PCO$_2$R Partnership

Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

COMPARISON OF NON-EOR AND EOR LIFE CYCLE ASSESSMENTS

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DOE DISCLAIMER

COMPARISON OF NON-EOR AND EOR LIFE CYCLE ASSESSMENTS

ABSTRACT

The Energy & Environmental Research Center worked with The CETER Group, Inc., through the Plains CO_2 Reduction Partnership to evaluate whether life cycle greenhouse gas (GHG) emissions associated with incremental oil produced by enhanced oil recovery (EOR) using anthropogenic carbon dioxide (CO_2) are less than GHG emissions associated with conventional oil production. A cradle-to-grave approach was used to quantify the full life cycle GHG emissions for four scenarios: conventional natural gas production and conventional oil production (i.e., the current conventional approach), natural gas processing with CO_2 capture coupled with typical West Texas EOR, natural gas processing at Shute Creek plant and conventional oil production, and natural gas processing at Shute Creek plant with CO_2 capture coupled with EOR at the Bell Creek oil field.

Two tools were used to conduct the life cycle analysis (LCA), including 1) a customized programming of the Argonne National Laboratory Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model, known as the GREET model, and 2) Microsoft Excel® spreadsheet models using emission factors from peer-reviewed literature and U.S. Department of Energy National Energy Technology Laboratory publications. The modeling results show that the scenarios with CO_2 capture and CO_2 EOR produce both natural gas and oil with lower life cycle emissions than conventional systems producing natural gas and oil independently. These results are supported using both different modeling approaches and sets of modeling inputs.

While considerable effort was put into acquiring necessary detail for accurate models, much of the data used were obtained from secondary sources. Significantly greater detail and more rigorous treatment would be required to produce an LCA for use as proof of CO_2 emission reduction.

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ACRONYMS AND ABBREVIATIONS

AGR	acid gas removal
bbl	barrel
CH_4	methane
CO_2	carbon dioxide
CO_2eq	CO_2 equivalent; used to put all greenhouse gases on the same basis (i.e., 1 = CO_2)
DOE	U.S. Department of Energy
EERC	Energy & Environmental Research Center
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (model)
GWP	global warming potential
He	helium
hp	horsepower
H_2S	hydrogen sulfide
kg	kilogram
kW	kilowatt
lb	pound
LCA	life cycle analysis
LPG	liquefied petroleum gas
MMbbl	million barrel
MMBtu	million British thermal unit
MMscf	million standard cubic feet (at Oil and Gas standard of 60°F and 12 atm)
Mscf	thousand standard cubic feet
Mt	million tonne
MWh	megawatt hour
N_2	nitrogen
NGL	natural gas liquid
NETL	National Energy Technology Laboratory
N_2O	nitrous oxide
NO_x	nitrogen oxides
OOIP	original oil in place
PCOR	Plains CO_2 Reduction (Partnership)
RF	recovery factor
tonne	metric ton
UF_{net}	net CO_2 utilization factor

COMPARISON OF NON-EOR AND EOR LIFE CYCLE ASSESSMENTS

EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC) is working with The CETER Group, Inc. (CETER), through the Plains CO_2 Reduction (PCOR) Partnership to evaluate whether life cycle greenhouse gas (GHG) emissions associated with incremental oil produced by enhanced oil recovery (EOR) using anthropogenic carbon dioxide (CO_2) are less than GHG emissions associated with conventional oil production because of the significant amount of CO_2 that is permanently stored in the oil reservoir during CO_2 EOR (approximately ½ ton [450 kg] of CO_2 per barrel of incremental oil produced [Azzolina and others, 2015]).

This report assesses a cradle-to-grave system boundary to quantify the full life cycle GHG emissions associated with the extraction of crude oil, pipeline transport of crude oil to a refinery, refining of crude oil into fuels, transportation of fuels to the point of sale, and finally combustion of the fuels. In this report, four different scenarios were modeled and compared:

Scenario NA1: North American natural gas processing and U.S. primary and secondary petroleum recovery and processing.

Scenario NA2: North American natural gas processing with CO_2 capture and U.S. EOR and processing using the captured CO_2.

Scenario BC1: LaBarge (Shute Creek) natural gas processing and Bell Creek-like conventional oil production (because Bell Creek does not currently produce oil conventionally).

Scenario BC2: LaBarge (Shute Creek) natural gas processing with CO_2 capture and Bell Creek incremental oil production via EOR using the captured CO_2.

Two different tools were used to conduct the life cycle analysis (LCA): 1) customized programming of the Argonne National Laboratory Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model, known as the GREET model, and 2) Microsoft Excel® spreadsheet models using emission factors from the peer-reviewed literature and U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) publications.

A set of spreadsheet models was constructed for all four scenarios using Microsoft Excel® spreadsheets and emission factors from the peer-reviewed literature and NETL publications. Spreadsheet models are easy to use, are accessible to a broad array of practitioners, and allow the integration of emission factors from multiple literature sources. Each spreadsheet model contained

three segments: natural gas extraction, processing, and transport; crude oil extraction, also called gate-to-gate processing; and downstream processing of the oil. The spreadsheet model segments were integrated into each of the four scenarios. To permit fair comparisons across scenarios, the natural gas and oil production for all four scenarios was normalized to the forecasted Bell Creek performance over 25 years.

The GREET model was also used to construct segments similar to those of the spreadsheet model. The GREET model is quite complex. For example, the GREET conventional crude oil recovery and processing model contains seven pathways, 13 technologies, and 23 processes that describe emissions related to U.S. crude oil recovery, processing, transport, and refining into six major U.S. petroleum refinery products. Unfortunately, a default EOR crude oil recovery and processing pathway does not exist within the GREET model. Therefore, the Scenario NA2 and Scenario BC2 simulations were constructed outside of GREET. Ultimately, default GREET modules, GREET modules modified with site-specific inputs, and spreadsheet models had to be combined to derive a final life cycle emission for a particular scenario.

The results of the LCA spreadsheet model indicated that the scenarios with CO_2 capture and CO_2 EOR produce both natural gas and oil with lower emissions. For example, the life cycle emission for Scenario NA1 is 10.62 Mt CO_2eq and for Scenario NA2 is 9.54 Mt CO_2eq, or approximately 10% lower. Similarly, the life cycle emission for Scenario BC1 is 11.78 Mt CO_2eq and for Scenario BC2 is 8.67 Mt CO_2eq, or approximately 26% lower. Preliminary sensitivity analysis of the spreadsheet model shows that the model results are sensitive to the net CO_2 utilization, which directly impacts the purchased CO_2 requirement and, therefore, dictates the upstream emissions associated with raw natural gas extraction and processing.

Analogous to the spreadsheet modeling results, the GREET scenarios with CO_2 capture and CO_2 EOR also produce gas and oil with less emission of CO_2. For example, the life cycle emissions for Scenario BC1 are 13.86 Mt CO_2eq and for Scenario BC2 are 10.22 Mt CO_2eq, or approximately 26% lower. The life cycle emissions for Scenarios BC1 and BC2 modeled using GREET differ from the spreadsheet model results by approximately 15% (11.78 vs. 13.86 Mt CO_2eq for NA2 and 8.67 vs. 10.22 Mt CO_2eq for BC2).

The results highlight the uncertainty in the estimates. However, when comparing scenarios within one modeling approach (i.e., all-spreadsheet or all-GREET), the internally consistent approaches yield the same result: there is a net reduction in life cycle CO_2 emissions when processing natural gas and producing incremental oil via EOR using captured CO_2.

While considerable effort was put into acquiring necessary detail for accurate models, much of the data used were obtained from secondary sources. Significantly greater detail and more rigorous treatment would be required to produce an LCA for use as proof of CO_2 emission reduction.

COMPARISON OF NON-EOR AND EOR LIFE CYCLE ASSESSMENTS

INTRODUCTION

The Energy & Environmental Research Center (EERC) worked with The CETER Group, Inc. (CETER), through the Plains CO_2 Reduction (PCOR) Partnership to evaluate whether life cycle greenhouse gas (GHG) emissions associated with incremental oil produced by enhanced oil recovery (EOR) using anthropogenic carbon dioxide (CO_2) are less than GHG emissions associated with conventional oil production. Life cycle GHG emissions may be lower for incremental oil produced via CO_2 EOR versus conventional oil production because of the significant amount of CO_2 that is permanently stored in the oil reservoir during CO_2 EOR, amounting to approximately ½ ton (450 kg) of CO_2 per barrel of incremental oil produced (Azzolina and others, 2015).

This report assesses a cradle-to-grave system boundary for quantifying the full life cycle GHG emissions associated with the extraction, processing, and combustion of oil under different production scenarios. Two different tools were used to conduct the life cycle analysis (LCA): 1) Microsoft Excel® spreadsheet models using emission factors from the peer-reviewed literature and U.S. Department of Energy (DOE) National Energy Technology (NETL) publications and 2) customized programming of the Argonne National Laboratory Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model, known as the GREET model.

The following sections describe the LCA modeling boundaries and assumptions as well as the GREET and spreadsheet modeling inputs and results.

LCA METHODS AND ASSUMPTIONS

LCA is a systematic approach that calculates the environmental burdens of a product or system (International Organization for Standardization, 2006a,b). In this report, the sole focus was on accounting for GHG emissions in the system, with the primary product being oil. To compare life cycle GHG emissions for incremental oil produced via CO_2 EOR against a baseline conventional oil, two systems were defined, System 1 and System 2, and are described below.

System Boundaries

Figure 1 illustrates the system boundaries for System 1 and System 2.

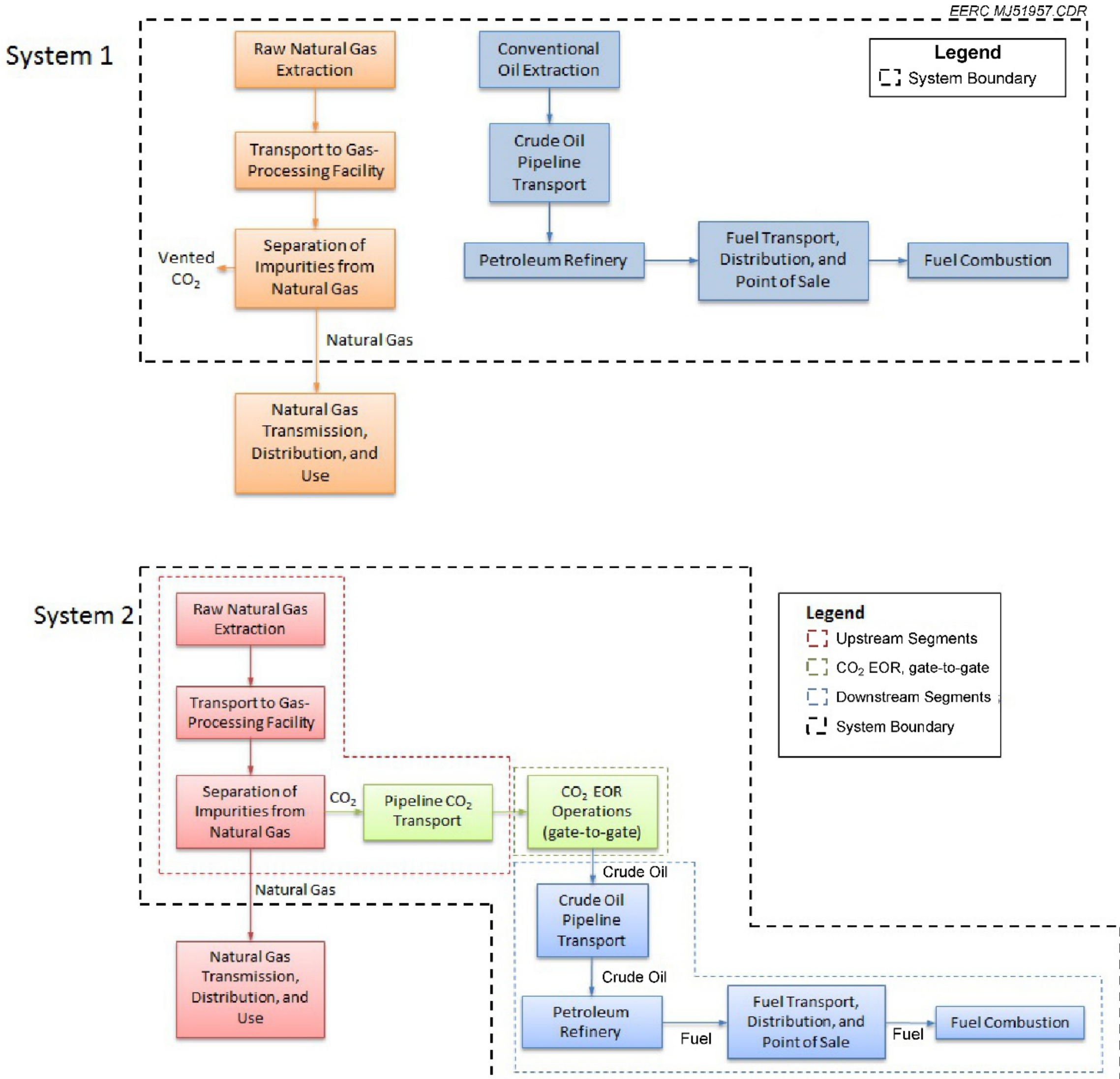

Figure 1. Boundaries for System 1 (top) and System 2 (bottom) used in the LCA.

System 1 represents two separate production processes, one for natural gas extraction, transport, and processing and another for crude oil extraction, refining, and combustion. Two important characteristics of System 1 are that during the natural gas processing, CO_2 is vented to the atmosphere and crude oil production assumes primary or secondary (waterflood) extraction without CO_2 EOR. System 1 represents the conventional baseline, or status quo, for producing natural gas and oil.

System 2 represents a coupled natural gas and oil system, where CO_2 is captured from the natural gas-processing plant and transported to the oil field and the crude oil is produced via CO_2 EOR (tertiary recovery). An important distinction about System 2 is that instead of venting all of the CO_2 to the atmosphere at the gas-processing plant, some of the CO_2 is instead captured and sent to the oil field where it is permanently stored in the oil reservoir as part of the EOR process.

The remaining CO_2 is vented to the atmosphere; however, the amount of CO_2 that is captured is approximately twice the amount that is vented. The vented CO_2 is accounted for in System 2. System 2 represents the alternative system that was evaluated against the conventional baseline.

Functional Unit of Comparison

This work focuses on the life cycle GHG emissions associated with crude oil. All results were expressed in million metric tons (tonnes) of CO_2 equivalent (Mt CO_2eq).

Global Warming Potential Coefficients for Methane and Nitrous Oxide

While CO_2 is the most commonly produced GHG, methane (CH_4) and nitrous oxide (N_2O) also act as GHGs. In this report, GHG emissions are expressed in units of CO_2eq using the 100-year global warming potential (GWP) coefficients of 34 for CH_4 and 298 for N_2O (Forster and others, 2007; Intergovernmental Panel on Climate Change, 2013). The GWP coefficient for CO_2 is one. Expressing GHGs in units of CO_2eq allows a summation of all three values (CO_2, CH_4, and N_2O) into a single number, i.e., kg CO_2eq.

LCA Modeling Scenarios

GHG emissions from four different scenarios were modeled and are compared in this report:

Scenario NA1: North American natural gas processing and U.S. primary and secondary petroleum recovery and processing (North America System 1).

Scenario NA2: North American natural gas processing with CO_2 capture and U.S. EOR and processing using the captured CO_2 (North America System 2).

Scenario BC1: LaBarge (Shute Creek) (hereafter "Shute Creek") natural gas processing and conventional oil production at a Bell Creek-like field because the Bell Creek Field does not currently employ conventional oil production methods (Bell Creek System 1).

Scenario BC2: Shute Creek natural gas processing with CO_2 capture and Bell Creek incremental oil production via EOR using the captured CO_2 (Bell Creek System 2).

The specific inputs for each scenario are dependent upon whether they were modeled using the spreadsheet models or GREET, as described in their respective sections.

DEVELOPMENT OF A LIFE CYCLE SPREADSHEET MODEL

A set of models was constructed for all four scenarios using Microsoft Excel spreadsheets and emission factors from the peer-reviewed literature and NETL publications. The primary reasons for pursuing spreadsheet models is that they are easy to use and are accessible to a broad array of practitioners (i.e., nearly everyone has Microsoft Office® on their computers). In addition, the spreadsheet models allow the integration of emission factors from multiple literature sources.

Emission Factors for Natural Gas Extraction and Processing

There are two segments associated with the upstream natural gas portions of the models: 1) raw natural gas extraction and 2) natural gas processing.

Raw Natural Gas Extraction (all four scenarios)

Emission factors from NETL (2010a) for raw natural gas extraction were used across all four scenarios. This unit process provides a summary of relevant input and output flows associated with the extraction of natural gas from a conventional onshore gas well. The boundaries begin with raw natural gas extracted from nature and end with natural gas ready for pipeline transport. The operation of compressors and dehydrators is included in this unit process; hydrogen sulfide removal (sweetening) is not included in this unit process.

The NETL (2010a) emission factors include 0.112 kg CO_2, 1.53E-03 kg CH_4, and 1.66E-07 kg N_2O per kg of natural gas extracted. The net emission factor for raw natural gas extraction is the sum total of these emission sources, which is 3.13 kg CO_2eq/Mscf (thousand standard cubic feet) of raw natural gas extracted $(([0.112 + (0.0015 \times 34) + (1.66E\text{-}07 \times 298)]) \times 19.05)$. In converting from Mscf natural gas to kg, we assume 0.042 lb/scf (American Petroleum Institute, 2009), which is 19.05 kg/Mscf. These emission factors for natural gas extraction compare well to the ones presented by NETL (2014).

Natural Gas Processing (Scenarios NA1 and NA2)

Emission factors from NETL (2010b) were used for natural gas processing for Scenarios NA1 and NA2. This unit process provides a summary of relevant input and output flows associated with the acid gas removal (AGR) of natural gas, specifically the removal of hydrogen sulfide (H_2S). The boundaries begin with the receipt of “sour” natural gas and end with “sweetened” natural gas ready for pipeline transmission.

The NETL (2010b) emission factors include emissions associated with both venting and fuel usage. Venting includes 0.0868 kg CO_2 and 9.72E-04 kg CH_4 per kg of natural gas sweetened. Additional emissions associated with fuel usage include 6.47E-05 kg CO_2, 1.27E-06 kg CH_4, and 3.53E-07 kg N_2O per kg of natural gas processed. The net emission factor for raw natural gas extraction is the total of these emission sources, which is 2.28 kg CO_2eq/Mscf of natural gas processed calculated as follows: $[(0.0868 + 6.47E\text{-}05) + \{[9.72E\text{-}04 + 1.27E\text{-}06) \times 34] + (3.53E\text{-}07 \times 298)\}] \times 19.05)$. These emission factors for natural gas extraction compare well to the ones presented by NETL (2014).

In Scenario NA2 where CO_2 is captured from the natural gas-processing plant, a simplifying assumption is made that 90% of the CO_2 that is vented during the sweetening process (AGR) is, instead, captured and transported to the EOR field. The net emission factor for natural gas processing in Scenario NA2 is, therefore, significantly lower: 0.8 kg CO_2eq/Mscf of raw natural gas processed.

In determining emissions associated with natural gas processing, NETL (2010b) refers to the U.S. nonhydrocarbon gases removed from natural gas, which were 721,507 MMscf (million standard cubic feet) in 2009 (U.S. Energy Information Administration, 2009a), and assumes that the percent volume of CO_2 in nonhydrocarbon gas was 90% (649,356 MMscf). U.S. natural gas gross withdrawals in 2009 were 26,056,893 MMscf (U.S. Energy Information Administration, 2009b), which translates to an average CO_2 content of the raw natural gas of Approximately 2.5% (649,356 / 26,056,893). In addition, NETL (2010b) assumes a H_2S content of the natural gas of 1.0 mole per kg of natural gas.

To simplify the subsequent life cycle calculations for Scenarios NA1 and NA2, the gas flows into and out of the generic natural gas-processing plant were normalized to the raw natural gas processed, to the natural gas product to sales, or the amount of CO_2 captured and transported (Scenario NA2 only). For example, as shown in Table 1 (Scenario NA1), 1.0 MMscf of raw natural gas processed yields approximately 1.0 MMscf of natural gas product to sales and emits 0.09 MMscf of CO_2 and <0.01 MMscf of CH_4 and N_2O. In Table 2 (Scenario NA2), 1.0 MMscf of CO_2 captured and transported requires 12.81 MMscf of inlet raw natural gas, which emits 0.11 MMscf of CO_2.

Table 1. Scenario NA1 Natural Gas-Processing Plant Emissions with CO_2 Capture, MMscf/MMscf

Shute Creek Facility Emissions	Normalized to CO_2 Captured and Transported	Normalized to Raw Natural Gas Processed	Normalized to Natural Gas Product to Sales
Raw Natural Gas Processed	NA[1]	1.00	1.00
CO_2 Captured and Transported	NA	NA	NA
CO_2 Emitted	NA	0.09	0.09
CH_4 Emitted	NA	0.00[2]	0.00
NO_x (nitrogen oxides) Emitted	NA	0.00	0.00
Natural Gas Product to Sales	NA	1.00	1.00

[1]Not applicable.
[2]Values <0.01 are displayed as 0.00.

Table 2. Scenario NA2 Natural Gas Processing Plant Emission Ratios with CO_2 Capture, MMscf/MMscf

Shute Creek Facility Emissions	Normalized to CO_2 Captured and Transported	Normalized to Raw Natural Gas Processed	Normalized to Natural Gas Product to Sales
Raw Natural Gas Processed	12.81	1.00	1.00
CO_2 Captured and Transported	1.00	0.08	0.08
CO_2 Emitted	0.11	0.01	0.01
CH_4 Emitted	0.01	0.00[1]	0.00
NO_x Emitted	0.00	0.00	0.00
Natural Gas Product to Sales	12.82	1.00	1.00

[1]Values <0.01 are displayed as 0.00.

Natural Gas Processing (Scenarios BC1 and BC2)

As of January 2016, the Bell Creek oil field sources 100% of its CO_2 from ExxonMobil's Shute Creek Gas Plant (Wyoming Oil and Gas Conservation Commission, 2016). Therefore, emission factors derived for the Shute Creek natural gas-processing plant in Green River, Wyoming, were used for Scenarios BC1 and BC2 (Bell Creek Systems 1 and 2). The Shute Creek natural gas-processing model for the spreadsheet models is identical to the one used in the modified GREET simulations.

Shute Creek receives natural gas from the LaBarge Field located in Sublette County. Shute Creek handles the lowest-hydrocarbon-content natural gas commercially produced in the world. The gas composition entering Shute Creek is 65% CO_2, 22% CH_4, 7.4% nitrogen (N_2), 5% H_2S, and 0.6% helium (He) (Wyoming Tax Appeals, 2006). One noticeable difference between the inlet gas composition at Shute Creek versus the inlet gas composition used by NETL (2010b) is the significantly greater amount of CO_2 (65% versus 2.5% CO_2, respectively) (Table 3). The high CO_2 content of the Shute Creek inlet gas plays an important role in the Scenarios BC1 and BC2 models, as described below in Tables 4 and 5.

Table 3. Raw Inlet Gas Chemical Composition for the Shute Creek Facility, mass percent (Source: Wyoming Tax Appeals, 2006)

Component	Raw (production)
CO_2	65.0
CH_4	22.0
N_2	7.4
He	0.6
H_2S	5.0
Total	100.0

Table 4. Shute Creek (Scenario BC1) Natural Gas-Processing Plant Emission Ratios Without CO_2 Capture, MMscf/MMscf

Shute Creek Facility Emissions	Normalized to CO_2 Captured and Transported	Normalized to Raw Natural Gas Processed	Normalized to Natural Gas Product to Sales
Raw Natural Gas Processed	NA	1.00	6.10
CO_2 Captured and Transported	NA	NA	NA
CO_2 Emitted	NA	0.69	4.22
CH_4 Emitted	NA	0.00[1]	0.00
NO_x Emitted	NA	0.00	0.00
Natural Gas Product to Sales	NA	0.16	1.00

[1]Values <0.01 are displayed as 0.00.

Table 5. Shute Creek (Scenario BC2) Natural Gas-Processing Plant Emission Ratios with CO_2 Capture, MMscf/MMscf

Shute Creek Facility Emissions	Normalized to CO_2 Captured and Transported	Normalized to Raw Natural Gas Processed	Normalized to Natural Gas Product to Sales
Raw Natural Gas Processed	2.12	1.00	6.10
CO_2 Captured and Transported	1.00	0.47	2.88
CO_2 Emitted	0.46	0.22	1.33
CH_4 Emitted	0.00	0.00	0.00
NO_x Emitted	0.00	0.00	0.00
Natural Gas Product to Sales	0.35	0.16	1.00

Note: Values <0.01 MMscf are displayed as "0.00."

The 17 production wells of the LaBarge Field are sited in the high country of the Rocky Mountains. The gas from each well flows to one of three manifolds. Gas collected at the manifolds then flows to the glycol-based primary treatment facility at Black Canyon for initial treatment (dehydration). After the initial treatment, the gas is exported 46 miles to Shute Creek via a 28-inch trunk line for final treatment (Parker and others, 2011). Emissions associated with pipeline transport from Black Canyon to Shute Creek (pipeline fugitives and electricity usage) are not captured in the current modeling approach.

The Shute Creek natural gas-processing model is based on flows of raw inlet natural gas, captured CO_2, venting, flare, and other volumes as recently reported by the State of Wyoming Oil and Gas Conservation Commission (Form 9). The raw inlet natural gas rate to the Shute Creek facility is 720 MMscfd (million standard cubic feet of raw natural gas per day), from which 340 MMscfd CO_2 is captured and transported and 92 MMscfd CO_2 is vented, producing 118 MMscfd of natural gas product to sales (ready for pipeline transport). In addition to the venting of CO_2, there are 65.4 MMscfd of CO_2eq emissions associated with plant equipment use (electric cogeneration fuel, boiler fuel, furnace fuel, flare stack, and reciprocating compressor). In total, there are 186.1 MMscfd of CO_2 emissions from the Shute Creek facility.

Analogous to the examples for Scenarios NA1 and NA2, to simplify the subsequent life cycle calculations for Scenarios BC1 and BC2, the gas flows into and out of the Shute Creek natural gas-processing plant were normalized to the amount of CO_2 captured and transported, to the raw natural gas processed, or to the natural gas product to sales (Table 4 [BC1] and Table 5 [BC2]). For example, as shown in Table 5, 1.0 MMscf of CO_2 captured and transported requires 2.12 MMscf of inlet raw gas, which produces 0.46 MMscf of CO_2 emissions and 0.35 MMscf of natural gas product to sales.

In Scenario BC1, the Shute Creek facility is assumed to operate as if CO_2 is not captured and all of the CO_2 is, therefore, vented to the atmosphere. In aggregate, these changes result in 497 MMscfd of CO_2 emissions from the Shute Creek facility without capture, or 340 MMscfd greater than Scenario BC2 with capture. There would be a small reduction in the amount of CO_2 emissions associated with plant equipment use related to the CO_2 capture unit; however, these are not captured in the current modeling approach.

The values in Tables 4 and 5 underscore the importance of the raw natural gas composition on the overall gas flows for the gas-processing plant. For example, in the generic example from NETL (2010b) for Scenario NA2, 1.0 MMscf of CO_2 captured required 12.81 MMscf of raw natural gas and emits 0.11 MMscf of CO_2. In contrast, 1.0 MMscfd of CO_2 captured at Shute Creek only requires 2.12 MMscf of raw natural gas (about six times less than NA2) and generates 0.46 MMscf CO_2 emissions (about 1.3 times more than NA2).

Pipeline Transport of CO_2

In the emission factors for natural gas processing in System 2 models (Scenarios NA2 and BC2), emissions associated with 500 miles of CO_2 pipeline transport from the Shute Creek facility to the Bell Creek oil field were also included. Using these inputs, the MMscf CO_2 emitted from electric generation for transport per MMscf CO_2 captured and transported is approximately 0.084267 MMscf/MMscf, which results in 28.65 MMscfd of CO_2 emissions associated with the pipeline transport of CO_2 from the Shute Creek facility to the Bell Creek oil field (0.084267 × 340 MMscfd CO_2 captured and transported).

Emission Factors for the Gate-to-Gate Segment (crude oil Extraction)

Conventional Oil Extraction

Systems NA1 and BC1 extract oil using conventional methods. For these systems, a gate-to-gate emission factor of 56 ± 15 kg CO_2eq/bbl was used for conventional oil extraction. This factor was derived by Mangmeechai (2009) and includes extraction of raw feedstock from the earth and any partial processing of the raw materials that may occur. It is unclear if this estimated emission factor includes drilling or other primary recovery/waterflood-related emissions. However, similar estimates of 40 to 60 kg CO_2eq/bbl have been published in the literature (McCann and Magee, 1999; Intergovernmental Panel on Climate Change, 2000).

Incremental Oil Extraction via CO_2 EOR

Systems NA2 and BC2 extract oil via CO_2 EOR, whereby CO_2 is injected into an oil reservoir, where it mixes with the oil to swell it and reduce the oil viscosity, making it lighter and detaching it from the rock surfaces. These subsurface alterations cause the oil to flow more freely within the reservoir to producing wells. During this process, approximately half of the injected CO_2 is produced together with oil, separated, and reinjected, but nearly all (over 95%) of the purchased CO_2 delivered to the oil field remains securely trapped within the deep geologic formation (U.S. Department of Energy National Energy Technology Laboratory, 2010a; Melzer, 2012; Azzolina and others, 2015). For estimating the gate-to-gate emissions associated with CO_2 EOR in Scenario NA2, the model and approach by Azzolina and others (2016) was used. This approach presents the results of a detailed LCA of GHG emissions associated with CO_2 EOR where the CO_2 is obtained from a coal-fired power plant. Azzolina and others (2016) represents a generic gate-to-gate model for CO_2 EOR that reflects average reservoir conditions and performance for the Permian Basin in Texas. The work builds upon previous investigations by NETL (2010c, 2013a) and Cooney and others (2015) and integrates new information to provide more plausible ranges for CO_2 storage in the reservoir during CO_2 EOR from Azzolina and others (2015).

The gate-to-gate emissions were modeled for System BC2 by taking the total electrical and natural gas usage of the site rather than attempting to reconstruct the energy usage from individual pumps, compressors, etc., as was done in Azzolina and others (2016). These energy usage data were provided to the EERC by Denbury Onshore, LLC (Denbury). The Bell Creek EOR field uses 200 to 288 MWh of electricity per day and 210 to 350 Mscf of natural gas per day for both the CO_2 recycle facility and well test sites. The electrical usage is largely associated with approximately 16,000 hp (12,000 kW) of compression, which is currently running at approximately 70% capacity but will eventually run at 100% capacity later in the CO_2 flood. The electricity usage is scaled up assuming a linear progression from 70% capacity to 100% capacity over 10 years and then assuming that the facility operates at 100% capacity for the remaining 15 years.

The emission factor for delivered electricity in Montana is 620 kgCO_2eq/MWh, which includes emissions associated with both power generation (586 kgCO_2eq/MWh) and gross grid loss from the transmission and distribution of electricity (5.7% for the western region). Thus 586 × 1.057 = 620 kgCO_2eq/MWh (U.S. Environmental Protection Agency, 2012). Life cycle emissions associated with electricity use at the Bell Creek EOR field are, therefore, 200 MWh × 620 kgCO_2eq/MWh × 365 days/year = 45.3 million kgCO_2eq per year. At full capacity (288 MWh/day) 10 years into the CO_2 flood, the emissions are 65.2 million kgCO_2eq per year.

The natural gas used at the site is taken from the natural gas supply line for the main facility. A generic emission factor from NETL (2014) of 9.1 kgCO_2eq/Mscf was applied. An average natural gas use of 280±70 Mscf/day (the average of 210 to 350 Mscf/day used at the Bell Creek oil field) was assumed.

Emission Factors for the Downstream Segment

The downstream segment includes 1) crude oil transport from the CO_2 EOR field to the refinery, 2) refining of the crude oil, 3) fuel transport and distribution from the refinery to point of sale, and 4) combustion of the refined petroleum fuel. The baseline NETL petroleum-based transportation fuel model was used to account for the downstream emissions (U.S. Department of Energy National Energy Technology Laboratory, 2008). In developing the emissions factor for refining, the emission factor for each fuel was weighted by the fraction of the total refinery production to derive a product-weighted average refinery emissions per m^3 of crude oil, assuming seven different refined fuel products (motor gasoline, diesel, kerosene and kerosene-based jet fuel, residual fuel oil, coke, light ends, and heavy ends). In estimating fuel consumption, a conservative value was adopted by assuming that the carbon contained in crude oil is converted into CO_2 through the combustion of the fuel. The U.S. Environmental Protection Agency (EPA) Greenhouse Gas Equivalencies Calculator (2016) was used. It assumes an average heat content for crude oil of 5.88 MMBtu/bbl, an average carbon coefficient for crude oil of 20.31 kg carbon/MMBtu, and 100% oxidation to derive an emission factor of 430 kg CO_2/bbl. The emission factors for downstream subsegments are 5 (crude oil transport), 45 (refining), 5 (fuel transport), and 430 (fuel combustion) kg CO_2eq/bbl, for a total of 485 kg CO_2eq/bbl incremental oil consumed.

Integrating the Spreadsheet Model Segments

Normalizing All Four Scenarios to Bell Creek

The above sections establish emission factors for segments of two different systems and four different scenarios, each producing natural gas and oil. To scale all four scenarios to the same volumes of natural gas and oil, thereby permitting fair comparisons across scenarios, the natural gas and oil production for all four scenarios was normalized to the forecasted Bell Creek performance over 25 years.

The forecasted Bell Creek cumulative incremental oil recovery factor (RF, %OOIP [original oil in place]) and net CO_2 utilization factor (UF_{net}, Mscf/bbl) come from the EERC's 2015 Bell Creek Test Site Simulation Report (Bosshart and others, 2015). These predictive simulations were conducted to aid in monitoring long-term behavior of injected CO_2 and should not be construed to represent a formal estimation of petroleum reserve estimates for the operators of the field or to prepare annual petroleum reserve certifications for filers with the U.S. Securities and Exchange Commission. The RF and UF_{net} at 25 years into the CO_2 flood are forecasted to be 10.2 %OOIP and 8.7 Mscf/bbl, respectively, resulting in 9.2 MMbbl of incremental oil produced (90 MMbbl OOIP × 10.2%) and a purchased CO_2 requirement of 81,500 MMscf CO_2. In calculating the purchased CO_2 requirement, a 2% fugitive loss rate of purchased CO_2 was assumed (Melzer, 2012), which inflates the purchased CO_2 requirement above the net CO_2 utilization (8.7 Mscf/bbl × 9.2 MMbbl × 1.02). This fugitive loss rate is conservative and represents an assumption based on estimates found in the literature. There is currently no evidence of fugitive CO_2 loss at the Bell Creek oil field. Therefore, across all four scenarios, 9.2 MMbbl of incremental oil was used after which the natural gas segments were scaled to the purchased CO_2 requirement of 81,500 MMscf CO_2, as described below.

Calculating Upstream Emissions from Natural Gas

Upstream emissions are expressed in units of either Mscf of raw natural gas extracted (3.13 kg CO_2eq/Mscf) or Mscf of natural gas product processed (2.28 kg CO_2eq/Mscf). The ratios in Table 2 (NA2) and Table 5 (BC2) allow us to calculate upstream emissions for each scenario based on the purchased CO_2 requirement. For example, in Scenario NA2 the generic natural gas-processing plant captures 1.0 MMscf of CO_2 for every 12.81 MMscf of raw natural gas. Therefore, a purchased CO_2 volume of 81,500 MMscf requires 1,044,000 MMscf of raw natural gas processed. An example calculation is provided below.

$$
\begin{aligned}
\text{MMscf raw gas} &= \text{MMscf purchased } CO_2 \times \text{MMscf raw natural gas/MMscf } CO_2 \text{ captured} \\
&= 81{,}500 \text{ MMscf} \times 12.81 \text{ MMscf/MMscf} \\
&= 1{,}044{,}000 \text{ MMscf raw natural gas}
\end{aligned}
$$

For the same purchased CO_2 requirement, the Shute Creek gas plant results in different values, with much less raw natural gas required to generate the purchased CO_2 volumes. For example, in Scenario BC2 the Shute Creek gas plant captures 1.0 MMscf of CO_2 for every 2.12 MMscf of raw natural gas processed. Therefore, a purchased CO_2 volume of 81,500 MMscf requires 172,800 MMscf of raw natural gas processed, or about one-sixth as much as Scenario NA2.

In Scenarios NA1 and BC1, there is no CO_2 capture and the same volume of raw natural gas and natural gas product to sales are used as were done in Scenarios NA2 and BC2 (i.e., NA1 = NA2 and BC1 = BC2).

Since the downstream emission factor is expressed entirely in units of barrels of oil (485 kg CO_2eq/bbl), the barrels of incremental oil produced drive the entire downstream emissions and no additional calculations are needed.

GREET MODELING

GREET Inputs

The GREET model contains emission information related to North American recovery and processing of conventional and shale natural gas. In addition, the GREET conventional crude oil recovery and processing model contains seven pathways, 13 technologies, and 23 processes that describe emissions related to U.S. crude oil recovery, processing, transportation, and refining into six major U.S. petroleum refinery products (residual oil, petroleum coke, liquefied petroleum gas (LPG), low-sulfur diesel, gasoline blendstock, and conventional jet fuel). Inputs to the GREET simulation consisted of the model's default natural gas composition and the "crude oil average for use in U.S. refineries." Because the GREET model does not contain a single pathway that accepts crude oil input for the production of a refined product output mixture, emission values for each pathway were transferred to a spreadsheet and total emissions were calculated based upon the weighted average of individual product emissions.

Bell Creek crude oil has been characterized as a fairly sweet, light (32° to 41° API) crude oil (Haddenhorst and Gary, 1968; Ballard, 2009). A chemical analysis of two Bell Creek oil samples by the EERC (Gorecki and Pu, 2001) indicated the oil to be fairly paraffinic and provided this study with compositional breakouts by carbon number. Based upon these analyses; assuming typical cut points for straight-run gasoline, jet and diesel fuels, and light and heavy vacuum oil and residuum; and assuming a refinery configuration that included a hydrocracker, catalytic cracker, and coker, this study arrived at a notional refined product slate depicted in Table 6. The notional product distribution is intended to represent (rather than define) the products that could be produced from Bell Creek oil. Admittedly, the distribution does not reflect market conditions that might drive the slate toward more gasoline, it assumes that all feedstock is processed into only six products, and the configuration is an overestimate for a facility configured to process light crudes. However, it is believed that this distribution is superior to adopting a national or regional (e.g., Petroleum Administration for Defense Districts) average that reflects higher coke production, and emission volumes associated with it are less sensitive to reasonable changes in product distribution than such averages.

Table 6. Notional Refined Product Distribution from Bell Creek Crude Oil

Finished Petroleum Products	%
Gasoline	44
Diesel	36
Jet Fuel	9
LPG	5
Residual Fuel Oil	5
Petroleum Coke	1
Total	100

GREET Modeling Challenges for Scenario NA2 and Scenario BC2

Each life cycle scenario was to be composed of three major steps: 1) natural gas recovery and processing; 2) petroleum recovery and processing; and 3) transportation, storage, and refining of petroleum and petroleum products. Each step contains multiple processes and technologies. Based upon EERC application of basic GREET functionality, the GREET model posed a few challenges to its use for performing LCAs for these scenarios:

- The structure of and defaults within the GREET model do not permit linkage of natural gas-processing rates with petroleum recovery and processing rates into a single comprehensive pathway.

- The GREET structure does not provide for production of simultaneous, multiple main products (CO_2, sulfur, and pipeline-quality natural gas) from processing of the raw natural gas. GREET provides for the production of "coproducts," but these products require allocation or displacement accounting and cannot serve as inputs to other processes.

- The model lacks predefined pathways, processes, and default values that would allow CO_2 captured from raw natural gas to feed directly to an EOR petroleum recovery operation. In fact, the GREET model's default natural gas composition is only approximately 2% CO_2 in the raw natural gas, which may not be economical to recover.

The result of these challenges was that a default EOR crude oil recovery and processing pathway did not exist within the GREET model; consequently, the Scenario NA2 (North America System 2) and Scenario BC2 (Bell Creek System 2) simulations were constructed outside of GREET.

Final GREET Models

The final GREET models combined default GREET modules, modified GREET modules with site-specific inputs, or spreadsheet models to derive a final life cycle emission for a particular scenario. Table 7 summarizes which model segments were modeled in GREET and which were modeled using spreadsheets.

Table 7. **Summary of Segments Modeled in GREET or Spreadsheet**

Model Segment	Scenario NA1	Scenario NA2	Scenario BC1	Scenario BC2
Raw Natural Gas Extraction	Not modeled in GREET	Not modeled in GREET	GREET – U.S. natural gas product w/export	GREET – U.S. natural gas product w/export
Natural Gas Processing	Not modeled in GREET	Not modeled in GREET	Spreadsheet model (Shute Creek gas plant)	Spreadsheet model (Shute Creek gas plant)
Gate-to-Gate Oil Recovery	Not modeled in GREET	Not modeled in GREET	GREET – modified[1]	Spreadsheet model (Azzolina and others, 2016)
Downstream Oil Transport, Refining, and Combustion	Not modeled in GREET	Not modeled in GREET	GREET – U.S. conventional[2]	GREET – U.S. conventional[1]

[1] Modified to the Bell Creek-specific petroleum chemistry.
[2] Includes the following GREET modules weighted to the percentages in Table 9: Crude Oil for U.S. Refineries; Crude Oil after Conventional Transportation to U.S. Refineries Production and Transportation; Heavy Butane Gasoline Blendstock; Residual Oil; Petroleum Coke; LPG; Low-Sulfur Diesel; Gasoline Blendstock; and Conventional Jet Fuel.

LCA RESULTS

Spreadsheet Model Results

An emission summary by model segment for each of the four scenarios is presented in Table 8 for the spreadsheet models. These results are shown graphically in Figure 2 (top panel). Appendix A contains more detailed breakdowns of the individual emissions and calculations.

One of the largest differences between Scenarios NA1/NA2 and BC1/BC2 is the volume of raw natural gas extracted, which is 1,043,160 MMscf for NA1/NA2 and 172,511 MMscf for BC1/BC2. As noted above, this is largely attributable to the different raw natural gas compositions, which result in Scenarios NA1/NA2 requiring about six times more raw natural gas to generate 1.0 MMscf of captured CO_2. This results in approximately six times greater emissions for natural gas extraction and transport in Scenarios NA1/NA2 than Scenarios BC1/BC2 (3.27 vs. 0.54 Mt).

Table 8. Spreadsheet Modeling Results by Model Segment for Each of the Four Scenarios, Mt CO_2eq

Model Segment	NA1	NA2	BC1	BC2
Bell Creek EOR Field Data (used to scale all models)				
Incremental Oil Recovered, MMbbl	9.2	9.2	9.2	9.2
CO_2 Demand, MMscf	–	81,463	–	81,463
Raw Natural Gas Extracted, MMscf	1,043,160	1,043,160	172,511	172,511
Emission Summary by Segment, Mt CO_2eq				
Natural Gas Extraction and Transport	3.27	3.27	0.54	0.54
Natural Gas Processing	2.38	0.83	6.28	1.99
CO_2 Transport	–	0.13	–	0.13
Gate-to-Gate Oil Extraction	0.51	0.86	0.51	1.56
Downstream	4.45	4.45	4.45	4.45
Life Cycle Emissions, Mt CO_2eq	10.62	9.54	11.78	8.67

Another significant difference is the emissions with and without CO_2 capture at the natural gas-processing facility. Scenarios NA2 and BC2 both emit less CO_2 than their noncapture counterparts in Scenarios NA1 and BC1, respectively, because CO_2 that would otherwise be vented to the atmosphere is being captured and transported to the EOR field.

Finally, the gate-to-gate emissions are greater for the CO_2 EOR Scenarios NA2 and BC2 than their conventional oil extraction counterparts in Scenarios NA1 and BC1, respectively, on account of the higher energy intensity associated with the separation, compression, and reinjection of CO_2 involved in CO_2 EOR.

In aggregate, the scenarios with CO_2 capture and CO_2 EOR produce both products, natural gas and oil, with less emissions. For example, the life cycle emission for Scenario NA1 is 10.62 Mt CO_2eq and for Scenario NA2 is 9.54 Mt CO_2eq, or approximately 10% lower. Similarly, the life cycle emission for Scenario BC1 is 11.78 Mt CO_2eq and for Scenario BC2 is 8.67 Mt CO_2eq, or approximately 26% lower.

GREET Model Results

An emission summary by model segment for each of the four scenarios is presented in Table 9 for the GREET models. These results are shown graphically in Figure 2 (bottom panel).

Analogous to the spreadsheet modeling results, the scenarios with CO_2 capture and CO_2 EOR produce both products, natural gas and oil, with less emissions. For example, the life cycle emissions for Scenario BC1 are 13.86 Mt CO_2eq and for Scenario BC2 are 10.22 Mt CO_2eq, or approximately 26% lower. The life cycle emissions for Scenarios BC1 and BC2 modeled using GREET differ from the spreadsheet model results by approximately 15% (11.78 vs. 13.86 Mt CO_2eq for NA2 and 8.67 vs. 10.22 Mt CO_2eq for BC2).

Table 9. GREET Model Emission Summary by Model Segment for Each of the Four Scenarios, Mt CO_2eq

Model Segment	NA1	NA2	BC1	BC2
Bell Creek EOR Field Data				
(used to scale all models)				
Incremental Oil Recovered, MMbbl	–	–	9.2	9.2
CO_2 Demand, MMscf	–	–	–	81,463
Raw Natural Gas Extracted, MMscf	–	–	172,511	172,511
Emission Summary by Segment				
Natural Gas Extraction and Transport	–	–	0.72	0.72
Natural Gas Processing	–	–	8.30	3.36
CO_2 Transport	–	–	–	0.13
Gate-to-Gate Oil Extraction	–	–	0.49	1.65
Downstream	–	–	4.35	4.35
Life Cycle Emissions	–	–	13.86	10.22

The GREET modeling could not be extended to Scenarios NA1 or NA2 because the GREET gas-processing module was built primarily for cases in which CO_2 is captured from the Shute Creek gas plant. The quantity of CO_2 contained in the raw natural gas that is processed at Shute Creek is sufficiently high such that little raw natural gas is required to be processed for that situation relative to typical North American raw natural gas that contains considerably less CO_2. Because the two models could not be put on the same basis, GREET was not used to model the natural gas portion of Scenarios NA1 or NA2.

Even though there is uncertainty in the CO_2 emission estimates when scenarios within one modeling approach (i.e., all-spreadsheet or all-GREET) are compared, the internally consistent approaches yield the same result: there is a net reduction in life cycle emissions when processing natural gas and producing incremental oil via EOR with CO_2 capture.

While considerable effort was put into acquiring necessary detail for accurate models, much of the data used were obtained from secondary sources. Significantly greater detail and more rigorous treatment would be required to produce an LCA that could be used as proof of CO_2 emission reduction.

SENSITIVITY ANALYSIS

The sensitivity analysis explores the change in the life cycle emission estimates as a function of changing different input parameters in the model. The sensitivity analysis employed here focuses on three key inputs: 1) the net CO_2 utilization of the Bell Creek oil field, which directly impacts the purchased CO_2 requirement; 2) the emission factor for raw natural gas extraction; and 3) the ratio of raw natural gas required per CO_2 captured. The sensitivity analysis modifies these inputs by ±10% and ±20% and then records the life cycle emission factor result from the

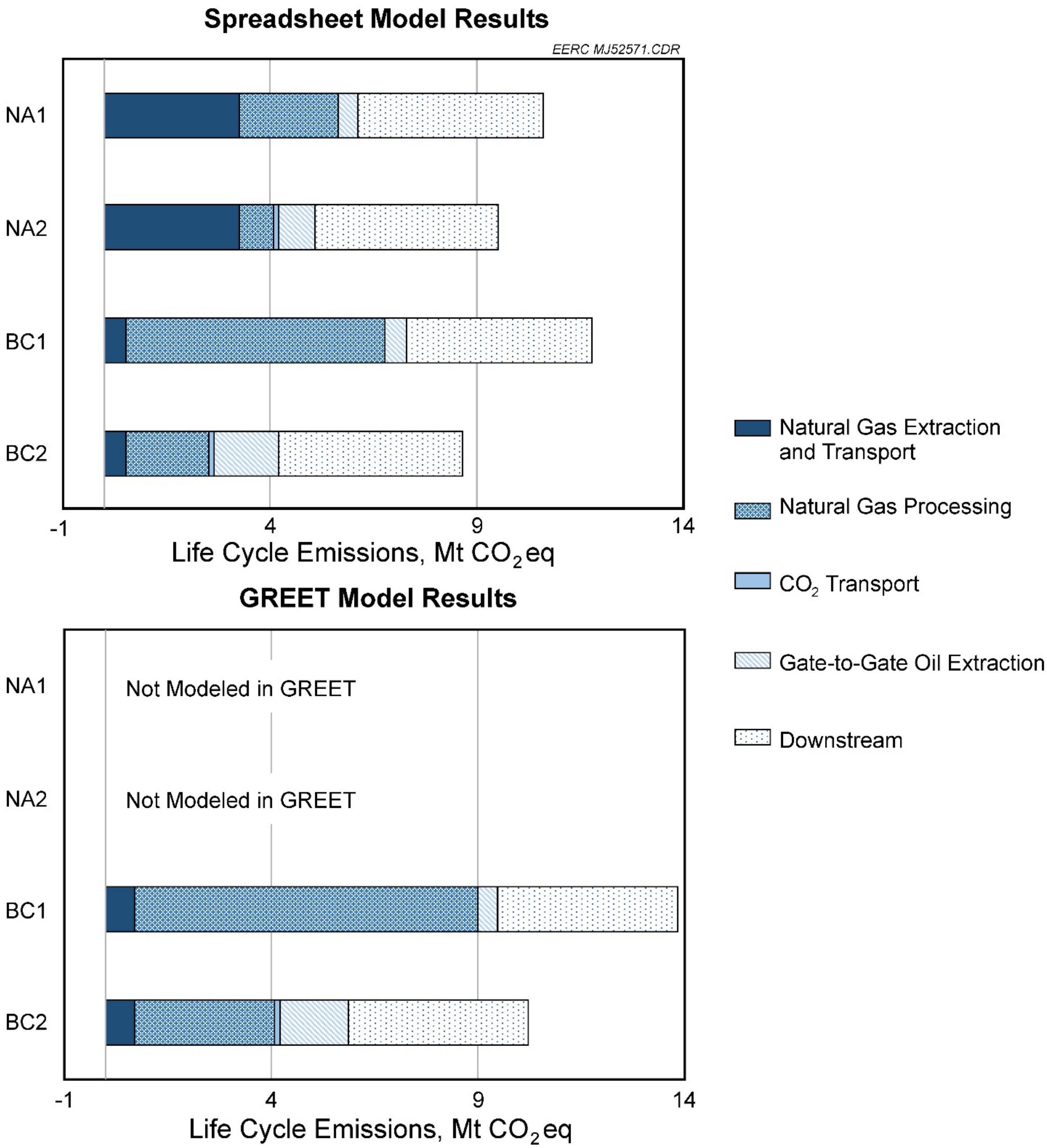

Figure 2. Stacked bar chart showing the life cycle emissions (Mt CO_2eq) associated with each model segment for the four different scenarios that were modeled using spreadsheet models (top panel) or GREET (bottom panel).

spreadsheet model for Scenario BC2 (Bell Creek with CO_2 capture). Sensitivity analysis was not done using the GREET models because of the labor-intensive process of rerunning the GREET simulations, which underscores the value of developing spreadsheet-based models. The net CO_2 utilization was varied from 6.96 to 10.44 Mscf/bbl, the raw natural gas extraction emission factor was varied from 2.5 to 3.8 kg CO_2eq/Mscf, and the ratio of raw natural gas extracted per CO_2 captured and transported was varied from 1.69 to 2.54 MMscf/MMscf (unitless).

The sensitivity analysis results are summarized in Table 10. The top table reports the life cycle emissions in Mt CO_2eq, and the bottom table reports the percentage change from the base case. The largest percentage change was associated with changing the net CO_2 utilization, which resulted in a 6% change in life cycle emissions for a 20% change in net CO_2 utilization. Changing the raw natural gas extraction emission factor and the ratio of raw natural gas extracted per CO_2 captured and transported did not result in a significant change to the overall life cycle emissions, with only a 1% change in life cycle emissions for a 20% change in these inputs. These results also provide a confidence in the significant difference of >3Mt CO_2eq from the Scenario BC1 model (without capture).

Table 10. Sensitivity Analysis Summary for Scenario BC2 (Bell Creek with CO_2 capture)

	Life Cycle Emissions (Mt CO_2eq) for the Stated Case				
Parameter	**−20%**	**−10%**	**0% (Base Case)**	**+10%**	**+20%**
Modifying Net CO_2 Utilization	8.14	8.41	8.67	8.94	9.21
Modifying Raw Natural Gas Extraction Emission Factor	8.57	8.62	8.67	8.73	8.78
Modifying Ratio of Natural Gas Processed per CO_2 Captured	8.57	8.62	8.67	8.73	8.78

	% Change in Life Cycle Emissions for the Stated Case				
Parameter	**−20%**	**−10%**	**0% (Base Case)**	**+10%**	**+20%**
Modifying Net CO_2 Utilization	94	97	100	103	106
Modifying Raw Natural Gas Extraction Emission Factor	99	99	100	101	101
Modifying Ratio of Natural Gas Processed per CO_2 Captured	99	99	100	101	101

CONCLUSIONS

The modeling results show that the scenarios with CO_2 capture and CO_2 EOR produce both natural gas and oil with lower life cycle emissions than conventional systems producing natural gas and oil independently. These results are supported using two different modeling approaches and sets of modeling inputs (spreadsheet models and GREET).

Sensitivity analysis of the spreadsheet models shows that the model results are sensitive to the net CO_2 utilization, which directly impacts the purchased CO_2 requirement and, therefore, dictates the upstream emissions associated with raw natural gas extraction and processing.

While considerable effort was put into acquiring necessary detail for accurate models, much of the data used were obtained from secondary sources. Significantly greater detail and more rigorous treatment would be required to produce an LCA for use as proof of CO_2 emission reduction.

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APPENDIX A

DETAILED LIFE CYCLE INVENTORY RESULTS

Scenario NA1: North American Natural Gas Processing and U.S. Primary and Secondary Petroleum Recovery and Processing (North America System 1)

Model Component	Value	Unit
Bell Creek EOR Field Data (used to scale all models)		
Operational Lifetime	25	Years
Net Carbon Dioxide (CO_2) Utilization	8.7	Mscf/bbl
Incremental Oil Recovery Factor	10.2%	%OOIP
Original Oil in Place (OOIP)	90	MMbbl
OOIP	90,000,000	bbl
Incremental Oil Recovered	9.2	MMbbl
Incremental Oil Recovered	9,180,000	bbl
Fugitive CO_2 Leakage Rate (surface losses)	2.0%	%
Bell Creek CO_2 Demand	81,463,320	Mscf
Bell Creek CO_2 Demand	81,463	MMscf
Natural Gas Extraction and Transport		
Ratio: Raw Natural Gas/CO_2 Captured and Transported		MMscf/MMscf
Raw Natural Gas Required	1,043,160	MMscf
Raw Natural Gas Extraction and Transport Emission Factor	3130	kg CO_2eq/MMscf
Emissions from Raw Natural Gas Extraction and Transport	3,265,554,755	kg CO_2eq
Emissions from Raw Natural Gas Extraction and Transport	356	kg CO_2eq/bbl
Natural Gas Processing		
Natural Gas-Processing Emission Factor (with capture)	2284	kg CO_2eq/MMscf
Emissions from Natural Gas Processing	2,383,082,466	kg CO_2eq
Emissions from Natural Gas Processing	260	kg CO_2eq/bbl
CO_2 Transport		
MMscf CO_2 Emitted from Electric Generation for Transport/MMscf Captured CO_2	0.00000	MMscf/MMscf
Emissions from CO_2 Transport	0	MMscf
Emissions from CO_2 Transport	0	kg CO_2eq
Emissions from CO_2 Transport	0	kg CO_2eq/bbl
Conventional Oil Gate to Gate		
Conventional Oil Emission Factor	56	kg CO_2eq/bbl
Emissions from Electricity Use, lifetime	514,080,000	kg CO_2eq
Downstream Crude Oil Pipeline, Refining, Transport to Point of Sale, and Combustion		
Emissions from Downstream	485	kg CO_2eq/bbl
Emissions from Downstream	4,452,300,000	kg CO_2eq
Life Cycle Emissions without Displacement	10,615,017,221	kg CO_2eq
Life Cycle Emissions without Displacement	1156	kg CO_2eq/bbl

Scenario-NA2: North American Natural Gas Processing with CO_2 Capture and U.S. EOR and Processing Using the Captured CO_2 (North America System 2)

Model Component	Value	Unit
Bell Creek EOR Field Data (used to scale all models)		
Operational Lifetime	25	Years
Net CO_2 Utilization	8.7	Mscf/bbl
Incremental Oil Recovery Factor	10.2%	%OOIP
OOIP	90	MMbbl
OOIP	90,000,000	bbl
Incremental Oil Recovered	9.2	MMbbl
Incremental Oil Recovered	9,180,000	bbl
Fugitive CO_2 Leakage Rate (surface losses)	2.0%	%
Bell Creek CO_2 Demand	81,463,320	Mscf
Bell Creek CO_2 Demand	81,463	MMscf
Natural Gas Extraction and Transport		
Ratio: Raw Natural Gas/CO_2 Captured and Transported	12.81	MMscf/MMscf
Raw Natural Gas Required	1,043,160	MMscf
Raw Natural Gas Extraction and Transport Emission Factor	3130	kg CO_2eq/MMscf
Emissions from Raw Natural Gas Extraction and Transport	3,265,554,755	kg CO_2eq
Emission Factor from Raw Natural Gas Extraction and Transport	356	kg CO_2eq/bbl
Natural Gas Processing		
Natural Gas-Processing Emission Factor (with capture)	798	kg CO_2eq/MMscf
Emissions from Natural Gas Processing	832,677,995	kg CO_2eq
Emissions from Natural Gas Processing	91	kg CO_2eq/bbl
CO_2 Transport		
MMscf CO_2 Emitted from Electric Generation for Transport/MMscf Captured CO_2	0.08427	MMscf/MMscf
Emissions from CO_2 Transport	6865	MMscf
Emissions from CO_2 Transport	130,777,949	kg CO_2eq
Emissions from CO_2 Transport	14	kg CO_2eq/bbl
Generic (Permian Basin) Gate to Gate		
Gate-to-gate Emissions, lifetime	855,131,754	kg CO_2eq
Gate-to-gate Emission factor, lifetime	93.2	kg CO_2eq/bbl
Downstream Crude Oil Pipeline, Refining, Transport to Point of Sale, and Combustion		
Emissions from Downstream	485	kg CO_2eq/bbl
Emissions from Downstream	4,452,300,000	kg CO_2eq
Life Cycle Emissions without Displacement	9,536,442,453	kg CO_2eq
Life Cycle Emissions without Displacement	1039	kg CO_2eq/bbl

Scenario-BC1: Shute Creek Natural Gas Processing and Bell Creek Conventional Oil Production (Bell Creek System 1)

Model Component	Value	Unit
Bell Creek EOR Field Data (used to scale all models)		
Operational Lifetime	25	Years
Net CO_2 Utilization	8.7	Mscf/bbl
Incremental Oil Recovery Factor	10.2%	%OOIP
OOIP	90	MMbbl
OOIP	90,000,000	bbl
Incremental Oil Recovered	9.2	MMbbl
Incremental Oil Recovered	9,180,000	bbl
Fugitive CO_2 Leakage Rate (surface losses)	2.0%	%
Bell Creek CO_2 Demand	81,463,320	Mscf
Bell Creek CO_2 Demand	81,463	MMscf
Natural Gas Extraction and Transport		
Ratio: Raw Natural Gas Extracted/CO_2 Captured and Transported		MMscf/MMscf
Raw Natural Gas Extracted	172,511	MMscf
Raw Natural Gas Extraction and Transport Emission Factor	3130	kg CO_2eq/MMscf
Emissions from Raw Natural Gas Extraction and Transport	540,034,912	kg CO_2eq
Emissions from Raw Natural Gas Extraction and Transport	59	kg CO_2eq/bbl
Shute Creek Natural Gas Processing (without capture)		
CO_2 Emitted/Raw Natural Gas Extracted	0.69	MMscf/MMscf
CH_4 (methane) Emitted/Raw Natural Gas Extracted	0.00	MMscf/MMscf
CO_2 Emitted	119,188	MMscf
CH_4 Emitted	15	MMscf
CO_2 Density	52,591	kg CO_2/MMscf CO_2
CH_4 Density	19,124	kg CH_4/MMscf CH_4
Emissions from Natural Gas Processing	6,278,050,336	kg CO_2eq
Emission Factor from Natural Gas Processing	36,392	kg CO_2eq/MMscf
Emission Factor from Natural Gas Processing	684	kg CO_2eq/bbl
CO_2 Transport		
MMscf CO_2 Emitted from Electric Generation for Transport/MMscf Captured CO_2	0.00000	MMscf/MMscf
Emissions from CO_2 Transport	0	MMscf
Emissions from CO_2 Transport	0	kg CO_2eq
Emissions from CO_2 Transport	0	kg CO_2eq/bbl
Bell Creek Gate to Gate (conventional)		
Conventional Oil Emission Factor	56	kg CO_2eq/bbl
Emissions from Electricity Use, lifetime	514,080,000	kg CO_2eq
Downstream Crude Oil Pipeline, Refining, Transport to Point of Sale, and Combustion		
Emissions from Downstream	485	kg CO_2eq/bbl
Emissions from Downstream	4,452,300,000	kg CO_2eq
Life Cycle Emissions without Displacement	11,784,465,249	kg CO_2eq
Life Cycle Emission Factor without Displacement	1284	kg CO_2eq/bbl

Scenario-BC2: Shute Creek natural gas processing with CO_2 capture and Bell Creek incremental oil production via EOR and the captured CO_2 (Bell Creek System 2)

Model Component	Value	Units
Bell Creek EOR Field Data (used to scale all models)		
Operational Lifetime	25	Years
Net CO_2 Utilization	8.7	Mscf/bbl
Incremental Oil Recovery Factor	10.2%	%OOIP
OOIP	90	MMbbl
OOIP	90,000,000	bbl
Incremental Oil Recovered	9.2	MMbbl
Incremental Oil Recovered	9,180,000	bbl
Fugitive CO_2 Leakage Rate (surface losses)	2.0%	%
Bell Creek CO_2 Demand	81,463,320	Mscf
Bell Creek CO_2 Demand	81,463	MMscf
Natural Gas Extraction and Transport		
Ratio: Raw Natural Gas Extracted/CO_2 Captured and Transported	2.12	MMscf/MMscf
Raw Natural Gas Extracted	172,511	MMscf
Raw Natural Gas Extraction and Transport Emission Factor	3130	kg CO_2eq/MMscf
Emissions from Raw Natural Gas Extraction and Transport	540,034,912	kg CO_2eq
Emission Factor from Raw Natural Gas Extraction and Transport	59	kg CO_2eq/bbl
Shute Creek Natural Gas Processing (with capture)		
CO_2 Emitted/CO_2 Captured and Transported	0.46	MMscf/MMscf
CH_4 Emitted/CO_2 Captured and Transported	0.00	MMscf/MMscf
CO_2 Emitted	37,725	MMscf
CH_4 Emitted	15	MMscf
CO_2 Density	52,591	kg CO_2/MMscf CO_2
CH_4 Density	19,124	kg CH_4/MMscf CH_4
Emissions from Natural Gas Processing	1,993,810,510	kg CO_2eq
Emission Factor from Natural Gas Processing	11,558	kg CO_2eq/MMscf
Emission Factor from Natural Gas Processing	217	kg CO_2eq/bbl
CO_2 Transport		
MMscf CO_2 Emitted from Electric Generation for Transport/MMscf Captured CO_2	0.08427	MMscf/MMscf
Emissions from CO_2 Transport	6865	MMscf
Emissions from CO_2 Transport	130,777,949	kg CO_2eq
Emission Factor from CO_2 Transport	14	kg CO_2eq/bbl
Bell Creek Gate to Gate		
Electricity Use (average over life cycle)	270	MWh/day
Electricity Use Emissions Factor	619	kg CO_2eq/MWh
Emissions from Electricity Use, lifetime	1,528,312,495	kg CO_2eq
Emission Factor from Electricity Use, lifetime	166	kg CO_2eq/bbl
Natural Gas Use	280	Mscf/day
Natural Gas Use Emissions Factor	11.2	kg CO_2eq/Mscf
Emission from Natural Gas Use, lifetime	28,698,140	kg CO_2eq
Emission Factor from Natural Gas Use, lifetime	3.1	kg CO_2eq/bbl
Emissions from Electricity + Natural Gas Use, lifetime	1,557,010,635	kg CO_2eq
Emission Factor from electricity + Natural Gas Use, lifetime	170	kg CO_2eq/bbl
Downstream Crude Oil Pipeline, Refining, Transport to Point of Sale, and Combustion		
Emission factor from Downstream	485	kg CO_2eq/bbl
Emissions from Downstream	4,452,300,000	kg CO_2eq
Life Cycle Emissions without Displacement	8,673,934,006	kg CO_2eq
Life Cycle Emissions Factor without Displacement	945	kg CO_2eq/bbl