ECONOMIC IMPACT OF CO2 EOR IN NORTH DAKOTA

Interim Report

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Approach

• **Scope:** Economics of CO2 EOR application for conventional and unconventional developments in North Dakota

• **Process:** Research, screening, analysis, validation

• **Sources:**
  - IHS proprietary databases and research
  - Third party information such as research reports, presentations, etc.
  - Industry models
  - Proprietary cost and economic models
EOR-CO2 analysis – Conventional vs. Unconventional

• Conventional EOR - well established and documented
  • Performed since the mid-1980s
  • Many fields undergoing CO2 EOR in the US
  • Narrow range of uncertainties – more highly predictable
• Unconventional EOR (Bakken / Three Forks)
  • Still in concept / modeling stage
  • No fields / one small pilot (EC 2009) – pilot planned at Sanish field
  • High range of uncertainties – We don’t know how will work for sure

Concept → Modelling → Laboratory → Pilot – Field test → Failure → Optimize → Upside → Manufacture → Improve performance

In progress
Bakken - attractive candidate for CO2 EOR consideration

1. Wide spread in seven ND counties consisting of 10,300 square miles
2. One – four possible Bakken/Three Fork zones
3. Recent estimates of OOIP 167 - 900 Bbbls; 5% recovery rate would be 8.4 - 45 Bbbls
4. Over-pressured reservoirs - BHP: 6000-7000 psi – more likely to reach MMP
5. CO₂ EOR model has produced some encouraging, yet diverse outcomes
6. Meets all of IHS field screening criteria
7. As Bakken production begins to decline per IHS forecast in about 10 years (2026):
   1. Infrastructure already in place
   2. Oil price increase/recovery underway
   3. Evolution of technology (1) CO2 injection (2) carbon Capture

CLR investor presentation 2012

Recovery perception change
Uncertainties: Lie buried deep within the rock itself

1. Heterogeneity of the Bakken reservoir properties
2. Extent and ability of micro fractures to carry CO$_2$ into pore spaces for commercial recovery
3. How CO$_2$ will react with oil within the micro-pores
4. MMP and effect of pressure increase and drops (due to hydraulic fracturing)

How do we derive inputs for an economic model which is intended to affect public policy?

(1) Review of published work such as CO$_2$-EOR Bakken modelling
(2) Build on knowledge of the Bakken / Three Forks primary production
(3) Apply lessons-learned from conventional CO$_2$ - EOR
Bakken/Three Forks – what we know and don’t know

1. Play extent & sweet spots
   - Production performance ranges
   - OOIP & primary recovery
   - Well completion designs
   - Bakken, Upper Three Forks works

2. Performance of 0.25 mile spacing
   - Timing of oil price recovery
   - Second and third Three Forks viability
   - Long-term well life and production decline

3. CO₂ per bbl needed for CO2
   - CO₂ recovery factors
   - MMP
   - CO₂ source and availability

4. Extent of Bakken/Three Forks EOR
   - Three Forks benches
   - Fractures interferences
   - Spacing - CO₂ penetration
   - Shape of oil production profile
   - CO₂ re-injection percentage
Bakken areas modelled for seven counties

- Primary and EOR properties determined for each of the four areas shown on map
- Counties assigned to areas
  - Sanish – Sweet spot
    - Mountrail County
  - Nesson – Recently developing highly productive area
    - Williams County
    - McKenzie County
  - Bailey – Less potential
    - Dunn County
  - Elm Coulee – considered fringe with lower potential
    - Billings County
    - Burke County
    - Divide County

Source: IHS
Bakken/Three Forks primary recovery

- **Bailey**
  - OOIP/mi² - 5270 bbls
  - EUR/well – 374 bbls
  - Prim RF – 7.1% ½ mi sp
  - Prim RF – 14.2% ¼ mi sp

- **Sanish**
  - OOIP/mi² - 9078 bbls
  - EUR/well – 501 bbls
  - Prim RF – 5.5% ½ mi sp
  - Prim RF – 11.0% ¼ mi sp

- **Nesson**
  - OOIP/mi² - 6736 bbls
  - EUR/well – 440 bbls
  - Prim RF – 6.5% ½ mi sp
  - Prim RF – 13.1% ¼ mi sp

- **Elm Coulee**
  - OOIP/mi² - 4815 bbls
  - EUR/well – 189 bbls
  - Prim RF – 3.9% ½ mi sp
  - Prim RF – 7.8% ¼ mi sp

Source: IHS
CO2 EOR Bakken economic model input assumptions

CO2 EOR recovery factor of OOIP (oil in place) - We used

5% (1/2 mi injector well spacing)
7.5% (1/4 mi injector well spacing)

1. Low end of ND conventional RF range 4.6 – 16.8% -
2. EERC suggests 4%
3. Mid range of 0.5%-24% recovery factors obtained from published CO2-EOR modeling (All results are coming from simulations or analytical calculations).

1. CO2 Flooding the Elm Coulee Field; Shehbaz, Shoaib, et, al; SPE 123176; 2009
2. Geologic Characterization of a Bakken Reservoir for Potential CO2 EOR; Basak Kurtoglu, et, al; SPE 168915 / URTeX 1619698; 2013
3. Modeling Gas Injection into Shale Oil Reservoirs in the Sanish Field, North Dakota; Cuiya Dong, et, al; SPE 168827 / URTeC 1581998; 2013
4. CO2-Based Enhanced Oil Recovery from Unconventional Reservoirs: A Case Study of the Bakken Formation; G. Liu, et, al; SPE 168979-MS; 2014
5. Integrated Reservoir Characterization and Modeling in Support of Enhanced Oil Recovery for Bakken; Basak Kurtoglu; Williston Basin Petroleum Conf, North Dakota; 2014
6. The EERC’s CO2 Enhanced Bakken Recovery Research Program; John Harju; ND Legislative Council Energy Development and Transmission Committee Meeting; 2012
7. Overview of the EERC’s Bakken CO2 EOR Research Programs; John Harju; 8th Annual Wyoming CO2 Conference; 2014
CO2 EOR Bakken economic model input assumptions

Production profile – We used

- Single well model – flat production for a 10 year cycle
- Field production created by applying schedule of drilling or conversion of injector wells
- CO2 EOR production may occur independently of primary production profile

![Graph showing primary and CO2 EOR production profiles over time](image)
Bakken / Three Forks development unit – Case 1

• No new injectors drilled, alternating producers being converted to injectors

• Two producer – injector pairs for each 2-square mile unit in both the Bakken and Upper Three Forks

• IHS Bakken/Three Forks primary production forecast assumes 9500 ft laterals spaced ¼ mile (1320 feet) apart

• Each alternating injector well to add to each producer:
  • Nesson – 336 Mbbls
  • Sanish – 454 Mbbls
  • Bailey – 266 Mbbls
  • Elm Coulee – 241 Mbbls
Bakken / Three Forks development unit - Case 2

- Drill new injectors into the lower Bakken to produce both the middle Bakken and the upper Three Forks
- Contingency if closer spacing were needed (660-feet from producer) for effective EOR
- One injector for two producers in combined Bakken and Upper Three Forks
- Due to closer spacing we assume 50% increase in recovery per injector
- Each injector well to add to each producer:
  - Nesson – 252 Mbbls
  - Sanish – 340 Mbbls
  - Bailey – 200 Mbbls
  - Elm Coulee – 181 Mbbls
CO2 EOR Bakken economic model input assumptions

CO2 Sources:
Due to potential size and scalability much more CO2 may be required –
Up to 2.2 bcf/d for Case 2
We added 2.00 $/mcf long-haul transport fee to CO2 cost for economic modelling

Amount or Use of CO2 mcf/bbl:
14.5 mcf/bbl for case 1
11.3 mcf/bbl for case 2 (injection wells closer to producers)

1. Comparable to amounts projected for conventional fields
2. Reasonable mid point between 0.15-33 mcf/bbl obtained from published CO2-EOR modeling

Re-injection of CO2
20% after two years – this is less than half of conventional re-injection, but the Bakken / Three Forks are less permeable, so we assume less CO2 recovery
CO2 EOR Bakken economic model input assumptions

• Percentage of Bakken/Three Forks area which could be developed or how much of the Bakken is likely to undergo CO2 EOR
  • 20% in core counties,
  • 13% in fringe counties
    1. Conservative assessment but allows us to apply scalability like we currently have in the Bakken
    2. Risked area
      1. 50% geologic properties will allow this to work
      2. 50% access to large amounts of CO2
      3. 80% price recovery and technology advancement

• What Three Forks benches to include – Only upper Three Forks
  1. Similar reservoir properties to the middle Bakken
  2. Established commercial primary production
  3. Unsure if lower benches will be extensively developed – possibly no producing wells in these benches in large areas throughout the play

Conventional production peaked in 1985 at 140 Mbbls/d – Our forecast shows the Bakken / Three Forks peaking in 2026 at 10 times that amount
CO2 EOR Bakken summary

- During a 20-year development cycle, over 3600 injector wells would be converted or drilled.
- CO2 requirements would be enormous with case 1 requiring 10.6 Tcf and Case 2 requiring 12.4 Tcf over this 20 year cycle.
- Much more work is required to realize these types of numbers, however, this analysis provides a view of the potential for CO2 EOR in the Bakken.
- We assume for our economic modeling that production will begin in 2021, so only a portion of this production is realized in the 2017 – 2036 forecast time period.
## Technical Evaluation – Conventional Fields

### Reservoir modelling objectives and results

<table>
<thead>
<tr>
<th>Purpose</th>
<th>Simulation</th>
<th>Reservoir Modeling</th>
</tr>
</thead>
<tbody>
<tr>
<td>Screen all conventional North Dakota fields for good CO2 – EOR candidates</td>
<td>IHS used the numerical simulation methodology to model conventional fields using Eclipse reservoir simulation software</td>
<td>Calculate oil recovery factor as a percentage of OOIP (oil in place) – ultimate recovery</td>
</tr>
<tr>
<td>We began with 126 fields that had undergone water flooding and identified 18 candidate fields for economic modelling</td>
<td>Establish a production profile forecast – cash flow stream</td>
<td>Establish a production profile forecast – cash flow stream</td>
</tr>
<tr>
<td></td>
<td>Generate the number and configuration of injector wells – basis for development plan</td>
<td>Generate the number and configuration of injector wells – basis for development plan</td>
</tr>
<tr>
<td></td>
<td>Calculate the amount of CO2 needed – sourcing and cost</td>
<td>Calculate the amount of CO2 needed – sourcing and cost</td>
</tr>
</tbody>
</table>
Worldwide EOR conventional project categories

- Chemical, polymer, surfactant
- CO₂ Immiscible
- CO₂ Miscible
- HC Immiscible
- HC Miscible
- Nitrogen Immiscible

Source: IHS

- In North America, CO₂ miscible, Hydrocarbon (HC) immiscible and miscible mechanisms are the most successful EOR processes.
- Above summary excludes steam based EOR processes.
- Miscibility is the capacity of a solvent, such as CO₂, to mix with oil and form one homogenous phase in all properties – oil becomes less viscous and the bonded CO₂ expands the oil molecules, forcing some of them to flow toward production wells.
CO₂-EOR Process Mechanism

- The CO₂ miscible process is displayed below:

- There are two categories of miscible floods:
  - First Contact Miscible (FCM)
  - Multiple Contact Miscible (MCM)

- Due to the lack of Pressure Volume Temperature (PVT) data, the FCM process was utilized in this study using average API gravity and viscosity values which were publically available.
Field Screening Process

Collect/calculate production/reservoir/fluid data for each field

851 Fields

725 Fields

Waterflooded?

No → Unfavorable Candidate for CO2-EOR

77 Fields

Fail → 77 Fields

31 Fields

Non Effective

Yes → Conduct screening using IHS criteria

126 Fields

Pass → 49 Fields

Evaluate waterflood effectiveness

18 Fields

CO2-EUR estimation

725 Fields

851 Fields
# IHS screening criteria for potential CO$_2$-EOR floods

- Extensive literature review was conducted to collect the reservoir/operation parameters of current successful CO$_2$ miscible floods.
- A data set was set up for 100+ CO$_2$ projects in the US and Canada.
- In some projects, reservoir parameters were reported as a range instead of a specific value, hence an average value was used for the analysis.
- Reservoir parameters from the successful and promising projects were selected to set up the screening criteria.

<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>Depth, ft</td>
<td>&gt;2300</td>
<td>&gt;3000</td>
<td>&gt;2500</td>
<td>&gt;2500</td>
<td>&gt;2500</td>
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<tr>
<td>Oil Gravity, API</td>
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<td>&gt;22</td>
<td>&gt;22</td>
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<tr>
<td>Viscosity, cp</td>
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<td>&lt;12</td>
<td>&lt;10</td>
<td>&lt;10</td>
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<tr>
<td>Oil Saturation, %</td>
<td>&gt;25</td>
<td>&gt;25</td>
<td>&gt;20</td>
<td>&gt;20</td>
<td>&gt;20</td>
</tr>
<tr>
<td>Temperature, F</td>
<td>&lt;250</td>
<td>nc</td>
<td>nc</td>
<td>nc</td>
<td>&gt;86</td>
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</tbody>
</table>

49 of the 126 ND fields analyzed passed this screening criteria
Screening fields for successful waterflood

Examples of fields with poor waterflood performance

Reasons for failing the final screening
- High current GOR
- No current active waterflood.

Reasons for failing the final screening
- High current GOR
- Poor waterflood performance.

- Successful waterflood scheme results in constant or decreasing GOR trend vs time.

Only 18 of the 49 ND fields analyzed had successful waterfloods
List of North Dakota fields with “good” and “poor” results

<table>
<thead>
<tr>
<th>No.</th>
<th>Field Name</th>
<th>Class</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Beaver Lodge Devonian Unit</td>
<td>Good</td>
</tr>
<tr>
<td>2</td>
<td>Fryburg Heath-Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>3</td>
<td>Cedar Hills North Red River B Unit</td>
<td>Good</td>
</tr>
<tr>
<td>4</td>
<td>Cedar Hills South Red River B Unit</td>
<td>Good</td>
</tr>
<tr>
<td>5</td>
<td>Big Stick Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>6</td>
<td>Charlson North Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>7</td>
<td>Blue Buttes Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>8</td>
<td>North Elkhorn Ranch Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>9</td>
<td>T.R. Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>10</td>
<td>Newburg Spearfish-Charles Unit</td>
<td>Good</td>
</tr>
<tr>
<td>11</td>
<td>Medora Heath-Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>12</td>
<td>Rough Rider East madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>13</td>
<td>Horse Creek Red River Unit</td>
<td>Good</td>
</tr>
<tr>
<td>14</td>
<td>Disckinson Heath Unit</td>
<td>Good</td>
</tr>
<tr>
<td>15</td>
<td>West Rough Rider Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>16</td>
<td>Charlson South Madison Unit</td>
<td>Good</td>
</tr>
<tr>
<td>17</td>
<td>Bear Creek Duperow Unit</td>
<td>Good</td>
</tr>
<tr>
<td>18</td>
<td>Hufflund Madison Unit</td>
<td>Good</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>No.</th>
<th>Field Name</th>
<th>Class</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Antelope Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>2</td>
<td>Medicine Pole Hills Red River Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>3</td>
<td>Medicine Pole Hills West Red River Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>4</td>
<td>Medicine Pole Hills South Red River B Unit</td>
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</tr>
<tr>
<td>5</td>
<td>Northeast Foothills Madison Unit</td>
<td>Poor</td>
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<tr>
<td>6</td>
<td>Antelope Devonian Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>7</td>
<td>North Tioga Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>8</td>
<td>Foothills Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>9</td>
<td>North Black Slough Midale</td>
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<tr>
<td>10</td>
<td>South Black Slough Midale-Rival Unit</td>
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<td>11</td>
<td>Hawkeye Madison Unit</td>
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</tr>
<tr>
<td>12</td>
<td>West Dickinson Lodgepole Unit</td>
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<tr>
<td>13</td>
<td>Versippi Lodgepole Unit</td>
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<tr>
<td>14</td>
<td>Dickinson Lodgepole Unit</td>
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<tr>
<td>15</td>
<td>Duck Creek Lodgepole Unit</td>
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<td>16</td>
<td>Hiline Lodgepole Unit</td>
<td>Poor</td>
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<tr>
<td>17</td>
<td>Livestock Lodgepole Unit</td>
<td>Poor</td>
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<td>18</td>
<td>Subdivision Lodgepole Unit</td>
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<td>19</td>
<td>Tioga Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>20</td>
<td>Beaver Lodge Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>21</td>
<td>Red Wing Creek Madison Unit</td>
<td>Poor</td>
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<tr>
<td>22</td>
<td>Rival Madison Unit</td>
<td>Poor</td>
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<tr>
<td>23</td>
<td>Capa Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>24</td>
<td>Clear Creek Maddison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>25</td>
<td>South Starbuck Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>26</td>
<td>Plaza Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>27</td>
<td>Little Misouri Redi River Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>28</td>
<td>State Line Red River Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>29</td>
<td>Little Knife North Madison Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>30</td>
<td>South Westhope Spearfish-Charles Unit</td>
<td>Poor</td>
</tr>
<tr>
<td>31</td>
<td>Fryburg South River Unit</td>
<td>Poor</td>
</tr>
</tbody>
</table>

- If the waterflood of a field had poor performance, then this field was categorized as a “Poor” candidate for CO$_2$-EOR process. Successful waterflood preferentially nominated a field as a “Good” candidate for the CO$_2$-EOR process.
- These 18 “Good” fields were modelled for CO$_2$-EOR process.
Numerical reservoir modeling assumptions

- **Flooding pattern**: 5 Spot (injector well pattern)
- **Drainage area of numerical model**: 120 acres/(2 wells)
- **CO₂ injection volume**: 40% Hydrocarbon Pore Volume (HCPV)
- **Homogenous properties**: The reservoir properties (permeability and porosity as well as the fluid properties) were assumed to be constant in the horizontal and vertical directions.
- **Continuous CO₂ injection**
- **No free gas at current reservoir pressure**
- **No external water**: The water production is associated with the current water saturation within the drainage area of the well.
- **Injection Constraint**: Maximum injection rate
- **Production Pressure**: Slightly above Minimum Miscibility Pressure (MMP). MMP is the minimum pressure at which CO₂ is miscible in oil (at any proportion of injected CO₂)
- **CO₂ Miscibility**: First contact miscible (FCM) with limited dispersion over the grid block size
Reservoir Model

Grid Pattern

• For the purpose of the economic analysis, a 5 spot pattern was selected in the reservoir modeling section. The 5-spot pattern figure displays a 120 acres drainage area in which one injector and one producer is needed.

• For each field, the total number of required injectors and producers was calculated. For example Beaver Lodge Devonian unit requires ~110 injectors and ~110 producers in order to develop the entire field with CO2-EOR scheme (based on the area of the field).

• In this study, areal heterogeneity (variation within the reservoir) was not included due to the lack of detailed petrophysical analysis; 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 pattern was modeled. However, the injection/production profiles were up-scaled to the field level.
CO₂-EOR Simulation Results

Beaver Lodge Devonian Unit

• The figures below show incremental oil and gas production profiles from the CO₂-EOR process for the Beaver Lodge Devonian unit that was used in the economic model.

• The CO₂-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.

• Producing GOR is constant and equal to initial Rₘ. Recovery factor for Beaver Lodge Devonian unit is 16.8%

• Incremental recovery 30.5MMbbl
**CO₂-EOR Simulation Results**

*Beaver Lodge Devonian Unit*

- CO₂ was injected into Beaver Lodge Devonian at a constant rate. A total of 280 BCF CO₂ was injected over 20 years of injection/production.
- With the current modeling assumptions, it takes ~4 years for the CO₂ to reach out to the location of the producer. As a result, during the first four years of production, the amount of CO₂ production is zero. Over a 20 year forecast, ~130 BCF (46%) of the injected CO₂ is produced (and can be re-injected).
CO₂-EOR Simulation Results

Beaver Lodge Devonian Unit

- CO₂ utilization factor per (mscf/stb for Beaver Lodge Devonian unit varies between 10-18 mscf/stb.

- Initially significant volumes of CO₂ is required to be dissolved into the oil. Near the end of the forecast period, CO₂ breakthrough occurs which causes an increasing trend in the CO₂ utilization factor.
Numerical results of oil recovery for suitable fields

- Numerical simulation was conducted for 18 fields that passed all screening criteria. For each field, average reservoir properties were utilized. Table below summarizes the EUR from CO₂-EOR for each field. The Beaver Lodge Devonian and the Hofflund Madison Units display maximum and minimum recovery among the suitable fields respectively.

- Table below presents a comparison between the results of current study and similar studies that were conducted for North Dakota fields.

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Rank</th>
<th>Numerical Np Estimate Mstb</th>
<th>Recovery Factor %</th>
<th>Utilization Factor Mscf/bbl</th>
<th>Recovery Factor, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>BEAVER LODGE DEVONIAN UNIT</td>
<td>1</td>
<td>30,530</td>
<td>16.8</td>
<td>9.0</td>
<td>8.0</td>
</tr>
<tr>
<td>FRYBURG HEATH-MADISON UNIT</td>
<td>2</td>
<td>20,624</td>
<td>13.3</td>
<td>5.0</td>
<td>8.0</td>
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<tr>
<td>CEDAR HILLS NORTH RED RIVER B UNIT</td>
<td>3</td>
<td>19,110</td>
<td>6.9</td>
<td>12.0</td>
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<tr>
<td>CEDAR HILLS SOUTH RED RIVER B UNIT</td>
<td>4</td>
<td>18,416</td>
<td>5.1</td>
<td>17.5</td>
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<td>BIG STICK MADISON UNIT</td>
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<td>9.5</td>
<td>10.5</td>
<td>8.0</td>
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<td>CHARLSNOWN NORTH MADISON UNIT</td>
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<td>6,961</td>
<td>8.7</td>
<td>11.1</td>
<td>8.0</td>
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<td>BLUE BUTTES MADISON UNIT</td>
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<td>6.2</td>
<td>13.6</td>
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<td>4,524</td>
<td>8.2</td>
<td>11.0</td>
<td></td>
</tr>
<tr>
<td>T. R. MADISON UNIT</td>
<td>9</td>
<td>4,242</td>
<td>9.9</td>
<td>9.6</td>
<td></td>
</tr>
<tr>
<td>NEWBURG SPEARFISH-CHARLES UNIT</td>
<td>10</td>
<td>4,157</td>
<td>4.3</td>
<td>18.2</td>
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</tr>
<tr>
<td>MEDORA HEATH-MADISON UNIT</td>
<td>11</td>
<td>3,978</td>
<td>6.9</td>
<td>12.0</td>
<td></td>
</tr>
<tr>
<td>ROUGH RIDER EAST MADISON UNIT</td>
<td>12</td>
<td>3,715</td>
<td>12.0</td>
<td>9.1</td>
<td>8.0</td>
</tr>
<tr>
<td>HORSE CREEK RED RIVER UNIT</td>
<td>13</td>
<td>3,391</td>
<td>7.4</td>
<td>9.0</td>
<td></td>
</tr>
<tr>
<td>DICKINSON HEATH UNIT</td>
<td>14</td>
<td>2,849</td>
<td>4.6</td>
<td>23.5</td>
<td></td>
</tr>
<tr>
<td>WEST ROUGH RIDER MADISON UNIT</td>
<td>15</td>
<td>2,386</td>
<td>8.0</td>
<td>12.2</td>
<td></td>
</tr>
<tr>
<td>CHARLSNOWN SOUTH MADISON UNIT</td>
<td>16</td>
<td>1,267</td>
<td>8.7</td>
<td>11.1</td>
<td></td>
</tr>
<tr>
<td>BEAR CREEK DUPEROW UNIT</td>
<td>17</td>
<td>931</td>
<td>6.8</td>
<td>16.4</td>
<td>8.0</td>
</tr>
<tr>
<td>HOFFLUND MADISON UNIT</td>
<td>18</td>
<td>675</td>
<td>6.5</td>
<td>16.8</td>
<td></td>
</tr>
</tbody>
</table>
Comparison of analytical and numerical CO₂-EOR performance results – IHS used the Numerical method

The analytical approach that was developed by Claridge is utilized to estimate the incremental oil produced using CO₂ miscible injection. This utilizes a complex equation for estimating the fraction of oil produced from a CO₂ miscible flood:

Analytical methods are quick and easy to be utilized for EUR estimation for case studies with minimal available information. However, it suffers from oversimplification of the process and excludes several important parameters/processes which lead to over estimating of recoveries. Numerical results can be used to correct the analytical estimations.

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Rank</th>
<th>Analytical Np Estimate (Mstb)</th>
<th>Numerical Np Estimate (Mstb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beaver Lodge Devonian Unit</td>
<td>1</td>
<td>54,046</td>
<td>30,530</td>
</tr>
<tr>
<td>Fryburg Heath-Madison Unit</td>
<td>2</td>
<td>28,597</td>
<td>20,624</td>
</tr>
<tr>
<td>Cedar Hills North Red River B Unit</td>
<td>3</td>
<td>32,982</td>
<td>19,110</td>
</tr>
<tr>
<td>Cedar Hills South Red River B Unit</td>
<td>4</td>
<td>38,914</td>
<td>18,416</td>
</tr>
<tr>
<td>Big Stick Madison Unit</td>
<td>5</td>
<td>35,022</td>
<td>15,770</td>
</tr>
<tr>
<td>Charlson North Madison Unit</td>
<td>6</td>
<td>16,531</td>
<td>6,961</td>
</tr>
<tr>
<td>Blue Buttes Madison Unit</td>
<td>7</td>
<td>14,990</td>
<td>5,776</td>
</tr>
<tr>
<td>North Elkhorn Ranch Madison Unit</td>
<td>8</td>
<td>10,760</td>
<td>4,524</td>
</tr>
<tr>
<td>T.R. Madison Unit</td>
<td>9</td>
<td>7,025</td>
<td>4,242</td>
</tr>
<tr>
<td>Newburg Spearfish-Charles Unit</td>
<td>10</td>
<td>7,477</td>
<td>4,157</td>
</tr>
<tr>
<td>Medora Heath-Madison Unit</td>
<td>11</td>
<td>8,267</td>
<td>3,978</td>
</tr>
<tr>
<td>Rough Rider East madison Unit</td>
<td>12</td>
<td>5,976</td>
<td>3,715</td>
</tr>
<tr>
<td>Horse Creek Red River Unit</td>
<td>13</td>
<td>6,967</td>
<td>3,391</td>
</tr>
<tr>
<td>Disckinson Heath Unit</td>
<td>14</td>
<td>10,495</td>
<td>2,849</td>
</tr>
<tr>
<td>West Rough Rider Madison Unit</td>
<td>15</td>
<td>5,238</td>
<td>2,386</td>
</tr>
<tr>
<td>Charlson South Madison Unit</td>
<td>16</td>
<td>2,996</td>
<td>1,267</td>
</tr>
<tr>
<td>Bear Creek Duperow Unit</td>
<td>17</td>
<td>2,670</td>
<td>931</td>
</tr>
<tr>
<td>Hufflund Madison Unit</td>
<td>18</td>
<td>1,915</td>
<td>675</td>
</tr>
</tbody>
</table>
Co2 EOR Conventional Modeling Summary

• IHS constructed a CO$_2$-EOR Screening data base for identification of North Dakota fields that are amenable to such process. North Dakota reservoir parameters were obtained from a compilation of IHS’ data base and the public domain. These values are not carved in stone and require in-depth analysis and updating. Therefore, results from this study should be considered as a starting point in the screening process and should not be used to replace an in-depth evaluation and study of a CO$_2$-EOR process for a specific field.

• No optimization scenarios were considered. Also the CO$_2$-EOR process is premised to be implemented after the waterflood mechanism is exhausted.

• Of the 100+ fields investigated in the present study, only 18 fields passed all the screening criteria. The following fields show potential incremental in reserves:
  • Beaver Lodge Devonian Unit
  • Fryburg Heath Madison Unit
  • Cedar Hills River B Unit
  • Big Stick Madison Unit
  • Charlson North Madison Unit

• Estimated incremental cumulative oil production of CO$_2$-EOR for candidate fields in North Dakota ranges between 0.7 and 30.5 MMstb per field (technically recoverable), requiring between 32 and 486 BCF of CO$_2$. 
CO2 EOR Economic Impact – Interim Report / April 2016

Contents

1. CO2 EOR in Unconventional Reservoirs
2. Conventional Field CO2 EOR
3. Economic Model Assumptions
4. Upstream Economics
Critical costs for EOR field economic modeling

- Well and facilities cost
- Infrastructure
- Scheduling
- Opex and maintenance
- Source and price of CO2
- Oil price forecast
- Fiscal terms and tax incentives
- Multiple scenarios
IHS leveraged in-house expertise along with extensive literature review and projects research to map the capital and operating costs related to CO2 EOR projects.
CO2 EOR Development Schematic

Carbon Capture Sources
Gas Plants (High CO2 fields)
Industrial/Power Plants
Refining/Chemical Plants
Lignite
Natural Sources

CO2

Compressor

EOR Field Separation & Recovery Plant

CO2 Recycled for Reinjection

Produced Oil, Gas, & Water

Gas-used as fuel for plant

Natural Gas

Used as industrial fuel or sold to market

Crude Oil to Market

Gas used as fuel for plant

Produced Oil, Gas, & Water
# Cost – Facilities: Project Components

<table>
<thead>
<tr>
<th>Wells</th>
<th>Production Wells</th>
<th>Injection Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Production and Injection</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Reuse wells that are currently producing</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Re-drill through temporarily abandoned wells</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>CO2 Pipeline</th>
<th>CO2 Pipeline</th>
<th>CO2 Separator</th>
</tr>
</thead>
<tbody>
<tr>
<td>• From CO2 source or trunk line</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• 4, 6, 8, 12, 16, 20 or 24 inch pipelines depending on throughput</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>CO2 Separator</th>
<th>Compression</th>
<th>Gathering System</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Extracts CO2 for injection from gases produced</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| CO2 Compression                                                                              |                  |                 |
| • Combines imported and separated CO2                                                         |                  |                 |
| • Pressurizes CO2 for injection into the reservoir (miscible pressure)                        |                  |                 |

| Gathering system                                                                             |                  |                 |
| • For flow between wells and central facilities for oil, gas and CO2                          |                  |                 |
Well Types

The following well types are encountered during a CO2 EOR project

1. Production Well
   - Drilled to produce oil and gas. Oil and CO2 migrates from the injection well to the production well.

2. Injection Well
   - Injects CO2 into the reservoir allowing CO2 to mix with, and release, oil from the formation.

3. Production Well Workover
   - Re-entry and redevelopment of the production tubing string on existing production wells to protect from the highly corrosive nature of the gas.

4. Redrill CO2 Injection Well
   - Temporarily abandoned wells re-drilled and recommissioned to use as a CO2 injection well.

Assumptions:
- Any currently producing wells will be reused, temporarily abandoned wells will be recommissioned and reused, and tubing will be upgraded for highly corrosive gas.
- Well costs, lease equipment, and operating costs are be based on IHS regional cost databases.
Well Opex Methodology

Fixed monthly opex per well (injectors and producers)

- Opex based on depth
  - Includes scheduled maintenance, road restoration, labor, pumping costs and energy
  - Based on US cost rates from EIA data for Rocky Mountain region
    - Netted down to consider other operating costs already modeled

Variable Costs

- Oil
  - Oil Transportation to market
    - Determine market based on region
    - Determine distance to market
    - Determine combination of transport (pipeline, truck and rail) to get a $/bbl/mile
- Gas
  - Gas transportation and marketing (to Chicago)
    - If gas is marketable, use regional gas transportation rates
    - Gas is assumed to require minimal processing for dehydration

G/A

- General and administrative expenses
2022 Assumption for ND CO2 Available Sources

Conventional - Sources and Cost of CO2 –
- Low case scenario has fewer sources of CO2, with some projects having long distances to a source – limited to 187 MMcf/d – Purchase price $1.56/mcf
- Base case scenario has more CO2 sources making the distance to source shorter for some projects – limited to 493 MMcf/d – Purchase price $1.61/mcf
- High case scenario has many more sources with most projects benefitting from shorter distances to the CO2 source – Limited to 1,175 MMcf/d – Purchase price $1.71/mcf

Bakken - source and cost of CO2
- Due to the large requirements of CO2 for proposed high volume Bakken projects CO2 requirements as high as 2.3 bcf/day will be required
- Assuming that CO2 may have to be transported long distances – purchase price includes an added $2.00/mcf transport fee
IHS aggregated production into broad field designations

For each field, the calculation of transport costs involved decisions:
- whether crude produced in the field would move via truck out of the wellhead to secondary transportation options
- whether crude would move via gathering pipeline or if it could be directly trucked to a trunkline pipeline or rail loading terminal
- whether crude would move via pipeline or rail to its ultimate destination

Transportation Cost includes all costs to get to market -- gathering, pipeline, rail, & trucking.

<table>
<thead>
<tr>
<th>Market</th>
<th>Transportation Cost ($/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>East Coast</td>
<td>$13.32-16.03</td>
</tr>
<tr>
<td>West Coast</td>
<td>$15.85-16.77</td>
</tr>
<tr>
<td>Cushing (OK)</td>
<td>$9.14-11.80</td>
</tr>
<tr>
<td>Gulf Coast</td>
<td>$9.33-12.14</td>
</tr>
</tbody>
</table>
## North Dakota Fiscal Terms

### Taxes

<table>
<thead>
<tr>
<th>Corporate Income Tax</th>
<th>Depreciation</th>
<th>Depreciation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Federal:</strong> 35%</td>
<td><strong>Tangible</strong> (50%)</td>
<td><strong>Intangible</strong> (50%)</td>
</tr>
<tr>
<td><strong>State:</strong> 4.31% (max rate modelled)</td>
<td>• Double declining balance</td>
<td>• 30% (5-year straight line); 70% expensed</td>
</tr>
<tr>
<td>• ND depreciation is same as for Federal income tax</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• State income tax is deductible for Federal income tax</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Production Tax</th>
<th>Extraction Tax</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil gross production tax of 5%.</td>
<td>Oil extraction tax rate of 5%*</td>
</tr>
<tr>
<td>Gas production tax is an annually adjusted flat rate per thousand cubic feet of all nonexempt gas produced in ND.</td>
<td>*Rate is reduced based on various circumstances. Rate rises to 6% if crude prices average above $90/bbl for 3 consecutive months. Tertiary recovery projects get a 10-year exemption.</td>
</tr>
<tr>
<td>$0.1106 per mcf (2016 rate), adjusted annually for oil price.</td>
<td></td>
</tr>
<tr>
<td>Production tax applied to wellhead income</td>
<td></td>
</tr>
<tr>
<td>• CO2 injection operating costs assumed to be deductible post-production costs</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ad Valorem Taxes</th>
</tr>
</thead>
<tbody>
<tr>
<td>No ad valorem production tax for oil and gas production.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Extraction Tax</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil extraction tax rate of 5%*</td>
</tr>
<tr>
<td>*Rate is reduced based on various circumstances. Rate rises to 6% if crude prices average above $90/bbl for 3 consecutive months. Tertiary recovery projects get a 10-year exemption.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Lease Terms</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Royalty</strong> 12.5-22% (18% assumed)</td>
</tr>
<tr>
<td><strong>Rental</strong> Typically a nominal amount paid on per-acre basis (i.e. $1/acre, not modelled)</td>
</tr>
<tr>
<td><strong>Bonus</strong> $2,500-$4,000/acre in Bakken region. (not modelled).</td>
</tr>
</tbody>
</table>
Fiscal Analysis – Bakken in Mountrail County (Sanish)

- Case 1 break even at 10% IRR is $90/bbl and Case 2 break even is $115/bbl under current fiscal terms.

- Current fiscal terms are already efficient for more profitable sections of the play under Case 1.

- Fiscal incentives may only be able to improve the break even price by $3.14/bbl for Bakken Case 1.

- For Bakken Case 2, which is much more capital intensive, fiscal incentives may improve the break even price by as much as $8.37/bbl.
• Case 1’s break even price at 10% IRR is $102/bbl and Case 2’s break even price is $167/bbl under current fiscal terms.

• Fiscal incentives may only be able to improve the break even price by $5.40/bbl to develop Bakken Case 1.

• For Bakken Case 2, fiscal incentives may improve the break even price by as much as $14.55/bbl.
Fiscal Analysis – Bakken in Divide County (Elm Coulee)

- Case 1’s break even price at 10% IRR is $104/bbl and Case 2’s break even price is $154/bbl under current fiscal terms.

- Fiscal incentives may only be able to improve the break even price by $5.6/bbl for Bakken Case 1.

- For Bakken Case 2, which is much more capital intensive than Case 1, fiscal incentives may improve the break even price by as much as $13.20/bbl.
Scenarios - Commercial assumptions

- Projects are scheduled to begin when the forecasted price needed to achieve a 10% IRR is reached
- For conventional fields each scenario is constrained by a respective CO2 amount
- Amount of CO2 for Bakken is unconstrained

*Bakken development will require large amounts of CO2, $2.00/mcf for transportation is included
**Based on IHS UCCI scenarios
***Base on IHS Price outlook scenarios

Scenarios and oil price forecast

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Costs**</th>
<th>Prices***</th>
<th>Purchase of CO2* $/Mcf</th>
<th>Supply of CO2 MMcf/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Case</td>
<td>-3%</td>
<td>-33%</td>
<td>1.56</td>
<td>187</td>
</tr>
<tr>
<td>Base</td>
<td>0%</td>
<td>0%</td>
<td>1.61</td>
<td>493</td>
</tr>
<tr>
<td>High Case</td>
<td>+6%</td>
<td>+13%</td>
<td>1.71</td>
<td>1,175</td>
</tr>
</tbody>
</table>
Bakken CO2 EOR
ND Production and Revenue Outlook - Case 1

- Incremental Bakken CO2 EOR production
- Base Case – 590 MMbbls
- High Case – 635 MMbbls

- Incremental direct revenue to the state over the next 20 years
- Base Case - $5.8 B
- High Case - $7.5 B
Bakken Case 1 – ND Production and Revenue

Eliminating production taxes altogether has a marginal effect on production while impacting significantly government revenue.

- Incremental Bakken CO2 EOR production
- Base Case – 590 MMbbls
- No Prod Tax - 633 MMbbls

- Incremental direct revenue to the state over the next 20 years
- Base sc – $5.8 B
- No Prod Tax- $1.6 B
Bakken Revenue by County – Case 1

- Williams currently is one of the most active counties and has the most potential for Bakken EOR.
- Dunn, McKenzie and Mountrail counties are expected to have significant activity too.
- Billings, Burke and Divide counties will likely not see much EOR activity.

Notes: Ad Valorem Revenue until 2036
Source: IHS

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Bakken Co2 EOR

ND Production and Revenue Outlook - Case 2

- Incremental Bakken CO2 EOR production
- Base sc – 199 MMbbls
- High sc – 385 MMbbls

- Incremental direct revenue to the state over the next 20 years
- Base sc - $1.3 B
- High sc - $4.2 B
Bakken Case 2 – ND Production and Revenue

Eliminating production taxes altogether results in additional $145 MMbbl of incremental production – however impact on government revenue is significant.

- Incremental Bakken CO2 EOR production
- Base sc – 199 MMbbls
- No Prod Tax– 344 MMbbls

- Incremental direct revenue to the state over the next 20 years
- Base sc - $1.3 B
- No Prod Tax- $276 MM
Bakken Revenue by County – Case 2

- Williams County has the most potential under the high scenario.
- Mountrail County is projected to have the best recovery and has the best potential under scenario 1.
- Billings, Burke, Dunn and Divide counties will likely not see much EOR activity as recoveries in these counties is lower and these may not be economic.

Notes: Ad Valorem Revenue until 2036
Source: IHS

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### Conventional Field CO2 EOR

**ND Production Outlook by County**

- Few EOR projects have low enough costs to be developed within the study period.
- Only Billings, McKenzie and Williams counties are expected to have CO2 EOR projects.

#### Scenario 1 Base case - Conventional Production with Tertiary Recovery by County

![Graph showing conventional production outlook by county with data points for various counties like Billings, McKenzie, and Williams.](image)

#### Production Unit Costs

<table>
<thead>
<tr>
<th>Production Unit</th>
<th>EOR Unit Cost $/bbl</th>
</tr>
</thead>
<tbody>
<tr>
<td>BEAVER LODGE DEVONIAN</td>
<td>30</td>
</tr>
<tr>
<td>FRYBURG HEATH-MADISON</td>
<td>48</td>
</tr>
<tr>
<td>ROUGH RIDER MADISON</td>
<td>48</td>
</tr>
<tr>
<td>CHARLSON MADISON</td>
<td>50</td>
</tr>
<tr>
<td>BIG STICK MADISON</td>
<td>58</td>
</tr>
<tr>
<td>BLUE BUTTES MADISON</td>
<td>68</td>
</tr>
<tr>
<td>NEWBURG SPEARFISH / CHARLES</td>
<td>109</td>
</tr>
<tr>
<td>ELKHORN RANCH N MADISON</td>
<td>133</td>
</tr>
<tr>
<td>MEDORA HEATH /LM/</td>
<td>134</td>
</tr>
<tr>
<td>CEDAR HILLS RED RIVER</td>
<td>143</td>
</tr>
<tr>
<td>T R MADISON</td>
<td>160</td>
</tr>
<tr>
<td>HORSE CREEK RED RIVER</td>
<td>164</td>
</tr>
<tr>
<td>BEAR CREEK DUPEROW</td>
<td>234</td>
</tr>
<tr>
<td>HOFFFLUND MADISON</td>
<td>268</td>
</tr>
<tr>
<td>DICKINSON HEATH /LM/</td>
<td>300</td>
</tr>
</tbody>
</table>

Note: Green – may start development by 2036
Orange – unlikely to be developed by 2036

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Conventional Field CO2 EOR

**ND Production and Revenue Outlook**

**ND Conventional Tertiary Recovery Forecast**

- **Baseline**
- **Low**
- **Base**
- **High**

<table>
<thead>
<tr>
<th>Year</th>
<th>Baseline</th>
<th>Low</th>
<th>Base</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2026</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2029</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2032</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>2035</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Notes: Only conventional production is included
Source: IHS

**ND Incremental Revenue - Conventional EOR**

- **Low**
- **Base**
- **High**

<table>
<thead>
<tr>
<th>Year</th>
<th>Low</th>
<th>Base</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td></td>
<td></td>
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<tr>
<td>2023</td>
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<td></td>
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<tr>
<td>2026</td>
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<td>2029</td>
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<tr>
<td>2032</td>
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<td></td>
</tr>
<tr>
<td>2035</td>
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</tr>
</tbody>
</table>

Notes: Only revenue from conventional projects is included
Source: IHS

- Incremental Bakken CO2 EOR production
  - Low sc – 19 MMbbls
  - Base sc – 34 MMbbls
  - High sc – 38 MMbbls

- Incremental direct revenue to the state over the next 20 years
  - Low sc - $105 MM
  - Base sc - $307 MM
  - High sc - $394 MM
Conventional EOR – ND Production and Revenue

Eliminating production taxes altogether has a marginal effect on production while impacting significantly government revenue.

- Incremental Bakken CO2 EOR production
- Base sc – 34 MMbbls
- No Prod Tax - 38 MMbbls

- Incremental direct revenue to the state over the next 20 years
- Base case - $307
- No Prod Tax - $128
Conventional County Level EOR Activity

For the base case most of the potential resides in the Billings county while in the low case most of the potential resides in the Williams county.

- Williams county will see the largest project activity with Beaver Lodge expected to be developed despite a poor economic climate.
- Billings and McKenzie counties need strong markets to justify developments before 2036.

<table>
<thead>
<tr>
<th>EOR Project</th>
<th>County</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beaver Lodge Devonian</td>
<td>Williams</td>
</tr>
<tr>
<td>Bid Stick Madison</td>
<td>Billings</td>
</tr>
<tr>
<td>Charlson Madison</td>
<td>McKenzie*</td>
</tr>
<tr>
<td>Fryburg Heath-Madison</td>
<td>Billings</td>
</tr>
<tr>
<td>Rough Rider East Madison</td>
<td>McKenzie</td>
</tr>
</tbody>
</table>

*1% is in Williams county.
CO2 EOR Economic Summary
The Bakken will have a much higher impact than the conventional production, however, its future success in less certain

- Proof of concept for CO2 EOR in the Bakken still needs to be established
- Based on our current knowledge and assumptions significant long-term price recovery will be required for the Bakken CO2 EOR to produce large revenues
- Significant revenues are likely to occur in the mid to late 2020s – by that time there may be improved technology for CO2 EOR and CO2 capture and transport
**Recommendations and next steps**

- Complete the economic impact portion of the study and benchmark such activity against primary Bakken economic impact

- Encourage and help fund future activities to determine the technical and commercial feasibility of CO2 EOR in the Bakken including
  - Research and development activities such as geologic and engineering studies and EOR CO2 modelling
  - Pilot programs which include more costly drilling and development testing
  - Development of CO2 capture as large amounts of CO2 will be required

- As it will take time to progress through optimization phases to commercial manufacturing maintaining current tax policies will be important

- If it appears that large capital outlays will be required to drill additional wells (as modelled in Bakken case 2), give consideration to extended tax breaks to stimulate more production.
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