural gas processing	Power plants
Northeast	47	40	43	83	47	37	115
Gulf Coast	37	40	43	83	37	37	115
Mid Continent	40	40	43	83	40	37	115
Southwest	39	40	43	83	39	37	115
Rocky Mountains	39	40	43	83	39	37	115
West Coast	39	40	43	83	39	37	115
N. Great Plains	40	40	43	83	40	37	115

Source: Compiled from EIA OGSM 2012 and 2015 © 2016 IHS

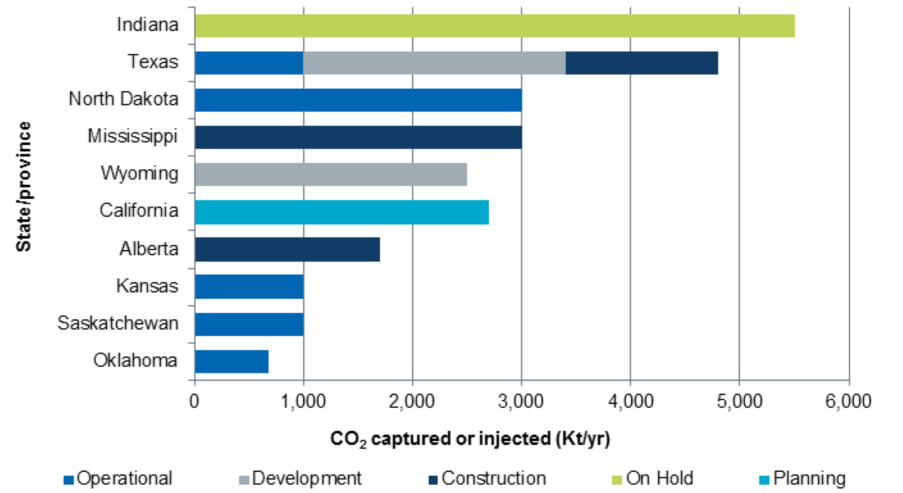
CO_2 captured from power plants at $115/metric ton—per US Energy Information Administration (EIA) 2012 Oil and Gas Supply Module (OGSM) publication—is the highest cost supply alternative for EOR projects. Despite the investments made by the DOE to incentivize commercial demonstration and deployment of CCS technologies, the DOE CCS program has not reached the critical mass to bridge the gap between the price of CO_2 used for EOR projects associated with natural CO_2 fields and the cost of CO_2 captured from power plants. CCS adds 70–80% to the capital costs of new supercritical pulverized coal plants and 100–110% to the capital costs of new combined-cycle gas turbine plants. Even retrofit post-combustion technology—currently the least expensive one—involves significant cost for capture facility and plant upgrades.[67]

According to the EIA OGSM 2015 data[68], technology and market constraints prevent the total volumes of CO_2 produced from other industrial sources from becoming immediately available. Commercial-scale CCS projects in the United States include four natural gas–processing facilities, two fertilizer plants, a synfuel plant, and a hydrogen plant that capture CO_2 for use in EOR.[69] The first commercial-scale power plant with CCS for EOR—Boundary Dam project in Saskatchewan (southern Canada)—became operational in 2014. The project, which benefited from grants from the federal and provincial government, has faced a number of operational challenges since it came online. In 2015, the CCS unit functioned at 40% of capacity, thus triggering payment of penalties to the EOR operator for failure to supply the full contracted amount. The CO_2 capture cost for the project is estimated to be $100/metric ton. The power plant has entered a long-term contract with the EOR operator for a CO_2 sales price of $25/metric ton. It is expected that the $75/metric ton gap between cost and price of CO_2 will be passed on to the consumers through increased electricity pricing.

[67] S. Julio Friedman, “Carbon Capture and Sequestration as a Major Greenhouse Gas Abatement Option,” November 2007.
[68] EIA, “Assumption to the Annual Energy Outlook 2015,” *www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf*.
[69] Center for Climate and Energy Solutions, “Carbon Capture Use and Storage,” *www.c2es.org/technology/factsheet/CCS.*

Figure 3.5

2015 US & Canada existing and planned large-scale CCS projects for CO_2 EOR (excl. gas processing plants)



Source: IHS © 2016 IHS

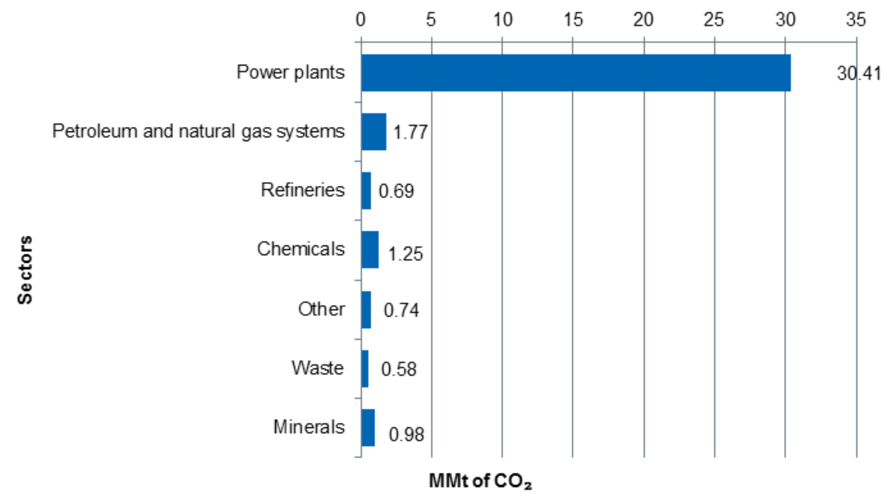
In the United States, the Petra Nova project in Texas is the only active large-scale power plant CCS project that received funding from the DOE. The project, which is scheduled to become operational by the end of 2016, is expected to reach a CO_2 supply cost of $50/metric ton based on 15-year life expectancy of the CCS unit. Should the project stay on schedule and budget, it will become the first large-scale power plant CCS EOR project in the United States.

3.2 North Dakota CO_2 supply scenarios

Deployment of large-scale commercial CO_2 EOR projects could create an opportunity for North Dakota to lower carbon emissions and offset some of the costs associated with carbon capture and sequestration. Power plants in North Dakota emit 30 MMt of CO_2e per year, about 83% of total GHG emissions from industrial sources (see Figure 3.6). Coal generation accounts for 74% of electricity generation in the state. CCS for EOR can allow fossil fuels, such as coal and natural gas, to remain part of the energy mix in the state, by limiting the emissions from their use. The extent to which power plants will deploy CCS technology for EOR will depend on the commercial viability of these technologies and targeted state and federal government policies enabling CCS and carbon capture, use, and storage (CCUS) form power plants.

Figure 3.6

ND direct GHG emissions reported by sector



Notes: Data reported to EPA as of 8/16/2015
Source: IHS, EPA

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At present, there is only one commercial-scale facility in North Dakota that supplies CO_2 via 12–14 inch pipeline to two EOR fields located in Saskatchewan. The CO_2 contracts for the two fields in Saskatchewan are set to expire in 2016 and 2025[70], potentially making available 2.37 MMt of CO_2 in 2016, and 3 MMt by 2025. Supply of CO_2 from within the state will be primarily based on CCS from power plants, the Great Plains Synfuels Plant, and gas processing facilities from fields located in the Williston Basin. North Dakota could also benefit from supply of CO_2 from natural fields in nearby states.

In conducting this analysis, IHS considered the possibility of including sources of CO_2 the from Permian Basin and potential basins from southern Canada. While the presence of natural CO_2 fields has been established in these basins, there is a very low probability that these areas will contribute CO_2 to North Dakota given the very high transportation cost involved with long distance pipelines (see Table 3.3). Besides, CO_2 from these basins has been already committed to existing EOR projects in the region.

Table 3.3

CO_2 transportation assumptions ($/ton)

Origin	Destination						
Region	Northeast	Gulf Coast	Mid Continent	Southwest	Rocky Mountains	West Coast	N. Great Plains
Northeast	7.2	14.4	14.4	28.8	28.8	43.2	43.2
Gulf Coast	14.4	7.2	14.4	14.4	28.8	36.0	28.8
Mid Continent	14.4	14.4	7.2	14.4	14.4	28.8	14.4
Southwest	28.8	14.4	14.4	7.2	14.4	28.8	28.8
Rocky Mountains	28.8	28.8	14.4	14.4	7.2	14.4	14.4
West Coast	43.2	36.0	28.8	28.8	14.4	7.2	21.6
N. Great Plains	43.2	28.8	14.4	28.8	14.4	21.6	7.2

Source: EIA OGSM, IHS

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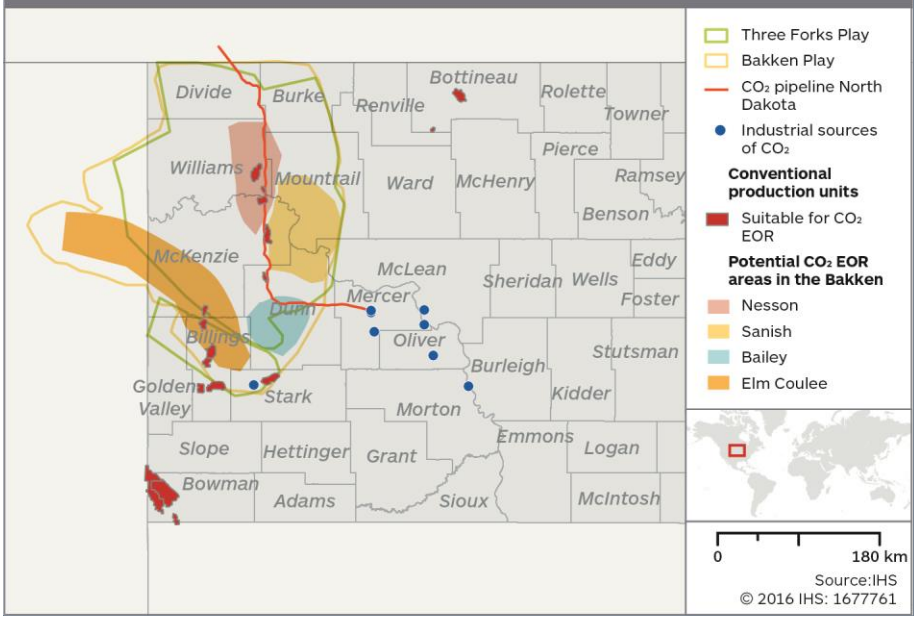
[70] Dakoda Gasification Company, *www.dakotagas.com/Products/pipeline_liquefied_gases/carbon-dioxide*.

3.2.1 Potential CO_2 supply sources within North Dakota

A review of the potential industrial sources of CO_2 supply in the region shows a close proximity of most areas with CO_2 EOR potential in the state and the pipeline that supplies CO_2 to EOR projects in Saskatchewan (see Figure 3.7). Other industrial sources of supply are also concentrated close to the western part of the state, where any future EOR activity is expected to take place. In this section, we will examine the capacity of each source of supply, the potential investments required, and the likely CO_2 cost associated with each supply source.

Figure 3.7

Proximity of industrial sources of CO_2 in North Dakota to potential CO_2 EOR areas



3.2.1.1 Dakota Gasification Plant

The Dakota Gasification Plant (Beulah), located in Mercer County, is the only commercial-scale coal gasification plant in the United States that manufactures natural gas from coal combustion. The carbon sequestration project at the plant is one of the largest in the world. It was originally sponsored by the DOE and began operations in October 2000. CO_2 captured at the plant is transported through a 205-mile 12- to 14-inch CO_2 pipeline to Saskatchewan for EOR activities in the Weyburn and Midale fields. Approximately 3 MMt/y (154 MMcf/d) is exported, of which 2.37 tons are used at the Weyburn field and 0.63 tons are used in the Midale field.[71] In 2014, it was reported that 51.4 Bcf of CO_2 was sold from this plant for a revenue stream of $64 million or about $24/ton ($1.24/Mcf).[72]

With increasing demand for the capture and storage of CO_2, Dakota Gas—the plant operator—has seen a dramatic reduction in its CO_2 emissions at the Dakota Gasification Plant. When the plant is running at full capacity, the plant captures approximately 50% of the produced CO_2. The coal gasification process results in a CO_2 stream that is very dry and about 96% pure, and as a result the CO_2 does not require further processing. This is in contrast to CO_2 captured from power plants, which is very wet and diluted with nitrogen and oxygen, and does require further processing.[73]

[71] Steve Whittaker and Neil Wildgust, "Lessons Learned: IEAGHG Weyburn-Midale CO2 Monitoring & Storage Research Project," Industry CCS Workshop, Dusseldorf, Germany, November 2011.
[72] Basin Electric Annual Report 2014.
[73] Id.

The need for CO_2 in the two Canadian fields is likely to diminish over time as other Canadian sources of CO_2 become available. With the completion of the Canada Boundary Dam CCS project in 2014, CO_2 is being transported by pipeline to nearby fields in Saskatchewan for use in EOR. According to the Basin Electric Power Cooperative 2011 report, Dakota Gas Company is under contract to deliver CO_2 to the Weyburn field until 2016 and the neighboring Midale field until 2025. If these contracts are not renewed, the 3 MMt/y (154 MMcf/d) of CO_2 will become available to North Dakota fields, and IHS expects that the cost of CO_2 would be slightly less than $24/ton ($1.25/Mcf) owing to shorter pipeline transport.[74]

3.2.1.2 Lignite coal–fired power plants

A combined total of 30 MMt/y of CO_2 emissions are recorded from six major North Dakota lignite power plants.[75] These power plants provide some of the highest emission rates in the United States. Owing to the proximity of these plants to the Williston Basin oil fields, there is great potential to lower the overall economic impact of reducing atmospheric CO_2 emissions using captured CO_2 for EOR projects in these nearby fields.

Currently available retrofit post-combustion technologies can capture about 90% of the CO_2 per processed unit. While the potential is significant, the viability of these technologies will depend on the extent to which they bridge the gap between the cost of CO_2 sequestration and the CO_2 price the oil and gas companies are willing to pay in order to go forward with EOR projects. Our cost estimates for the level of investment required to capture CO_2 from the power plants in North Dakota is based on data from similar projects, using them as analogs. Currently, there are only three similar projects in North America that are complete or under construction. In determining appropriate analogs for this analysis, IHS has taken into consideration factors related to project timelines and original and final cost estimates. Based on these criteria, the Kemper County Facility project in Mississippi has been eliminated as an analog owing to significant project delays and cost overruns in the order of 300%.[76]

Table 3.4

Coal-fired power plant CCS cost comparison

Power plant CCS	Location	Status	Capture capacity (MW)	CO_2 captured (MMt/y)	Percent captured	Technology	Estimated capital investment (billion $)	CCS cost for 15-year life (million $/MW)
Boundary Dam CCS	Saskatchewan	Operational	110	1.00	90%	Post-combustion	1.30	11.80
Petra Nova	Texas	Construction	240	1.60	90%	Post-combustion	1.20	5.00

Notes: Cost of Petra Nova is an estimate. Project is expected to be completed in 2016.

Source: IHS

The Petra Nova power plant is the only CCS project on its way to a successful launch in the United States. Should the project be completed on schedule and on budget, it will represent the lowest cost of electricity technology to be deployed on a large commercial-scale project. This study has found similarities between the Petra Nova power plant and North Dakota lignite power plants: both power plants were built within between 1950s and 1980s and have aging boiler units, and each facility already has a certain degree of emission system installed. In order to comply with EPA regulations, North Dakota lignite power plant operators have spent between $200 million and $500 million per plant since 2000 to install emission control facilities, including wet scrubbers removing sulfur dioxide (SO_2) and nitrogen oxide (NOx), mercury control, and fluidized bed installation to reduce SO_2 emissions (see Table 3.5).[77] The Petra Nova power plant uses low-sulfur sub-bituminous coal from Wyoming that typically burns cleaner than the lignite coals used in the North Dakota plants. Nevertheless, these similarities suggest that the MHI technology could be employed at the North Dakota power plants and that capital expenditure for CCS should be comparable to Petra Nova project costs.

[74] Id.
[75] EPA facility level GHG emission data, *ghgdata.epa.gov/ghgp/main.do*.
[76] The project was initially budgeted at a total cost of $2.2 billion when it was approved for DOE funding. By Spring of 2016 the project cost estimate had skyrocketed to $6.6 billion.
[77] Lignite Energy Council, *www.lignite.com/mines-plants/power-plants*.

The North Dakota plants may require some additional investment for pre-CCS treatment of the lignite coals if such investments have not already been made.

Table 3.5

North Dakota power plant emissions capture equipment already in place

Power plant	Existing emission equipment	Number of units
Leland Olds Station	Wet scrubbers remove SO_2 from flue gas; mercury control	2
Antelope Valley Station	Dry scrubbers to capture and remove up to 90% sulfur from stack gases; mercury control	2
Coal Creek Station	SO_2 removal from stack gases ($200 million)	2
Coyote Station	Dry scrubbers to capture and remove SO_2 from stack gases	1
Milton R. Young Station	95% removal of SO_2 and 55–60% NOx; 55–60% mercury reduction ($425 million)	2
R.M. Heskett Station	Fluidized bed installed in second units boiler to reduce SO_2 emissions	2

Source: IHS

If the MHI technology were applied in a similar fashion to the Petra Nova plant with similar capital costs of $50/metric ton, the total CCS capital investment for the six North Dakota plants to capture 9.8 MMt/y would be as high as $7.46 billion (see Table 3.6). This is based on that assumption that five of the six major power plants will make CCS investment to capture 30–40% of their annual CO_2 emission.

Table 3.6

North Dakota lignite coal–fired power plant CCS cost assumptions

Power plant	In service	PPT capacity (MW)	2014 CO_2 emission (MMt/y)	CCS capacity (MW)	Annual CO_2 captured (MMt/y)	Percent of CO_2 captured	Total investment (billion $)
Leland Olds Station	1966	669	3.97	263	1.60	40%	1.32
Antelope Valley Station	1984	900	6.67	354	2.36	35%	1.77
Coal Creek Station	1979	1,100	9.17	433	2.89	31%	2.16
Coyote Station	1985	420	3.18	165	1.10	35%	0.83
Milton R. Young Station	1970	705	4.83	277	1.85	38%	1.39
R.M. Heskett Station	1954	100	0.70	0	0.00	0%	0.00
Total		**3,894**	**28.52**	**1,492**	**9.80**	**34%**	**7.46**

Source: IHS

The extent to which power plants in North Dakota will be able to invest the billions of dollars necessary to capture part of their CO_2 emissions will depend on state and federal policy solutions to encourage such investments. Recent setbacks faced by several CCS/CCUS projects in the United States reflect poor economics and insufficient policy support. One cancelled project close to home is the Antelope Valley Power Plant project. In July 2009, the Antelope Valley Power Plant located in Mercer Country, near the Dakota Gasification Plant, was awarded a $100 million grant from the DOE to capture 1 MMt (53 MMcf/d) of CO_2 from a 120 MW stream. In December 2010, the plant's operator Basin Electric cancelled the project, owing to regulatory and cost uncertainty. While the original projected cost was $387 million, the operator was projecting a $500 million total cost early on in the implementation phase, just prior to project cancellation.[78] Based on our assessment of completed or nearly completed projects, we believe that had the project progressed to fruition, the total cost would have been much higher (most likely in the $800 million range). While the 120 MW represented only a fraction of the 900 MW capacity of the plant, had it been successful, it would have demonstrated a "proof of concept" for lignite-burning power plant CCS in North Dakota. The plant is strategically located near the end of the same CO_2 pipeline used by the Dakota Gasification Plant that would have provided ready transport and access to CO_2 EOR markets.

[78] Id.

3.2.1.3 Gas processing from fields in Williston Basin

Gas processing from fields located within the Williston Basin is not likely to have enough critical mass to perform carbon capture for EOR at the scale required for the Bakken. According to the EPA published data[79], the total CO_2 emission from 12 major gas processing plants in North Dakota was 697,468 metric tons in 2014 (see Table 3.7). If all emitted CO_2 were captured and used for EOR, it would only generate 697 thousand metric tons per year of CO_2 supply, or about 2% of the coal-burning power plants CO_2 emissions. Furthermore, production in these conventional fields is in decline, and CO_2 concentration from associated gas in the Bakken is not sufficient to warrant consideration.

Table 3.7

North Dakota gas processing plant CO_2 emissions, 2014

Facility name	City name	GHG emissions (metric ton/year CO_2e)	GHG emissions (MMcf/d)
Aux Sable Midstream-Palermo Conditioning Plant	Palermo	14,577	0.77
Badlands Gas Plant	Rhame	79,076	4.17
Belfield Gas Plant	Belfield	27,500	1.45
BPE GPRP Garden Creek	Watford City	40,402	2.13
BPE GPRP Grasslands Gas Plant	Cartwright	83,465	4.41
BPE GPRP Stateline	Williston	78,336	4.14
Norse Gas Plant	McGregor	30,972	1.64
Petro-Hunt LLC	Killdeer	32,409	1.71
Robinson Lake Gas Plant	New Town	54,898	2.90
Targa Badlands LLC—Little Missouri Gas Plant	Watford City	14,925	0.79
Tioga Gas Processing Plant	Tioga	177,551	9.37
Watford City Gas Plant	Alexander	63,357	3.34
Total		**697,468**	**36.82**

Source: EPA

3.2.2 Potential CO_2 supply from the region

CO_2 produced from natural gas fields in Wyoming could potentially serve as a supply source for EOR projects in North Dakota if both the price of CO_2 and project economics permit it. CO_2 from high-concentration fields in southwest and central Wyoming is transported via the Greencore pipeline to fields in central and northeast Wyoming for EOR operations. Additional plans to connect the CO_2 from Riley Ridge to the main pipeline system already exist. The proposed extension of the Greencore pipeline into southeast Montana that will transport CO_2 for EOR operations in the Cedar Creek Anticline Field could be of interest to North Dakota. Denbury Resources, the pipeline owner, plans to spend $225 million for the 130-mile extension of the pipeline. Further expansion of this pipeline is the most likely conduit for future transport of CO_2 into western North Dakota.

While Wyoming may have the potential to source CO_2 into North Dakota, there are a number of concerns about future CO_2 supply from Wyoming basins. First, natural gas production (with associated CO_2) is not likely to increase in the future. Gas prices are highly depressed throughout North America and the cost of new gas supply in the Rocky Mountains is not as competitive as other areas, such as the Marcellus Shale or Eagle Ford Shale. As a result, new activity in Wyoming will most likely remain depressed relative to other lower-cost areas. There are currently only 13 active rigs in the entire state of Wyoming. Until rig activity picks up significantly, virtually all of the future production will come from existing wells, which will continue a slow steady decline. Gas with high CO_2 concentrations has an even higher cost of supply (because of low Btu content and high processing costs). Thus, development in fields with high CO_2 concentrations in the Rocky Mountains will take a backseat to higher-quality gas fields in other areas.

[79] Id.

Table 3.8

Wyoming natural gas–processing plants with CO_2 capture

Plant	Start year	State	Operator	CO_2 Offtaker	Maximum CO_2 capture (MMt/y)	Maximum CO_2 capture (MMcf/d)	CO_2 content
Shute Creek	1986	Wyoming	ExxonMobil	Anadarko/Denbury	7.0	370	65%
Riley Ridge	2020	Wyoming	Denbury	Denbury	2.5	132	65%
Lost Cabin	2013	Wyoming	Denbury	Denbury	0.9	48	20%

Source: IHS, Global CCS Institute, MIT CCS Projects Database

It was projected that 7.3 MMt/y would be needed for EOR operations in the Rocky Mountains in 2015.[80] The current processing capacity is 7.9 MMt. While this capacity may appear high, it nevertheless shows that a large amount of gas is needed in the Rocky Mountains basins for the seven EOR projects currently in operation, and that there may be very little remaining for North Dakota EOR projects. The demand from the Cedar Creek field in Montana will be an additional drain on CO_2 supply.

Proved remaining reserves in the LaBarge and Lost Cabin areas total just 3–4 trillion cubic feet (Tcf), a figure that is an order of magnitude less than the 39 Tcf of CO_2 found in natural CO_2 fields that supply the Permian Basin. At the current 7.9 MMt/y rate of use, this leaves enough supply for about 23 years. Given these factors, it is unlikely that sufficient quantity of proved CO_2 reserves exists to begin supplying North Dakota potential EOR projects.

Various research publications from the National Energy Technology Lab and Denbury Resources indicate there may be a very large potential resource base of CO_2 in southwest Wyoming LaBarge area, perhaps as high as 100 Tcf. This has not been proven yet, therefore, it should be classified as "potential resource" rather than reserves. The development of potential resources is not likely in the near future, unless there is a significant demand in the market for $CO_{2.}$

3.2.3 CO_2 supply scenarios

IHS developed three CO_2 supply scenarios, taking into account the technological challenges, the cost, and the lead time it takes to bring various CCS projects on stream, as well as various policy developments that could affect the behaviour of market players. Given that the technologies required to capture CO_2 from power plants are still in their early stages of development, the supply scenarios are tied to the success or failure of the DOE research and development and demonstration program (see Figure 3.8).

Scenario A: The DOE research and development program misses the currently stated goals of having second-generation technologies ready for commercial deployment by 2025 at a COE of $45/ton for post-combustion retrofits, and the development and deployment of transformational technologies ready for demonstration in the 2030–35 time frame at a COE of about $30/ton for post-combustion retrofits. The price gap between the cost of CO_2 from power plant CCS and price of CO_2 for EOR remains greater than $30/ton.

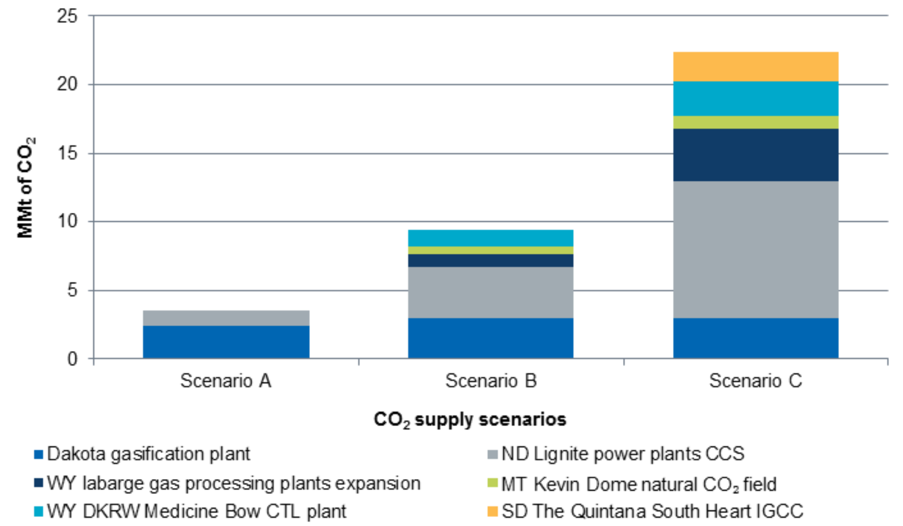
Scenario B: The DOE research and development program achieves the stated goal of having second-generation technologies ready for commercial deployment by 2025 at a COE of $45/ton for post-combustion retrofits, however, misses the target for the development and deployment of transformational technologies ready for demonstration in the 2030–35 time frame at a COE of about $30/ton for post-combustion retrofits. The price gap between the cost of CO_2 from powerplant CCS and price of CO_2 for EOR narrows to $20/metric ton.

[80] Matthew Tanner, Projecting the scale of the pipeline network for CO2-EOR and its implications for CCS infrastructure development, Office of Petroleum, Gas, & Biofuels Analysis, U.S. EIA, October 2010.

Scenario C: The DOE research and development program achieves its third target of development and deployment of transformational technologies ready for demonstration in the 2030–35 time frame at a COE of $10/ton for IGCC and post-combustion new plants, and about $30/ton for post-combustion retrofits. The price gap between the cost of CO_2 from power plant CCS and price of CO_2 for EOR narrows to less than $10/metric ton.

Figure 3.8

Assumption of 2022-35 CO_2 sources of supply for EOR in ND



Source: IHS © 2016 IHS

Under Scenario A, CO_2 supply of 3.54 MMt/y is forecast to come from two sources within North Dakota: the Dakota Gasification Plant and one of the existing power plants in the state. This would significantly limit the applicability of EOR projects to a couple of conventional EOR production units and the Bakken.

Scenario B results in a combination of in-state and out-of state sources of supply amounting to $9.2 MMt/y of CO_2. Under this scenario, the full capacity of the Dakota Gasification Plant is applied to projects within North Dakota. That is combined with CCS capture from three power plants in the state for a total of 6.7 MMt/y of CO_2 from within the state, with an additional 2.7 MMt/y sourced from Wyoming. Depending on the size of the projects, this scenario could support a third of the potential EOR projects in the state.

Scenario C projects 22.33 MMt/y of CO_2 supply, enabling a significant number of conventional and unconventional CO_2 EOR projects in North Dakota. About 12 MMt/y is expected to come from sources within the state, the Dakota Gasification Plant, and the installation of carbon capture capacity in five power plants. The technological advances and the narrowing of the gap between the price of CO_2 for EOR and the cost of CO_2 from industrial sources of supply will enable a greater reliance on sources of supply from Wyoming and South Dakota.

CHAPTER FOUR

4. CO_2 EOR potential in North Dakota

Initial production for conventional resources in North Dakota started in 1950 with the discovery of oil in Williams County. To date, North Dakota has produced over 4 billion bbl of oil from its conventional resources. Recent activity in the Bakken play—with over 1 billion bbl produced to date—has positioned North Dakota as the second-largest oil producer in the United States. The estimates for the recovery factor from the Bakken formation range from 3–10% according to Energy & Environmental Research Center (EERC), to 15–20% for some of the best areas of the play according to Continental Resources.[81] It is expected that CO_2 EOR could improve the recovery factor and bring additional volumes of production on stream. While the technology for CO_2 EOR in conventional oil fields has been used successfully in the United States and other parts of the world for over 40 years, the research and development and field testing for unconventional CO_2 EOR is in its infancy. From a conventional production standpoint, this report will analyze non–thermal EOR methods, review CO_2 EOR methods in North America, detail the screening process for North Dakota production units, and estimate incremental recovery from North Dakota production units that meet the technical screening criteria.

Evaluating the economic impact of EOR using CO_2 in the Bakken/Three Forks play (Bakken) requires a forecast of future production and drilling activity. Significant work has been performed through research, laboratory modeling and field tests, however, actual field knowledge is limited, and a whole-scale commercial proof of concept has yet to occur. Consequently, some technical questions remain unanswered, and the range of uncertainty is extensive for key input parameters required to generate the production and drilling forecast.[82] Nevertheless, IHS developed drilling and production forecasts that allow us to evaluate potential economic impacts within the State of North Dakota. Our EOR production outlook for the Bakken was based on research of technical data, results of studies (in the laboratory and the field tests), and IHS knowledge of the Bakken unconventional play and long-standing conventional CO_2 EOR practices.

The extensive geologic and reservoir engineering work performed thus far by organizations such as the EERC and others have generated data and insight regarding the use of CO_2 based technologies for the Bakken EOR and CO_2 storage. The objective of this study is to build upon that knowledge and describe plausible production profiles, development plans, oil recovery rate, and CO_2 demand that will serve as the basis for EOR project economics and economic impact analysis.

4.1 Enhanced oil recovery fundamentals

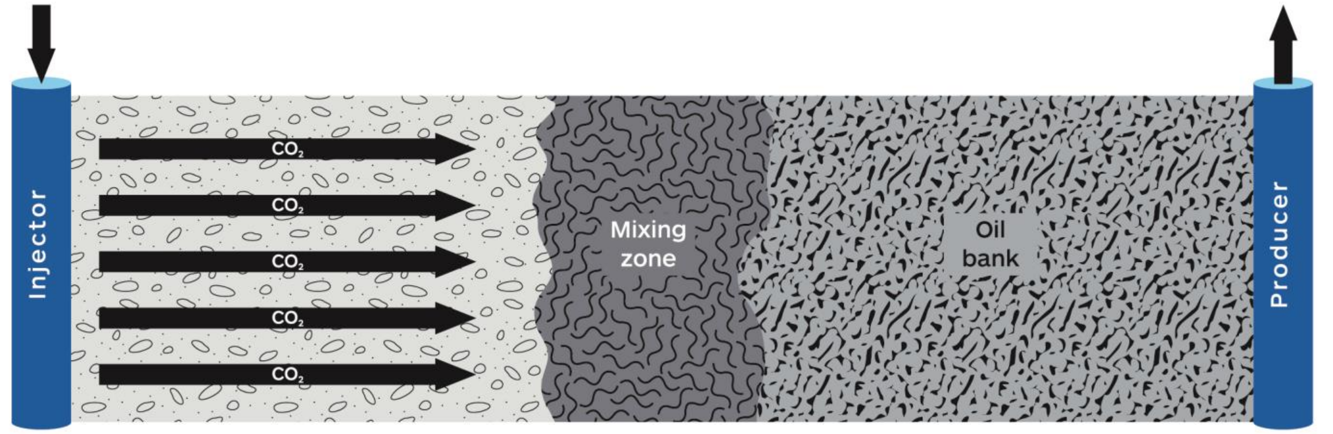
Typically only about 25–40% of the "original oil in place" (OOIP) is recovered during normal primary production from conventional reservoirs. The process of CO_2 EOR was developed to extract additional oil from the producing rock or reservoir by injecting CO_2 into the reservoir so that the CO_2 could combine with the oil and (1) cause the oil molecules to swell, and (2) reduce the viscosity of the oil, thus enabling the oil to flow out of the rock toward the well bore. The ability or the degree to which the CO_2 is able to attach to or combine with the oil molecule is called "miscibility". CO_2 is pumped down an injector well and the oil is flushed toward a producing well where a mixture of oil and CO_2 is produced (see Figure 4.1). The produced CO_2 is separated from the oil and recycled for future use. A continuous supply of CO_2 is needed since only about 40–50% of the injected CO_2 is produced with the oil, while the remainder stays permanently in the reservoir, a process which is often referred to as incidental storage of CO_2. Ultimately all CO_2 injected during the EOR process is stored in the reservoir, as the recycled CO_2 is re-injected in numerous cycles.[83]

[81] James Sorensen et al, Bakken CO2 Storage and Enhanced Oil Recovery Program, EERC, August 2015. See also "The Bakken: How Long will the Resource Last" *seekingalpha.com/article/2510885-the-bakken-how-long-will-the-resource-last*, retrieved 13 June 2016.
[82] IHS used a proprietary database and public sources to provide estimates of missing reservoir/fluid parameters such as Reservoir Pressure (PR), Reservoir Temperature (TR), Oil Viscosity (µO) and MMP (Minimum Miscibility Pressure) for North Dakota fields.
[83] Steve Whittaker and Ernie Perkins, Technical Aspects of CO2 Enhanced Oil Recovery and Associated Carbon Storage, Global CCS Institute, October 2013.

The CO_2 EOR process can only occur if a specific pressure—called the minimum miscibility pressure (MMP)—is attained. Since most mature fields undergoing CO_2 EOR have been de-pressurized, another function of the CO_2 injection is to re-pressure the reservoir up to the MMP. The MMP can be variable, depending on such factors as reservoir temperature, amount and size of pore space, oil properties and type of gas being injected. Increasing pressures above the MMP may also improve recovery; however, the operator has to weigh the additional cost of injecting more CO_2 to increase pressure against the added recovery and find the optimal balance. Incremental oil recovery using CO_2 EOR typically ranges between 5% and 18% of the OOIP.

Figure 4.1

Schematic of CO_2 EOR process in conventional reservoir



Source: IHS

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Some fields and reservoirs are better candidates for CO_2 EOR than others. Good candidate reservoirs generally have the following characteristics:

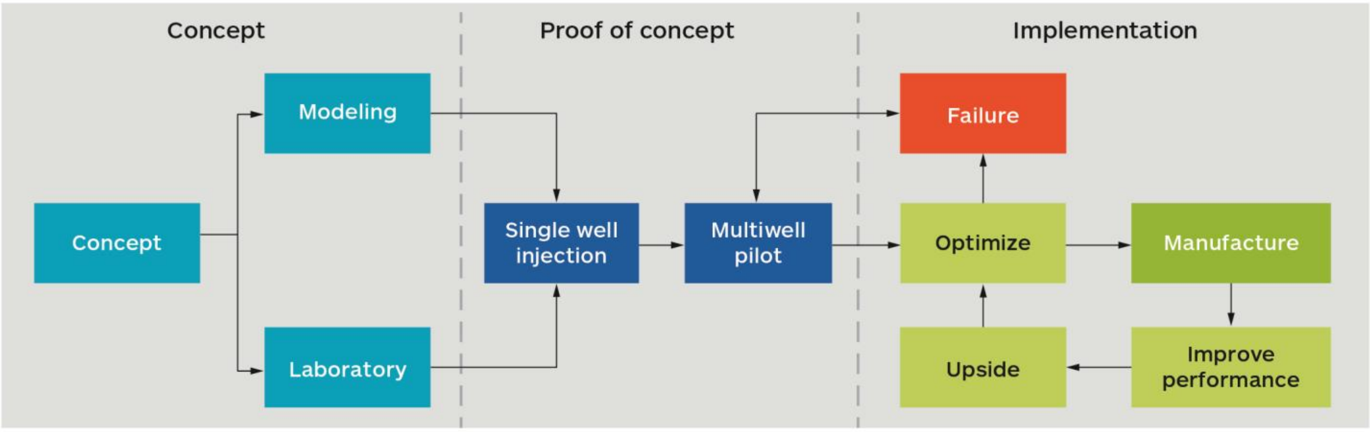
- Water Flood: Historically there is a good correlation between successful water floods and successful CO_2 EOR. Some fields have undergone water floods, but these have not been effective
- Sufficient depth and pressure (>2,500 feet) so that MMP is more easily attained
- Lighter oils with lower viscosities (>22 degree API and less than 10 centipoises)
- Low water saturations (<25%)
- Higher permeability (ability of the reservoir to pass fluids), which allows for both the CO_2 and oil to pass more easily through the rock
- Higher porosity: There is a strong correlation between the size of the pore spaces and the pore connections or “pore throats” that allow fluid passage
- Lack of natural fractures in the rock as fractures may cause uneven CO_2 flow
- Homogeneous reservoirs which allow CO_2 to flow more uniformly from the injector well to the producer

4.2 CO_2 EOR potential of the Bakken

The technology for CO_2 EOR in tight oil plays it is still in the early stages of development. There are various stages from concept to proof of concept to commercial deployment of EOR technologies (Figure 4.2). As primary recovery for tight oil resources proof of concept requires more than single well pilots. This process has been very well established for primary production in the Bakken.

Figure 4.2

Unconventional EOR road map



Source: IHS

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Because the rocks are different in "tight oil" plays, such as the Bakken, we are still in the initial stages of progressing EOR concepts to the "proof of concept" stage. While a considerable amount of modeling and laboratory testing has been performed at the "concept" stage, there is limited work for the "proof of concept" in the Bakken and Eagle Ford. At the time of this study, several single well pilots had been performed in the Bakken—however, there has been only one multiwell EOR pilot performed in Eagle Ford. The results and knowledge from the modeling and laboratory studies as well as data from single well injection pilots help us better understand what is required for the successful technical and economic recovery of oil from application of CO_2 EOR in the Bakken and formulate assumptions and determine the input variables for a production and drilling forecast.

4.2.1 The Bakken characteristics

The first question we face when examining the application of EOR methods to tight oil reservoirs is whether the same criteria that apply to conventional fields would apply to tight oil plays. Some of the characteristics of the tight oil reservoirs would be disqualifiers in a conventional EOR screening process. The less favorable properties in tight oil reservoirs include:

- Low permeability: <0.1 millidarcy (mD) which is at least two orders of magnitude less than what would normally be found in a good conventional reservoir of 10–100 mD.

- Low porosity: the Bakken porosity ranges 2–9% while conventional reservoir porosity ranges 8–25%. This suggests that not only are pores smaller, but that the "pore throats" are also smaller, which makes oil molecule passage more difficult.

- Fractures: in conventional reservoirs, the fractures cause uneven CO_2 flow, but in the Bakken fractures are likely the primary keys to success. Induced fractures caused by hydraulic fracturing can act as conduits for CO_2 and oil transmission; however, it has been determined that these may allow CO_2 to pass too quickly through the reservoir, therefore not allowing the CO_2 to have sufficient contact with the oil located in the rock matrix. On the other hand, natural micro-fractures in the rock will be important as these will enhance porosity and act as conduits for both CO_2 and oil transport.

Favorable properties in the Bakken that enhance the prospects of CO_2 EOR include the following:

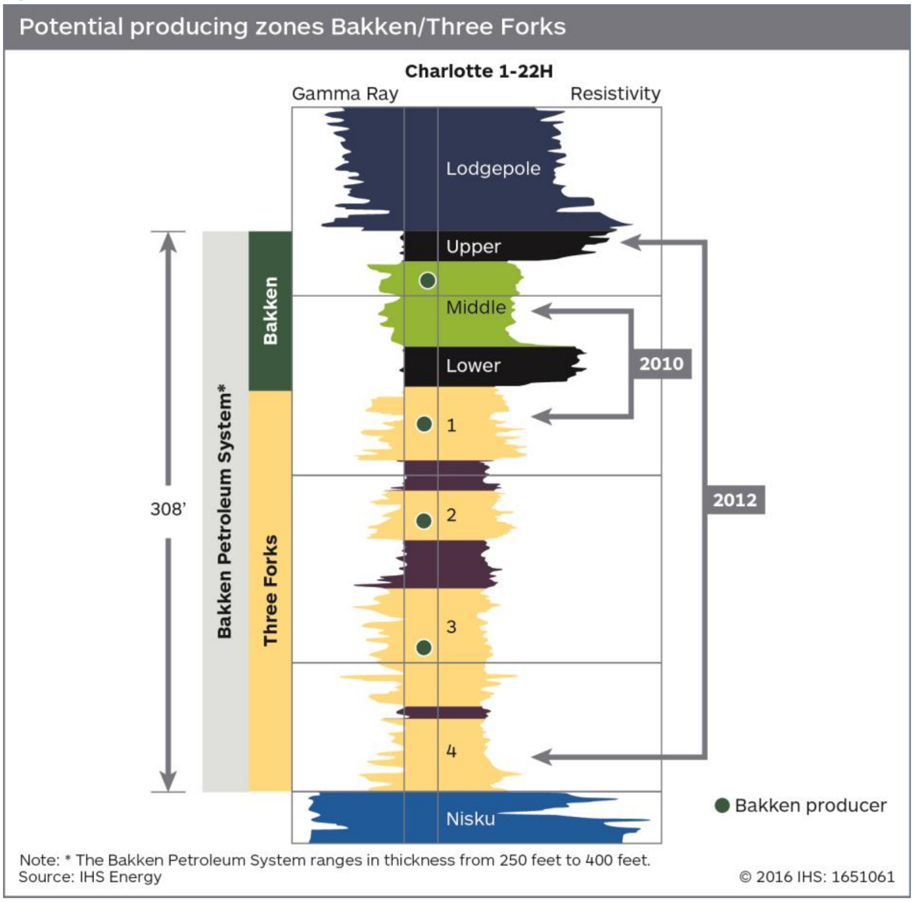
- Depth and temperature: The Bakken is at a depth of approximately 10,000 feet where higher pressures in the 6,000–7,000 psi range occur and will be favorable for helping to achieve MMP.
- Quality of the oil: While there are concerns about the Bakken reservoir, the light gravity (39–42 degree API) and low viscosity of the oil are in an optimal range for CO_2 EOR.
- Low water saturation (Sw <25%). The Bakken is an oil–wet reservoir, meaning that an oil film, not water, lines the pore spaces. Since this is the case, many experts[84] agree that for maximum incremental oil recovery, water flood or injection should be skipped and that CO_2 or other gas injection would be the next step after primary production.

Given the concerns regarding some of the reservoir properties, why is there so much effort being put forth to discover ways to implement commercial CO_2 EOR in the Bakken? When we compare the Bakken to conventional fields in North Dakota, the sheer magnitude of the play becomes obvious.

- The Bakken is widespread, covering over 10,300 square miles in seven western North Dakota counties.
- There are four potential zones that could be exploited for both primary production and CO_2 EOR (see Figure 4.3). Widespread commercial production has been established in the Bakken and Upper Three Forks and encouraging results have occurred from pilot test programs in the Three Forks 2 and 3 zones.
- Recent estimates of OOIP range between 167 billion bbl and 900 billion bbl[85]. Primary oil production is expected to extract only 5–15 % of this oil. If CO_2 EOR could recover an additional 5% of that amount, the prize would be 8.4–45 billion bbl.
- The Bakken is on order of magnitude larger than all of the conventional oil field production in North Dakota. Conventional oil production in North Dakota peaked at 140,000 b/d in 1985 and has been declining ever since. On the other hand, Bakken production reached 1.1 million b/d in 2014 and is expected to peak at 1.4 million b/d in 2026.

[84] Kurtoglu, et al, Geologic Characterization of a Bakken Reservoir for Potential CO2 EOR, SPE 168915 / URTeC 1619698, 2013
[85] Hawthorn, et al, Laboratory Studies of MMP and Hydrocarbon Mobilization in Conventional and Bakken Plays using CO2, Methane and Ethane, EERC presentation at the 21st Annual CO2 Flooding Conference , 10–11 December 2015.

Figure 4.3



As the Bakken primary production begins to decline in the late 2020's, IHS forecasts that the oil price recovery will be well underway with oil prices in the \$80–90 range in real terms. Furthermore, infrastructure such as pipelines and gas processing facilities will already be in place so that potential additional production can be accommodated. If the technology also evolves to overcome the technical hurdles and uncertainties by that time, the confluence of these factors could spur commercial development of CO_2 EOR.

Some key questions and concerns about the reservoir remain and are being addressed through laboratory modeling and field injection test work. These concerns include:

- Heterogeneity of the rock: While we understand the stratigraphy, rock types and depositional systems of the Bakken, local and regional changes in porosity, permeability, and mineralogy will affect the ability of CO_2 to move through the rock and displace the oil.
- Since micro-fractures will play a key role as conduits for CO_2 and oil movement, their extent, size and quantity will vary across the play, thus leading to unpredictable results.
- We still don't fully understand the mechanisms for CO_2 being able to enter the small pore spaces and rock matrix and how it will react with the oil; or in other words what will be the requirements for the miscible process to work within such tiny pore spaces.
- There is still much to learn about what goes on inside the reservoir during primary oil recovery and how those processes may affect CO_2 EOR.

As more work is done, we will better understand all of the factors required for success and will be able to ultimately determine development programs that will optimize the process. The following sections briefly summarize the work that has been done, lessons learned and how some of the results could be applied to a production and drilling forecast.

4.2.2 Laboratory work and modeling

2.2.2.1 Laboratory work

Doing scientific experiments in the laboratory is the first step to moving good ideas from the "concept" to "proof of concept" and ultimately the "implementation stage". Tests are performed on specially prepared rock samples and cores obtained from the field and observations are recorded. Areas of investigation include:

- Detailed studies of the rock matrix, including porosity and permeability
- The nature, size, orientation, and amount of micro fractures
- Oil and CO_2 movement through the rock
- The effects of CO_2 on the oil and how it causes the oil molecules to swell or reduce viscosity
- The ability of CO_2 to remove oil from the tiny pore spaces and rock matrix
- Pressures and temperatures required to achieve MMP in low porosity and permeability reservoirs

Results of laboratory work performed to date are encouraging for CO_2 EOR in the Bakken. Experiments show that water is not effective, but that CO_2 is highly effective in releasing virtually all of the oil from the core samples over a period of several hours. Key to the process is the development of a conceptual model for how CO_2 and oil interact within the rock itself.[86] Studies performed by EERC show that:

- CO_2 will quickly move through induced fractures and will need time to "soak" into the rock matrix, before a production response is detected.
- Micro-fractures play a significant role in connecting induced fractures to the rock matrix.
- Unlike conventional CO_2 EOR, CO_2 is not able to sweep oil through the rock in "tight oil" reservoirs, but requires a much slower process of "bathing" the rock in order to move oil out into the induced fractures where it can ultimately flow to an induced fracture and producing well bore.

These findings suggest that when developing a production and drilling program for EOR in the Bakken we should

- add several months between CO_2 injection and production response;
- increase the amount of CO_2 needed per barrel of oil to 11–14 Mcf/bbl range which is higher than for most conventional CO_2 EOR rates—higher pressures will be needed; and
- recover and recycle only 20% of the CO_2 instead of the 40–50% normally recovered from conventional production since more CO_2 is likely to remain in the rock matrix because of the "bathing" process.

[86] Harju, Overview of the EERC's Bakken CO2 EOR Research Programs, 8th Annual Wyoming CO2 Conference, July 9, 2014

While CO_2 EOR is the focus of this study, we make mention of other injectable gases which could potentially be used in lieu of CO_2 for EOR activities. Field gas, which generally consists of a mix of methane and other natural gas liquids (NGLs), including ethane, is produced as associated natural gas within the field and could be more easily accessible.

Laboratory tests conducted by the EERC demonstrate that ethane is more effective at recovering oil at similar MMP than CO_2[87]. However, pure ethane is more expensive than either CO_2 or methane and it would have to be transported back to the injection site from a gas processing facility. A more likely solution would be to inject a rich mixture of methane–ethane. The Bakken associated gas is rich containing a mole 15–25% ethane. While this mixture is less effective than pure CO_2 it nevertheless could be an effective alternative solution because of local availability.

4.2.2.1 Modeling

Computer modeling of CO_2 EOR in the Bakken utilizes a commercial program which simulates or projects the results of a small scale development scenario. This modeling typically utilizes one to four producer–injector horizontal well pairs in a confined area of about one to four square miles. Input variables are required and include rock type, porosity/permeability, water saturation, oil properties, thickness, depth, induced and natural micro fracture analysis, pressure and temperature.[88]

Output results from these modeling exercises include oil recovery, production profiles, and CO_2 usage. Because the model output is quantifiable, we have relied heavily on published literature results of the Bakken CO_2 EOR modeling to inform our production and drilling forecast assumptions. Furthermore, development plan input such as the ratio of injectors to producers and well spacing were also useful in helping us to design appropriate drilling configurations which can be scaled for a large regional development plan and production outlook. Our use of modeling results will be discussed in more detail in Section 4.2.4 when we describe the production and drilling forecast assumptions.

In general, the modeling results have been encouraging; however, the following cautionary points need to be emphasized:

- Modeling programs have been developed primarily for CO_2 EOR in conventional reservoirs, and as such may not adequately address the additional complexities of a "tight oil" reservoir.

- Models by their very nature rely on a relatively simple set of input variables and assumptions; thus generally failing to capture the multiple phases, complexities and heterogeneities of a "real world" reservoir situation. CO_2 EOR modeling in "tight oil" reservoirs such as the Bakken requires additional "hard to measure and obtain" variables to adequately address the complexities of the reservoir.

- The results from some initial injection testing in the Bakken did not produce the same robust results as some of the modeling exercises.

- The results of the several modeling exercises that we reviewed are highly variable, so we have had to rely on values somewhere between the high and low values for our modeling assumptions.[89]

Despite this cautionary approach, modeling will continue to play a valuable role in helping transition from the purely technical perspective to a commercial and economic outlook. Future improvements will include specialized functions that address unconventional reservoirs, more robust data that can be applied within the models and a better correlation between what is learned in the field from injection tests and pilot programs and model output.

[87] See Hawthorn, et al, note 85 supra.
[88] Shebaz Shoaib, B. Todd Hoffman, CO2 Flooding the Elm Coulee Field, SPE 123176, 2009; Dong, et al, Modeling Gas injection into Shale Oil Reservoirs in the Sanish Field, North Dakota, SPE 168827 / URTec 1581998, 2013.
[89] Id.

4.2.3 Injection tests

4.2.3.1 Injection tests in the Bakken

Between 2008 and 2014, five injection tests were conducted in the Bakken. Specific injection test details and data were obtained from the NDIC database and the IHS well and production database. A brief summary of some of the injection tests is shown in Table 4.1 and test descriptions are described below.

Table 4.1

Summary of Bakken injection test data

NDIC ID	Well direction	Operator	Fluid type	Flood date	Fluid amount	Production response
16713	Horizontal	EOG	CO_2	Sep 2008	5,580 Mcf	No
16713	Horizontal	EOG	CO_2	Oct 2008	15,119 Mcf	No
17170	Horizontal	EOG	Water	Apr 2012	10,380 bbl	No
17170	Horizontal	EOG	Water	May 2012	28,797 bbl	No
16986	Horizontal	EOG	Water	Apr 2012–Feb 2014	438,968 bbl	No
16986	Horizontal	EOG	Field gas	Jun 2014	4,598 Mcf	Yes
16986	Horizontal	EOG	Field gas	Jul 2014	50,871 Mcf	Yes
16986	Horizontal	EOG	Field gas	Aug 2014	33,260 Mcf	Yes
24779	Vertical	Whiting	CO_2	Feb 2014	10,000 Mcf	No

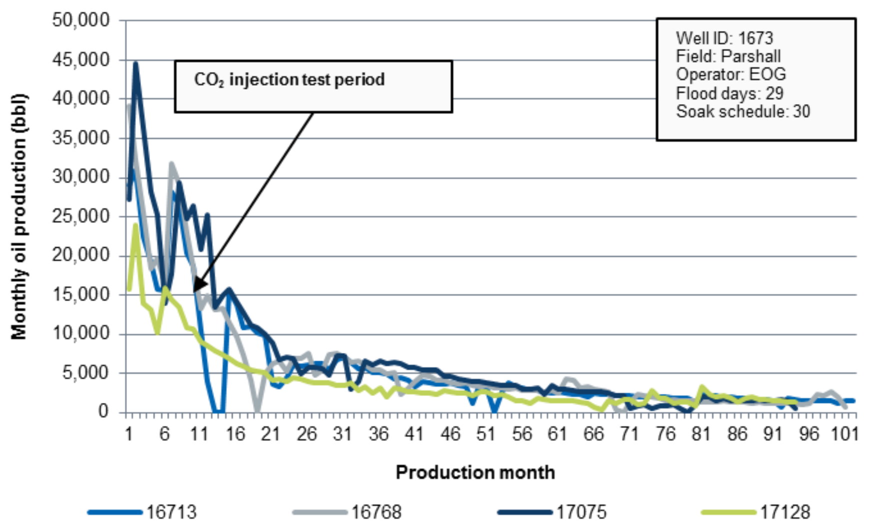
Source: IHS

Results of Well NDIC 16713 and offset wells

In 2008, EOG conducted an injection test using CO_2 EOR for horizontal well NDIC 16713 (API 3306100549) located in the Parshall Field of Mountrail County. The injection period lasted for 29 days (September–October 2008) with an additional 10 days of soak, after which the well was put back on production. Over the period, injection volumes totaled 30,519 Mcf. The normalized historical monthly oil production data for the test well and four offset wells, as shown in Figure 4.4, indicates that liquid production was not affected and the normal production decline trend was unaffected. This type of test where gas is injected and then the well put back on production is commonly called "huff and puff" and could be a possible method for future development.

Figure 4.4

Injection and offset wells—Monthly production comparison



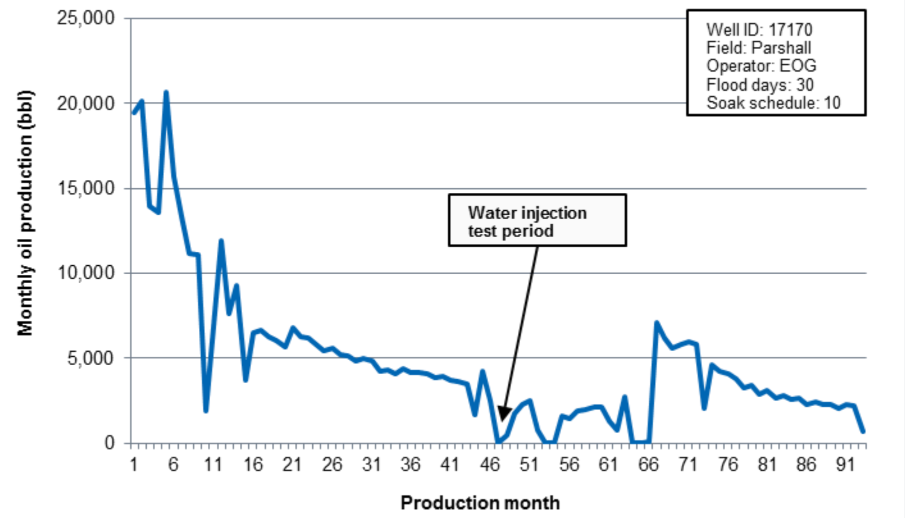
Source: IHS

Results of Well NDIC 17170

In 2012, EOG conducted another well test with water injection in the Parshall field, Mountrail County, using well NDIC 17170. Under a similar "huff-and-puff" scheme, the injection period lasted from April to May with a total injection water volume of just over 39,000 bbl. No other offset wells were investigated, but the monthly production data as shown in Figure 4.5 shows no observable improvement in oil production for this well. The results of this test corroborate results obtained in the laboratory, highlighting the ineffectiveness of water injection in the Bakken.

Figure 4.5

Injection well monthly production comparison



Source: IHS

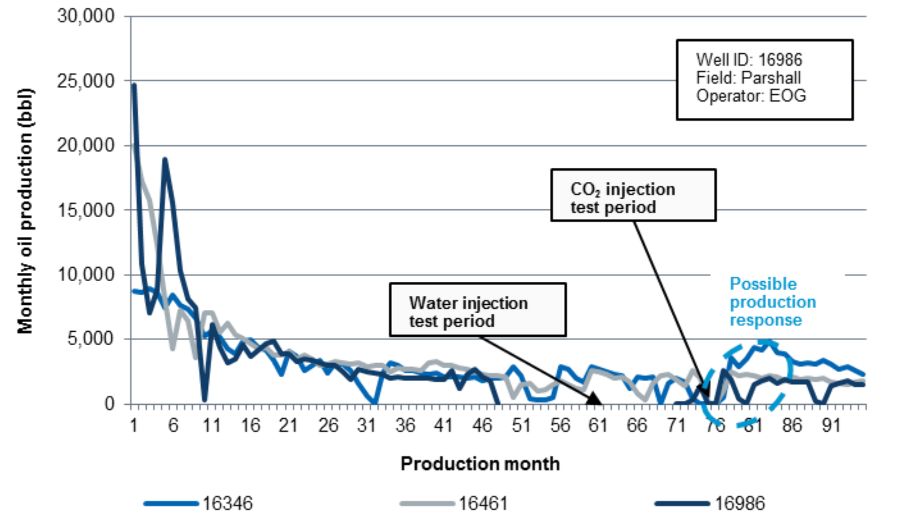
© 2016 IHS

Results of Well NDIC 16986 and offset wells

The third EOG injection well test NDIC 16986 combined both initial water flooding and later field gas injection. The water injection stage was conducted from April 2012 through February 2014 and the second stage of field gas injection lasted from June 2014 to August 2014 with a total injection volume of 90,000 Mcf. As shown in Figure 4.6, the injection test well was put back on production, but no production response was observed. However, the monthly oil production for offset well NDIC 16346, located less than one mile away, had increased after the field gas injection. Table 4.2 shows detailed oil production data over a six-month period before and after the field gas injection test from that well. Average post-injection six-month oil production is nearly two times higher than pre-injection volume.

Figure 4.6

Injection and offset wells—Monthly production comparison



Source: IHS © 2016 IHS

Table 4.2

Pre and post injection monthly oil production volumes from the NDIC 16346 offset well

Pre injection date	Monthly oil production (bbl)	Post injection date	Monthly oil production (bbl)
Dec 2013	2,120	Sep 2014	513
Jan 2014	n/a	Oct 2014	3,576
Feb 2014	1,648	Nov 2014	2,915
Mar 2014	1,955	Dec 2014	3,470
Apr 2014	1,714	Jan 2015	4,390
May 2014	396	Feb 2014	4,390
Average 6-month production	1,567	Average 6-month production	3,173

Source: NDIC and IHS © 2016 IHS

Results of Well NDIC 24779

Unlike the previous injection tests, NDIC 24779, operated by Whiting, is a vertical well test designed to only evaluate the injectivity of the Bakken and its suitability for CO_2 injection. Injection started in February 2014 with no current available results. Although results did not compare favorably with the CO_2 EOR results obtained from modeling, two encouraging criteria were established:

- Several of the tests proved that injectivity and movement of CO_2 and other gases into the Bakken was possible.
- One of the tests showed an increase in production response from injected field gas in an offset well.

A key observation is that water injection did nothing to increase production, and it could be argued that in the NDIC 16986 well, it may have actually dampened a possible production response when the well was put back on production. While the industry has gained some insight from field tests, injection test results are variable and the sampling is extremely small, so more work is required before definitive conclusions can be drawn.

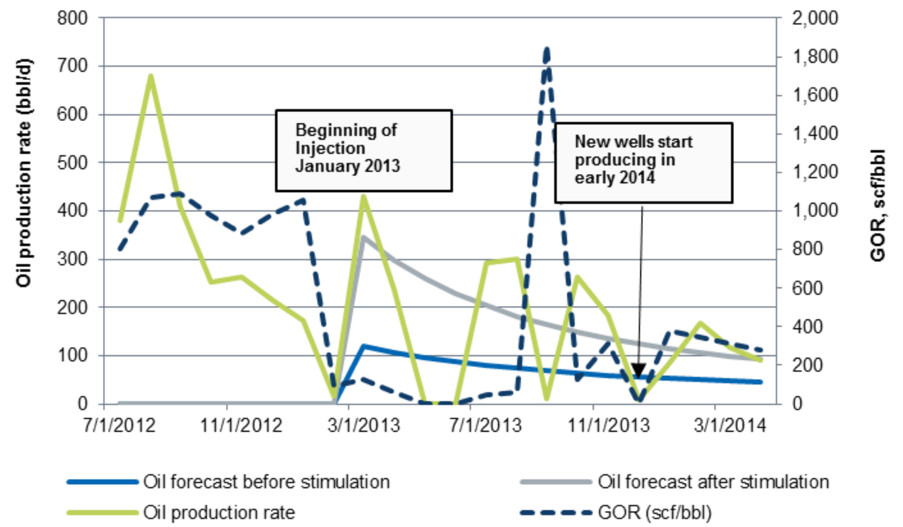
4.2.3.2 Multiwell pilot

Because field testing in the Bakken has been limited to single well injection tests, and no real multiple-well pilot program has been implemented, we turn attention to a multiple-well gas EOR pilot program performed in the Eagle Ford "tight oil" play, which was also conducted by EOG. The following is our summary of research and analysis from this encouraging test.

In its first quarter 2016 earnings release call, on 5 May 2016, EOG finally unveiled results from an EOR pilot project in Eagle Ford after three years of testing in its. According to EOG, this was the first successful EOR test in a US shale play using a proprietary technology developed by EOG. The pilot included 16 wells which made use of produced gas readily available at the field site. While a lot of information has been made public, EOG did indicate that the results of the pilot testing would increase recovery by 30–70%—all delivered at potential costs of $6.00/bbl or less using dry gas transported from their Marshall plant and injecting it into horizontal well bores at pressure of 12,000 psi.

Figure 4.7

Steen Scrugs 1H



Source: IHS © 2016 IHS

Though field gas, not CO_2, was the injected gas, a miscible process was confirmed by EOG management. Our research and analysis determined that EOG's first EOR test well was the Steen Scruggs No 1 well located in Gonzales County, and that the well was tested with gas injection to enhance oil production in early 2013. At that time, this well was the only producing well located on the Scruggs ease, so we were able to track production history and response from field gas injection and analyze the results using monthly production reported to the state. This well used cyclic gas injection (huff and puff) with the dry gas. Our production forecast indicates that this technique achieved a 60% uplift in recovery. The elevated gas oil ratios (GOR) shown in Figure 4.7 clearly indicate periods of gas injection, followed by elevated oil production rates.

We applied production decline profiles to the original production profile and to the enhanced production profile to determine an incremental production amount and to assess the actual incremental production profile. Results shown in Table 4.3 indicate that approximately 65,000 b/d or a 60% uplift could be achieved.

Table 4.3

Comparative decline curve of Scruggs 1H well

Period	Total well EUR (bbl)	Remaining oil (bbl) at injection date	Type curve B-factor	Type curve initial decline rate (%/year)	Terminal decline rate (%/year)
Before injection	178	93	0.8	61	5
After injection	243	158	0.6	72	5

Source: IHS © 2016 IHS

While the results of the overall 16-well program were not disclosed, the enthusiasm of EOG management in the 5 May investor call and the documented results of the Steen Scruggs 1H suggest that there is reason to be optimistic that significant production increases can be achieved by injecting a gas such as a methane/ethane mix or CO_2 rich gas into a producing well. We are hopeful that additional disclosure of pilot test results will help us understand whether or not huff and puff production or offset well production will be most effective going forward.

4.2.4 Proposed production and drilling forecast

While we have been able to get insights from laboratory work, modeling and field testing, many questions remain unanswered and uncertainties remain high regarding key parameters for a CO_2 EOR production and drilling forecast. Ongoing testing will be required to determine optimal production responses, incremental recovery factors, distance from injector to producer, whether or not "huff and puff" will be viable, and the amounts of CO_2 or other gas needed for each barrel of incremental oil production. Nevertheless, results to date suggest that CO_2 EOR could be commercially viable in the foreseeable future, particularly in light of a forecasted oil price recovery and continued technological advances.

4.2.4.1 Bridging the gap between current technical results and potential economic recovery

In order to build a production and drilling forecast which will serve as the foundation of an economic impact study we will relied on the following knowledge and research:

- Lessons learned from laboratory work, modeling and field testing as it applies to EOR in the Bakken,
- Well documented historical results of production using CO_2 EOR in conventional reservoirs, and
- Our wealth of knowledge pertaining to primary production within the Bakken.

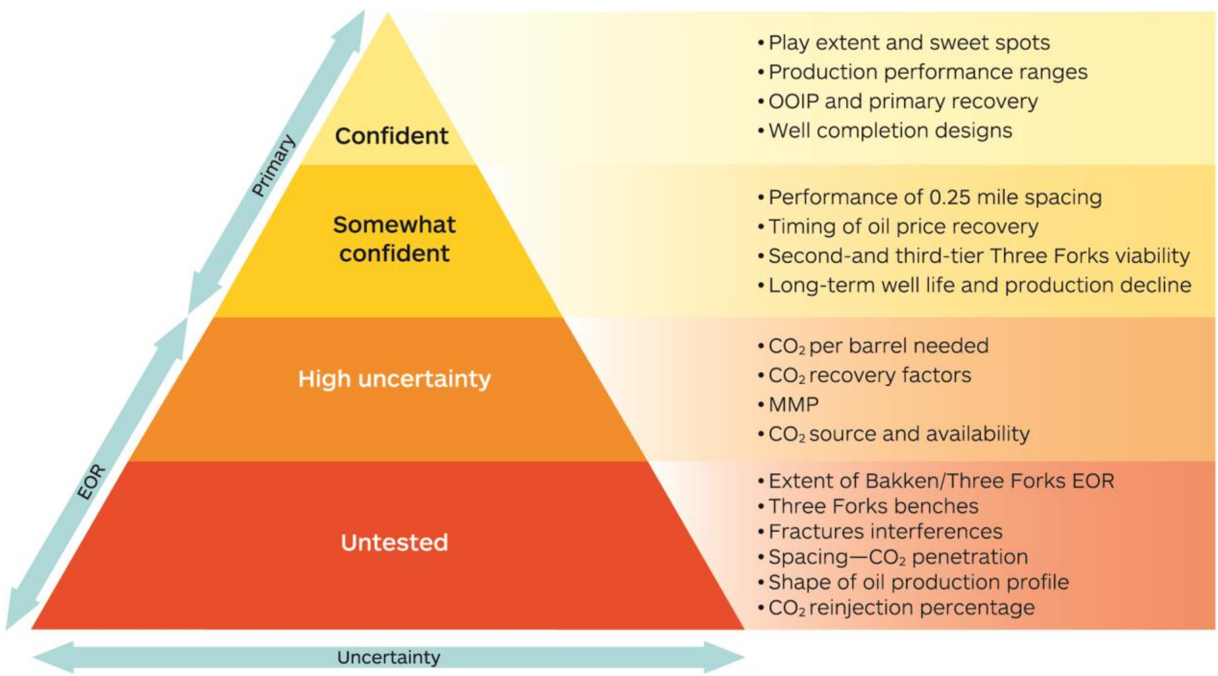
Ultimately field development and production from the Bakken will most likely be a gradual transition from primary production to EOR which will utilize a combination of CO_2 and/or field gas. Based on results obtained to date, we believe that water flooding will not occur. Furthermore, while additional capital outlays will be needed for processing and transport facilities directly related to CO_2 EOR, much of the needed infrastructure such as wells and oil transport will already be in place, thus offering an additional incentive to move forward.

4.2.4.2 The range of uncertainty about the Bakken

As we began the process of constructing production and drilling cases, it was critical that we take a step back to identify and classify what we know and do not know into groups or "buckets" of uncertainty (see Figure 4.8). It is clear that the industry has a good understanding about the issues listed in group 1, while little is known about those listed under group 4.

Figure 4.8

Bakken/Three Forks—Degree of uncertainty



Source: IHS

Figure 4.8 further illustrates that we can be much more confident about issues related to primary production, but as we transition to issues related to EOR, the gap of uncertainty widens considerably. Nevertheless ultimate commercial success is going to be contingent upon each issue regardless into which group it may fall. As discussed below the issues in each group are related to maturity and de-risking of the play.

Group 1 issues indicate that the Bakken is a mature play well entrenched in manufacturing mode. Companies continue development despite low oil prices because they know where to drill profitably. Operators know what type of wells to drill, where to drill them, and what type of production performance to expect. The production potential can be easily predicted and ultimate value can be obtained with relatively no guess work.

Group 2 addresses the upside of primary production which includes closer spacing, additional producing zones, and longer term well optimization. Since future production performance and breakeven costs are more uncertain, much of the commercial success in the Bakken will be contingent on an oil price recovery. The results here will also influence the timing and scope of future CO_2 EOR; and thus we have to address some uncertainty before as we consider other factors directly related to EOR in groups 3 and 4.

Groups 3 and 4 are directly related to CO_2 EOR and address an additional higher level of upside potential which is less clearly defined and for the most part has not been established.

4.2.4.3 Primary production and drilling outlook

IHS developed a production and drilling forecast by county for each of the seven North Dakota counties associated with primary production activity from the Bakken. We analyzed four areas within the boundaries of the Bakken and Three Forks plays (Figure 4.9) and applied the analysis from these four areas to each of the seven counties as per Table 4.4.

Table 4.4

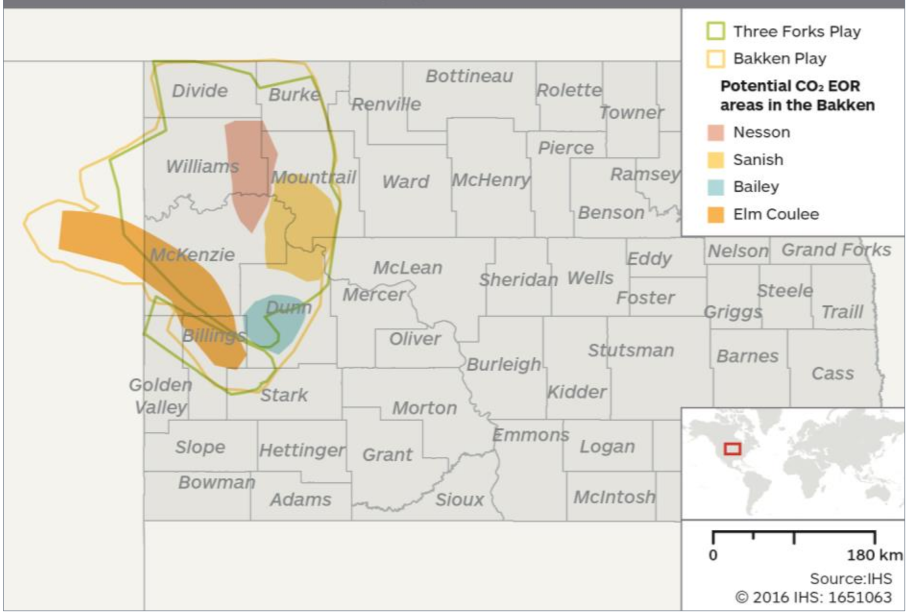
Sections of the Bakken incorporated in the analysis

Section of the play	Characterization/counties
Sanish	Sweet spot
	Mountrail
Nesson	Recently developing highly productive area
	Williams
	McKenzie
Bailey	Less productive
	Dunn
Elm Coulee	Considered fringe with lower potential
	Billings
	Burke
	Divide

Source: IHS

Figure 4.9

Extent of Bakken/Three Forks play and the areas modelled for CO_2 EOR.



Relying on our knowledge of the primary Bakken production, we applied the following assumptions to build the foundation for the production and drilling forecast:

- **Extent and sweet spots:** While the potential for CO_2 EOR is possible throughout the entire 10,700 square miles of the play, the mix of geologic and reservoir properties that contribute to the best areas of primary production are likely to favor CO_2 EOR in those same areas. For example we assumed that the best results would occur in the Sanish "Sweet Spot" of the play where production performance per well has been the highest. Not coincidentally, this is where all of the recent field injection testing has been performed. By carrying this idea a step further we established a relationship or correlation between primary production performance and potential EOR performance throughout the play.

- **Well completion design and spacing:** The Bakken is a mature play and the well and completion designs are well established. Lateral lengths average 9,500 feet and producing wells are spaced about 0.25 mile (1,320 feet) apart in both the Middle Bakken and Upper Three Forks. We concluded that this pattern would likely be utilized and incorporated into future CO_2 EOR efforts.

- **Producing zones:** Since commercial production is well documented in the Middle Bakken and Upper Three Forks, but still has not been established in the Lower Three Forks benches, we applied our modeling to the Middle Bakken and Upper Three Forks and omitted the Lower Three Forks zones.

For each of the four areas analyzed we calculated an OOIP per square mile and an average estimated ultimate recovery (EUR) for each well. We noted that at 0.5 mile (2,640 feet) spacing, each 9,500-foot horizontal well occupied about one square mile and at 0.25 mile (1,320 feet) spacing each well occupied one-half square mile. From these calculations we were able to estimate approximate primary oil recovery factors as shown in table 4.5.

While the results shown in Table 4.5 may be subject to interpretation, these analysis used real geologic data to calculate the OOIP and historical production data to determine the EURs, thus enabling us to begin the CO_2 EOR incremental production and drilling forecasting process on a sure foundation of primary oil recovery.

Table 4.5

Calculation of the Bakken primary recovery factors

Section of the play	Original oil in place/mi^2 (thousand bbl)	Expected ultimate recovery/well (thousand bbl)	Primary recovery factor (1/2 mile spacing, %)	Primary recovery factor (1/4 mile spacing, %)
Sanish	9,078	501	5.5	11.0
Nesson	6,736	440	6.5	13.1
Bailey	5,270	374	7.1	14.2
Elm Coulee	4,815	189	3.9	7.8

Source: IHS

4.2.4.4 Incremental drilling and production outlook

In addition to our observations and assumptions related to primary oil production, several other assumptions were needed in order to create the production and drilling forecast cases. Each of these assumptions is directly related to CO2 EOR (with inherent high ranges of uncertainty). These assumptions include:

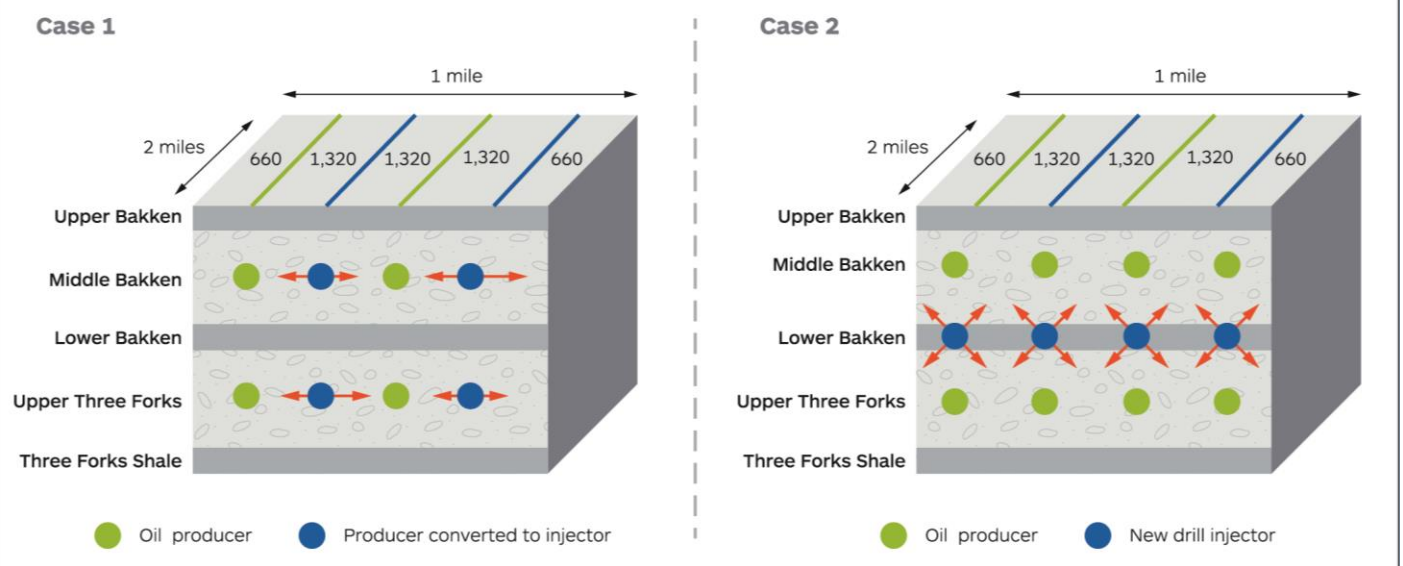
- A drilling configuration and program which includes injector and producer wells
- Average incremental production profiles for producing wells
- Total number of locations within the Bakken and Three Forks
- Quantities of CO_2 needed

4.2.4.4.1 Drilling program and configuration

Development plans for CO_2 EOR had to be predicated on a primary development plan of active producing wells in the Middle Bakken and Upper Three Forks with laterals averaging approximately 9,500 feet in length and spaced 0.25 mile (1,320 feet) apart. We noted that there could be a number of CO_2 EOR development scenarios that would utilize this primary development plan; however, we proposed two cases which are depicted in Figure 4.10.

Figure 4.10

Drilling configurations



Source: IHS

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Case 1 is based on the assumption that alternating producers will be converted to gas or CO_2 injectors at a relatively modest cost, after an area of several square miles has been completely drilled out within the Middle Bakken and upper Three Forks. The injector wells will be used exclusively for injection of CO_2 or field gas at high pressures which will be needed to reach MMP and all incremental production will flow from the alternating pre-existing producing wells. A portion of the injected CO_2 will be recovered from the produced oil, and then recycled for future injection. This configuration will avoid the high capital expenditures needed to drill and complete new injection wells.

Case 2 is based on the assumption that new injector wells will need to be drilled. Some studies[90] suggest that optimal recovery of oil using CO_2 EOR will need to occur at a closer spacing than the 0.25 mile separation depicted in Figure 4.10, thus a 0.125 mile (660 foot) separation between injector and producer may be required. Since producer wells are unlikely to be drilled any closer than a 0.25 mile separation within the same Middle Bakken or Three Forks zone, some additional infill injector wells will be required to achieve an optimal recovery. We therefore assume under this scenario that injector wells are drilled in the Lower Bakken in between producing wells, so that one injector well will be paired with a producing well from both the Middle Bakken and Upper Three Forks. This drilling configuration is considered a contingency case that would apply only if operators were not able to effectively convert producers to injectors.

4.2.4.4.2 Drilling program and configuration

We applied an oil recovery factor of 5% for the Case 1 drilling configuration and 7.5% for the Case 2 configuration. The 50% recovery uplift for Case 2 was attributed to the much closer spacing of the injector wells which could access a higher volume of oil. Because there was not any history of CO_2 EOR production from “tight oil” reservoirs, we based these assumptions on the following:

[90] Kurtoglu,Basak, Integrated Reservoir Characterization and Modeling in Support of Enhanced Oil Recovery of Bakken, Williston Basin Petroleum Conference, North Dakota, 21 May 2014.

- Previous CO_2 EOR Bakken modeling studies[91]: Simulations have been performed at Bailey, Sanish-Parshall, and Elm Coulee by several companies or individuals. Approaches, inputs, and attention to detail are variable and several drilling configurations have been proposed, which has resulted in a wide range of incremental recovery factors ranging between 0.5–24%. Although the range of uncertainty is wide, we have some boundaries to work with, and our 5–7.5% estimates fall in the middle to low end of the ranges derived from the studies reviewed.

- Conventional CO_2 EOR comparisons: Primary production from conventional fields averages a wide range of 15–40% of OOIP. Historical incremental oil recovery from conventional EOR Projects ranges from 4–18% of OOIP. Modeling of CO_2 EOR recovery from North Dakota conventional fields ranges from 4.6–16.8%. These results suggest that CO_2 EOR recovers an additional amount of oil which is about 30–50% of the primary recovery. Since we anticipate that primary oil recovery from the Bakken will range between 8–14% for the one-quarter-mile spacing, the lower CO_2 EOR recoveries of 5–7.5% would follow a similar pattern of 30–50% of anticipated primary recovery from the Bakken.

Applying the Case 1 and Case 2 incremental recovery factors in each area produces the estimated per well recoveries shown in Table 4.6. While the Case 2 overall recovery is higher, per well recovery is lower since there will be two producers for each injector well (each occupying ½ square mile), whereas, there is only one producer well for each injector well (each occupying 1 square mile) for Case 1.

Table 4.6

Calculation of the Bakken primary recovery factors

Section of the play	OOIP/mi^2 (thousand bbl)	Case 1—expected ultimate recovery/well (thousand bbl)	Case 2—expected ultimate recovery/well (thousand bbl)
Sanish	9,078	454	340
Nesson	6,736	337	253
Bailey	5,270	266	200
Elm Coulee	4,815	241	181

Source: IHS

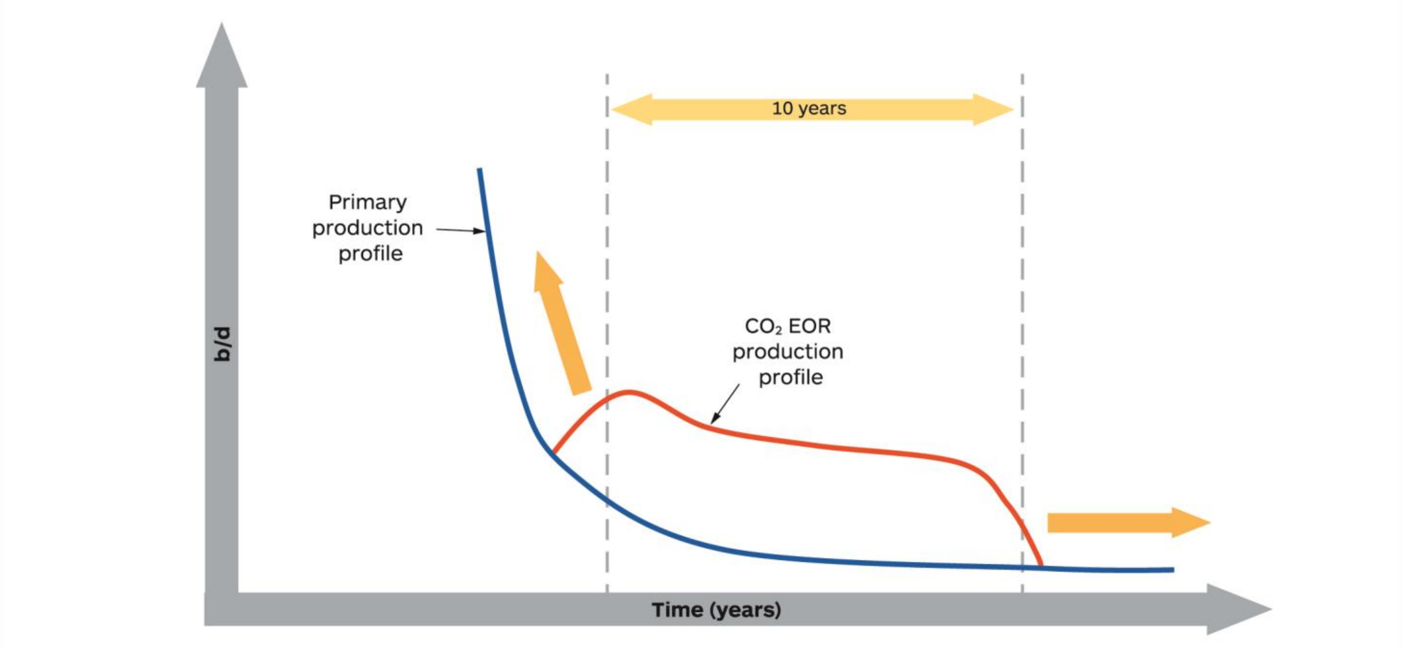
Estimating the EUR per well allowed us to generate an incremental production profile for each well which distributes the incremental recovery over a period of time. Conceptually, we expected that once oil began flowing through the production well, the rate would be fairly constant because of a continuous flow of CO_2 from the injector wells through the reservoir, thus we agreed with previous work[92] which suggested a flat production profile for a number of years. In our forecast, the production profile occurs over a 10-year period before a rapid decline and termination (see Figure 4.11).

[91] Kurtoglu,Basak, supra—implies a 0.5% recovery factor at the Bailey field using CO2 injection. See Shoaib, supra note 88—indicates an 18–20% recovery uplift with continuous CO_2 flood, but only a 1% recovery using huff and puff; Dong, et al, note 88 supra—indicates a range of recovery factors at Sanish including a 5.48% recovery from a 1 injector producer pair, 9.45% from two injectors, and a 24.6% recovery from a four injector configuration; Liu, et al, CO_2 Base Enhanced Oil Recovery from Unconventional Reservoirs: A Case Study of the Bakken Formation, SPE 168979-MS, 2014, indicates a 43% and 58% uplift in primary production at Bailey and Grenora fields.

[92] Shoaib note 88 supra—shows production increases due to solvent injection relative to the primary production profile; Dong, et al, note 88 supra—shows slightly increasing, but relatively flat incremental increases relative to the primary production profile.

Figure 4.11

Schematic presentation of unconventional well CO_2 EOR production profile



Source: IHS

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Figure 4.11 also illustrates how an incremental production profile might be superimposed onto the primary production decline profile; however, it was impossible to predict the onset of incremental production timing for any single well as there were many factors which could influence this, such as initiation of injection in relation to primary production, well production in relation to surrounding wells and infrastructure availability. Given this timing uncertainty, we did not attempt to directly relate incremental production to primary production on a well-by-well basis, but instead created county and play level incremental production forecasts that could be layered on top of the county and play level primary forecasts during the economic analysis.

4.2.4.4.3 Drilling locations

Within the seven North Dakota Counties, the Bakken play covers 10,399 square miles and the Three Forks 9472 square miles. If this area were 95% developed at a 0.25 mile (1,320 spacing) with lateral lengths of 9,500 feet in both the Middle Bakken and Upper Three Forks, we could add another 29,000 wells over and above the 10,000 wells already producing. When considering the potential impact of wide spread CO_2 EOR development in the Bakken, we had to consider how much of that total area could be developed, which in turn would drive the total incremental oil recovery and magnitude of the production profile.

Given the current ranges of uncertainty and the lack of any CO_2 EOR activity in the Bakken, we needed to strike a balance between being conservative in our risking of the play, yet on the other hand presenting scenarios that allowed us to apply a similar degree of scalability that we saw in the successful “tight oil” plays. In other words if CO_2 EOR were indeed to become a reality in the Bakken, then it would likely occur on a massive scale. On the other hand, this potential impact needed to be balanced with persistent concerns regarding areas of uncertainty that pose a risk to developing the full play which include:

- The successful advancement of technology that will enable development despite concerns about geologic and reservoir properties;
- Access to sufficient quantities of CO_2 (or other injectable gas) at reasonable prices;

- A strong and sustainable long-term oil price recovery that will contribute to profitability; and
- A strong enough position within the producers' portfolio that investments will flow here instead of elsewhere.

In light of these concerns, our production and drilling forecast would utilize 20% of the area in the Mountrail, McKenzie, Dunn and Williams Counties, which are considered core areas and 13% of the area in Billings, Burke and Divide Counties, which are classified as fringe counties. This meant that:

- For Case 1, there would be 3,626 producers converted to injectors, and 3,626 producers that would benefit from the production uplift, and
- For Case 2, there would also be 3,626 new injector wells drilled which would enable 7,151 producer wells to benefit from production uplift.

4.2.4.4.4 Quantity of CO_2 needed

For the Case 1 drilling configuration we projected a CO_2 requirement of 14.5 Mcf/bbl and for Case 2 we projected a CO_2 requirement of 11.3 Mcf/bbl. Within Case 2 injection wells are located only at 660-foot distance from the producers, whereas they are 1,320 feet away in Case 1, hence the usage per barrel of oil is projected to be lower for Case 2. Here again the lack of any history required us to base these assumptions on the following:

- Previous CO_2 EOR Bakken Modeling Studies[93]: A few of the Bakken CO_2 EOR simulations which have been performed include CO_2 usage ranging from 0.13–33 Mcf/bbl. This wide range poses a challenge since there is a difference of two orders of magnitude between the low and high values. CO_2 averages of 11.3 and 14.5 Mcf/bbl from two simulations at the Bailey field are in the mid-range of these end-points and are similar to conventional field requirements.
- Conventional CO_2 EOR comparisons: Historically CO_2 requirements in conventional fields have been in the 5–8 Mcf/bbl range. Recent simulations performed for conventional fields in North Dakota by IHS produced a somewhat higher range of 5–23 Mcf/bbl with most of the fields requiring between 9 and 16 Mcf/bbl. Given the lower porosity and permeability of the Bakken, additional CO_2 may be required to dislodge the oil; hence the higher usage factors of North Dakota may be more applicable to the amounts of CO_2 needed.

As previously mentioned, about 20% of the injected CO_2 will be produced with the oil and re-injected, nevertheless, by the time that production ramps up to projected levels, Case 1 CO_2 usage will be 1.86 Bcf/d (35.2 MMt/y) and for Case 2 it will be 2.18 Bcf/d (41.3 MMt/y). These amounts are 15,220 times higher than the 0.133 Bcf/d (2.52 MMt/y) currently being produced in North Dakota. In our forecast we determined not to limit the use of CO_2 because of a lack of sourcing.

4.2.5 Technical incremental recovery potential

The forecast projected in this section focuses on the technical incremental recovery potential of the Bakken for the two scenarios developed for this study. This information serves as an input to the economic model which schedules the development of the various sections of the play based on the economic viability of the project in any particular year during the 20-year time frame. Table 4.7 shows a breakdown of the technically recoverable EOR resources by county and the respective CO_2 volumes for each case.

---

[93] Kurtoglu,Basak, note 84 supra—indicates 11.3 to 33.7 Mcf/bbl of oil ratio; Dong, et al, note 88 supra—indicates 1.15 Bcf of CO_2 for 3.4 MM bbl of oil (.338 Mcf/bbl of oil ratio); Liu, et al, note 91 supra—indicates 5.86 to 23.17 Mcf/bbl of oil ratio.

Table 4.7

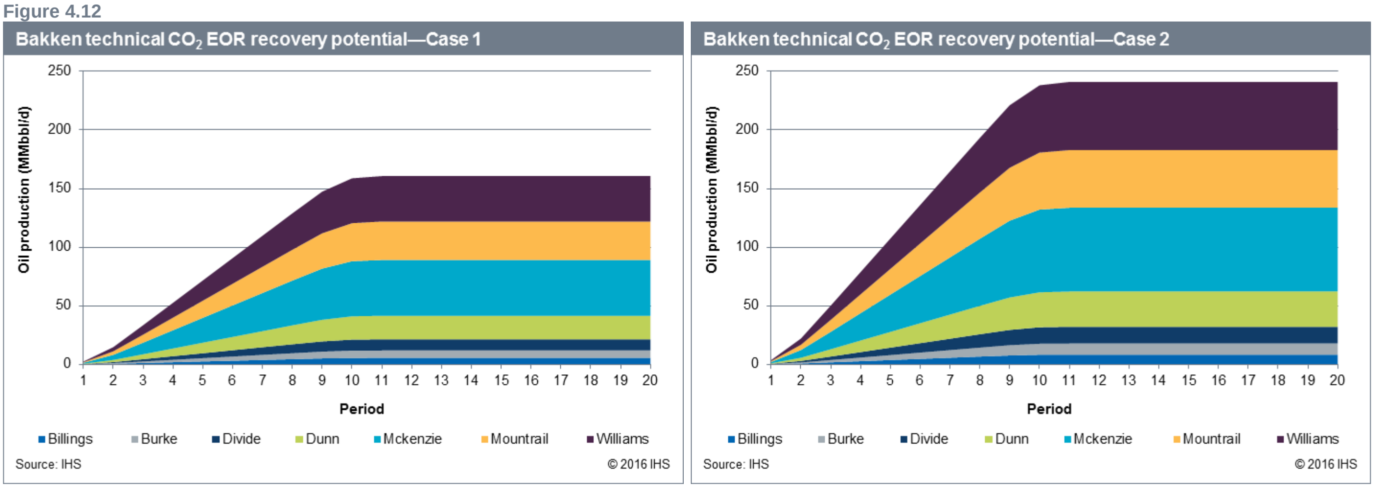
Total technically recoverable incremental production and CO_2 requirements

County	Case 1 resource (MMbbl)	Case 1 CO_2 requirement (Tcf)	Case 1 CO_2 requirement (MMt)	Case 1 resource (MMbbl)	Case 1 CO_2 requirement (Tcf)	Case 1 CO_2 requirement (MMt)
Billings	42.63	0.62	32.08	63.95	0.72	37.50
Burke	44.27	0.64	33.31	66.40	0.75	38.94
Divide	71.36	1.03	53.70	107.04	1.21	62.77
Dunn	149.50	2.17	112.50	224.25	2.53	131.50
McKenzie	348.90	5.06	262.54	523.36	5.91	306.90
Mountrail	242.02	3.51	182.11	363.02	4.10	212.88
Williams	281.95	4.09	212.16	422.93	4.78	248.01
Total	**1,180.63**	**17.12**	**888.39**	**1,770.95**	**20.01**	**1,038.49**

Source: IHS

These forecasts were intended to transpire over a 20-year period that could begin as early as 2017. However, the economic modeling (with an oil price forecast built into it), dictates the actual start year and the amount of production that will economically contribute to the production and drilling forecast during the next 20 years. In other words, this would be considered a technical production and drilling forecast, which we would expect to be constrained somewhat by low oil prices and other factors that could render a portion of it uneconomic.

Figure 4.12



The bottom line is a potential incremental recovery over a 20-year period of 1.18 billion bbl and 1.77 billion bbl for Case 1 and Case 2 respectively. CO_2 requirements are 888 MMt and 1,038 MMt respectively.

These totals fall in a mid-range of a total potential range proposed by EERC[94]:

- EERC—DOE methodology
  - Incremental yield: 0.42 to 0.67 billion bbl
  - CO_2 usage: 121 to 194 M tons

[94] Sorensen, James, Characterization and Evaluation of the Bakken Petroleum system for CO2 Storage and Enhanced Oil Recovery (EOR), 2015 Wyoming EOF CO2 Conference, 16 July 2015.

- EERC—Reservoir properties approach
    - Incremental yield: 4.0 to 7.0 billion bbl
    - CO_2 usage: 1,900 to 3,200 M tons

Although the approaches, assumptions and methodologies differ, the proposed potential is on the same order of magnitude.

4.3 CO_2 EOR potential of conventional production units

4.3.1 Reservoir screening of North Dakota conventional production units

Although CO_2 miscible floods have demonstrated promising outcomes through several commercial field operations, not all reservoirs are technologically or economically viable for CO_2 EOR. The first step in CO_2 EOR assessment is to conduct screening for the suitability of the field.

Previous studies have developed feasibility methodologies for application of CO_2 EOR process using a combination of screening and analytical methods. The criteria and the associated values from these studies were reviewed for comparison with the criteria IHS developed for the screening of North Dakota conventional production units.[95] IHS compiled a dataset of screening criteria based on worldwide commercial application of CO_2 EOR projects and their reservoir/operational parameters. Out of a database of over 100 CO_2 EOR projects, a set of screening criteria was assembled which is based solely on successful CO_2 EOR projects. Table 4-1 presents IHS' screening criteria and a summary of criteria that were available in published literature.[96]

Table 4.8

IHS screening criteria versus other publications

Reservoir parameter	National Petroleum Council 1976	M.A. Klins 1984	J.J. Taber 1997	J.L. Dickinson 2010	IHS
Depth, ft	>2,300	>3,000	>2,500	>2,500	>2,500
Oil gravity, API	>27	>30	>22	>22	>22
Viscosity, cp	<10	<12	<10	<10	<10
Oil saturation, %	>25	>25	>20	>20	>20
Temperature, F	<250	nc	nc	nc	>86

Source: 2015 IHS

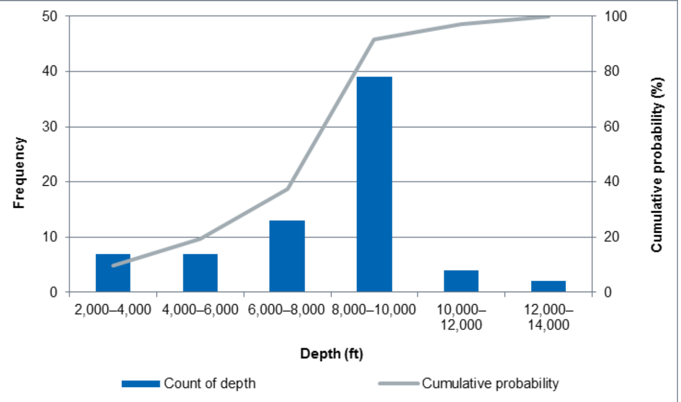
Reservoirs that failed to meet the above IHS screening criteria were excluded as candidates for CO_2 EOR potential. Reserves of oil in place were also taken into account in the screening process. Sufficient oil in place is necessary for the economic viability of the CO_2 EOR process. Figures 4.13–4.17 show the results of the statistical analysis that was used for each screening criteria.

[95] Shaw, J., Bachu, S., "Screening, Evaluation and Ranking of Oil Reservoirs Suitable for CO_2-Flood EOR and Carbon Dioxide Sequestration", JCPT, Vol. 41, No. 9, September 2002; Rivas, O., Embid, S., Bolivar, F., " Ranking Reservoir for Carbon Dioxide Flooding Processes", SPE Advanced Technology Series, Vol. 2, No. 1, 1994; Taber, J.J., Martin, F.D., Seright, R.S., "EOR Screening Criteria Revisted-Part 1: Introduction to Screening Criteria and Enhanced Oil Recovery Field Projects", SPE Reservoir Engineering, Vol. 12, No. 3, pp. 189-198, 1997; Ela, M.A.E., Sayyouh, H., Tayeb, E.S.E, "An integrated Approach for the Application of the Enhanced Oil Recovery Projects", Journal of Petroleum Science Research, Vol. 3, Issue 4, October 2014; Lake, L.W., Walsh, M.P., "Enhanced Oil Recovery (EOR) Field Data Literature Research", Prepared for Danish North Sea Partner, 2008; Adasani, A.A., Bai, B., "Analysis of EOR Projects and Updated Screening Criteria", Journal of Petroleum Science and Engineering, Vol. 79, PP. 10-24, 2011.

[96] Haynes, H.j., Thrasher, L.W., Katz, M.L., Eck, T.R., "Enhanced Oil Recovery: An Analysis of the Potential for Enhanced Oil Recovery from Known Fields in the United States", National Petroleum Council, 1976; Klins, M.A., "Carbon Dioxide Flooding: Basic Mechanisms and Project Design", International Human Resources Development Operation, Boston, Massachusetts, 267-275, 1984; Dickson, J.L., Dios, A.L., and Wylie, P.L. "Development of Improved Hydrocarbon Recovery Screening Methodologies", SPE 129768 presented at the SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, 24−28 April 2010.

Figure 4.13

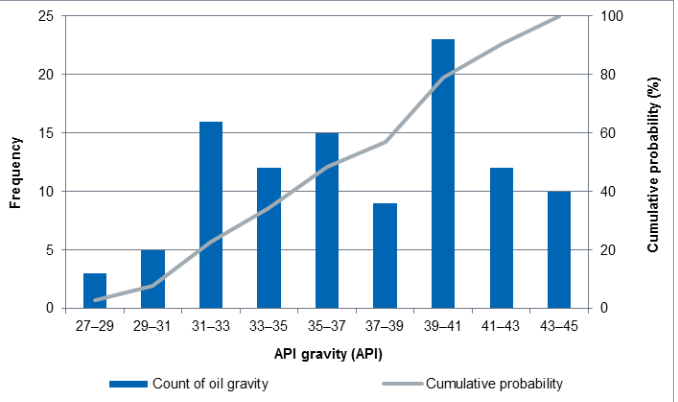
Range of reservoir depth for successful CO_2 EOR



Source: IHS © 2016 IHS

Figure 4.14

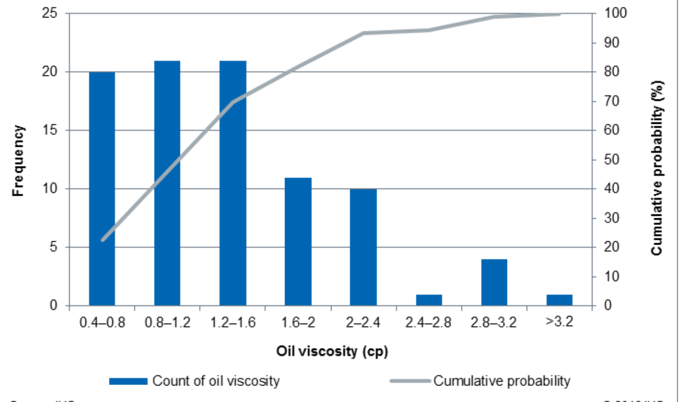
Range of oil gravity for successful CO_2 EOR



Source: IHS © 2016 IHS

Figure 4.15

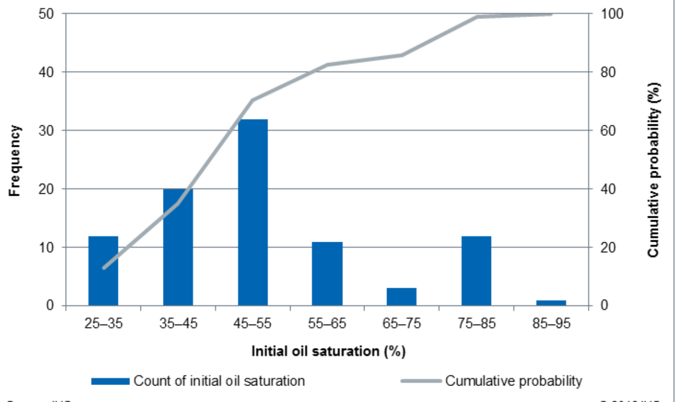
Range of oil viscosity for successful CO_2 EOR



Source: IHS © 2016 IHS

Figure 4.16

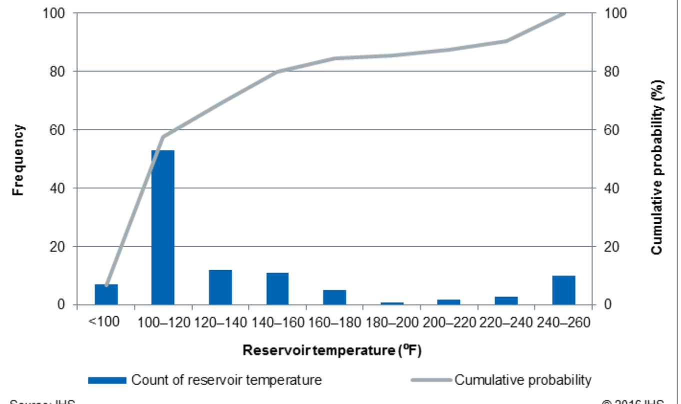
Range of initial oil saturation for successful CO_2 EOR



Source: IHS © 2016 IHS

Figure 4.17

Range of reservoir temperature for successful CO_2 EOR



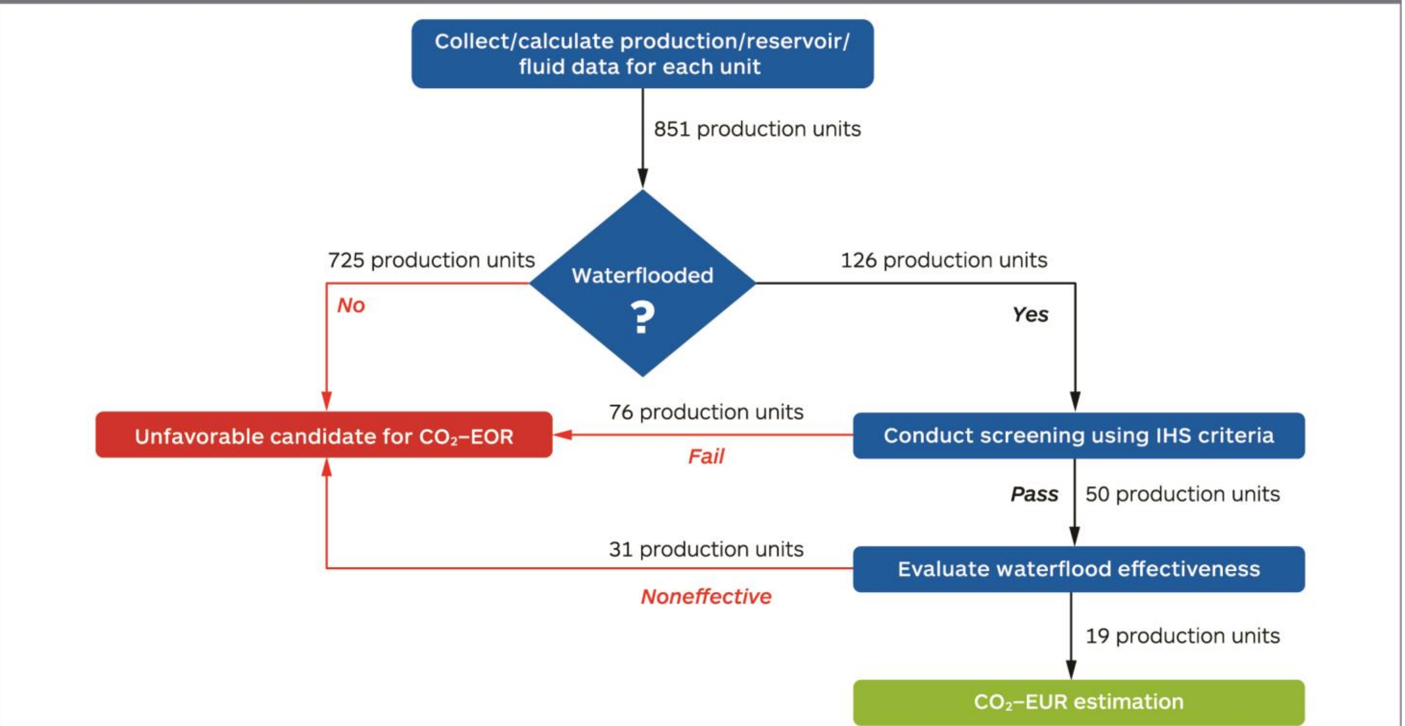
Source: IHS © 2016 IHS

There are over 800 conventional producing production units in North Dakota. However, not all these production units have satisfactory reservoir and fluid properties for application of the CO_2 EOR process. Data related to some production units was not available with regard to parameters such as reservoir temperature, pressure, or oil viscosity. As such, this study utilized both IHS' database and information in the public domain to develop three correlations to calculate the missing parameters for North Dakota production units. These correlations provide reasonable estimates for reservoir pressure (P_R), reservoir temperature (T_R), and oil viscosity (μ_O). Once values for the missing parameters were generated, we then conducted a complete screening of the production units. For further information on these correlations see Appendix A.1.

IHS developed a screening procedure that incorporates static and dynamic screening criteria. Static screening examined all production units against the IHS screening parameters. Dynamic screening focused on operational successes (such as efficiency of a waterflood scheme in each production unit). The rationale behind the dynamic screening is that successful waterfloods will make good miscible flood targets. Figure 4.18 presents the screening procedure and the corresponding results for North Dakota production units.

Figure 4.18

Production unit screening process



Source: IHS

The preliminary screening step was to eliminate the production units that are producing under a primary production mechanism. Of the 851 oil production units, 725 units are under primary production. Therefore, 126 production units underwent qualitative review using the parameters that were provided under the screening criteria. At this stage, 50 production units passed the screening criteria. The oil production units were further reviewed through dynamic criteria where the production/injection profile of each production unit was reviewed and it was discovered that the waterflood practices in some of these production units were not necessarily efficient.

Production units were classified into two categories: "Good" and "Poor" candidates. Successful waterflood schemes result in constant or decreasing gas-oil ratio (GOR) trend vs. time. For examples of production units with poor waterflood performance, see Appendix A.2. The "Good" candidate category contains 19 production units and includes production units with successful waterflood schemes. The "Poor" category includes production units where the current waterflood projects were not efficient; therefore we did not consider these production units as potential candidates at the time of this study. However, a number of these "Poor" production units contain significant amounts of oil in place, which makes them attractive for future consideration and development. For a list of the production units that passed the screening criteria as well as the poor candidates, see Appendix A.3.

4.3.2 Estimate of recovery rates for conventional production units

IHS relied on numerical modeling approach to estimate the incremental oil recovery using miscible CO_2 flooding. Details about the modeling approach can be found in Appendix A.4. Application of CO_2 EOR in conventional oil fields in North Dakota has the potential to add 154 million bbl of incremental production. Estimated incremental cumulative oil production resulting from the application of CO_2 EOR for the production units that satisfied the screening criteria ranges between 0.7 and 30.5 MMstb per unit. These volumes are technically recoverable. Chapter 5 contains further discussion about economic recovery of incremental production from these units. The EOR processes for the 19 production units require between 32 and 486 Bcf of CO_2 during a 20-year time-frame. Beaver Lodge Devonian and Hofflund Madison units display maximum and minimum recovery among the 19 production units respectively. Table 4.9 compares the results of this study and a University of North Dakota study performed in 2014.[97] The University of North Dakota study assumed three recovery factor values of 8%, 12%, and 18%, and three utilization factor values of 3, 5, and 8 Mcf of CO_2 per barrel of oil for the final expected ultimate recovery (EUR) estimates.

Table 4.9

Numerical results of oil recovery for candidate production units

Production unit	Rank	Numerical Np estimate (MMbbl)	Recovery factor (%)	Utilization factor (Mcf/bbl)	Recovery factor (%) University of North Dakota
Beaver Lodge Devonian Unit	1	30,530	16.8	9.0	8.0
Fryburg Heath-Madison Unit	2	20,624	13.3	5.0	
Cedar Hills North Red River B Unit	3	19,110	6.9	12.0	
Cedar Hills South Red River B Unit	4	18,460	5.1	17.5	
Big Stick Madison Unit	5	15,770	9.5	10.5	
Charlson North Madison Unit	6	6,961	8.7	11.1	
Blue Buttes Madison Unit	7	5,776	6.2	13.6	8.0
North Elkhorn Ranch Madison Unit	8	4,524	8.2	11.0	
Cedar Creek Ordovician	9	4,758	4.9	12.9	
T.R. Madison Unit	10	4,242	9.9	9.6	
Newburg Spearfish-Charles Unit	11	4,157	4.3	18.2	
Medora Heath-Madison Unit	12	3,978	6.9	12.0	
Rough Rider East Madison Unit	13	3,715	12.0	9.1	
Horse Creek Red River Unit	14	3,391	7.4	9.0	
Dickinson Heath Unit	15	2,849	4.6	23.5	
West Rough Rider Madison Unit	16	2,386	8.0	12.2	
Charlson South Madison Unit	17	1,267	8.7	11.1	8.0
Bear Creek Duperow Unit	18	931	6.8	16.4	
Hufflund Madison Unit	19	675	6.5	16.8	

Source: IHS

[97] Burton-Kelly, M.E., Peck, W.D., Glazewski, K.A., Doll, T.E., "Evaluation of Near-Term (5-year) Potential for Carbon Dioxide Enhanced Oil Recovery in Conventional Oil Fields in North Dakota", prepared for KLJ, July 2014.

Assessment of CO_2 EOR for North Dakota fields has been addressed by other studies, in which a constant recovery factor value was taken for all North Dakota fields[98]. The result of this study shows that recovery factor falls under a wide range if the proper methodology is chosen for estimation of recoverable oil from a CO_2 EOR process.

Numerical modeling approach requires extensive knowledge of reservoir and fluid properties, which may not always be practical for analysis of a large number of fields. More often, an analytical approach that is quick and easy may be utilized for EUR estimation. While minimal information is required, the methodology suffers from oversimplification of the process and excludes several important parameters and/or processes.

The analytical approach that was developed by Claridge was utilized to estimate the incremental oil production using a CO_2-EOR method.[99] Claridge developed the following equations for estimating the fraction of oil produced from a CO_2 miscible flood:

$$\left(\frac{\boldsymbol{N_p - V_{piBT}}}{\boldsymbol{1.0 - N_p}}\right) = \left(\frac{\boldsymbol{1.6}}{\boldsymbol{K^{0.61}}}\right)\left(\frac{\boldsymbol{F_i - V_{piBT}}}{\boldsymbol{1.0 - V_{piBT}}}\right)^{\left(\frac{\boldsymbol{1.28}}{\boldsymbol{K^{0.26}}}\right)} \tag{1}$$

$$\boldsymbol{K} = \left(\boldsymbol{0.78 + 0.22}\left(\frac{\boldsymbol{\mu_o}}{\boldsymbol{\mu_s}}\right)^{\boldsymbol{1/4}}\right)^{\boldsymbol{4}} \tag{2}$$

$$\boldsymbol{V_{piBT}} = \left(\frac{\boldsymbol{0.9}}{\boldsymbol{M + 1.1}}\right)^{\boldsymbol{0.5}} \tag{3}$$

$$\boldsymbol{M} = \frac{\boldsymbol{\mu_o}}{\boldsymbol{\mu_s}} \tag{4}$$

Where:

BT stands for breakthrough,

V_{pi} is the actual fraction of pore volume injected,

F_i is the fraction of hydrocarbon pore volume of solvent injected,

K is the Koval factor,

M is the mobility ratio,

μ_o is the oil viscosity, and

μ_s is the solvent viscosity.

The results of the analytical method were compared with numerical model in Table 4.10.

[98] Advanced Resources International, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Williston Basin", prepared for US Department of Energy Office of Fossil Energy-Office of Oil and Natural Gas, February 2006; Nelms, R.L., Burke, R.B., "Evaluation of Reservoir Characteristics to Assess North Dakota Carbon Dioxide Miscible Flooding Potential", 12th Williston Basin Horizontal Well and Petroleum Conference, North Dakota, 2-4 May 2004; Claridge, E.L., "Prediction of Recovery in Unstable Miscible Flooding", SPE 2930, April 1972.

[99] Todd, M.R., Longstaff, W.J., "The Development, Testing, and Application of a Numerical Simulator for Predicting Miscible Flood Performance", Journal of Petroleum Technology, July 972.

Table 4.10

Comparison of results of analytical and numerical methods

Production unit	Rank	Analytical Np estimate (MMbbl)	Numerical Np estimate (MMbbl)
Beaver Lodge Devonian Unit	1	54,046	30,530
Fryburg Heath-Madison Unit	2	28,597	20,624
Cedar Hills North Red River B Unit	3	32,982	19,110
Cedar Hills South Red River B Unit	4	38,914	18,460
Big Stick Madison Unit	5	35,022	15,770
Charlson North Madison Unit	6	16,531	6,961
Blue Buttes Madison Unit	7	14,990	5,776
North Elkhorn Ranch Madison Unit	8	10,760	4,524
Cedar Creek Ordovician	9	11,327	4,758
T.R. Madison Unit	10	7,025	4,242
Newburg Spearfish-Charles Unit	11	7,477	4,157
Medora Heath-Madison Unit	12	8,267	3,978
Rough Rider East Madison Unit	13	5,976	3,715
Horse Creek Red River Unit	14	6,967	3,391
Dickinson Heath Unit	15	10,495	2,849
West Rough Rider Madison Unit	16	5,238	2,386
Charlson South Madison Unit	17	2,996	1,267
Bear Creek Duperow Unit	18	2,670	931
Hufflund Madison Unit	19	1,950	675

Source: IHS

4.4 Conclusion

As technology improves and oil prices recover, the potential prize in the Bakken could be in the billions of barrels. There is still a high degree of uncertainty regarding the key factors associated with CO_2 EOR in the Bakken. These include incremental oil recovery factors and production profiles, development configurations, and CO_2 usage.

Because of its areal extent and multiple horizons, primary production is expected to recover only about 8–14% of the oil in place. If CO_2 EOR were to increase incremental recovery by just another 5% across the Bakken, the impact would be in the billions of barrels. While considerable R&D work has transpired, CO_2 EOR in the Bakken has yet to be proven commercially viable.

Our forecast has indicated that 160,000–240,000 b/d of incremental production could potentially be produced from the Bakken within the next 15–20 years, but in order to do so, amounts of CO_2 15 to 20 times greater than what is currently captured in North Dakota will be required. One possible source for incremental production may be a portion of the 1.4 Bcf of associated field gas currently being produced from the Bakken. The gas is very rich in NGLs, including ethane, which has proven to be effective in stimulating additional recovery. Re-injecting this gas may also be a constructive alternative to the current flaring of excess gas.

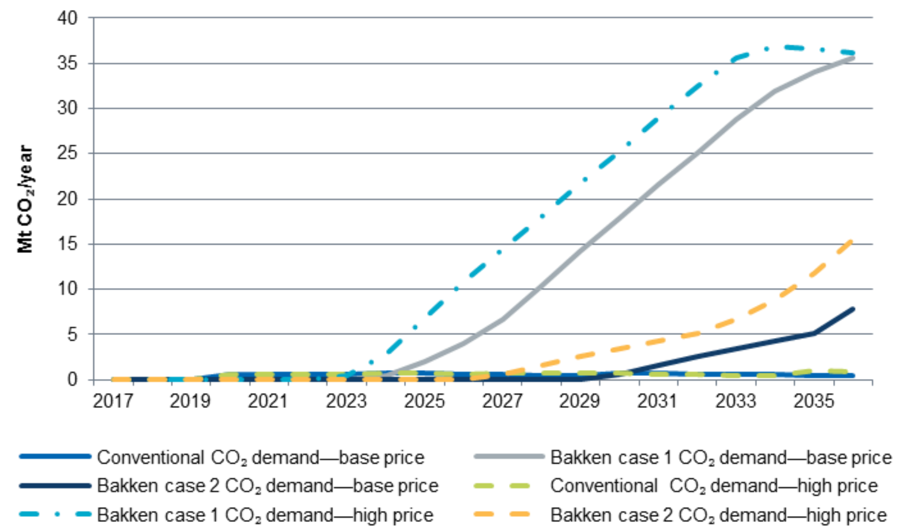
CHAPTER FIVE

5. CO_2 EOR upstream project economics

EOR associated with CO_2 injection in the Bakken is expected to yield 254–473 MMbbl of incremental production during the 2017–36 time frame, which accounts for 22–27% of the incremental technical recovery potential estimated under the two scenarios developed for this study. Direct revenues to the state via production and extraction taxes, income tax, and royalties on state land are expected in the order of 4.7–7.4 billion.[100] Most importantly, the CO_2 EOR activities are expected to have a benefit on the environment. The demand for CO_2 is likely to range from 233–307 MMt—56% of which could be met by anthropogenic sources of CO_2 projected to be captured in North Dakota (Figure 5.1).

Figure 5.1

CO_2 demand—Base and high price



Source: IHS

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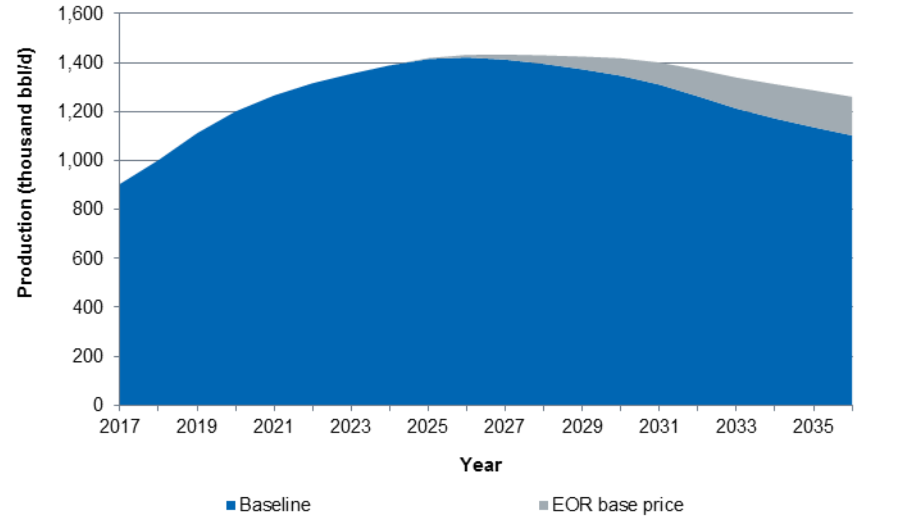
The full scale development of CO_2 EOR projects in the Bakken under Case 1 is expected to start in 2023 with significant impact continuing beyond the 20-year time frame for this study (Figure 5.2). The industry is expected to make capital investment of \$6.5–7.7 billion for CO_2 EOR in the Bakken. However, their largest expenditure by far is going to be operating costs, which are expected to be in the order of \$28.5–39.2 billion during the study period. Costs associated with the purchase of CO_2 are expected to make up 30% of the operating expenditure.

[100] The state of North Dakota holds 5–11% of the acreage in the counties where Bakken is located and 4% of the acreage under conventional oil production. This distribution is reflected in the share of royalties accruing to the state in this study.

Figure 5.2

ND Bakken primary recovery vs incremental production (Case 1)



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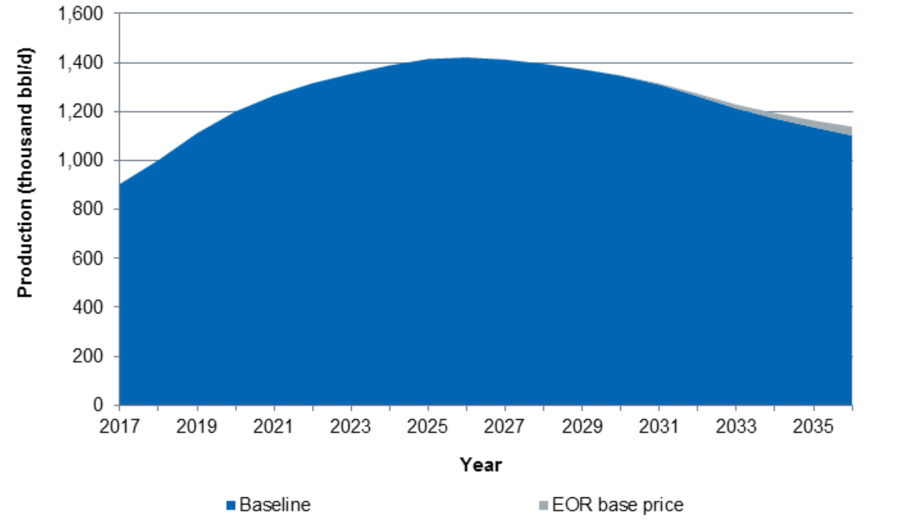
While Case 2 has the potential for significantly higher technical recovery of incremental production, the development of EOR projects under this scenario does not start before 2030 (Figure 5.3), thus limiting the amount of incremental production during the study period to 43–107 MMbbl of oil. The significant investment required for new drilling under Case 2 pushes the timeline for the start of these projects further out in the future when commodity price outlooks are sufficiently high to enable the economic recovery of incremental production under the CO_2 EOR process.

Figure 5.3

ND Bakken primary recovery vs incremental production (Case 2)



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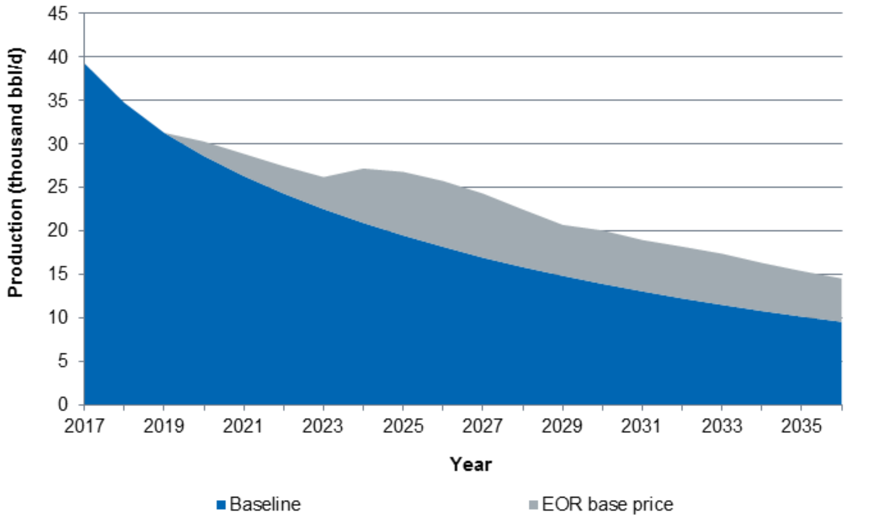
The impact of CO_2 EOR for conventional projects is forecast to be much smaller by comparison—about 7% of the incremental production potential of the Bakken in the same period (18–35 MMbbl)—with projected direct revenues to the state ranging between $139 and $439 million. The incremental production is expected to add about 7,500 b/d in 2026 (Figure 5.4). The CO_2 demand for conventional EOR should be 5.7–11.5 MMt during the 20-year time frame. Total spend by the industry on capital and operating costs combined is expected to range between $1.3 billion and $2.3 billion.

Figure 5.4

Conventional primary recovery vs incremental production



Source: IHS © 2016 IHS

5.1 Commercial challenges associated with CO_2 EOR in the Bakken

Industry's ability to unlock the EOR potential in the Bakken will depend on more than overcoming the challenge of identifying the technologies for optimum EOR. Bridging the gap between technical recovery and economic recovery is crucial. Our analysis found that in the best case scenario, only about 40% of the technically recoverable incremental production can be produced economically during the study period under Case 1 drilling configuration. Should CO_2 EOR projects require 660-foot separation between injectors and producers as modeled under Case 2, only about 7% of the CO_2 EOR technical recovery potential becomes economic in the study period.

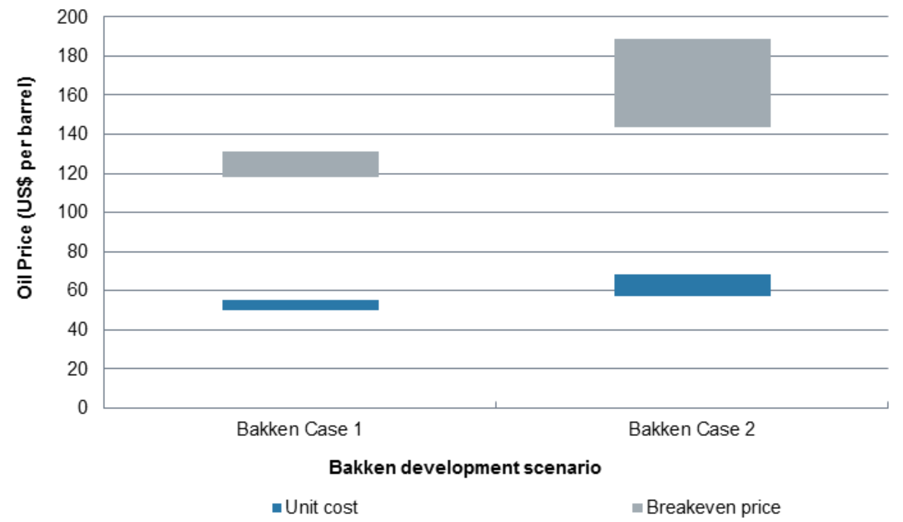
5.1.1 Costs

The EOR unit costs in the Bakken range between $50/bbl and $55/bbl in Case 1 and $57/bbl and $68/bbl in Case 2. The application of the fiscal system, however, pushes the breakeven prices for a 10% rate of return above $100/bbl for all CO_2 EOR projects in the Bakken (Figure 5.5).[101] This is because of the regressive nature of the North Dakota and US fiscal systems in general. Under regressive fiscal systems, government take has an inverse relationship with project profitability, i.e., as project profitability goes down the government take increases—not in terms of the amount of revenue accruing to the government, but in terms of the share of pre-tax revenue. The levy of royalties and production and extraction taxes that are based on gross revenue rather than profits deter the development of high cost sources of supply.

[101] We used 10% discount rate for this study. The US Securities and Exchange Commission requires 10% in filings for public companies. See Rhett G. Campbell, "Valuing Oil and Gas Assets in the Courtroom," presented at the American Institute of Business Law in conjunction with the Oklahoma Bar Review and the Conference on Consumer Finance Law, 7–8 February 2002.

Figure 5.5

Bakken—Range of EOR unit costs and breakeven prices



Source: IHS

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Costs associated with volumes of CO_2 required for the EOR process are obviously the main contributing factor. CO_2 related costs make up 37% of the capital costs and 31% of the operating costs under the Bakken Case 1 EOR development scenario.

5.1.2 Role of fiscal incentives

Like many oil-producing states, North Dakota has introduced fiscal incentives to encourage the development of EOR in the state. The most important and perhaps the most impactful incentive is the five-year exemption for tertiary recovery projects in the Bakken for the purposes of extraction tax. Another incentive applicable to the use of CO_2 for EOR offers exemption from property taxes for tangible property used to construct or expand a system used to compress, gather, collect, store, transport, or inject CO_2 for EOR. The same exemption applies to CO_2 capture systems installed at coal conversion facilities in the state.

Given the current low oil price environment, the cost structure of CO_2 EOR projects, and the high breakeven prices required for commercial deployment of such projects in the Bakken, fiscal incentives may not necessarily influence much the timing of such projects. However, they have the potential to impact how many projects go forward and take advantage of the tax relief when market conditions improve.

Market conditions will play a significant role regarding the timing of CO_2 EOR in the Bakken. In our long-term outlook, we anticipate a price recovery at $100/bbl in 2023 and staying above that level for the remainder of the study period.

5.2 Commercial challenges associated with CO_2 EOR in conventional fields

Out of 19 conventional production units that passed the screening criteria, only six units have the potential to be developed under the range of cost and market prices used for this study. This limits the forecasted CO_2 EOR activity to Williams, McKenzie, and Billings counties. A unit cost of $60/boe was the threshold for a tertiary recovery project to be economically feasible within the next 20 years.

CO_2 EOR costs for the majority of production units are prohibitively high (table 5.1). The high per unit costs associated with conventional field EOR are attributed to the significant number of new wells required to be drilled for such projects versus workover wells. The costs for new production wells for conventional fields range from $633,000 to $2.3 million at vertical depths of 3,350 feet to 11,450 feet, respectively. Workover costs for each production well range from $84,000–225,000 and workovers for each injection well range from $96,000–196,000.

Table 5.1

Conventional field EOR unit costs

Production unit	Field name	Unit costs ($/boe)
Beaver Lodge Devonian Unit	Beaver Lodge Devonian	30
Fryburg Heath-Madison Unit	Fryburg Heath-Madison	48
Rough Rider East Madison Unit	Rough Rider Madison	48
West Rough Rider Madison Unit		
Charlson North Madison Unit	Charlson Madison	50
Charlson South Madison Unit		
Big Stick Madison Unit	Big Stick Madison	58
Blue Buttes Madison Unit	Blue Buttes Madison	68
Newburg Spearfish-Charles Unit	Newburg Spearfish-Charles	109
North Elkhorn Ranch Madison Unit	North Elkhorn Ranch Madison	113
Medora Heath-Madison Unit	Medora Heath-Madison	134
Cedar Hills North Red River B Unit	Cedar Hills Red River	143
Cedar Hills South Red River B Unit		
Cedar Creek Ordovician	Cedar Creek Ordovician	150
T.R. Madison Unit	T.R. Madison	160
Horse Creek Red River Unit	Horse Creek Red River	164
Bear Creek Duperow Unit	Bear Creek Duperow	234
Hufflund Madison Unit	Hufflund Madison	268
Dickinson Heath Unit	Dickinson Heath	300

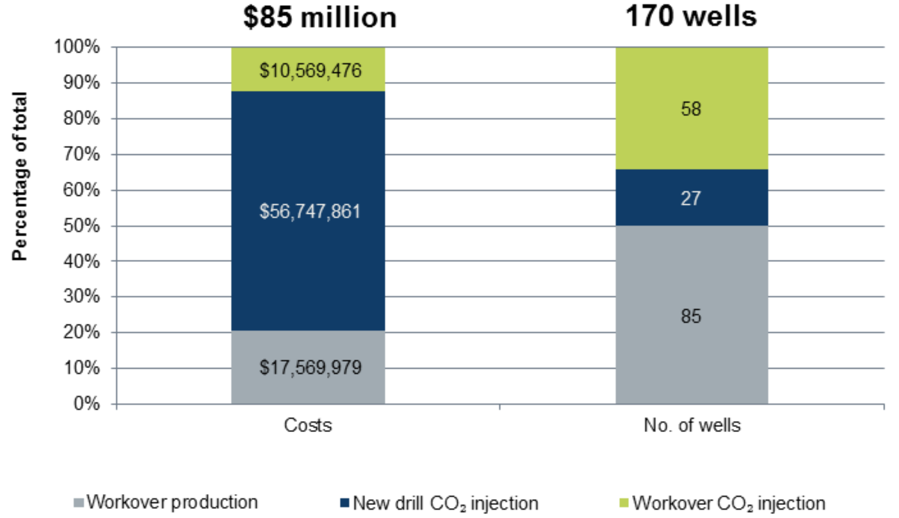
Note: Units that were part of the same field were developed as a single field.

Source: IHS

In determining the number of new wells versus workover wells needed for the EOR operations, IHS assessed the current status of the wells in each conventional field. We took an optimistic approach by considering any production or injection well that is currently active or temporarily abandoned to be reusable for EOR operations. Many of the higher cost conventional fields cover a large area, have few reusable wells compared with the number required for development, or do not perform well for CO_2 injection. Beaver Lodge Devonian, the most promising field, both in terms of estimated recovery and the unit cost did not require as many new wells as other candidates for CO_2 EOR in North Dakota (Figure 5.6).

Figure 5.6

Beaver Lodge Devonian—Wells by type and cost



Source: IHS

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Fryburg Heath-Madison field, which ranks second in unit cost, needed an investment of $277 million—nearly triple the amount of investment needed at Beaver Lodge Devonian—because of the number of new producing and injector wells required for the EOR activities. New drills comprise 78% of the total wells and 86% of the capital is allocated to drilling and workovers. CO_2 requirements per bbl of oil produced are much lower for the Fryburg unit compared with Beaver Lodge.

An analysis of the capital cost requirements in various conventional projects show that costs related to CO_2 are not necessarily the most significant ones in each project. Rather, the characteristics of the field and the status of the fields' wells may be the major drivers. The share of capital investments related to CO_2 pipeline, and facilities for compression and recycling of CO_2 ranged from 38% of total capital investment in Beaver Lodge to 3% in the Fryburg Heath-Madison unit.

While CO_2 EOR operations in conventional fields are subject to a more favorable fiscal system than the Bakken—they are subject to 10-year exemption from extraction tax versus five years applicable to the Bakken EOR—their potential is much more limited. Given that the EOR costs per unit for 11 of the 19 production units that passed the screening criteria are above $100/bbl, it is unlikely that any change in fiscal policy is going to have a significant impact on projected incremental production volumes associated with conventional fields.

CHAPTER SIX

6. Economic impact analysis

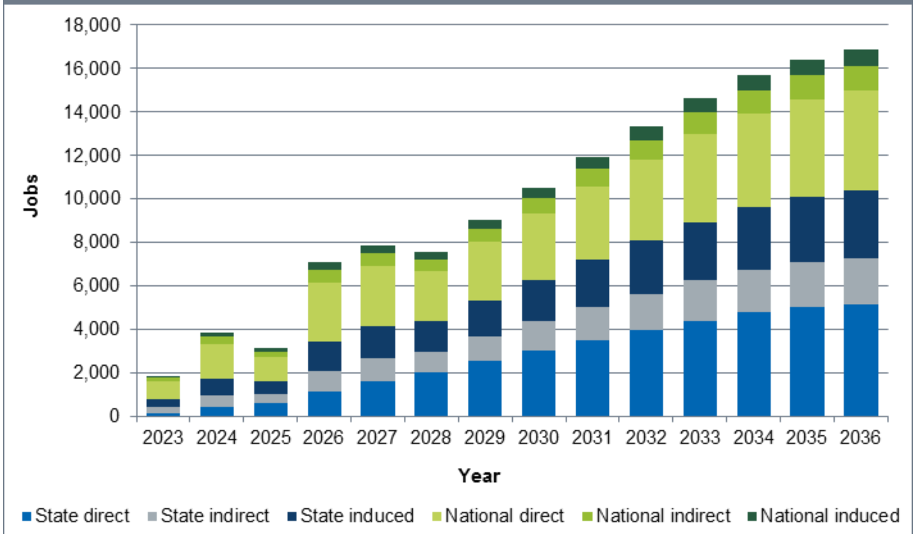
CO_2 EOR activities in the Bakken and conventional fields are expected to have a significant impact on the state of North Dakota and the nation in terms of employment, labor income, value added, and direct revenues to the state and the federal government. On average, about 50% of the overall economic contribution benefits the state of North Dakota, with the remaining 50% leaking to other states and the federal government in the case of tax revenues.

6.1 Employment

Spending associated with CO_2 EOR activities in the Bakken under Case 1 is expected to contribute, on average, 2,700 jobs per year directly related to the oil industry in the state of North Dakota, and 2,900 nationally during 2023–36 under the base-price assumption. The contribution to employment in the state and other states is much more significant when indirect and induced impacts are taken into account. On average, 3,100 jobs are created per year in the state of North Dakota, and 1,100 nationally through indirect and induced impacts. The total impact on employment on the state is expected to increase from 5,800 to 7,400 jobs on average per year in the high-price scenario. By 2036 the CO_2 EOR activities in the Bakken are expected to add over 10,000 jobs in the state and another 6,500 nationwide (Figure 6.1).

Figure 6.1

Bakken Case 1 EOR contribution to jobs—Base price

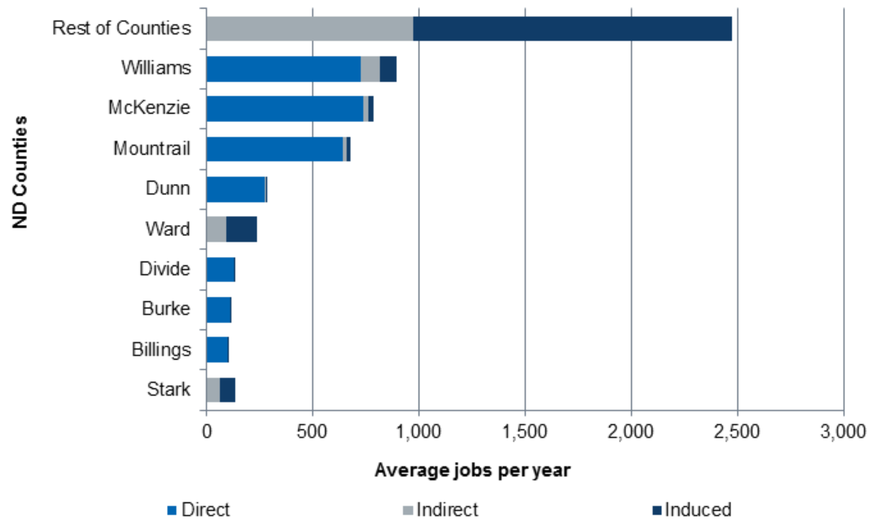


Source: IHS © 2016 IHS

Within North Dakota, the counties of Williams, McKenzie, and Mountrail are likely to experience the greatest impact in terms of direct and indirect jobs per year (Figure 6.2).

Figure 6.2

Impact of Bakken EOR Case 1 on jobs in the state—Base price



Source: IHS © 2016 IHS

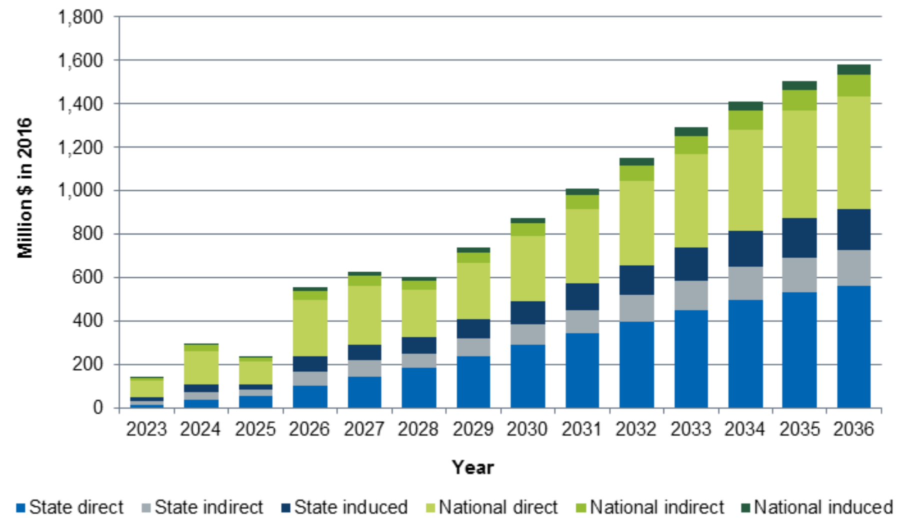
In the case of conventional EOR activities, a total of about 246 jobs on average per year are added in North Dakota and 244 nationally from 2018–36 under the base-price scenario. The highest impact on jobs is evidenced under the high oil price scenario with about 299 jobs added on average per year at the state level, and 291 at the national level during the same period. Four counties are impacted the most by EOR activities in conventional fields: Billings, Williams, McKenzie, and Ward. The combined EOR activities in the Bakken and conventional fields have the potential to contribute about 6,040 jobs on average at the state level under the base-price scenario and 7,660 under the high-price scenario during 2022–36.

6.2 Labor income

Employment is not the only impact of the EOR activities in the Bakken. The state is also going to experience a steady increase in labor income. The Bakken EOR activity will contribute on average $470 million per year, starting at $47 million in 2023, and contributing $917 million in real terms in 2036. The combined contribution at the state and national level at the end of the study period is nearly $1.6 billion in real terms (Figure 6.3). Under the high oil price scenario, the contribution is greater: $590 million on average, and reaching almost $1 billion ($988 million) by 2036 within the state. The conventional EOR activities also have the potential to contribute an additional $19–20.8 million on average per year to the state labor income, reaching a high of $39 million in 2035.

Figure 6.3

Bakken Case 1 EOR contribution to labor income—Base price

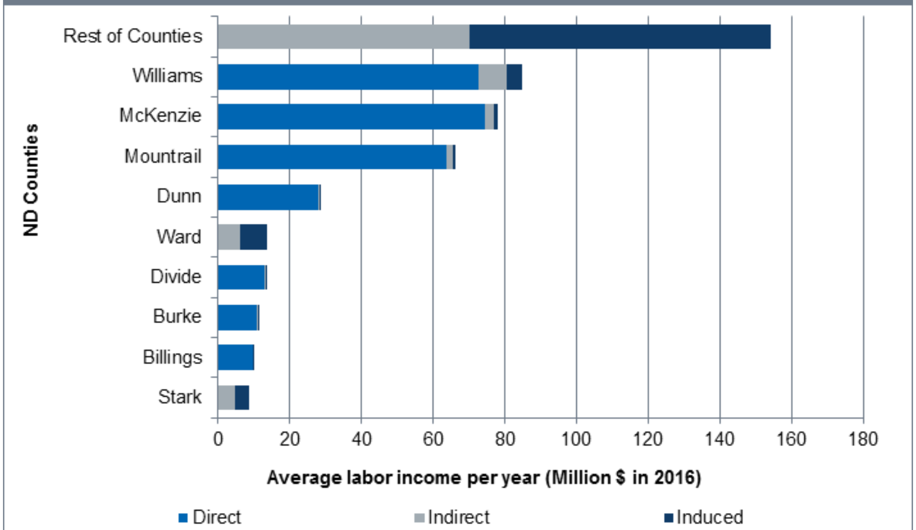


Source: IHS © 2016 IHS

The distribution of labor income addition by county follows the same pattern as for employment, with Williams, McKenzie, Mountrail, and to some extent Dunn benefiting the most (figure 6.4).

Figure 6.4

Impact of Bakken EOR Case 1 on labour income in the state—Base price



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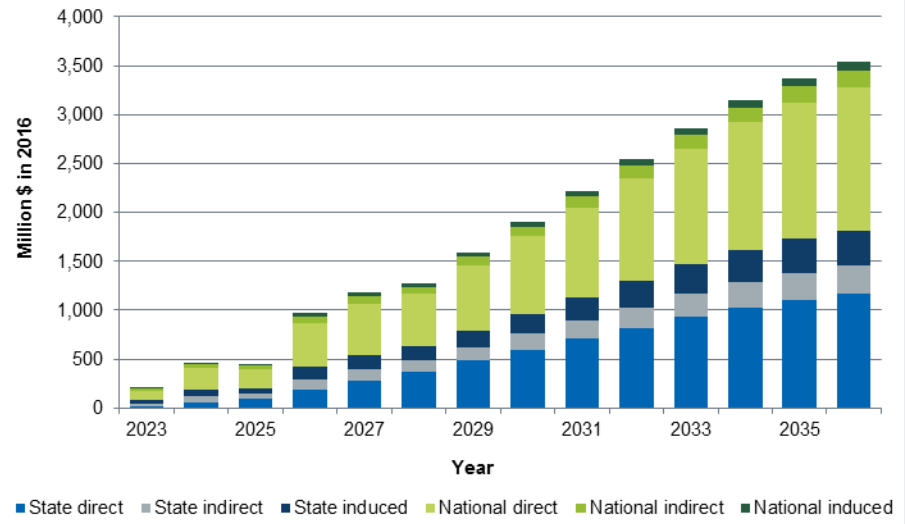
6.3 Gross value-added

The CO_2 EOR activities in the Bakken are expected to have on average a direct impact of $555 million per year on the economy of the state, and $773 million respectively at the national level. However, the increased activity ripples through the economy increasing gross value-added (contributions to GDP) along the way. The analysis shows that these ripple effects (indirect and induced) contribute 40% of the total value-added in the state and 16%of the value added nationwide (Figure 6.5). The total value-add to the state economy is on average $918 million per year. By the end of the study period in 2036, the yearly additions to the economy reach 1.8 billion at the state level and 1.7 billion at the national level, making for a combined $3.5 billion total.

Figure 6.5

Bakken Case 1 EOR contribution to GDP and GSP—Base price

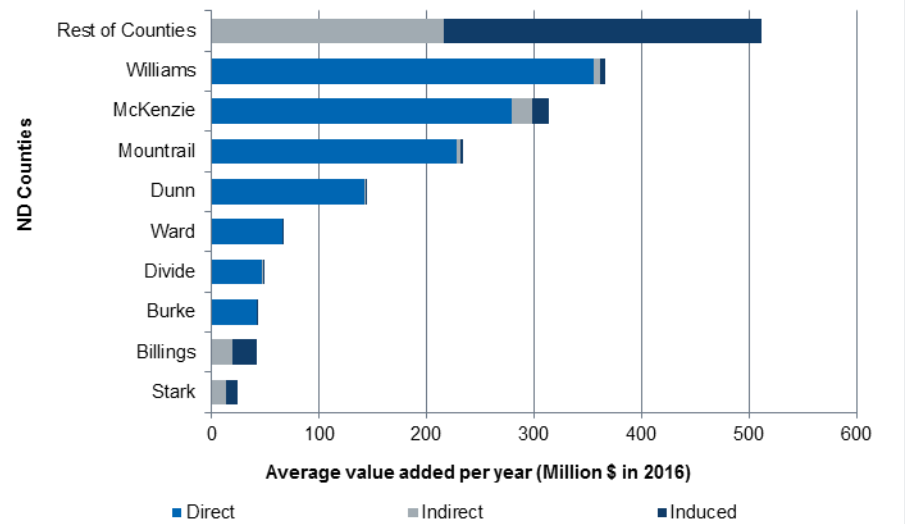


Source: IHS © 2016 IHS

The value addition by county follows the same pattern as for employment, with Williams, McKenzie, and Mountrail accounting for more than half of the value added in the state (see Figure 6.6).

Figure 6.6

Contribution of Bakken EOR Case 1 to GSP—Base price

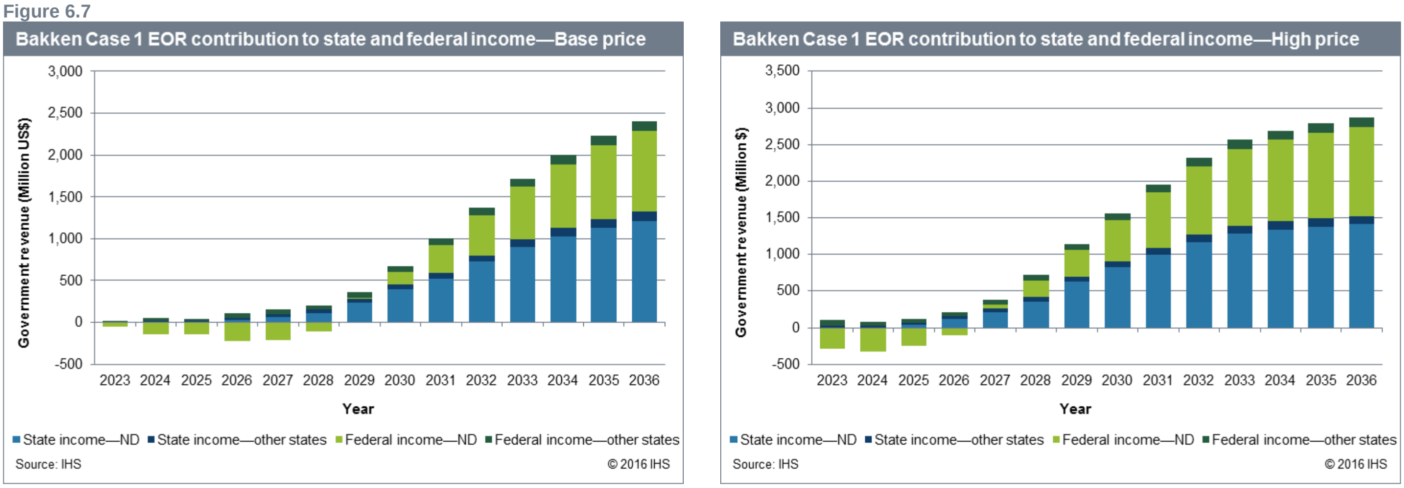


Source: IHS © 2016 IHS

6.4 Government revenue

Bakken Case 1 EOR has the potential to contribute between $11.4 billion to $18.6 billion in real terms to the states and the federal government under our base- and high-price assumptions. The direct revenues to the state of North Dakota are expected to range between $6.3 billion and $9.7 billion during the study period. In 2036 alone, the contribution to state and federal government revenue reaches $2.4–2.8 billion (see Figure 6.7).

Figure 6.7



Bakken Case 2, which relies on drilling a significant number of new wells, is expected to have a much more moderate effect on state and federal government revenues. Revenues under this scenario—with spending starting in 2029 and 2026 under base and high price assumptions respectively—are expected to be negative for the Federal Government owing to the deductions allowed for capital investments. Revenues accruing to the states under this scenario are expected to range between $867 million and $2.4 billion. North Dakota revenues in particular are expected to range between $580 million and $1.9 billion.

Revenues from EOR in conventional fields are expected to range between $1.3 billion and $1.6 billion to the federal and state governments under our base and high price scenarios. However, the government revenues have the potential to be as low as $310 million under our low oil price assumption. The revenues accruing to the state of North Dakota under the base- and high-price assumptions range between $420 million and $499 million.

CHAPTER SEVEN

7. Alternative policy solutions

While the current fiscal policies and incentives introduced by the State of North Dakota and the Federal Government could enable the industry to unlock 22–27%of the incremental technical recovery potential of the Bakken, we examine alternative policy scenarios that could narrow the gap between the technical recovery and economic recovery potential of CO_2 EOR activities in the state in general, and the Bakken in particular.

When considering the various policy solutions, we considered first the potential of the measure to influence investment decisions. We used breakeven price as an indicator to measure the potential impact of the alternative fiscal policy on upstream project economics. Measures that could not produce a marked change from the status quo were not considered further for economic impact analysis. Often the administrative burden placed by the introduction of certain policies does not justify the incremental benefit of the measure.

The other important consideration taken into account was a balancing of the benefits to the industry with revenues accruing to the government and the overall direct, indirect, and induced economic impact on the economy of the state and nationwide. In order to obtain an accurate basis for comparison, all alternative policy decisions were based on the base price scenario.

7.1 Breakeven price analysis

IHS considered multiple scenarios for each of the three development cases, i.e., conventional EOR, and EOR development in the Bakken under Case 1 and Case 2 accordingly. The following cases were considered as potential incentives either in addition to or replacing existing incentives, including one incentive at the federal income tax level.

Table 7.1

Conventional field EOR unit costs

Case	Application			Brief description
	Conventional	Bakken Case 1	Bakken Case 2	
Current terms	X	X	X	Preserves the currently applicable fiscal system
$440K credit per inj. Well for ET	X			Removes the current 10-year extraction tax exemption for Non-Bakken fields and introduces $400,000 tax credit for extraction tax per each new injector well drilled
CO_2 deductions for ET—no Holiday	X	X	X	Removes the current 10-year extraction tax exemption for Non-Bakken fields and 5-year extraction for the Bakken EOR and allow deductions for CO_2 operating costs against Extraction Tax
$5/ton CO_2 credit for ET—no Holiday	X	X	x	Removes the current 10-year extraction tax exemption for Non-Bakken fields and 5-year extraction for the Bakken EOR and allow a credit of $5/toc for CO_2 purchased and used for EOR.
50% reduction of ET and GP tax—no holiday	X	X	X	Removes the current 10-year extraction tax exemption for Non-Bakken fields and 5-year extraction for the Bakken EOR and lower the rates by 50% for both the Oil Extraction Tax (2.5% to 3%) and the Gross Production Tax on oil (2.5%)
10 year ET holiday, 50% reduction of GP tax	x			Preserves the 10 year extraction tax holiday for the non-Bakken EOR and reduces the production tax by 50%.
$10/ton of CO_2 credit for ET—no holiday	X	X	X	Removes the current 10-year extraction tax exemption for Non-Bakken fields and 5-year extraction for the Bakken EOR and introduces a $10/ton credit for CO_2 purchased and used for EOR.
$1.5 million credit per new inj. well			X	Removes the current 10-year extraction tax exemption for Non-Bakken fields and 5-year extraction for the Bakken EOR and allows for 1.5MM$ credit for each newly drilled horizontal injector well in the Bakken
5-year extraction tax holiday, 50% reduction of GP tax		X	x	Preserves the 5 year extraction tax holiday for the Bakken EOR and reduces the production tax by 50%.
10 year ET holiday		X	X	Extends the currently applicable 5-year holiday for extraction tax to 10 years.
No production taxes	X	X	x	Eliminates both extraction tax and production tax on incremental recovery revenue
FIT credit	X	X	x	Preserves current terms and assumes the current federal income tax credit of $10/ton of CO_2 used for EOR does not expire and increases annually to $20/ton over 10-year period.

Source: IHS

The breakeven price analysis for the various alternative scenarios described in table 7.1 above shows that most policies are not going to be very impactful with regards to conventional EOR production units. In fact, under some of the scenarios the breakeven prices for conventional production units would go up from the current terms scenario (see Table 7.2). By far the most impactful scenario is the one based on federal income tax credit for CO_2 used for EOR—which yields a $9/bbl drop in the breakeven price of Beaver Lodge and $12.71 on the higher-cost Charlson Madison. The breakeven price analysis of conventional projects shows that while the incentives have the potential to improve the economics of the lowest cost development alternatives, they are not likely to increase the number of projects that could be viable within the study period.

Table 7.2

EOR breakeven prices for conventional production units—High and low range ($/boe)

Production unit	$400 K credit per inj. well for ET	CO_2 deductions for ET—no holiday	$5/ton of CO_2 credit for ET—no holiday	Current terms	$10/ton of CO_2 credit for ET—no holiday	50% reduction of ET and GP tax—no holiday	10-year ET holiday, 50% reduction of GP tax	No production taxes	FIT credit
Beave Lodge	64.66	63.80	63.56	63.19	62.54	61.93	61.59	59.55	54.06
Charlson Madison	134.48	139.46	139.28	134.33	136.51	132.43	130.66	125.78	121.77

Source: IHS

Some of the incentives for the Bakken Case 1 drilling configuration show much more promise (Table 7.3). They are able to have a more significant impact on the breakeven prices of the low- and high-end cost projects under this scenario. The federal income tax credit is by far the most impactful one—bringing the breakeven prices below $100/barrel.

Table 7.3

EOR breakeven prices for Bakken Case 1—High and low range ($/boe)

County	Current terms	$5/ton of CO_2 credit for ET—no holiday	10-year ET holiday	5-year ET holiday, 50% reduction of GP tax	No holiday, 50% reduction of ET & GP tax	$10/ton of CO_2 credit for ET—no holiday	CO_2 deductions for ET—no holiday	No production taxes	FIT credit
Mountrail	112.70	111.28	109.96	108.96	107.11	106.55	105.52	100.59	86.60
Dunn	126.12	122.75	122.57	122.25	120.01	118.92	118.49	113.19	99.52

Source: IHS

Table 7.4

EOR breakeven prices for Bakken Case 2—High and low range ($/boe)

County	Current terms	$5/ton of CO_2 credit for ET—no holiday	10-year ET holiday	5-year ET holiday, 50% reduction of GP tax	CO_2 deductions for ET—no holiday	$10/ton of CO_2 credit for ET—no holiday	No holiday, 50% reduction of ET & GP tax	$1.5 million credit per new inj. well	No production taxes	FIT credit
Mountrail	132.79	130.81	129.00	128.86	127.49	127.12	125.97	125.87	118.54	112.11
Dunn	177.58	176.24	172.99	172.53	172.80	172.91	168.61	167.7	159.09	157.34

Source: IHS

While some of the incentives result in a $10 to $20 drop in the breakeven prices for the Bakken Case 2 (Table 7.4), this EOR drilling and development configuration will continue to be challenged by the rather high costs associated with this scenario. While certain incentives such as federal income tax credit could make a lot more of those projects feasible within the study period, the gap between the technical recovery and economic recovery under this scenario in the study period will remain wide.

7.2 Impact of policy alternatives on production environment and economy

7.2.1 Federal income tax credit alternative

Most projects in the Bakken may not be able to benefit from the federal income tax credit available to EOR projects under Section 45Q. The credit which is currently set at $10/metric ton of CO_2 used in EOR operations is scheduled to terminate after 75 MMt of qualified CO_2 have been captured and taken into account for the purpose of the credit. Based on the amount claimed to date and the rate of CO_2 utilization by projects that have been able to claim the credit or are scheduled to come on line anytime soon, the credit is expected to expire within the next 10 years.

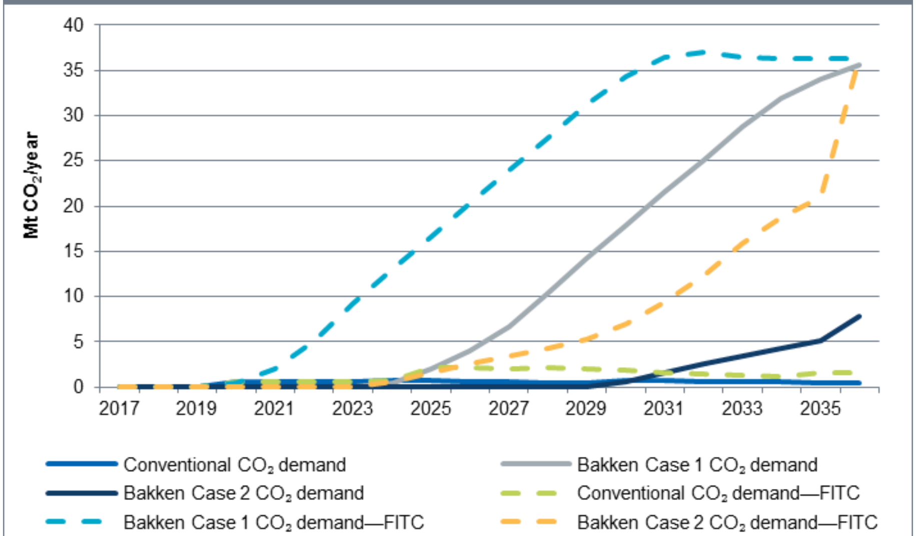
A coalition of environmental groups and fossil fuel companies are pushing for an amendment of the tax code to address the looming uncertainty associated with the carbon capture and sequestration projects. In a letter sent to the US House Committee on Ways and Means in February 2016, the coalition of representatives from environmental groups and the fossil fuel industry urged the lawmakers to support a permanent extension of Section 45Q tax credit. On 25 February 2016, a bipartisan bill, with 18 co-sponsors from both parties, was introduced by US Representative Mike Conaway of Texas. In addition to making permanent the credit for CO_2 capture and sequestration, the bill introduces a gradual increase of the credit for carbon dioxide storage through enhanced oil recovery or other types of geologic storage to $30/ton by 2025 (from $10/ton and $20/ton respectively).

Despite the bi-partisan support, the chances of the bill being passed in an election year are slim. However, for the purpose of this study we have taken a more conservative approach and modelled a scenario under which Congress makes the credit permanent and increases the credit for storage of CO_2 for EOR to $20/ton by 2025.

The federal income tax credit alternative scenario modeled in this study would result in an increased demand and therefore ultimate storage of CO_2 from 233 MMt to 402 MMt during the study period. This policy alternative is likely to contribute significantly towards the narrowing of the gap between the cost of CO_2 and the price of CO_2 EOR operators are willing to pay. While the amount of CO_2 needed for EOR operations reaches a plateau at about 36.5 MMt/y, the incentive brings forward the timeline for injection of CO_2 for EOR projects in the Bakken from 2023 to 2019 (Figure 7.1).

Figure 7.1

CO_2 demand under federal income tax credit alternative



Source: IHS

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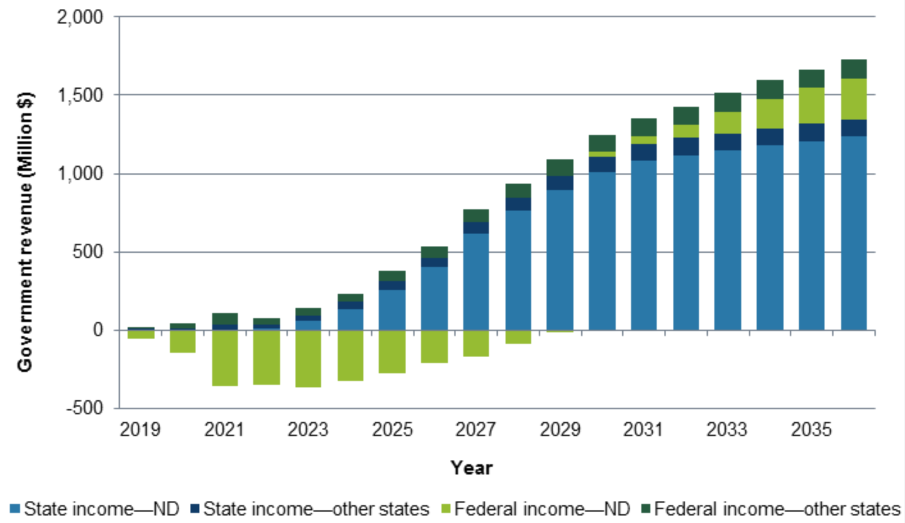
Under this policy alternative, incremental oil recovery for the Bakken Case 1 almost doubles from 353 million barrels to 625 million barrels. This in turn has a significant impact on direct and indirect revenues to the state and federal government combined (Figure 7.2).

Figure 7.2

Bakken Case 1 EOR contribution to state and federal income—FITC



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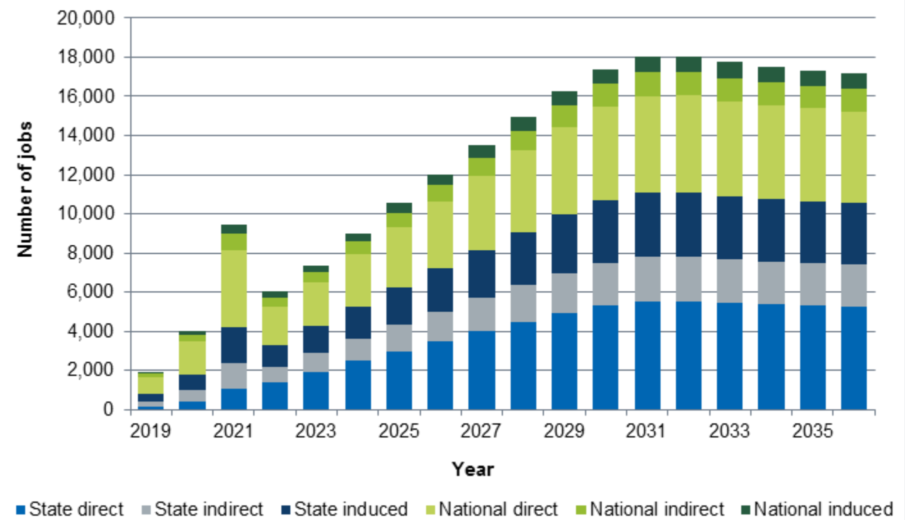
While the share of revenue accruing to the federal government does decline under this scenario, the overall revenues generated by the government of North Dakota, the Federal Government, and other states increases from $11.3 billion under the current fiscal system to $13.2 billion under the federal income tax credit alternative scenario. Most importantly, the benefit to the economy at large increases significantly. The application of this policy alternative results in 12,600 jobs added on average during the study period, with 7,500 of these jobs being added annually in the state of North Dakota.

Figure 7.3

Bakken Case 1 EOR contribution to jobs—FITC



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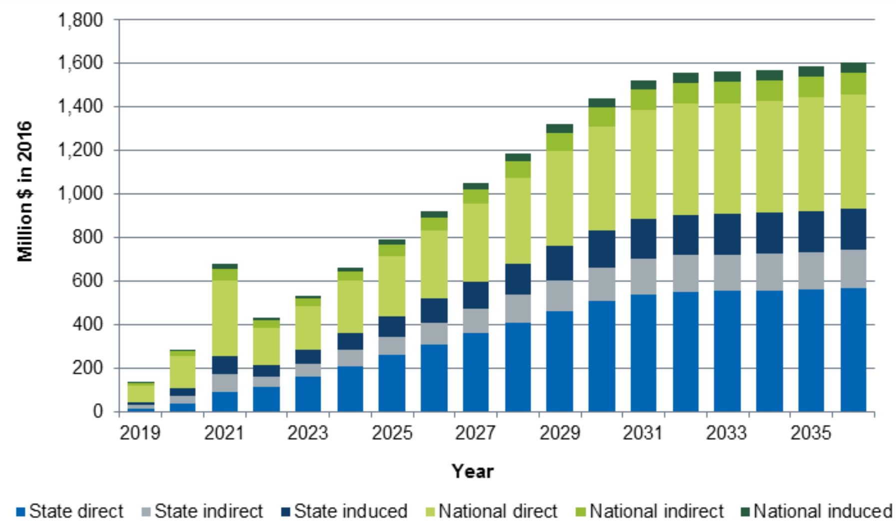
The increased economic activity under this policy alternative is expected to contribute on average over $1 billion in labor income annually during 2019–36, of which $586 million is contribution within the state of North Dakota. By the end of the study period, the combined contribution at the state and national level will reach 1.6 billion in real terms (Figure 7.4).

Figure 7.4

Bakken Case 1 EOR contribution to labor income—FITC



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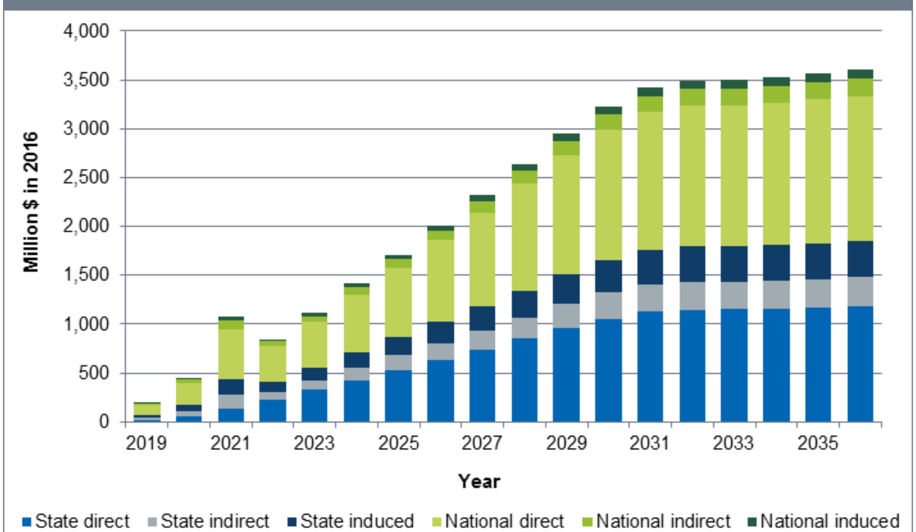
Under the federal income tax policy alternative, CO_2 EOR activities in the Bakken are expected to have, on average, a direct impact of $890 million per year on the economy of the state and $1.1 billion respectively at the national level. The ripple effects of increased activity are anticipated contribute on average $2.7 billion per year, with $1.7 billion per year being added to the state economy, almost double the amount estimated under the current fiscal system (Figure 7.5). By the end of the study period in 2036, the yearly additions to the economy will reach over 1.8 billion at the state level and over 1.7 billion at the national level, making for a combined $3.6 billion total.

Figure 7.5

Bakken Case 1 EOR contribution to GDP and GSP—FITC



Source: IHS © 2016 IHS

This is obviously the most impactful policy alternative to the current status quo. This solution enables a 77% increase in the EOR potential in the Bakken. The impact of the CO_2 EOR operations on the economy of the state under this scenario is 30% higher with respect to jobs, employment income, and gross value added. From the point of view of direct revenues to the state through taxation, this policy clearly could be the preferred one for the State of North Dakota since it leads to a 77% increase in government revenue.

While this policy solution is the most attractive option, it is not clear whether there will be enough support for the proposed bill both in the House of Representatives and the Senate of the United States.

7.2.2 CO_2 operating cost allowance alternative

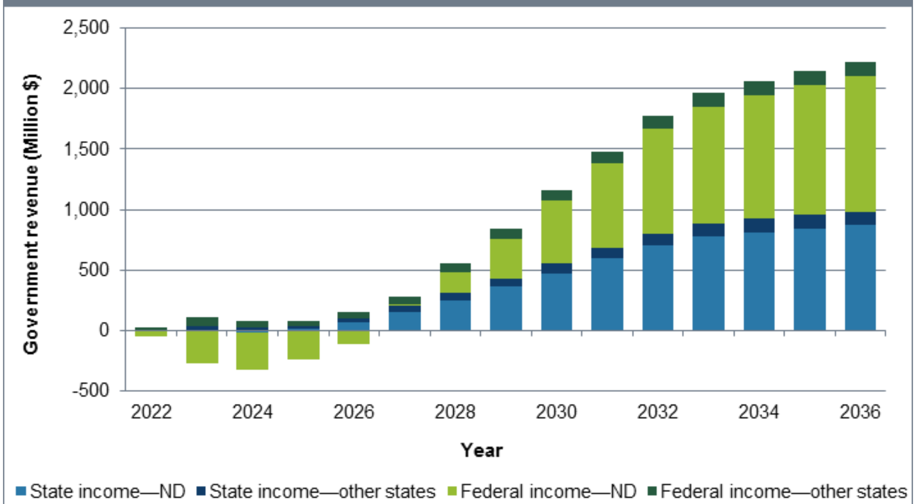
Of all the state level policy alternatives considered for this study, the alternative with the potential to have a significant impact on the CO_2 EOR activities in the Bakken is the one that eliminates the current five-year extraction holiday for the Bakken and introduces an allowance for the CO2 operating costs against the extraction tax liability. Under this policy solution, the incremental production recovery in the Bakken Case 1 increased from 353 million barrels to 473 million barrels during the study period. It had the same effect that the high oil price scenario had on the total EOR production volumes in the Bakken. By allowing a deduction for operating costs associated with CO_2, the state shares about 30% of the operating costs associated with CO_2 EOR operations in the Bakken.

Over the study period, the revenue accruing to the states and the federal government reaches $13.9 billion, with $5.9 billion being realized by the state of North Dakota. Revenue accruing to the state under this policy solution make up less than 50%of the overall government revenues generated nationwide. This is due to the fact that in this instance it is the state that is offering the incentive to the EOR operations.

The impact on environment is also significant with 307 MMt of CO2 being injected and ultimately stored. This represents a 32% increase in the demand for CO2 from the base case under the current fiscal system.

Figure 7.6

Bakken Case 1 EOR contribution to state and federal income—CO_2 operating cost allowance

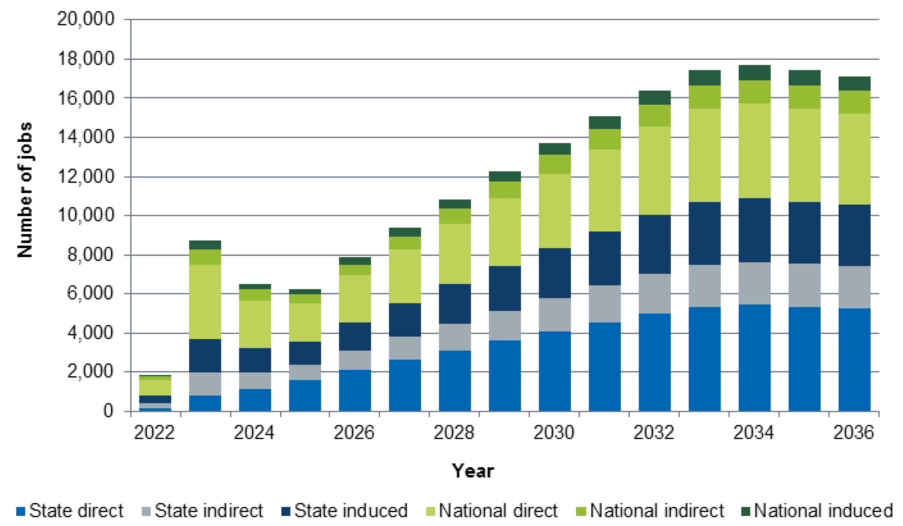


Source: IHS

The CO_2 operating cost allowance is expected to contribute on average over 7,000 jobs per year in North Dakota, and 11,900 per year nationally during the 2022–36 period. By 2034 the number of jobs added that year in North Dakota will reach 10,800, and is expected to stay above 10,000 per year beyond the study period (see Figure 7.7).

Figure 7.7

Bakken Case 1 EOR contribution to jobs—CO_2 operating cost allowance



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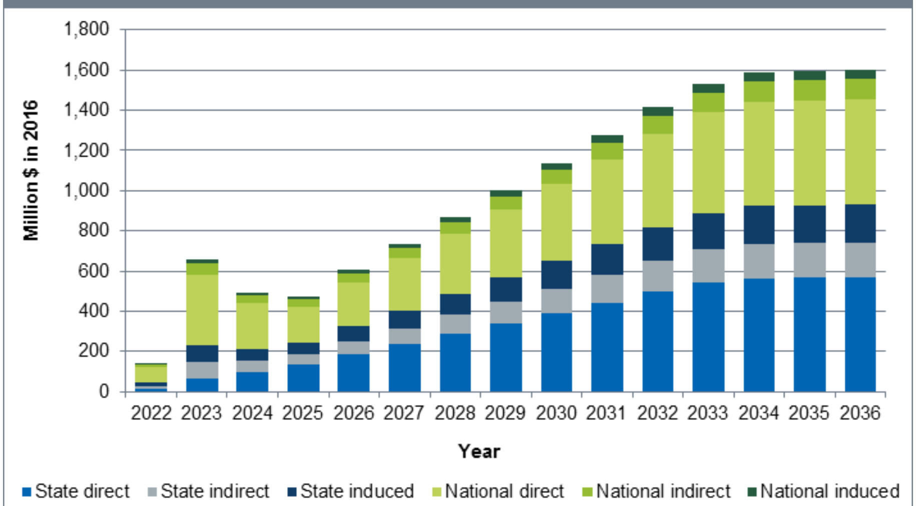
Increased activity associated with the CO_2 operating cost allowance results in a 19% increase in average annual labor income at the state level from the base case scenario, and a 17% increase nationally. The average annual labor income contribution to the state is expected to be \$558 million, with an average annual contribution of over \$1 billion. At the end of the study period, the contribution to the national economy reaches \$1.6 billion per year, with a \$931 million contribution being made to the economy of the state of North Dakota (see Figure 7.8).

Figure 7.8

Bakken Case 1 EOR contribution to labor income—CO_2 operating cost allowance



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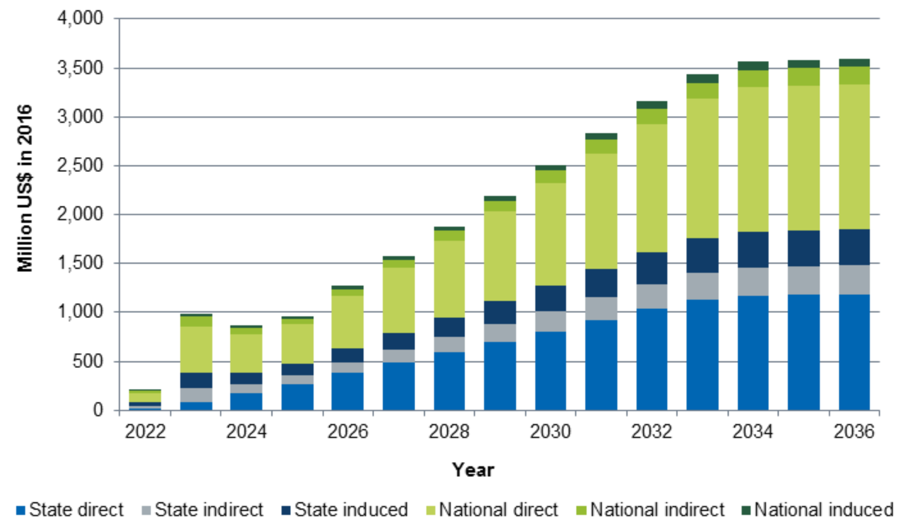
Increased activity resulting from the CO_2 operating cost allowance is estimated to contribute on average over $1 billion annually to the state GDP, and close to $2.2 billion annually to GDP. This represents a 19% increase in contribution from the status quo represented by the current fiscal system. By the end of the study period, the annual value added to the economy is $1.85 billion at the state level and $1.75 billion at the national level, making for a combined $3.6 billion total value added (see Figure 7.9).

Figure 7.9

Bakken Case 1 EOR contribution to GDP and GSP—CO_2 cost allowance



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Overall this policy solution has the potential to enable a 35%increase in the recovery of incremental production in the Bakken from the current fiscal system. While direct government revenue under this policy declines 8% compared with the status quo, that decline in revenue is outweighed by the overall benefits to the economy of the state. The economic contribution to the state via employment, labor income, and value added is 20% higher than under the current fiscal system.

7.3 Conclusion

The CO_2 EOR technologies have the potential to bring 1.2 billion to 1.8 billion barrels of incremental production to the state over the next 20 years. The technologies surrounding such developments are still in the very early stages of development. As is the case usually with major technology developments, they require a significant level of collaboration between the government, industry and research organizations, and policy support to enable technological breakthrough. The commercial deployment of CO_2 EOR technologies in North Dakota will depend largely on the following factors:

- The ability of the industry to narrow down the range of uncertainty currently associated with CO_2 EOR technologies for shale plays and tight oil formations within a relatively short period of time, and move from the laboratory and single-well testing to multiwell pilots, and ultimately to commercial deployment in the field.

- Technological breakthrough with regard to carbon capture technologies that will bridge the gap between the cost of capture and the price EOR operators are willing to pay for CO_2. This is largely contingent on the success of the DOE's research and development and demonstration program with regard to reaching critical mass as well as with regards to efficiency in moving projects developed under the CCRP from laboratory/bench to commercial large-scale demonstration.

- Availability of an abundant supply of CO_2 at affordable prices. The development of CO_2 sources of supply within the state will depend largely on state-wide policies that will be adopted to comply with CPP or other federal policy that may take its place.

- Development of fiscal incentives that encourage the utilization of CO_2 for EOR while acknowledging the benefits to the economy and the environment.

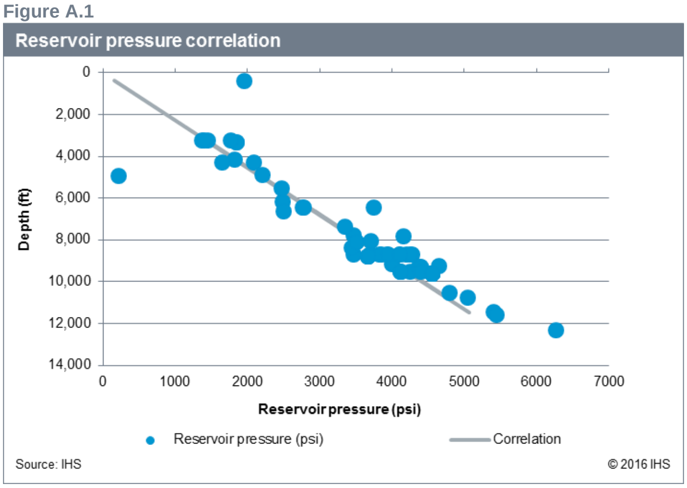
APPENDICES

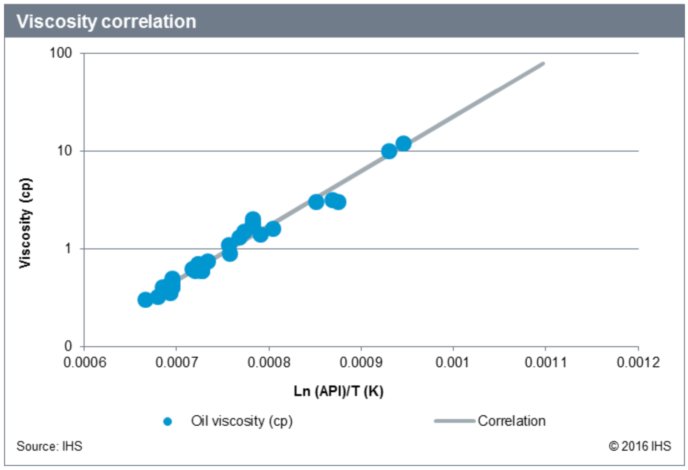
Appendix A—Conventional production unit screening methodology

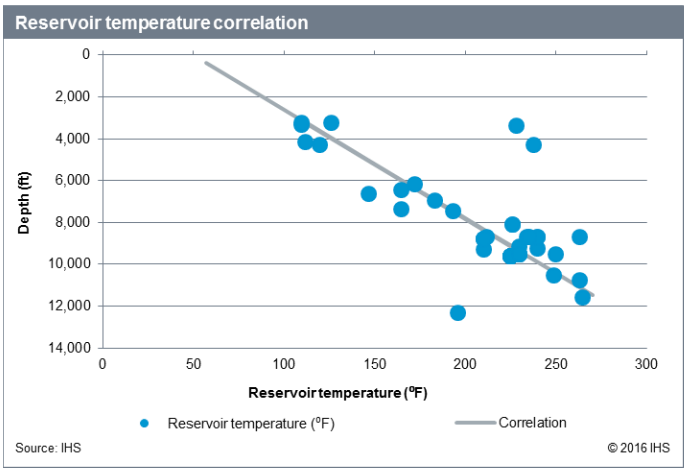
A.1 Correlations for reservoir pressure, temperature and viscosity

The following charts present the relationship between P_R versus depth, T_R versus depth, and μ_O versus oil gravity and T_R. Once we know the depth of the reservoir and oil gravity then P_R, T_R, and μ_O can be calculated.

Figure A.1





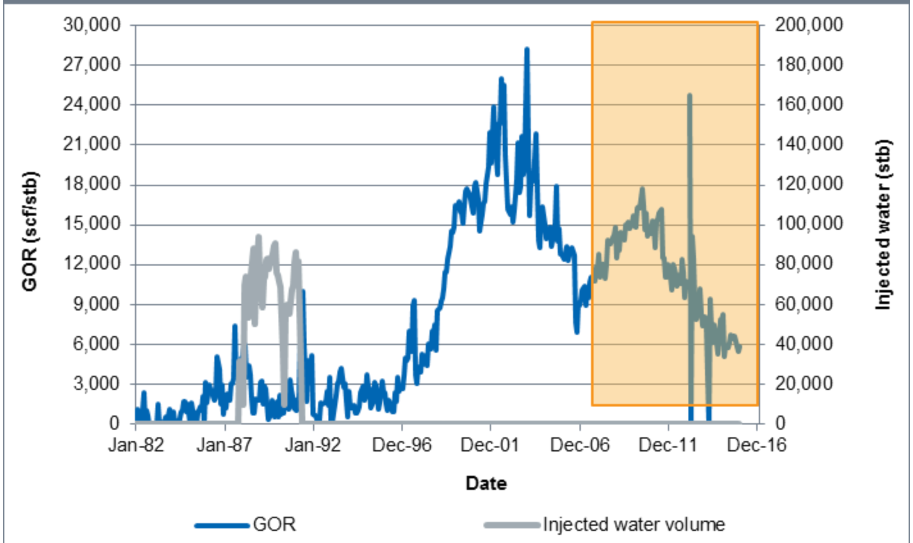


A.2 Samples of units that failed the screening criteria due to poor waterflood performance

The following charts present four examples for the production units with poor waterflood performance. Cases A, B, C, and D show GOR Injected water volume versus time for Antelope Madison, Tioga Madison, Beaver Lodge Madison, and Hawkeye Madison production units, respectively.

Figure A.2

Antelope Madison unit—Case A



Source: IHS

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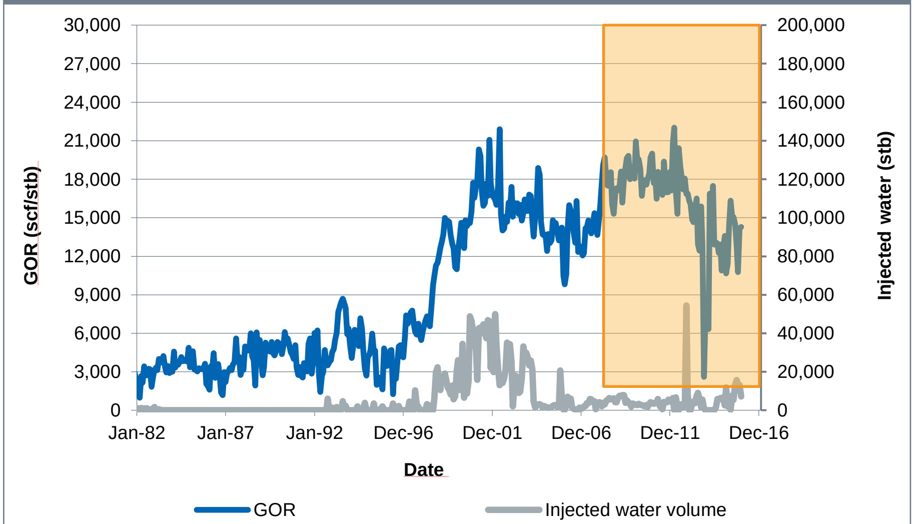
Reason for failing the final screening

- High GOR
- No current active waterflood

Figure A.3

Tioga Madison unit—Case B



Source: IHS

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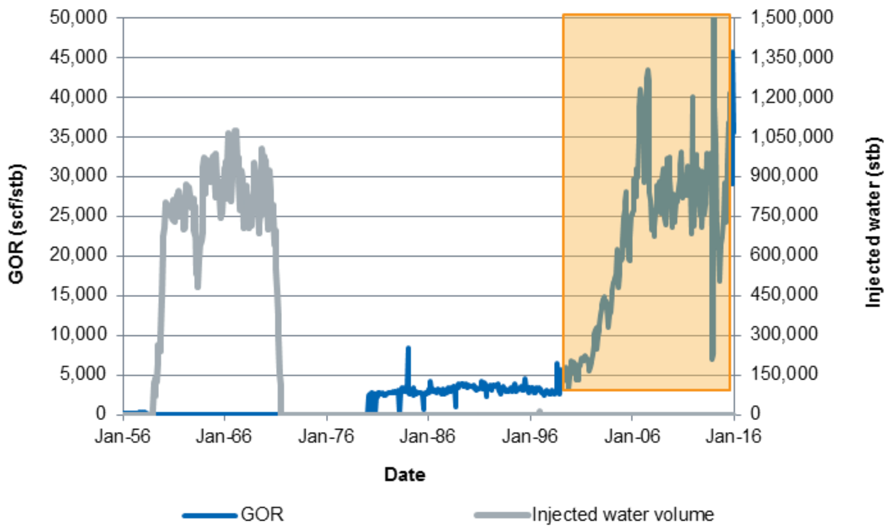
Reason for failing the final screening

- High GOR
- Poor waterflood performance

Beaver Lodge Madison unit—Case C

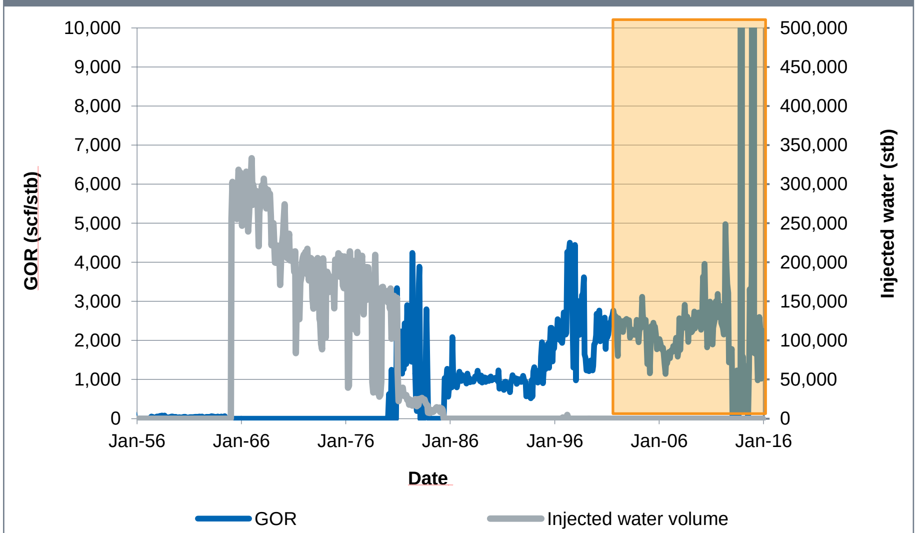


Source: IHS

Reason for failing the final screening

- High GOR
- No current active waterflood

Hawkeye Madison unit—Case D



Source: IHS

Reason for failing the final screening

- High GOR
- No current active waterflood

A.3 Production units that passed/failed screening criteria

Table A.1

Production units that passed the screening criteria

No.	Production unit name	Class
1.	Beaver Lodge Devonian Unit	Good
2	Fryburg Heath-Madison Unit	Good
3	Cedar Hills North Red River B Unit	Good
4	Cedar Hills South Red River B Unit	Good
5	Big Stick Madison Unit	Good
6.	Charlson North Madison Unit	Good
7	Blue Buttes Madison Unit	Good
8	North Elkhorn Ranch Madison Unit	Good
9	Cedar Creek Ordovician	Good
10	T.R. Madison Unit	Good
11	Newburg Spearfish-Charles Unit	Good
12	Medora Heath-Madison Unit	Good
13	Rough Rider East Madison Unit	Good
14	Horse Creek Red River Unit	Good
15	Dickinson Heath Unit	Good
16	West Rough Rider Madison Unit	Good
17	Charlson South Madison Unit	Good
18	Bear Creek Duperow Unit	Good
19	Hufflund Madison Unit	Good

Source: IHS

Table A.2

Production units that failed the screening criteria

No.	Production unit name	Class
1	Antelope Madison	Poor
2	Medicine Pole Hills Red River	Poor
3	Medicine Pole Hills West Red	Poor
4	Medicine Pole Hills South Red River B	Poor
5	Northeast Foothills Madison	Poor
6	Antelope Devonian	Poor
7	North Tioga Madison	Poor
8	Foothills Madison	Poor
8	North Black Slough Midale	Poor
10	South Black Slough Midale	Poor
11	Hawkeye Madison	Poor
12	West Dickinson Lodgepole	Poor
13	Versippi Lodgepole	Poor
14	Dickinson Lodgepole	Poor
15	Duck Creek Lodgepole	Poor
16	Hilne Lodgepole	Poor
17	Livestock Lodgepole	Poor
18	Sundivision Lodgepole	Poor
19	Tioga Madison	Poor
20	Beaver Lodge Madison	Poor
21	Red Wing Creek Madison	Poor
22	Rival Madison	Poor
23	Capa Madison	Poor
24	Clear Creek Madison	Poor
25	South Starbiuck Madison	Poor
26	Plaza Madison	Poor
27	Little Missouri red River	Poor
28	State Line Red River	Poor
29	Little Knife North Madison	Poor
30	South Westhope Sperfish-Charles	Poor
31	Fryburg South River	Poor

Source: IHS

A.4 Numerical modeling approach

A three-component/phase system considering reservoir oil, CO_2, and water was defined in ECLIPSE 100 software. The Pseudo-Miscible option which models the fuzzy cognitive mapping (FCM) process to approximate a MCM process was utilized. ECLIPSE 100 uses the Todd-Longstaff mixing modification technique to calculate the viscosity and density of a CO_2-Oil mixture.

According to Todd-Longstaff's recommendation, a dispersion factor (ω) of 0.33 should be used in CO_2 EOR modeling in order to compensate for the FCM assumption (i.e., a value of ω=1.0 results in full miscibility and piston-like displacement)[102]. ω is the dispersion factor that determines the amount of mixing between CO_2 and reservoir oil within each grid block of the numerical model.

[102] Todd, M.R., Longstaff, W.J., "The Development, Testing, and Application of a Numerical Simulator for Predicting Miscible Flood Performance," Journal of Petroleum Technology, July 1972.

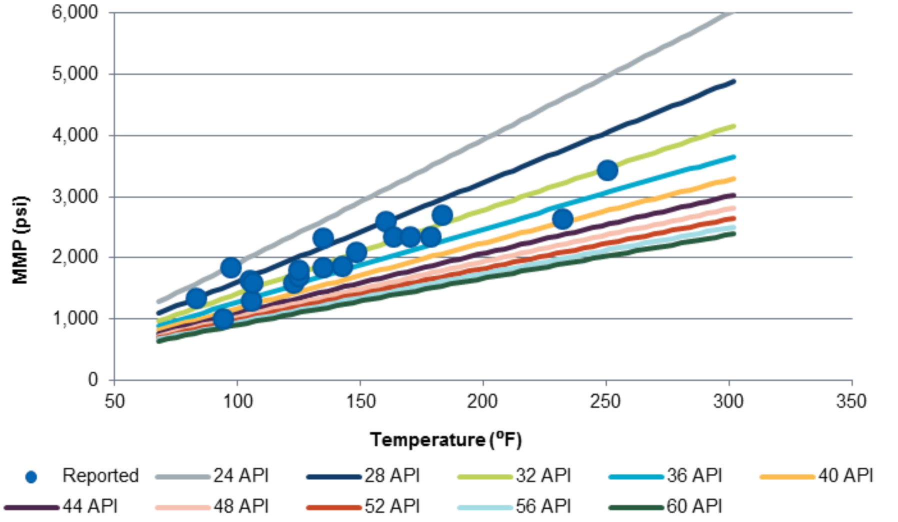
In addition to adjustment of ω value, relative permeability end points and volumetric sweep efficiency of the entire model was modified to adjust the over prediction of the FCM approach. The following assumptions were considered for the modeling of CO_2 EOR for North Dakota fields:

- Five-spot flooding pattern
- 120 acre drainage area
- Homogenous properties (porosity, permeability, and fluid properties) in the horizontal and vertical directions
- Constant CO_2 injection
- No free gas at current reservoir pressure
- No external water
- Production pressure was slightly above MMP
- FCM approach with limited dispersion over the grid block size

MMP is the minimum pressure at which CO_2 becomes miscible in oil at any proportion of injected CO_2, and the mixture forms one phase. The interfacial tension between CO_2 and the reservoir oil vanishes above the MMP. CO_2 MMP depends on several parameters, including reservoir temperature, oil composition and the impurities in the injected CO_2. It is essential to obtain a reasonable estimate of MMP for the "Good" candidates. The Modified Cronquist correlation was used to calculate the MMP for each field. Figure A.4 presents the MMP prediction response to changes in oil API and reservoir temperature (straight lines at varying oil API over the considered temperature range).[103] MMP of North Dakota fields range between 1,500 and 3,500 psi, most in the range from 2,400 to 3,200 psi. The minimum and maximum values are from the Newburg Spearfish and Horse Creek Red River Unit, respectively.

Figure A.4

Minimum Miscibility Pressure (MMP) correlation



Source: IHS

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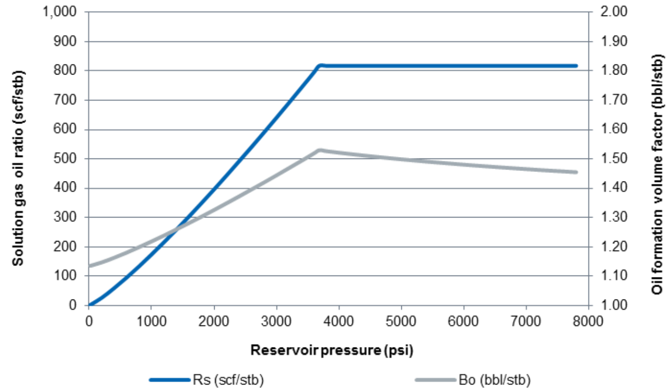
[103] Cronquist, C., "Carbon Dioxide Dynamic Displacement with Light Reservoir Oils," US DOE Annual Symposium, Tulsa, 28–30 August 1978.

In addition to modeling assumptions, numerical simulation requires petro-physical properties of the formation in each field and Pressure-Volume-Temperature (PVT) relation of the reservoir fluid. Both PVT and petro-physical properties may vary horizontally and vertically within a specific reservoir. However, for such scoping level studies, areal and vertical heterogeneity (variation within the reservoir) was not included, and instead average reservoir and fluid properties were utilized. Figure A.4 presents the PVT data that was generated for the Beaver Lodge Devonian unit. Bubble point pressure was assumed to be equal to MMP. Vasquez-Beggs and Beggs-Robinson correlations were used to generate solution gas oil ratio, oil formation volume factor, and oil viscosity profiles versus pressure. The correlations were adjusted so the initial solution gas oil ratio becomes equal to the latest producing gas oil ratio at the field level.

Figure A.5

Beaver Lodge Devonian unit



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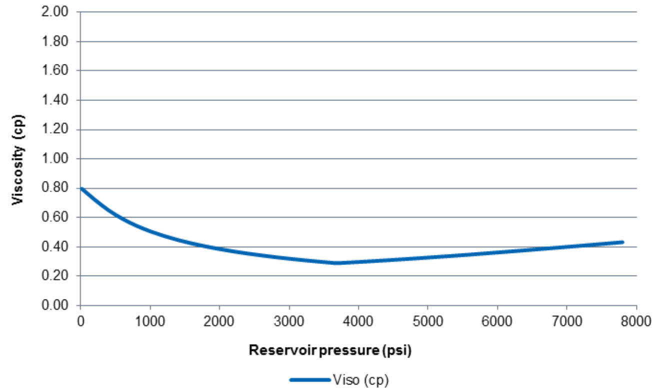
Beaver Lodge Devonian unit



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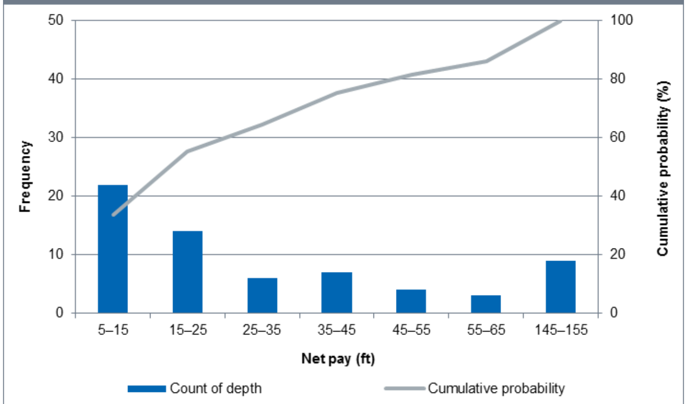
The reservoir properties such as net pay, porosity, permeability, depth, etc. for each field in North Dakota were obtained from the IHS database and public resources. Figure A.6 displays the statistical variations on each parameter for the conventional reservoirs in North Dakota fields.

For every "Good" field, a numerical model was built. The size of grid blocks in the i, j, and k direction of the numerical models were optimized in order to minimize the impact of gridding on recovery factor. Figure A.7 displays the five-spot pattern and a 3-D schematic of the numerical model for Beaver Lodge Devonian unit. The drainage area was 120 acres, and one injector and one producer was needed to maximize the recovery as well as minimize the economic impacts for the assumed pattern and drainage area. For each field, the total number of required injectors and producers was calculated. As an example, the Beaver Lodge Devonian unit requires ~110 injectors and ~110 producers in order to develop the entire field with a CO_2 EOR scheme.

In this study, the numerical models are homogenous in both vertical and horizontal directions, hence, an element of symmetry was present for the five-spot flood pattern. In order to reduce the numerical run time, a quarter of the five-spot patterns were modeled. However, the injection/production profiles that were obtained from numerical models were scaled up to the field level.

Figure A.6

Range of reservoir properties for North Dakota fields



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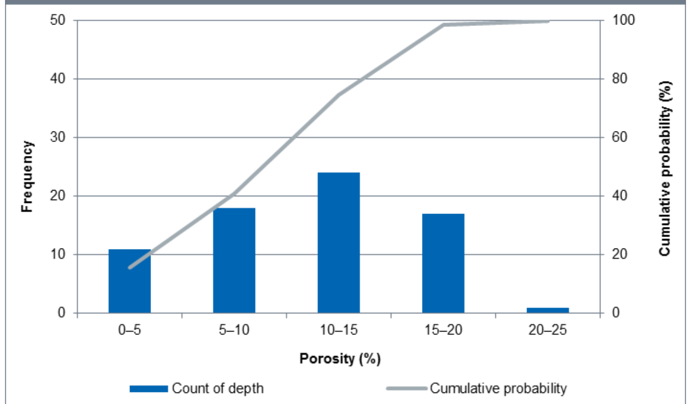
Range of reservoir properties for North Dakota fields



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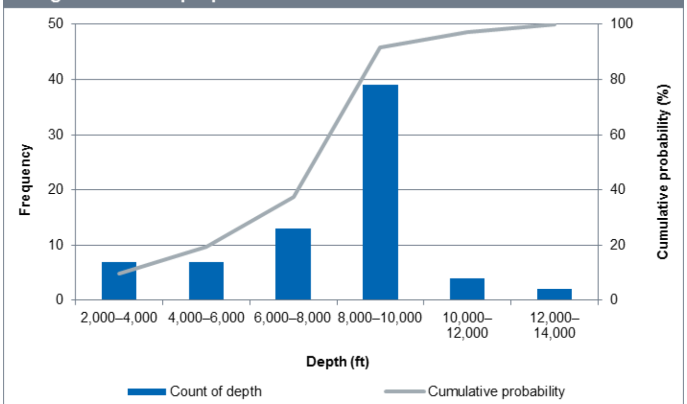
Range of reservoir properties for North Dakota fields



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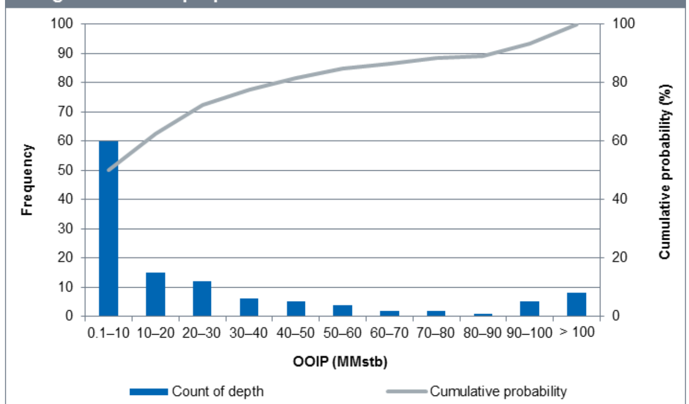
Range of reservoir properties for North Dakota fields



Source: IHS

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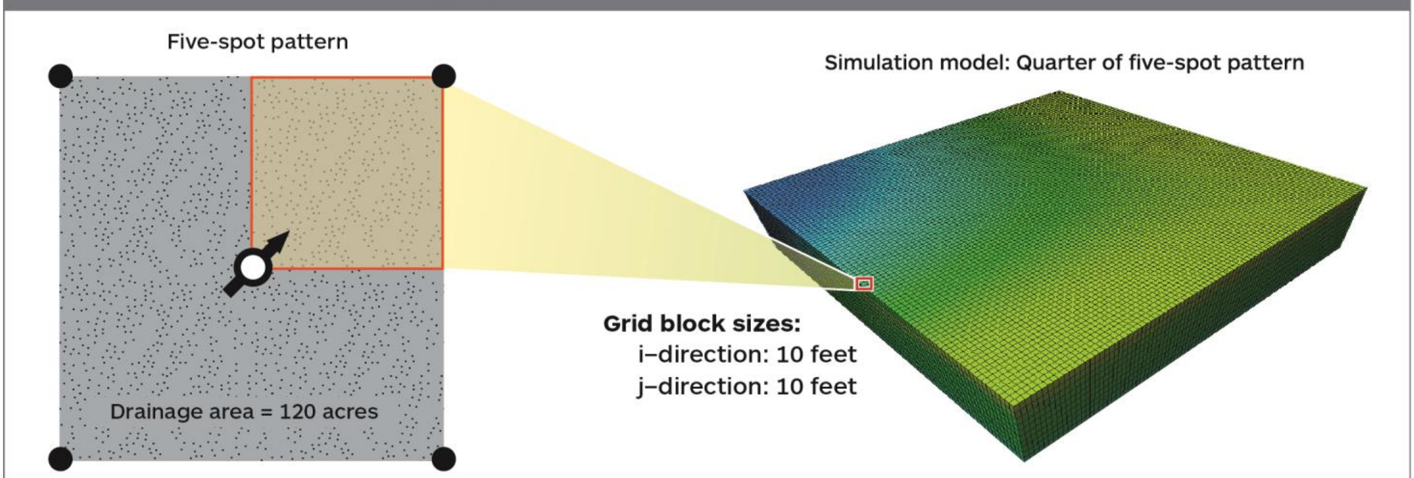
Figure A.7

Simulation model: Quarter of five-spot pattern



Source: IHS

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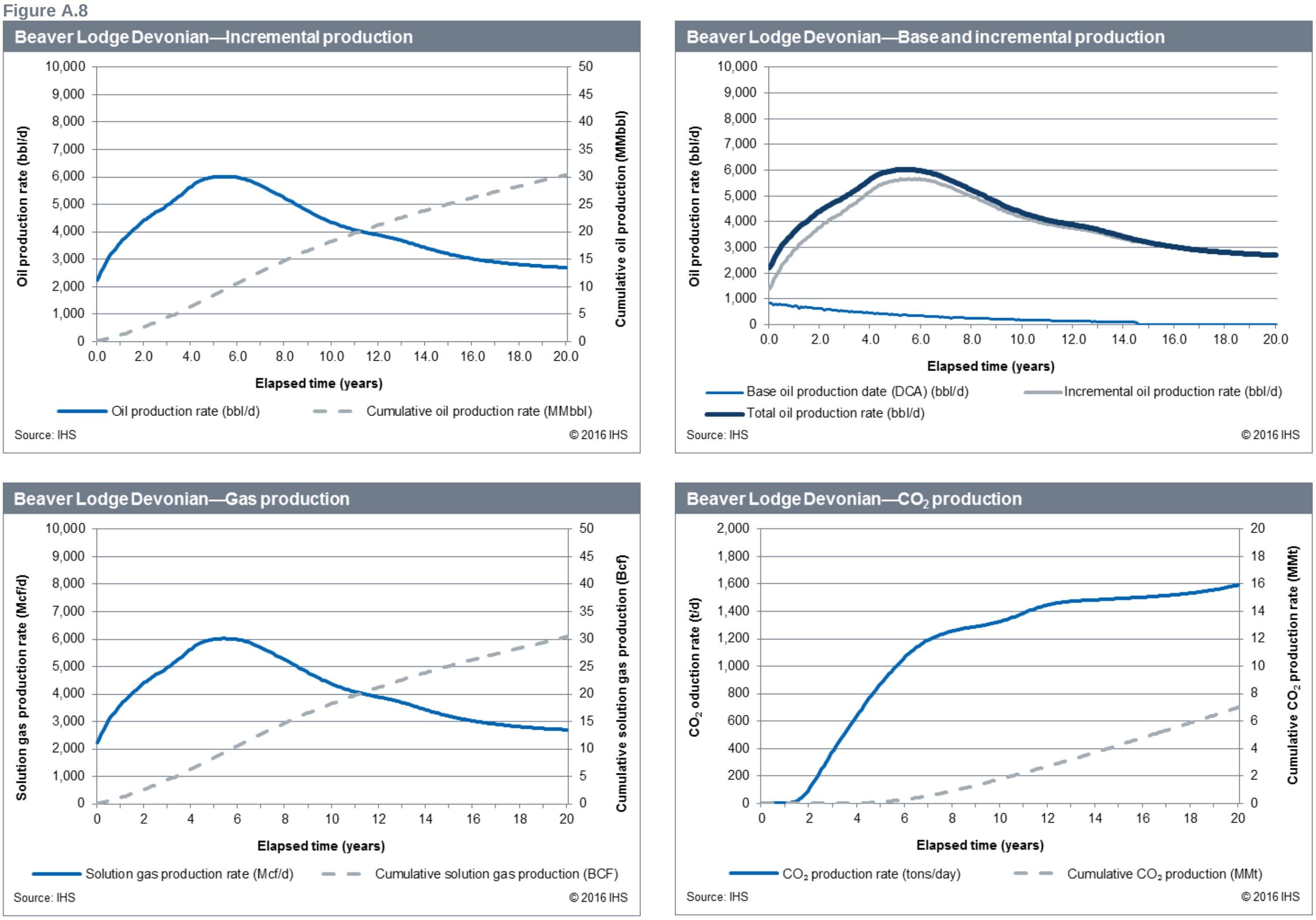
Figure A.8 demonstrates the simulation results for the Beaver Lodge Devonian Unit. As per the oil production profile, the CO_2 EOR response is very rapid in the current model, which is due to the selection of the FCM modeling approach. However, the final incremental recovery is expected to be very close to what is expected from a full field model. The “Base Oil Production Rate” profile was obtained from decline analysis of the field production history. Incremental oil production rate was obtained from subtraction of “Base line” rate from “Total Oil Production Rate”. The incremental recovery from the Beaver Lodge Devonian unit was 30.5 MMstb, which is equivalent to a recovery factor of 16.8%. CO_2 was injected into the Beaver Lodge Devonian unit at a constant rate. A total of 250 Bcf of CO_2 was injected over 20 years of injection/production.

Figure A.8



With the current modeling assumptions, it took nearly four years for CO_2 to reach out to the location of the producer. As a result, during the first four years of injection/production, the amount of CO_2 production was zero. Over the 20-year forecast, nearly 130 Bcf (46%) of the injected CO_2 was produced (and re-injected). The pressure at injector and producer locations was controlled to stay above MMP so the producing GOR was constant and equal to initial Rs. The CO_2 utilization factor for the Beaver Lodge unit varied between 10 Mcf/bbl and 18 Mcf/bbl. Initially, significant volumes of CO_2 were required to be dissolved into the oil. Near the end of the forecast period, CO_2 breakthrough occurs which causes an increasing trend in the CO_2 utilization factor.

Abbreviations, acronyms, and symbols

Acronym	Definition
μo	Oil viscosity
μs	Solvent viscosity
API	American Petroleum Institute, unit of measure for oil gravity, also a number system for well identification
ARRA	American Recovery and Reinvestment Act
bbl	Barrel of oil
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
b/d	Barrels per day
CCPI	Clean Coal Power Initiative
CCRP	The Clean Coal Research Program
CCS	Carbon capture and storage
CCUS	Carbon capture utilization and storage
CO_2	Carbon dioxide
COE	Cost of electricity
cp	Centipoises
CPP	Clean Power Plan
CPS	Carbon Pollution Standards
DOE	Department of Energy
EERC	Energy & Environmental Research Center
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EUR	Expected ultimate recovery
F	Fahrenheit
FIT	Federal income tax
FITC	Federal income tax credit
ft	Feet
GDP	Gross domestic product
GHG	Greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GOR	Gas-oil ratio
GSP	Gross state product
hp	Horsepower
ICCS	Industrial Carbon Capture and Storage
IGCC	Integrated gasification combined cycle
IMPLAN	Impact Analysis for Planning, input-output analysis assumptions
in	Inch
in-mi	Inch-mile
K	Koval factor
kWh	Kilowatt hour

Ln(api)/T(K)	Natural logarithm of API divided by temperature in Kelvin
M	Mobility ratio
Mcf/bbl	Thousand standard cubic feet per barrel of oil
MCM	Multiple Contact Miscible
mD	Millidarcy
MHI	Mitsubishi Heavy Industries
mi	Mile
mi^2	Square mile
MMcf/d	Million cubic feet per day
MMP	Minimum Miscibility Pressure
MMstb	Million standard barrels
MMt	Million metric ton
ND	North Dakota
NDIC	North Dakota Industrial Commission
NETL	National Energy Technology Laboratory
NGL	Natural gas liquids
Np	Cumulative oil production volume
NPV	Net present value
OOIP	Original oil in place
PISC	Post Injection Sire Care
P_R	Reservoir pressure
Prim RF	Primary recovery factor
psi	Pounds per square inch
PVT	Pressure, volume, temperature
R&D	Research and development
SC1	Case 1
SC2	Case 2
scf	Standard cubic feet
Sw	Water saturation
Tcf	Trillion cubic feet
T_R	Reservoir temperature
UIC	Underground injection control
Vpi	Fraction of pore volume injected
ω	Water dispersion factor

Source: IHS

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