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IHS ENERGY

ECONOMIC IMPACT OF CO_2 EOR IN NORTH DAKOTA

Final Report

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1 Federal and State Policies
2 CO_2 Supply Costs and Sources
3 CO_2 EOR Potential in North Dakota
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CO_2 EOR potential

- CO_2 EOR technologies have the potential to bring 1.2–1.8 billion bbl of incremental production to North Dakota over the next 20 years
- 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.
- 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.

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Factors influencing realization of CO_2 EOR potential

- 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, 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
- Access to economical and abundant supplies of CO_2. 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.

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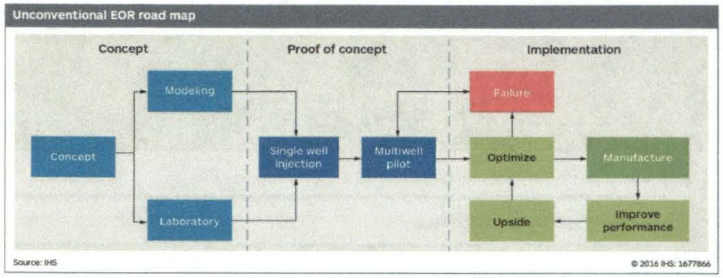
Narrowing down the range of uncertainty



- 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.

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Success factors

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.

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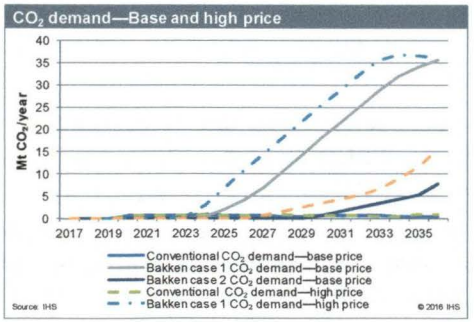
Bridging the gap between CO_2 cost and price

- The development of CO_2 EOR in the Bakken will require about 35 MMt of CO_2 per year by 2035.
- Currently there is a gap of $60-70/ton between CO_2 oil indexation price and cost of CO_2 captured from power plants



Federal Policies promoting CCS and EOR

- Funding for R&D
- American Recovery and Reinvestment Act (ARRA) & DOE coal program
  - Goal of developing technologies for commercial-scale demonstration in new and retrofitted power plants and industrial facilities by 2020
- Loan guarantees, federal tax credits, and EOR tax credit

ND policies promoting CCS and EOR

- Grants, loans, or other forms of financial assistance for development of CO_2 pipelines for EOR operations
- Temporary exemption from extraction tax for tertiary recovery projects
- 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

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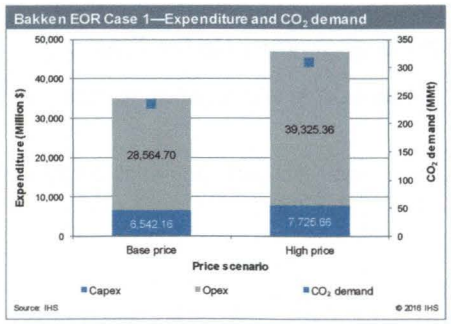
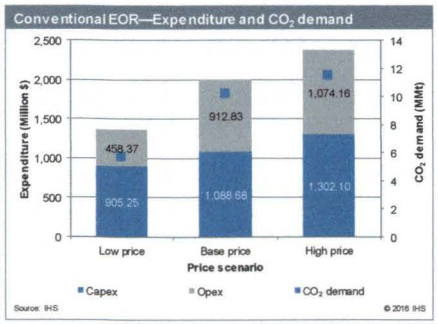
The Bakken CO_2 EOR economics

- 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 recovery 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)





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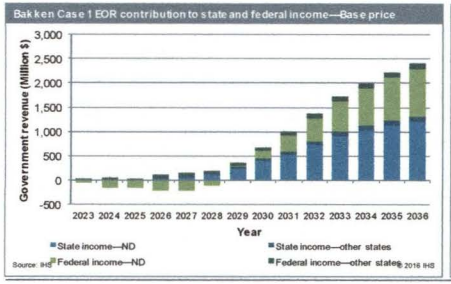
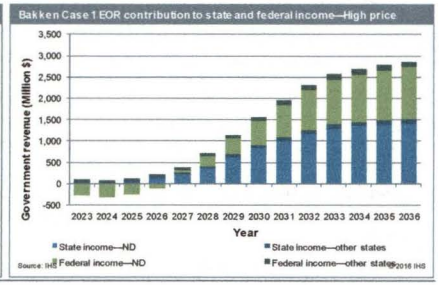
Economic impact of CO2 EOR

- 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
  - contribute on average $470 million per year in labour income, starting at $47 million in 2023 and contributing $917 million in 2036
  - contribute to the state economy is on average $918 million per year on value-added. 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
  - contribute between $11.4 billion to $18.6 billion in direct revenues 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





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Overcoming the constrains

Constrains

- Uncertainty surrounding the technology
- Current fiscal system that pushes the breakeven prices above $100/bbl

Policy Solutions

- **Federal income tax credit (FITC)**
  - brings forward the timeline for development of EOR projects in the Bakken from 2023 to 2019,
  - 77% increase of incremental production and revenues to the state of North Dakota compared with current fiscal system.
  - 30% higher impact with respect to jobs, employment income, and gross value added versus current terms.
- **CO_2 operating cost allowance against extraction tax**
  - increase in the recovery of incremental production in the Bakken from 353 million to 473 million bbl during the study period
  - direct government revenue under this policy declines 8% compared with the status quo
  - economic contribution to the state via employment, labour income, and value added is 20% higher than under the current fiscal system

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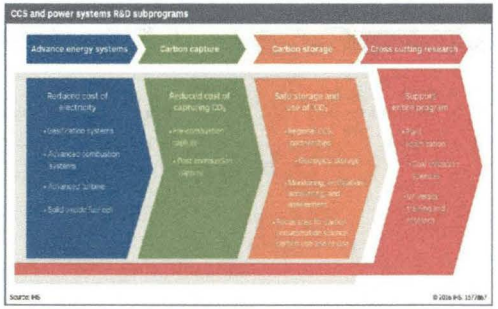
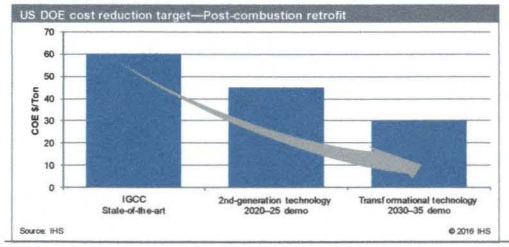
Federal policies that promote CCS

DOE R&D program





- CCS research has been funded by DOE since 1997
- Focus on beneficial uses of CO2 in recent years
- 53 active technology projects representing the laboratory/bench scale through pilot stages

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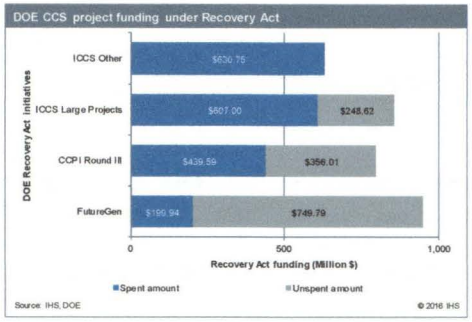
Federal policies that promote CCS

Funding of large-scale demonstration projects



- Since 2009 $3.4 billion were designated for CCS programs under the American Recovery and Reinvestment Act (ARRA) through 2015
- DOE has appropriated approximately $2.3 billion over the same period to CCS-related activities under its coal program
- 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
- 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
- Approximately 42% of the ARRA funds were unspent

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Federal policies that promote CCS

Other financial support/tax credit

- § 43 of Internal Revenue Code
- 15% credit for qualified EOR costs
- Credit is reduced if the reference price for the preceding calendar year is greater than $28/bbl (adjusted for inflation)
- Credit had been phased out for past 10 years

4 EOR Tax Credit

1 Loan Guarantees §1703 of Energy Policy Act

- $8 billion authorized by Congress in 2007 and 2008
- No CCS projects have received loan guarantees

CO2 Sequestration Credit 2

- § 45Q of Internal Revenue Code
- $20/t of CO_2 captured and sequestered
- $10/t of CO_2 used for EOR
- Cap of 75 MMt of CO_2 captured and taken into account

- Awarded on competitive basis at the rate of 30% of qualified investments
- §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
- § 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

Investment Credits for Advanced Coal Projects 3

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Incentives at state level

State incentives for CCS and CO_2 EOR

State	Grants & loan guarantees	Offtake agreements	Utility cost recovery	Financing incentives	Tax incentives: Income/ franchise tax	Tax incentives: Severance tax	Tax incentives: Property tax	Tax incentives: 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

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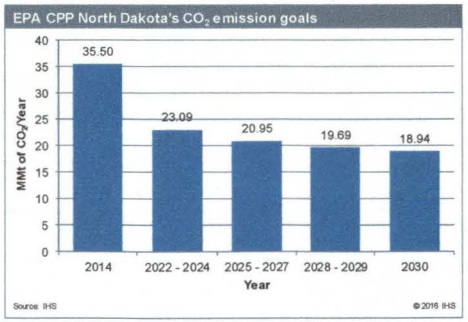
Policies that regulate CO_2

Power sector CO_2 policy

- **Carbon Pollution Standards (CPS)** - regulates CO_2 emissions from new, modified and reconstructed power plants
- **Clean Power Plan (CPP)** - regulates CO_2 emissions from existing power plants
  - The rule is being challenged in court
  - North Dakota is facing an overall 45% GHG reduction target in 2030 relative to a 2012 baseline
  - Many states have already expressed an interest in allowing power plants to comply via interstate trading



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Policies that regulate CO_2

Regulation of CO_2 storage

Class II Injection Wells – CO_2 EOR

- CO_2 EOR operators remain liable for Post Injection Site Care (PISC) for up to 50 years (negotiable) after closure
- 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
- If operators use standard reporting under subpart UU of the GHGRP that applies to Class II wells, and has been used by EOR facilities, they will not be able to claim storage credit
- 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

Class VI Injection Well - Saline storage of CO_2

- Class VI requirements are much more rigorous in terms of well construction, operational and mechanical integrity testing, well plugging, and post-injection site care
- CO_2 injected into Class VI are conditionally exempt from hazardous waste classification

States assuming liability for PISC

- Norht Dakota and Louisiana – 10 years after injection ceases
- Texas – immediately after the well is plugged (offshore)
- Montana – after 30 years
- Kansas – denies liability for CO2 storage wells outright

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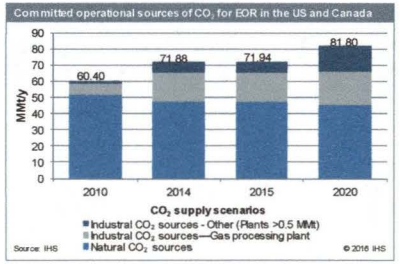
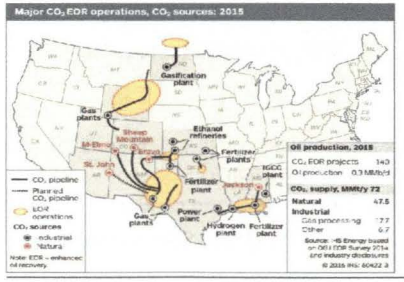
US major CO_2 EOR operations and CO_2 supply sources





- Three primary CO_2 sources in US:
  - Natural CO_2 fields (CO_2 content > 90%) – key enabler of CO_2 EOR because of low cost, large volume and accessibility, 67% of CO_2 EOR supply in 2015
  - Industrial sources – CO_2 captured from gas processing plants, 25% of CO_2 EOR supply in 2015
  - Industrial sources – CO_2 captured from other industrial plants, 8% of CO2 EOR supply in 2015
- Three major CO_2 EOR areas in US
  - Permian Basin – 65% of CO_2 EOR projects, sourced from natural CO_2 fields located in Colorado and New Mexico, and nearby gas processing plants
  - Gulf Coast – 15% of CO_2 EOR projects, sourced from Jackson Dome CO_2 field and nearby industrial plants
  - Wyoming – 12% of CO_2 EOR projects, sourced from two large gas processing plants
  - Other – 8%

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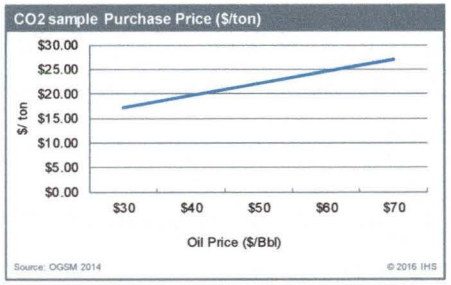
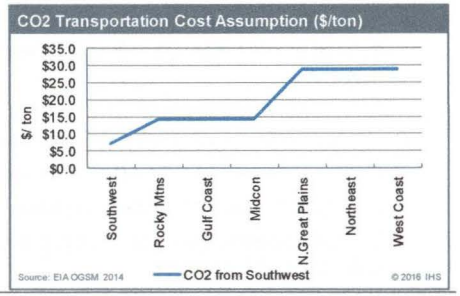
CO_2 Costs – Natural fields and transportation

- Natural CO_2 source is affordable and much less expensive than industrial sources
  - A handful of operators control the entire supply chain - supply source, pipeline and EOR operations
  - Contract price typically is related to oil price
- High transportation cost tends to limit CO_2 EOR within a reasonable distance of CO_2 sources
  - ~ 75k/mile/inch (e.g. a 100-mile 20-inch pipeline would cost ~$150 MM)
  - High compression transport and stainless steel pipe due to CO_2 properties
  - Transport costs increase by about $5.8 to $15.4 per metric ton for each region cross-over





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Industrial CO_2 cost of supply

$/Metric ton	Natural Gas Processing	Hydrogen	Ammonia	Ethanol	Cement	Refineries	Power Plants
East Coast	37	47	40	43	83	47	115
Gulf Coast	37	37	40	43	83	37	115
Midcon	37	40	40	43	83	40	115
Southwest	37	39	40	43	83	39	115
Rocky Mtns	37	39	40	43	83	39	115
West Coast	37	39	40	43	83	39	115
N.Great Plains	37	40	40	43	83	40	115

Source: EIA OGSM 2012 & 2015 Model

- Industrial CCS is more expensive than development of natural sources of CO_2
- The cost of CO_2 from gas processing plants is more competitive compared to other industrial sources due to a more mature technology and longer operation history
- Cost estimates have increased slightly from earlier studies
  - Industry CCS project CO_2 capture cost is between $37-$115/MT, excluding transportation
  - Recent EIA projections (OGSM model) suggest costs for CCS at power plants to be $115/MT

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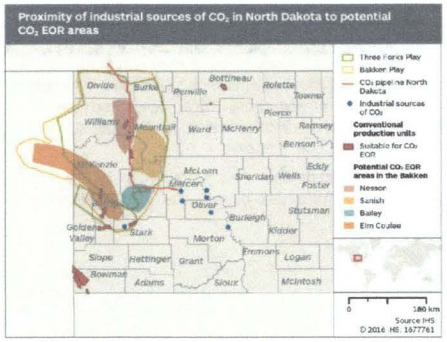
Potential CO2 supply sources for North Dakota



- The Dakota - Great Plains Gasification plant
  - Currently in operation capture 3 MMt/yr, contracted to Canadian Weyburn and Midale fields at $24/metric ton
- Six lignite coal-fired power plants – current CO_2 emissions could be potential sources
  - Current CO_2 emission - 28 MMt/yr
- Twelve Small gas processing facilities located near oil fields in the Williston Basin
  - Current CO_2 emission -0.7MMt/yr, might be too small to capture
- CO_2 captured from gas processing plants in Wyoming may be available upon plant expansion and pipeline extension

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Power plant CCS analogs (US & Canada)

Coal-fired power plant CCS cost comparison

Power plant CCS	Location	Status	Capture capacity (MW)	CO_2 captured (MMt/y)	Percent captured	Estimated capital investment (billion $)	CCS cost for 15-year life (million $/MW)	CO2 capture cost ($/ton)
Boundary Dam CCS	Saskatchewan	Operational	110	1.00	90%	1.30	11.80	100
Petra Nova	Texas	Construction	240	1.60	90%	1.20	5.00	50

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

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- SaskPower Boundary Dam retrofit project – 1.0MMt/yr CO2 capture
  - Total cost of $1.3Bn, 20% over-run; estimated CO2 capture cost is $100 per metric ton
- The Petra Nova power plant is the only CCS project on its way to a successful launch in the United States – 1.6 MMt/yr CO2 capture
  - Expected project cost $1.0Bn, estimated capture cost is $50 per metric ton
  - Employ the KM-CDR process, a recent technology developed by Mitsubishi (MHI)
  - Vertical integration and joint venture have formed between power plant, investor, and CO2-EOR operator

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ND lignite coal power plant CCS cost assumptions

Power plant	In service	PPT capacity (MW)	2014 CO2 emission (MMt/y)	CCS capacity (MW)	Annual CO2 captured (MMT/Y)	% of CO2 captured	Total investment ($bn)
Leland Olds Station	1966	669	3.97	263	1.6	40%	$1.32
Antelope Valley Station	1984	900	6.67	354	2.36	35%	$1.77
Coal Creek Station	1979	1100	9.17	433	2.89	31%	$2.16
Coyote Station	1985	420	3.18	165	1.10	35%	$0.83
Milton R. Yong Station	1970	705	4.83	277	1.85	38%	$1.39
R.M. Heskett Station	1954	100	0.7	0	0.00	0%	$0.00
Total			**28.52**		**9.8**	**34%**	**$7.46**

Source: IHS

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- We estimate that 9.8 MMt/yr of CO2 needs to be captured to contribute towards meeting EPA 2022 GHG emission reduction goals (12MMt/yr needed to meet the target) assuming MHI technology applied
  - Total investment of $7.46 bn
  - Based on the assumption that five of the six major power plants will make CCS investment to capture 30–40% of their annual CO2 emission
- State and federal policy solutions to encourage such investments are needed
- Recent setbacks faced by several CCS/CCUS projects in the United States reflect poor economics and insufficient policy support.

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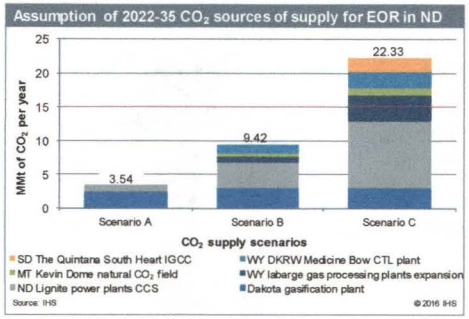
North Dakota CO_2 2022-35 supply scenarios assumption



- **Scenario C – 22.23 MMt/yr**
  - The DOE research and development program achieves its third target
  - 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.
  - 3 MMt/yr from Dakota Gasification Plant
  - 9.8 MMt/yr from CO2 captured from ND five major power Plant
  - 9.4 MMt/yr from other sources in WY, SD, and MT

- **Scenario A – 3.54 MMt/yr**
  - The DOE research and development program misses stated goal
  - 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
  - 2.37 MMt/yr from Dakota Gasification Plant
  - 1.17 MMt/yr from CO2 captured from Antelope Valley Power Plant
- **Scenario B – 9.42 MMt/yr**
  - The DOE research and development program achieves the stated goal
  - The price gap between the cost of CO_2 from power plant CCS and price of CO_2 for EOR narrows to $20/metric ton.
  - 3 MMt/yr from Dakota Gasification Plant
  - 3.7 MMt/yr from CO2 captured from three newest lignite coal power plants
  - 2.7 MMt/yr from gas plants in WY and CO2 fields in MT

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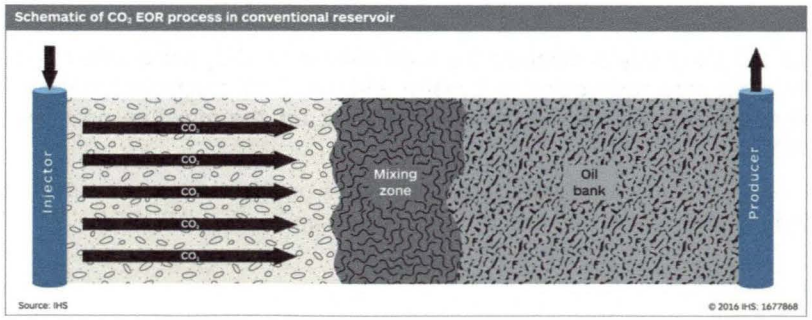
EOR Fundamentals

How CO2 EOR works

- Miscibility - The ability or the degree to which the CO_2 is able to attach to or combine with the oil molecule - Lowers Viscosity and swells oil molecule out of the pore space
- Miscibility Pressure (MMP) - The CO_2 EOR process can only occur if a specific pressure is achieved – one function of CO_2 (or other gas) is to re-pressurize reservoir
- Other gases/liquids are also miscible
  - Ethane (a natural gas liquid) is slightly more miscible than CO_2



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EOR Fundamentals

Characteristics of good conventional reservoir candidates

- Water Flood: Historically there is a good correlation between successful water floods and successful CO_2 EOR.
- 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 -allows CO_2 to flow more uniformly from the injector well to the producer

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The Bakken Characteristics

Unfavorable properties?

- **Low permeability**
  - 0.1 mD - at least two orders of magnitude less than what would normally be found in a good conventional reservoir of 10-100 mD
- **Low porosity**
  - 2-9% in the Bakken v.. 8.25% in conventional reservoirs
- **Fractures**
  - In conventional reservoirs fractures cause uneven CO_2 flow
  - In the Bakken fractures are likely the primary key to success

Favorable properties

- **Depth and remperature:**
  - 10,000 feet
  - 6,000 – 7,000 psi
- **Oil quality:**
  - Low gravity 39-42 degree API
  - Low viscosity
- **Low water saturation**
  - Sw<25%
  - Oil wet reservoir – not likely to undergo water flood

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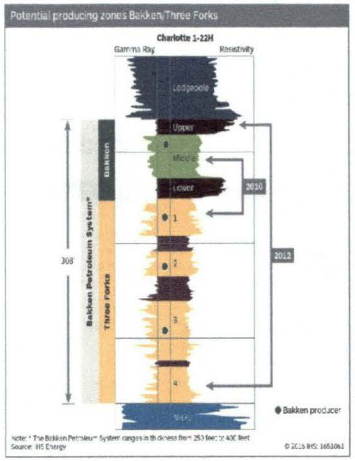
The Bakken – Attractive candidate for consideration

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. EOR Lab work has addressed many of the characteristics of CO_2 EOR in "tight oil" reservoirs
5. CO_2 EOR modeling has produced some encouraging, yet diverse outcomes
6. 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) CO_2 injection (2) carbon Capture



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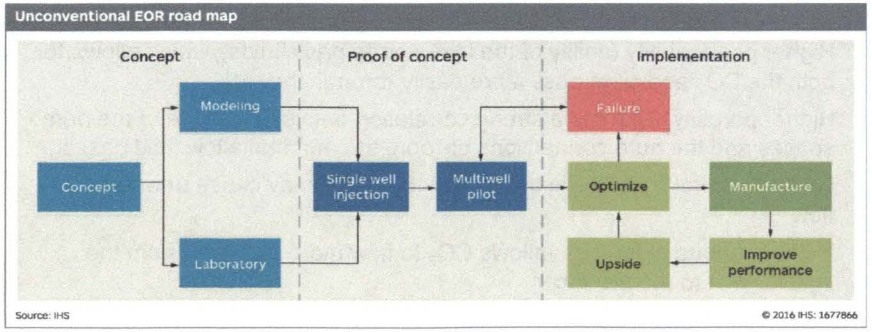
EOR-CO2 analysis – Conventional vs. unconventional

- Conventional EOR - well established and documented
  - Many fields undergoing CO_2 EOR in the US
  - Narrow range of uncertainties – more highly predictable
- Unconventional EOR (Bakken / Three Forks)
  - Field injection tests – mixed results
  - Eagle Ford Pilot – Encouraging results
  - High range of uncertainties – We don't know how or if this will work for sure



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CO_2 EOR potential in the Bakken

Concerns

- **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.

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Cautious optimism about the Bakken

Laboratory and modeling results and concerns

- Laboratory
  - CO_2 movement through primary fractures suggests a "bathing" process
  - Effectiveness of CO_2 – ineffectiveness of water
  - Micro-fractures play a significant role in connecting fractures to rock matrix
- Modeling:
  - Modeling programs have been developed primarily for CO_2 EOR in conventional reservoirs—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.
  - 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
    - Recovery factor range - 0.3 – 24%
    - CO_2 requirements – 0.13 -33 mcf/bbl

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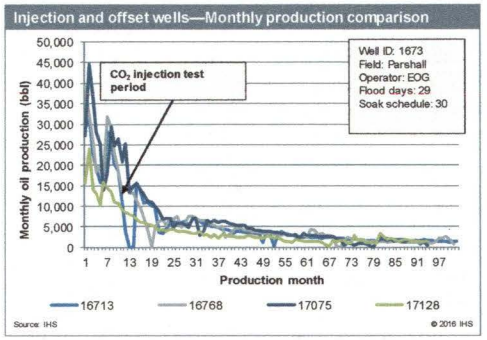
Injection and offset well results – CO_2 injection

Well ID: 1673

- 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.
- liquid production was not affected and the normal production decline trend was unaffected



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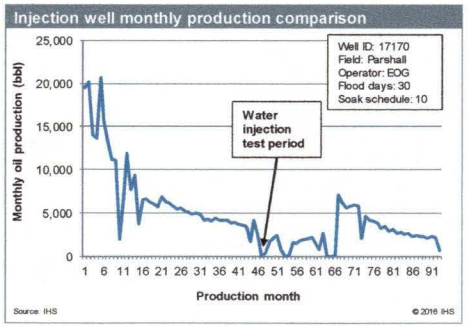
Injection and offset well results – water injection

Well ID: 17170

- the injection period lasted from April to May 2012 with a total injection water volume of just over 39,000 bbl.
- No other offset wells were investigated, but the monthly production data 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.



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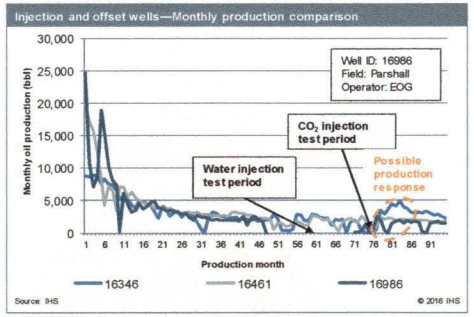
Injection and offset well results – water and CO_2

Well ID: 16986

- Combined both initial water flooding and later field gas (methane) 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.
- The injection test well was put back on production, but no production response was observed.
- The monthly oil production for offset well NDIC 16346, located less than one mile away, had increased after the field gas injection.
- Average post-injection six-month oil production is nearly two times higher than pre-injection volume



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
Av. 6-month	1,567	Av. 6-month	3,173

Source: NDIC and IHS © 2016 IHS

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Results of Bakken well tests summary

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 © 2016 IHS

- A true multi-well pilot has yet to be performed in the Bakken, although off-set well testing has been monitored
- Injection tests have shown that the reservoir can be injected with gas, but primary fractures may cause pre-mature breakthrough – a soaking period is needed
- Water injection is ineffective and might be harmful - similar to lab results

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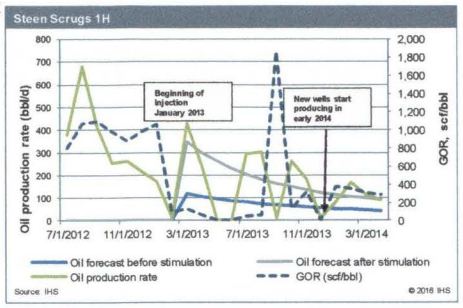
Encouraging results from Eagle Ford multi-well pilots and results from the Scruggs 1H well

- The pilot included 16 wells which made use of produced gas (dry gas) readily available at the field site.
- EOG indicated that the results of the pilot testing would increase recovery by 30–70%
- Potential costs of $6.00/bbl or less using dry gas
- Injecting into horizontal well bores at pressure of 12,000 psi
- Our production forecast indicates that this technique achieved a 60% uplift in recovery
- The elevated gas oil ratios (GOR) clearly indicate periods of gas injection, followed by elevated oil production rates



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

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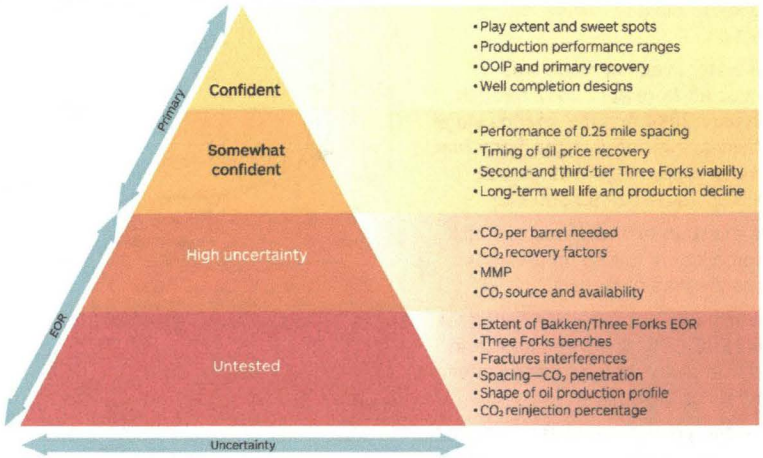
The range of uncertainty about the Bakken

Bakken/Three Forks—Degree of uncertainty



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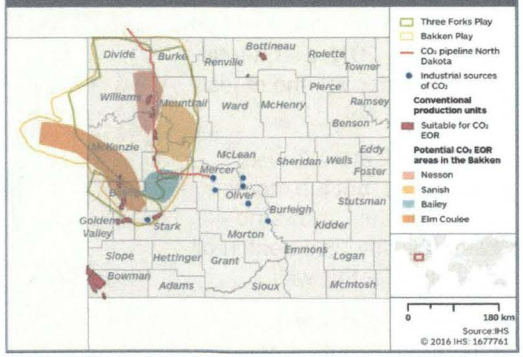
Bakken areas and recovery factor calculations

- **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*

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



Section of the play	Original oil in place/mi² (kbbl)	Expected ultimate recovery/well kbbl)	Primary recovery factor (1/2 mi spacing, %)	Primary recovery factor (1/4 mi 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

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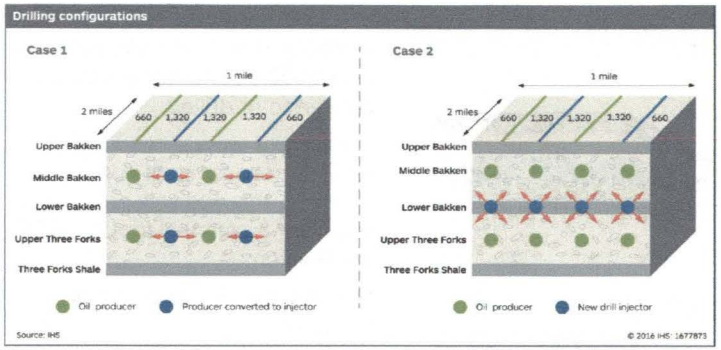
Bakken EOR – Potential drilling configurations



Case 1 –

- alternating producers will be converted to gas or CO_2 injectors at a relatively modest cost,
- injector wells will be used exclusively for injection of CO_2 or field gas at high pressures which will be needed to reach MMP
- an oil recovery factor of 5%

Case 2 –

- new injector wells will need to be drilled--0.125 mile (660 foot) separation between injector and producer may be required
- an oil recovery factor of 7.5%

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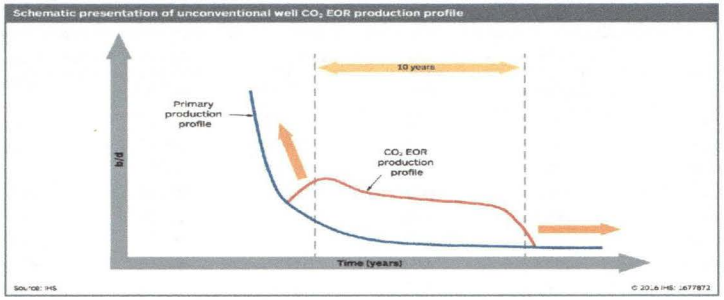
Estimating the EUR per well

- **Case 1 recovery – 5% from each well**
- **Case 2 recovery – 7.5% from each two wells**



Calculation of the Bakken primary recovery factors

Section of the play	OOIP/mi² (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

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CO_2 EOR economic model input assumptions

CO_2 Sources:

Due to potential size and scalability much more CO_2 may be required – Up to 2.2 bcf/d for Case 2 (41.31 MMt/yr)

Amount or Use of CO_2 mcf/bbl:

14.5 mcf/bbl (0.76 Mt/bb) for case 1

11.3 mcf/bbl (0.59 Mt/bb) 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 CO_2 EOR modeling

Re-injection of CO_2

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 CO_2 recovery

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CO_2 EOR economic model input assumptions

- **Percentage of Bakken/Three Forks area which could be developed or how much of the Bakken is likely to undergo CO_2 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 CO_2
       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

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Technical recovery estimate and comparisons

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 2 resource (MMbbl)	Case 2 CO_2 requirement (Tcf)	Case 2 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 © 2016 IHS

Comparison with EERC estimates

- DOE Methodology
  - Recovery 420 – 630 MMbbls
  - CO_2 requirements121 – 194 MMt
- Reservoir Properties Methodology
  - Recovery 4,000 – 7,000 MMBbbls
  - CO_2 requirements1900 – 3200 MMt

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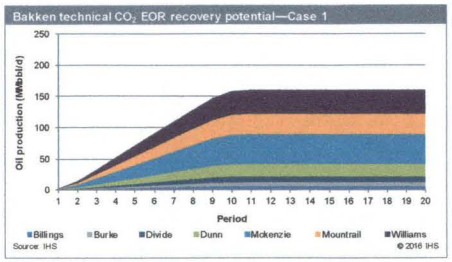
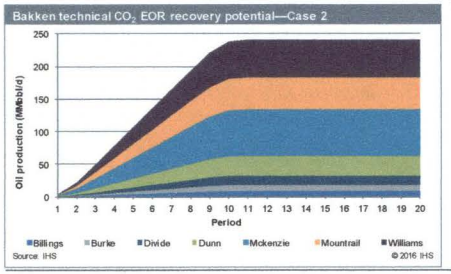
CO_2 EOR Bakken summary





- During a 20-year development cycle, over 3600 injector wells would be converted or drilled
- Much more work is required to realize these types of numbers, however, this analysis provides a view of the potential for CO_2 EOR in the Bakken
- We assume for our economic modeling
  - that production will begin in 2023, so only a portion of this production is realized in the 2017 – 2036 forecast time period
  - Development must be economic under an oil price recovery

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Screening of conventional fields for EOR

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 © 2016 IHS

- 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.
- 50 of the 126 ND fields analyzed passed this screening criteria

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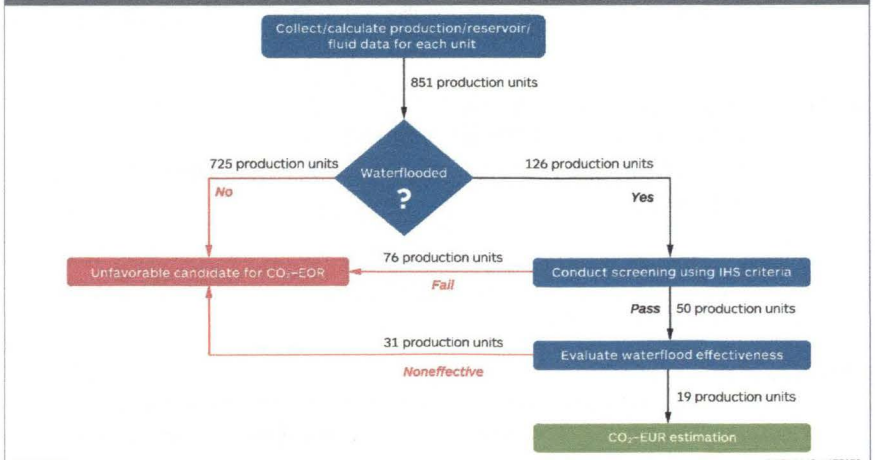
CO_2 EOR Evaluation – conventional fields screening process

Production unit screening process



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Results of oil recovery for suitable fields

- Numerical simulation was conducted for 19 fields that passed all screening criteria. For each field average reservoir properties were utilized. Table below summarizes the EUR from CO_2-EOR for each field. Table below presents a comparison between the results of current study and similar studies that were conducted for North Dakota fields.

Numerical results of oil recovery for candidate production units

Production unit		Numerical Np estimate (MMbbl)	Recovery factor (%)	Utilization factor (Mcf/bbl)	Recovery factor (%) UND	Analytical Np Estimate (MMbbl)
Beaver Lodge Devonian Unit	1	30,530	16.8	9.0	8.0	54,046
Fryburg Heath-Madison Unit	2	20,624	13.3	5.0		28,597
Cedar Hills North Red River B Unit	3	19,110	6.9	12.0		32,982
Cedar Hills South Red River B Unit	4	18,460	5.1	17.5		38,914
Big Stick Madison Unit	5	15,770	9.5	10.5		35,022
Charlson North Madison Unit	6	6,961	8.7	11.1		16,531
Blue Buttes Madison Unit	7	5,776	6.2	13.6	8.0	14,990
North Elkhorn Ranch Madison Unit	8	4,524	8.2	11.0		10,760
Cedar Creek Ordovician	9	4,758	4.9	12.9		11,327
T.R. Madison Unit	10	4,242	9.9	9.6		7,025
Newburg Spearfish-Charles Unit	11	4,157	4.3	18.2		7,477
Medora Heath-Madison Unit	12	3,978	6.9	12.0		8,267
Rough Rider East Madison Unit	13	3,715	12.0	9.1		5,976
Horse Creek Red River Unit	14	3,391	7.4	9.0		6,967
Dickinson Heath Unit	15	2,849	4.6	23.5		10,495
West Rough Rider Madison Unit	16	2,386	8.0	12.2		5,238
Charlson South Madison Unit	17	1,267	8.7	11.1	8.0	2,996
Bear Creek Duperow Unit	18	931	6.8	16.4		2,670
Hufflund Madison Unit	19	675	6.5	16.8		1,950

Source: IHS © 2016 IHS

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- 2 CO_2 Supply Costs and Sources
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- 5 Economic Impact of EOR Activities
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- 7 Conclusion

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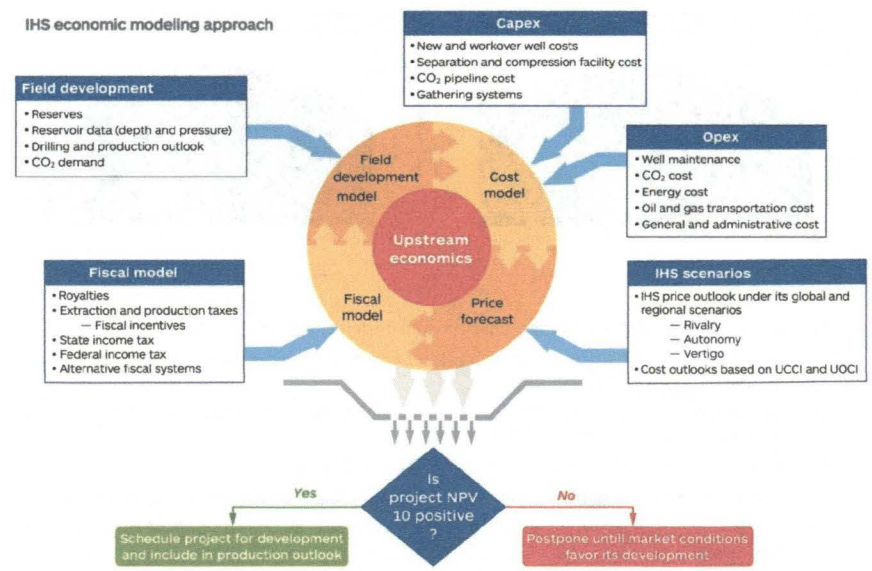
Upstream economics modeling approach



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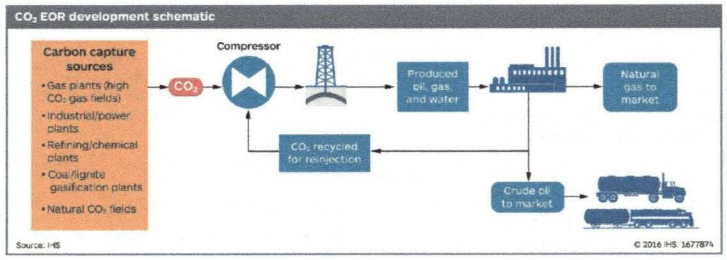
Cost modeling



- 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.
- 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.

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IHS North American scenarios

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 due 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

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Price and cost forecast

- 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.

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

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Fiscal Model

Taxes

Corporate Income Tax
Federal: 35%
State: 4.31% (max rate modelled)
- ND depreciation is same as for Federal income tax
- State income tax is deductible for Federal income tax

Depreciation Tangible (50%)
- Double declining balance

Depreciation Intangible (50%)
- 30% (5-year straight line); 70% expensed

Production Tax
Oil gross production tax of 5%.
Gas production tax is an annually adjusted flat rate per thousand cubic feet of all nonexempt gas produced in ND. $0.1106 per mcf (2016 rate), adjusted annually for oil price.

Extraction Tax
Oil extraction tax rate of 5%*
*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. For non Bakken and 5-year exemption for the Bakken areas

Ad Valorem Taxes
No ad valorem production tax for oil and gas production.
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

Lease Terms

Royalty
12.5-22% (18% assumed)

Rental
Typically a nominal amount paid on per-acre basis (i.e. $1/acre, not modelled)

Bonus
. $2,500-$4,000/acre in Bakken region. (not modelled).

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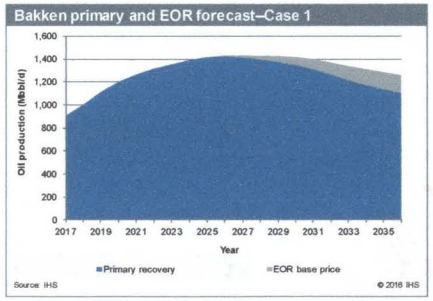
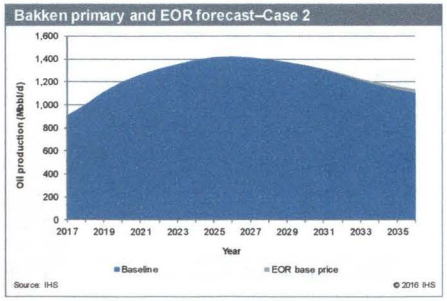
Bakken economic recovery of incremental production





- Estimate of **254–473 MMbbl** of incremental production during the 2017–36 time frame,
  - 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**.
- Capital investment of **$6.5–7.7** billion for CO_2 EOR in the Bakken.
- Operating costs 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**.

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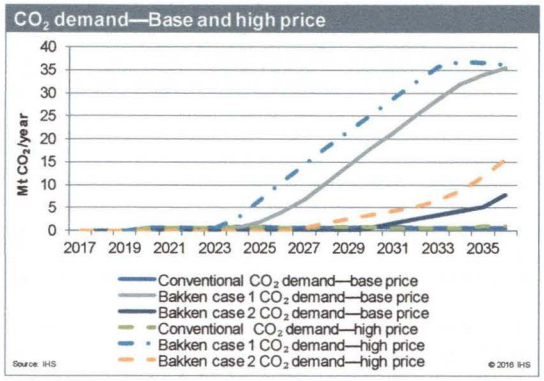
Impact on environment

Contribution to CCS



- 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
- By 2035 annual demand is expected to be around 35 MMt per year
  - This is almost double the amount of CO_2 reduction target under CPP versus 2014 emission levels

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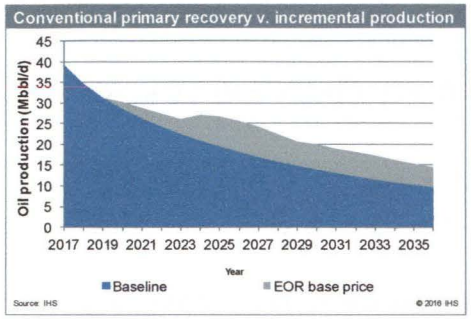
Conventional field incremental production



- 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)
- Projected direct revenues to the state range between $139 and $439 million.
- The incremental production is expected to add about 7,500 b/d in 2026.
- 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 is expected to range between $1.3 billion and $2.3 billion.

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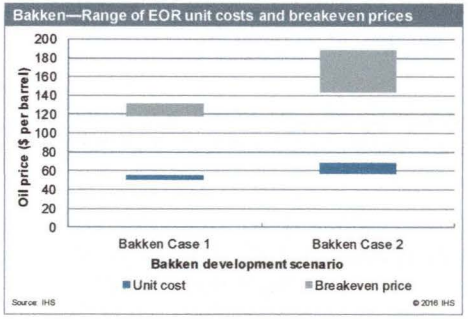
Commercial challenges associated with CO_2 EOR in the Bakken



- Case 1 unit costs $50/bbl and $55/bbl
- Case 2 unit costs $57/bbl and $68/bbl
- Breakeven prices for a 10% rate of return are above $100/bbl for all CO_2 EOR projects in the Bakken
- Costs associated with CO2 are the main contributing factor. Under Case 1 CO2 costs make up:
  - 37% of the capitals costs
  - 31% of the operating costs

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Commercial challenges associated with CO_2 EOR in conventional fields

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
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- 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 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

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Role of fiscal incentives

- Despite various incentives no CO_2 EOR projects have taken place in North Dakota
- The potential impact of fiscal incentives in the Bakken is countered by:
  - 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 for conventional fields are not likely to have any significant impact
  - the EOR costs per unit for 11 of the 19 production units that passed the screening criteria are above $100/bbl,
- A combination of fiscal incentives and price recovery could bring forward the timeline for Bakken EOR

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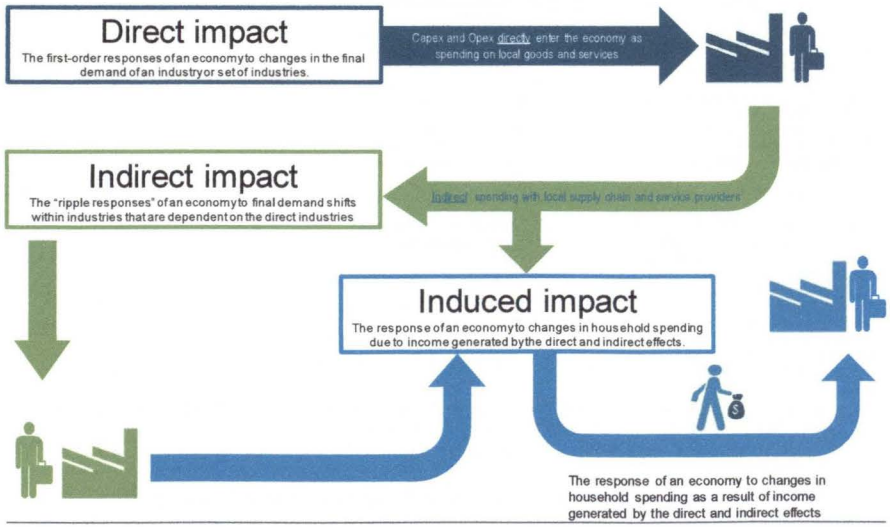
Economic impact analysis (EIA) model



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EIA indicators

- 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.

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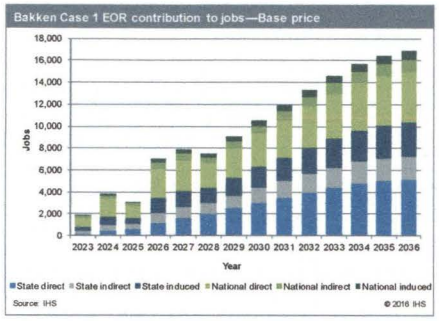
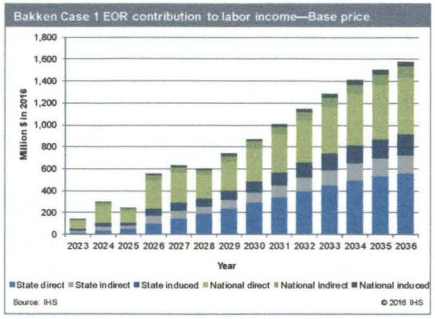
Contribution to jobs and labor income





- Total impact on employment on the state is expected to be from **5,800 to 7,400** jobs on average per year under the base and high-price scenarios
- 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
- The Bakken EOR activity will contribute on average **$470** million per year on labor income in the state
- The combined contribution at the state and national level at the end of the study period is nearly **$1.6 billion** in real terms

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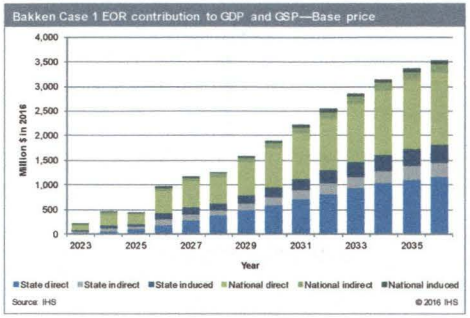
Bakken Contribution to GDP and GSP



- Direct impact on average **$555 million** per year value-added on the economy of the state, and **$773 million** respectively at the national level
- 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

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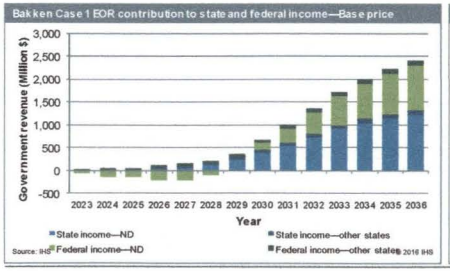
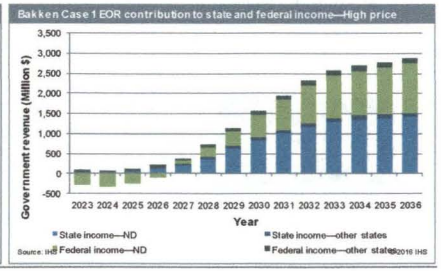
Government revenue for Bakken EOR

- **Bakken Case 1** 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
- Direct revenues to the state of North Dakota are expected to range between **$6.3 billion** and **$9.7 billion** during the study period
- **Bakken Case 2** is expected to have a much more moderate effect on state and federal government revenues
  - 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**.
- **Conventional field EOR** are expected to bring revenues ranging between **$1.3 billion** and **$1.6 billion** to the federal and state governments
  - Revenues accruing to the state of North range between **$420 million** and **$499 million**





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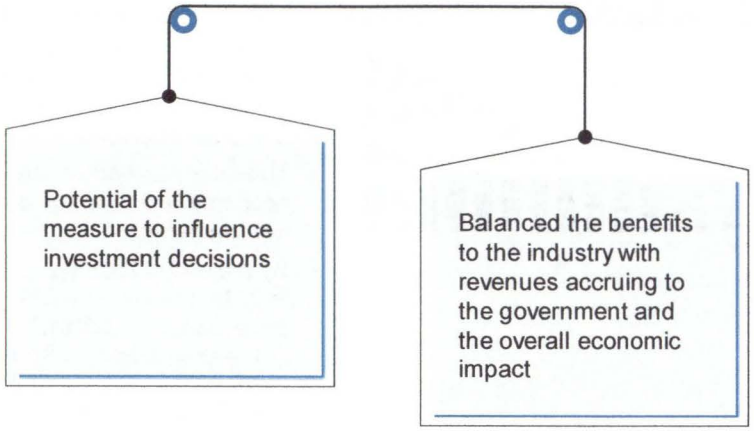
Policy considerations



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Alternative policy solutions

Policy Scenarios

Scenario	Conv	Application Bakken Case 1	Bakken Case 2	Brief description
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.

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Breakeven price analysis

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 © 2016 IHS

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 © 2016 IHS

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

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Federal income tax credit alternative

	2017	2025	Expiration
Section 45Q of IRC	• $10/ton credit for EOR • $20/ton credit for CCS	• $10/ton credit for EOR • $20/ton credit for CCS	• 75 million ton CO2
Conway Bill	• $10/ton credit for EOR • $20/ton credit for CCS	• $30/ton credit for EOR • $30/ton credit for CCS	• Dos not expire
Alternative solution modelled	• $10/ton credit for EOR • $20/ton credit for CCS	• $20/ton credit for EOR • $30/ton credit for CCS	• Dos not expire

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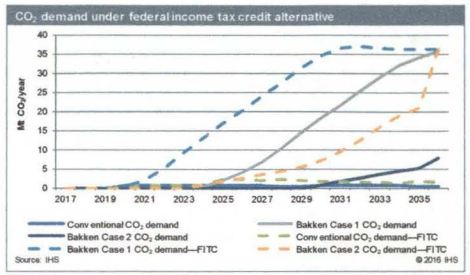
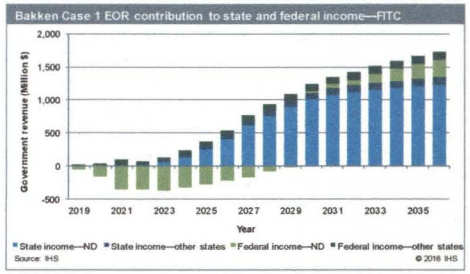
Impact of FTIC

- Increased demand and therefore ultimate storage of CO_2 from **233 MMt** to **402 MMt** during the study period.
- The incentive brings forward the timeline for injection of CO_2 for EOR projects in the Bakken from 2023 to 2019
- Incremental oil recovery for the Bakken Case 1 almost doubles from 353 million barrels to 625 million barrels
- overall revenues increase from **$11.3 billion** under the current fiscal system **to $13.2 billion** under the federal income tax credit alternative scenario





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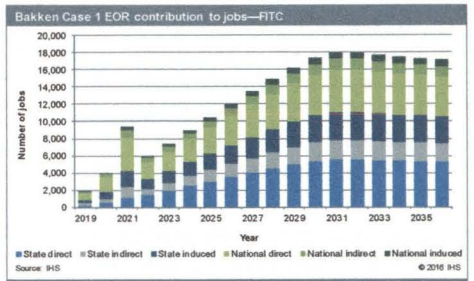
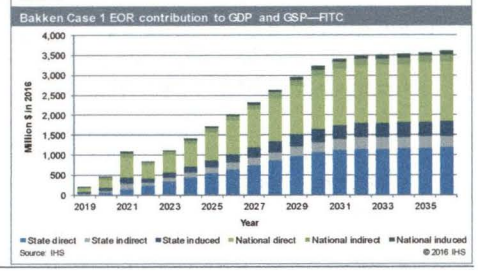
Economic contribution of Bakken Case 1 under FTIC alternative

- **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
- Over **$1 billion** in labor income annually during 2019–36, of which **$586 million** is contribution within the state of North Dakota
- Contribute on average **$2.7 billion per year** on value-add, with **$1.7 billion** per year being added to the state economy, almost double the amount estimated under the current fiscal system





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CO_2 operating cost allowance for extraction tax

Current incentive

- 5-year holiday for tertiary recovery projects in the Bakken

Alternative incentive

- Replace the 5-year holiday with CO2 operating cost allowance
  - CO2 separation costs
  - CO2 compression costs
  - CO2 purchase cost (including cost of transportation)

North Dakota Extraction Tax

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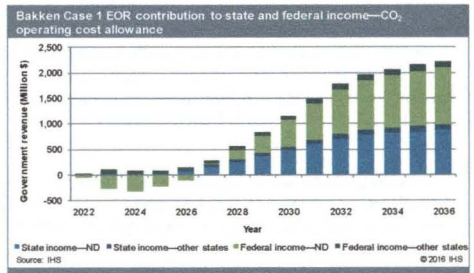
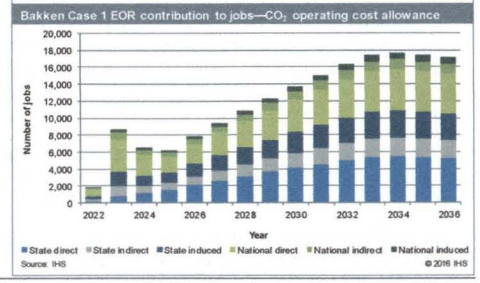
CO_2 operating cost allowance impact

- Incremental production increases from **353 million** barrels **to 473 million** barrels in the Bakken during the study period
- 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
- **307 MMt of CO_2** being injected and ultimately stored (a 32% increase from current system)
- Contribute on average over **7,000 jobs** per year in North Dakota, and **11,900 per year** nationally during the 2022–36 period





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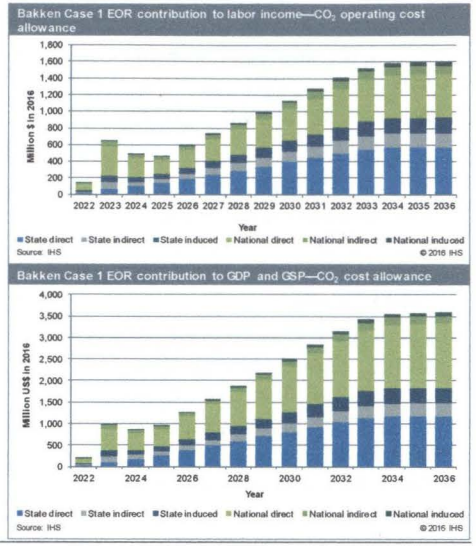
Economic contribution of Bakken Case 1 under CO_2 operating cost allowance alternative

- 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
- Average annual contribution to labor income of **$558 million** in ND, over **$1 billion** nationally
- Contribute on average over **$1 billion** annually to GSP, and close to **$2.2 billion** annually to GDP
  - a 19% increase in contribution from the status quo



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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.

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