International Journal of Greenhouse Gas Control 51 (2016) 369–379

Contents lists available at ScienceDirect

International Journal of Greenhouse Gas Control

journal homepage: www.elsevier.com/locate/ijggc

How green is my oil? A detailed look at greenhouse gas accounting for CO_2-enhanced oil recovery (CO_2-EOR) sites

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ARTICLE INFO

Article history:
Received 28 January 2016
Received in revised form 6 June 2016
Accepted 8 June 2016
Available online 21 June 2016

Keywords:
CO_2 storage
CO_2 utilization
Enhanced oil recovery
Life cycle analysis
Greenhouse gases
Global warming

ABSTRACT

This study presents the results of a detailed life cycle analysis of greenhouse gas (GHG) emissions associated with carbon dioxide-enhanced oil recovery (CO_2-EOR) where the CO_2 is sourced from a coal-fired power plant. This work builds upon previous investigations and integrates new information to provide more plausible ranges for CO_2 storage in the reservoir during CO_2-EOR. The system model includes three segments: upstream, gate-to-gate, and downstream processes. Our base case model using Ryan–Holmes gas separation technology for the CO_2-EOR site determined the emissions from upstream, gate-to-gate, and downstream processes to be 117, 98, and 470 kg CO_2e/bbl (CO_2 equivalents per barrel of incremental oil produced), respectively, for total emissions of 685 kg CO_2e/bbl. However, these emissions are offset by CO_2 storage in the reservoir and the resulting displacement credit of U.S. grid electricity, which results in a net life cycle emission factor of 438 kg CO_2e/bbl. Therefore, CO_2-EOR produces oil with a lower emission factor than conventional oil (~500 kg CO_2e/bbl). Optimization scenarios are presented that define a performance envelope based on the CO_2 capture rate and net CO_2 utilization and suggest that lower emission factors below 300 kg CO_2e/bbl are achievable. Based on these results, CO_2-EOR where the CO_2 is sourced from a coal-fired power plant provides one potential means for addressing the energy demand–climate change conundrum, by simultaneously producing electricity and oil to meet growing energy demand and reducing GHG emissions to abate global warming.

1. Introduction

World energy consumption continues to increase. Recent estimates of world total primary energy consumption in 2014 were 12,900 million tonnes of oil equivalent (Mtoe), or 5.4×10^{14} megajoules (MJ). This estimate is an increase of 0.9% from 2013 and 18% since the year 2004 (BP, 2015). Among the total primary energy supply (TPES), oil, coal, and natural gas accounted for 33%, 30%, and 24%, respectively, of the total energy portfolio in 2014, together representing 87% of the world's TPES (BP, 2015). TPES outlooks through the year 2035 suggest that the majority of the world energy supply will continue to comprise oil, coal, and natural gas, regardless of various policies under consideration (IEA, 2014). However, at the same time, concerns continue to mount over the threat of global climate change associated with carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions. Atmospheric CO_2 concentrations have increased by about 40% since preindustrial times, primarily from fossil fuel combustion. These increased atmospheric CO_2 concentrations are believed to create a positive radiative forcing, which results in an uptake of energy by the climate system, i.e., warming (Myhre et al., 2013). Mitigation measures for controlling climate change, therefore, all include some form of reduction in atmospheric CO_2 emissions. The result is that world TPES and climate change are juxtaposed – the world must develop global energy supplies to meet consumption demand but must simultaneously decrease CO_2 emissions. This conundrum presents a seemingly intractable societal challenge.

One proven technology that both produces oil and, through the process, permanently stores CO_2 in the subsurface is CO_2-enhanced oil recovery (CO_2-EOR). CO_2-EOR is most commonly a tertiary pro-

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http://dx.doi.org/10.1016/j.ijggc.2016.06.008
1750-5836/

duction phase process used after the primary and secondary oil production phases have been completed and refers to the process 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 50% 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 (DOE NETL, 2010a; Melzer, 2012; Azzolina et al., 2015). If the CO_2 that is used for CO_2-EOR is "captured" from a CO_2 emission source such as a coal-fired power plant, then the process helps mitigate CO_2 emissions because the gas will be injected into the subsurface and permanently stored rather than emitted to the atmosphere. The stored CO_2 will offset some portion of the emissions from production and combustion of the oil that is produced. This process is called carbon capture, utilization, and storage, or CCUS, and is one approach in a portfolio of GHG reduction technologies currently being pursued by the U.S. Department of Energy (DOE) (DOE NETL, 2012). As of 2014, a total of 136 active CO_2-EOR projects were identified in the United States (Koottungal, 2014), with forecasts predicting strong future growth (Kuuskraa and Wallace, 2014). Besides the United States, China and countries in the Middle East have expressed strong interest in using CO_2-EOR as part of a climate change mitigation strategy. Thus CO_2-EOR has the potential to partially address the energy demand–climate change challenge by producing oil with lower CO_2 emissions than oil generated by more conventional means of production. Sound policy decisions for supporting CCUS require a detailed assessment of the full life cycle CO_2 emissions of the CO_2-EOR process, which is the focus of this paper.

There are a number of studies that quantify the CO_2 emissions associated with CO_2-EOR. Several authors have summarized site-specific data from one or more particular oil reservoirs (Aycaguer et al., 2001; Khoo and Tan, 2006; Suebsiri et al., 2006; Fox, 2009; Jaramillo et al., 2009). While these works provide useful information with respect to evaluating the life cycle CO_2 emissions associated with CO_2-EOR, there are four primary issues that limit their use for policy decision making. First, methodological differences, primarily where the system boundaries are drawn or the functional unit of measure that is used, limit the ability to compare results across studies. Second, several of these studies lack transparency for the nonspecialist in life cycle analysis, which makes it difficult to both reproduce the work and incorporate the results into other analyses. Third, studies using modeled reservoir responses (as opposed to "real-world" or "measured" data) underestimate the amount of CO_2 that is stored in the subsurface associated with CO_2-EOR. This underestimation of CO_2 storage increases the net emission side of the accounting ledger. Fourth, several of these studies focus on the CO_2-EOR operations and do not evaluate the complete up- or downstream components and, therefore, do not quantify the full life cycle emissions from cradle to grave.

Over the past 5 years, DOE has published analyses of gate-to-gate GHG emissions for CO_2-EOR in the Permian Basin of West Texas (DOE NETL, 2010b) and, more generally, to quantify the environmental impacts of the various injection and recovery, gas separation, and bulk separation and storage processes associated with CO_2-EOR (DOE NETL, 2013a). The term "gate-to-gate" refers to the GHG emission balance specific to the CO_2-EOR field, without consideration for the upstream source of CO_2 or the downstream fate of the incremental oil that is produced. These works were later appended with up- and downstream sources of GHG emissions, finally incorporating gasoline combustion to assess the full life cycle (Marriott, 2013). Recently, Cooney et al. (2015) published a life cycle analysis of CO_2-EOR that builds on the earlier DOE methodology. The work rectifies most of the aforementioned limitations and presents a valid framework for analyzing the CO_2-EOR life cycle, integrating a detailed gate-to-gate model with a cradle-to-grave boundary. However, Cooney et al. (2015) identify one important data limitation, namely that oil recovery and CO_2 storage rates in their model are based on outputs of the CO_2 Prophet model, a legacy model developed by oil field experts as part of a DOE contract in 1986 (DOE NETL, 2015a). The authors note that the crude oil recovery ratio of the CO_2-EOR process, defined as barrels of produced crude oil per tonne of CO_2 stored, is a key parameter in determining the life cycle results for the CO_2-EOR supply chain. In their model, Cooney et al. (2015) use "current CO_2-EOR operations" and "advanced CO_2-EOR" estimates of 2.0 and 4.35 bbl/t CO_2, respectively, for the crude oil recovery ratios. Another limitation of Cooney et al. (2015) is that since the reservoir performance is dependent upon the CO_2 Prophet model outputs, the life cycle analysis is not fully integrated and, therefore, cannot easily be used by general practitioners to explore a variety of sites and scenarios for CO_2-EOR.

This work builds upon Cooney et al. (2015) by incorporating new information to address the data limitations of this previous study. We present a parameterized, cradle-to-grave life cycle analysis of incremental oil produced via CO_2-EOR. The inputs for the up- and downstream calculations rely on published sources from a thorough literature review. However, we integrate new information to provide more plausible ranges for CO_2 storage into the gate-to-gate CO_2-EOR analysis using the detailed statistical summary of reservoir performance data for 31 CO_2-EOR fields by Azzolina et al. (2015). We present a CO_2-EOR system where the CO_2 is sourced from a coal-fired power plant, which, in turn, displaces existing energy with the electricity coproduct. While CO_2 sourcing for most CO_2-EOR projects is currently from natural domes (i.e., not anthropogenic), we specifically explore an electricity–oil system where the CO_2 originates from a coal-fired power plant. Sourcing CO_2 from a natural gas dome would not receive credit for CO_2 storage in the reservoir because, in essence, all the CO_2-EOR process is doing is taking CO_2 from underground at the natural dome and re-storing it underground in the oil reservoir. In contrast, when sourcing CO_2 from an anthropogenic source like a coal-fired power plant, the CO_2 stored in the reservoir must be included in the overall life cycle GHG emission balance. Lastly, the model used in this analysis is fully integrated and was developed entirely in Microsoft Excel® (Excel) to improve transparency and provide a useful tool for other practitioners. This spreadsheet model may be expanded and refined as better information becomes available and is provided on the Web site of the Plains CO_2 Reduction (PCOR) Partnership, which is managed by the Energy & Environmental Research Center (EERC) of the University of North Dakota.

2. Materials and methods

2.1. System boundaries and scope

The system boundaries of our analysis are analogous to Cooney et al. (2015) and include emissions associated with three main parts of the CO_2-EOR life cycle: upstream, gate-to-gate, and downstream segments, which together comprise the cradle-to-grave system boundary (Fig. 1). These segments and the overall system are described in detail as follows. In the context of the GHG Protocol terminology, we include both direct emissions (Scope 1) associated with the unit processes for each segment and indirect emissions (Scope 2) associated with consumption of purchased electricity and natural gas for the CO_2-EOR gate-to-gate model. We do not include other indirect emissions (Scope 3) such as the extraction and production of purchased materials and fuels, outsourced activities, waste disposal, etc., that are not covered by Scope 2 (World Resources Institute, 2004).

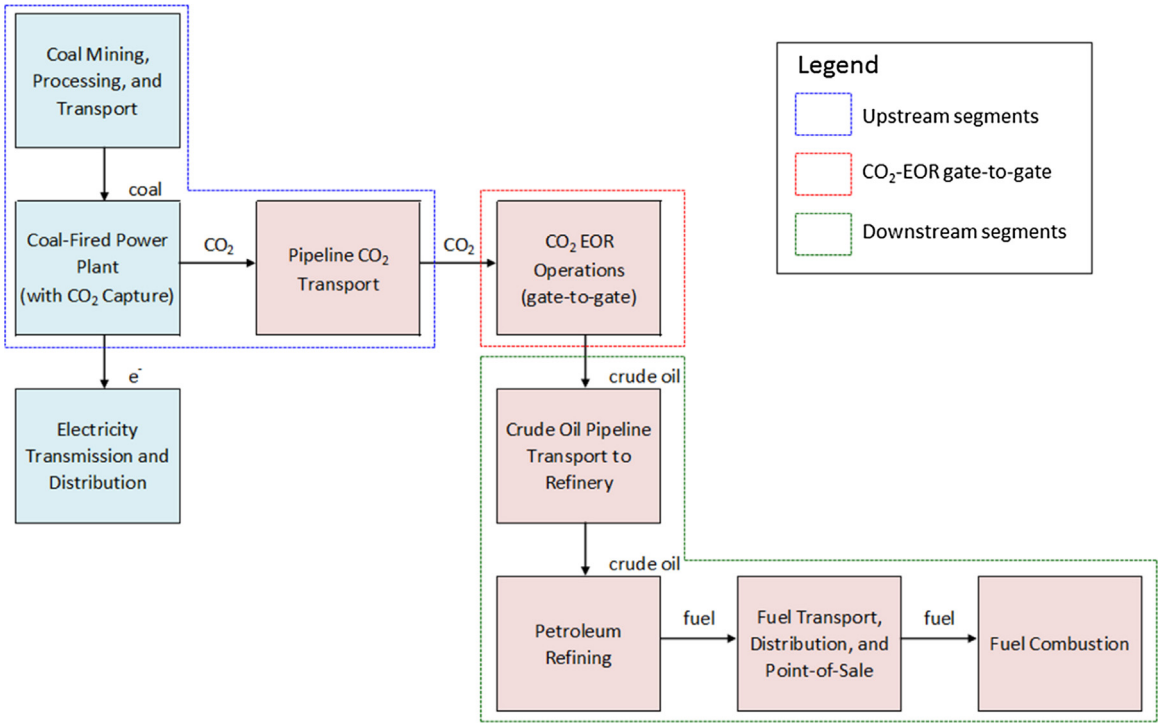

Fig. 1. System boundaries for evaluating the life cycle CO_2 emissions associated with CO_2-EOR.
[Source: Adapted from Cooney et al. (2015)]

2.2. Upstream segment

The upstream segment of the model includes three subsegments: coal mining, processing, and transport from the mine to the power plant; coal-fired power plant with CO_2 capture; and pipeline transport of the captured CO_2 from the power plant to the CO_2-EOR field (Spath et al., 1999; Rubin et al., 2007; Jaramillo et al., 2007, 2009).

2.2.1. Coal-fired power plant emissions

The coal-fired power plant emissions are derived from the higher heating value (HHV) and the carbon (C) content of the coal and the net conversion efficiency of the plant. HHV and carbon content estimates of four different types of coal are taken from Rubin et al. (2007): Pittsburgh No. 8 (bituminous, 8.57 kWh/kg [13,260 Btu/lb], 73.81% C); Illinois No. 6 (bituminous, 7.04 kWh/kg [10,900 Btu/lb], 61.20% C); Wyoming Powder River Basin (PRB) (subbituminous, 5.39 kWh/kg [8340 Btu/lb], 48.18% C); and North Dakota (ND) lignite (lignite, 3.89 kWh/kg 6020 Btu/lb], 35.04% C). This work evaluates a range of net conversion efficiencies from 29% to 36%, with an average value of 30%, to assess values that are representative of both pulverized coal (pc) and integrated gasification combined cycle (IGCC) plants with CO_2 capture, recognizing that the former typically has lower efficiency than the latter (IEA, 2007; Rubin et al., 2007; DOE NETL, 2013b). These HHV, carbon content, and efficiency values are used to estimate the CO_2 emission factor per unit of electricity (kWh) for each type of coal using the following relationship (The Engineering Toolbox, 2015):

$$EF_{CO_2,PP} = \frac{c_f}{h_f} \times \frac{C_{CO_2}}{C_m} \times \frac{1}{E_{net}} \quad (1)$$

where:

$EF_{CO2,PP}$ = power plant CO_2 emission factor (kg CO_2/kWh)
c_f = carbon content in the coal (kg C/kg fuel)
h_f = energy content of the coal (kWh/kg fuel)
C_m = molecular weight of carbon (kg/mol carbon)
C_{CO2} = molecular weight of carbon dioxide (kg/mol CO_2)
E_{net} = net conversion efficiency of the plant (fraction)

For example, using the Pittsburgh No. 8 bituminous coal of Rubin et al. (2007) and assuming their average value for net efficiency of 30% results in an emission factor of ([0.7381/8.57] × [44/12] × [1/0.30]) = 1.053 kg CO_2/kWh = 1053 kg CO_2/MWh. This CO_2 production per unit of electricity generation compares well with the base cases of 991 kg CO_2/MWh evaluated by Spath et al. (1999), 970 kg CO_2/MWh evaluated by Rubin et al. (2007), and 975 kg CO_2/MWh used by Jaramillo et al. (2007, 2009). We use this calculation approach to allow flexibility in assessing different types of coal and coal plant net conversion efficiencies.

CO_2 capture rates are assumed to range from 80% to 90%, with an average of 85% as reported by Rubin et al. (2007) for different power generation systems that they reviewed in conjunction with a Special Report by the Intergovernmental Panel on Climate Change (IPCC, 2005). Assuming an 85% CO_2 capture rate and using the average case above of 1053 kg CO_2/MWh results in 158 kg CO_2/MWh emitted to the atmosphere at the coal plant and 895 kg CO_2/MWh captured for use at the CO_2-EOR field (captured CO_2).

2.2.2. Coal mining, processing, and transport

Emission factors for coal mining, processing, and transport are taken from the ranges provided in Jaramillo et al. (2007) for upstream coal emissions (13–26 kg CO_2e/MWh), with an average value of 18 kg CO_2e/MWh taken from Jaramillo et al. (2009). Since these emission factors include methane (CH_4) emissions released from coal mining, they are expressed in units of CO_2 equivalents (CO_2e). The upper end of this range is comparable to the average upstream value for coal surface mining, processing, and transport used by Spath et al. (1999) in their life cycle assessment of coal-fired power production (26 kg CO_2/MWh). We use the more recently published ranges by Jaramillo et al. (2007, 2009) in this study. These emission factors must then be inflated by the coal plant net conversion efficiencies to account for the increased tonnage of coal required to produce each MWh of electricity. For example, using the

average emission factor of 18 kg CO_2e/MWh and an average value for net efficiency of 30% results in an adjusted emission factor of (18/0.30) = 60 kg CO_2e/MWh.

The amount of coal required to generate a unit of electricity (kWh) is related to the heat rate and HHV of the coal. The heat rate is defined as one unit of electricity (kWh = 3600 kJ/h) divided by the coal plant net conversion efficiency. For example, again using the average net conversion efficiency of 30%, the average heat rate is (3600/0.30) = 12,000 kJ/kWh. The amount of coal required to generate one kWh for this average case is then the heat rate divided by the HHV of the coal. Using the Pittsburgh No. 8 bituminous coal (HHV = 8.567 kWh/kg = 30,840 kJ/kg) requires (12,000/30,840) = 0.390 kg coal/kWh = 390 kg coal/MWh. CO_2 demand at the CO_2-EOR field (Section 2.4) drives upstream coal demand based on this relationship and the captured CO_2 emissions per MWh:

$$\text{kg coal required} = \text{purchased}CO_2\,(\text{kg}) \times \frac{\text{MWh}}{\text{captured kg}CO_2} \times \frac{\text{kg coal}}{\text{MWh}} \quad (2)$$

Continuing the previous examples, every 1000 kg (1 t) of purchased CO_2 would require (1000 × 1/895 × 390) = 436 kg of coal. Since 390 kg of coal generates one MWh, this amount of coal equates to roughly 1.1 MWh of electricity generation per 1000 kg of purchased CO_2.

2.2.3. CO_2 pipeline transport

The coal plant net conversion efficiency includes energy used to capture and compress CO_2 such that additional energy is not required prior to pipeline transport. However, energy is required to transport the CO_2 from the power plant to the CO_2-EOR field. To estimate this energy requirement, we use the same assumption as Jaramillo et al. (2009) that CO_2 will be transported between 100 and 1000 km, with an average distance of 500 km, which is comparable to the inputs used by Cooney et al. (2015) of 80, 402, and 885 km, respectively. We use data from McCoy (2008) who showed that 6.5 kWh of electricity is needed per tonne of CO_2 transported. In addition, we use the 2010 U.S. grid mix emission factor of 660 kg CO_2e/MWh (DOE NETL, 2015b).

Fugitive emissions from the pipeline transport of CO_2 were adjusted from fugitive emission factors for the pipeline transport of natural gas by applying a molar conversion from CH_4 to CO_2 (API, 2009):

$$EF_{CO_2,\text{pipeline}} = EF_{CH_4,\text{pipeline}} \times \sqrt{\frac{44}{16}} \quad (3)$$

where:

$\sqrt{\frac{44}{16}}$ = molar mass basis CH_4 to CO_2 conversion

$EF_{CH4,pipeline}$ = CH_4 natural gas pipeline leak emission factor (kg CH_4/km-yr)

$EF_{CO2,pipeline}$ = derived CO_2 pipeline emission factor (kg CO_2/km-yr)

We use emission factors assuming gas distribution using protected steel pipeline and based on direct measurements and statistics by Lamb et al. (2015). Average fugitive emissions from pipelines are assumed to be 45 kg CH_4/km-yr, which equates to 75 kg CO_2/km-yr (Eq. (3)). In addition, we also include emissions from pipeline servicing (inspection or pigging) of 2.2 kg CH_4/service-yr, which equates to 3.7 kg CO_2/service-yr (Eq. (3)) (Lamb et al., 2015), and we assume 10–20 services per year. The 95% upper confidence limits (UCLs) derived by Lamb et al. (2015) are used for the high estimate in our model (282 kg CO_2/km-yr and 5.5 kg CO_2/service-year).

Our model assumes an operational period of 20–30 years, with an average of 25 years. This estimate is supported by operational data for CO_2-EOR projects in the United States (Melzer, 2012; Azzolina et al., 2015).

2.3. CO_2-EOR gate-to-gate emissions

CO_2-EOR gate-to-gate emissions are associated specifically with CO_2-EOR field operations. We use the model and parameters taken from DOE NETL (2010b, 2013a) and Cooney et al. (2015) by incorporating pieces of 22 different Excel files from NETL's unit process library (DOE NETL, 2015b). Detailed descriptions of the CO_2-EOR gate-to-gate model may be found in those sources; a brief summary of the model is presented here.

The gate-to-gate model includes five key unit processes: (1) injection and recovery, (2) bulk separation and storage (gas–liquid separation, crude oil/natural gas liquids storage, and brine water storage and injection), (3) gas separation (refrigeration/fractionation, Ryan–Holmes, or membrane/amine separation), (4) supporting processes (e.g., venting and flaring, gas combustion for process heat), and (5) land use. The gas separation technology drives the electrical and natural gas needs of the CO_2-EOR facility and determines the percentages of natural gas liquids (NGLs) that are produced with the crude oil and separated during the gas–liquid separation process. There are differences in the diesel, natural gas, and electricity requirements among refrigeration/fractionation, Ryan–Holmes, and membrane/amine gas separation technologies. Therefore, analogous to DOE NETL (2013a), our model categorizes outputs for each of the three gas separation technologies. We do not differentiate between refrigeration-only and refrigeration with fractionation, as the energy needs for both systems are nearly identical.

The inputs to the gate-to-gate model include electricity delivered to the CO_2-EOR field by the electricity grid. We decouple the electrical needs for the CO_2-EOR field from the coal plant generating the captured CO_2 and use the 2010 U.S. grid mix emission factor of 660 kg CO_2e/MWh (DOE NETL, 2015b). While we could assume that the electricity originates from the same coal plant that is used to capture CO_2 for CO_2-EOR, thereby reducing the gate-to-gate emissions associated with electrical use at the field, this version of the model does not make that assumption.

Our gate-to-gate model inputs are comparable to DOE NETL (2013a) and Cooney et al. (2015), with one important exception: we inform the fluid balance for incremental oil recovery, crude oil recovery ratio, CO_2 recycle rate, brine production, and hydrocarbon gas production with real-world field performance results from 31 CO_2-EOR sites from Azzolina et al. (2015) (see Section 2.4).

2.4. Incorporating new information on CO_2-EOR performance

2.4.1. Crude oil recovery ratio and net CO_2 utilization

Cooney et al. (2015) showed that the crude oil recovery ratio of the CO_2-EOR process is not only the most sensitive parameter in their model but also a key in determining the life cycle results for the CO_2-EOR supply chain. In their work, they estimate a "low" (2 bbl/t CO_2) and "advanced" (4.35 bbl/t CO_2) crude oil recovery ratio; the low estimate is closer to U.S. operational data reported by Murrell and DiPietro (2013).

In our model, we use the results of a detailed statistical analysis of monthly reservoir performance data from 31 real-world CO_2-EOR sites summarized by Azzolina et al. (2015). The reservoir performance data were originally used to develop petroleum reserve estimates for the operators of the field and to prepare annual petroleum reserve certifications for filers with the U.S. Securities and Exchange Commission. These data include CO_2 injected and produced (recycled), incremental oil recovery, and water injected for each site. The sites in the data set reflect water alternating gas (WAG) CO_2 floods – all within the continental United

States and heavily dominated by West Texas carbonate floods. Other floods outside of this region, where the data were available, are also included (i.e., the Rocky Mountain region and the state of Oklahoma). Azzolina et al. (2015) used nonlinear regression techniques to extrapolate incremental oil recovery and net CO_2 utilization to 3.0 hydrocarbon pore volume (HCPV) injected and quantify the uncertainty in these estimates. Incremental oil recovery is expressed as a percentage of original oil in place (% OOIP). Net utilization is expressed in units of thousand standard cubic feet of CO_2 per stock tank barrel of oil produced (Mscf/bbl), which may be converted to tonnes CO_2/bbl by assuming 1 t of CO_2 per 19.25 Mscf at standard conditions of 101.4 kPa (14.7 psi) and 21.1 °C (70 °F) (DOE NETL, 2010a). Therefore, net utilization is simply the reciprocal of the crude oil recovery ratio with unit conversions. For consistency with oilfield terminology, we primarily use the term "net CO_2 utilization" in the text, with reference to the crude oil recovery ratio when necessary to compare our results to other works.

The 10th (P_{10}), 50th (median, P_{50}), and 90th (P_{90}) percentile estimates for incremental oil recovery and net CO_2 utilization at 3.0 HCPV as reported by Azzolina et al. (2015) are 5.3, 12.2, and 21.5% OOIP; and 4.8, 8.7, and 10.5 Mscf CO_2/bbl (249, 452, and 546 kg CO_2/bbl), respectively. The net utilization results may be converted to tonnes and then expressed as their reciprocal to define P_{10}, P_{50}, and P_{90} crude oil recovery ratios of 4.0, 2.2, and 1.8 bbl/t CO_2, respectively. A higher crude recovery ratio implies a more efficient CO_2 flood; therefore, the "advanced" value of 4.35 bbl/t CO_2 used by Cooney et al. (2015) applies to less than 10% of the sites analyzed (i.e., less than the P_{10}). Work by Jaramillo et al. (2009) assumes crude recovery ratios from 4.6 to 6.5 bbl/t CO_2, which applies to less than 2% of sites and greatly exaggerates the efficiency, which, in turn, significantly reduces the amount of CO_2 that is estimated to be stored in the reservoir. For example, a CO_2-EOR project that produces 500,000 bbl of incremental oil at a crude oil recovery ratio of 2 bbl/t CO_2 would store approximately 250,000 t of CO_2 in the reservoir (500,000 × 1/2), while a crude oil recovery ratio of 6 bbl/t CO_2 would only store approximately 83,000 t of CO_2 (500,000 × 1/6).

Azzolina et al. (2015) illustrate how the incremental oil recovery and net CO_2 utilization can be used to derive the mass of purchased CO_2 using the OOIP and incremental oil recovery factor via the following relationship:

$$\text{Purchased}CO_2 = \text{OOIP} \times \text{RF} \times \text{UF}_{\text{CO2net}} \quad (4)$$

where:

OOIP = original oil in place (bbl)

RF = incremental oil recovery factor (% OOIP)

$UF_{CO2,net}$ = net CO_2 utilization factor (kg/bbl)

Eq. (4) drives the entire carbon balance model from a user-provided estimate of OOIP, which, in turn, dictates the amount of incremental oil produced and, therefore, the purchased CO_2 requirement. That purchased CO_2 requirement then feeds back into Eq. (2), driving the MWh needed from the coal-fired power plant. Therefore, OOIP is an important input parameter in our model design.

2.4.2. Produced (recycled) CO_2

Azzolina et al. (2015) published results for CO_2 retention, which is a metric that expresses the fraction of total injected CO_2 at a CO_2-EOR facility that is not recycled but remains in the subsurface. Approximately 50% of the total injected CO_2 is produced together with the oil, separated, and recycled/reinjected, but nearly all (over 95%) of the purchased CO_2 delivered to the oil field is stored in the subsurface and remains securely trapped within the deep geologic formation (Melzer, 2012; Azzolina et al., 2015). This distinction between CO_2 retention (~50%) and CO_2 storage (~95%) is critical and is often a source of confusion during discussions of CO_2-EOR as a potential strategy for the geologic storage of anthropogenic CO_2.

The amount of recycled CO_2 is an important input for the gate-to-gate model because it affects the oil, gas, and brine separation and the gas-processing stages. CO_2 retention cannot be used directly to estimate the CO_2 recycle rate without knowing the total mass of CO_2 injected. However, the ratio of the *net* CO_2 utilization rate (i.e., the purchased mass of CO_2 injected per barrel of oil) to the *gross* CO_2 utilization rate (i.e., the total mass of CO_2 injected per barrel of oil) is equal to the CO_2 retention. Hence, we used the database of CO_2-EOR sites from Azzolina et al. (2015) to solve for a gross CO_2 utilization rate and then derived a recycle rate (where the recycle rate is the difference between gross and net CO_2 utilization):

$$\text{UF}_{CO_2,\text{gross}} = \frac{\text{UF}_{CO_2,\text{net}}}{\%\text{Retention}} \quad (5)$$

$$\text{UF}_{CO_2,\text{recycle}} = \text{UF}_{CO_2,\text{gross}} - \text{UF}_{CO_2,\text{net}} \quad (6)$$

where:

$UF_{CO2,gross}$ = total volume of CO_2 injected per barrel of oil (kg/bbl)

$UF_{CO2,net}$ = purchased volume of CO_2 injected per barrel of oil (kg/bbl)

%Retention = fraction of total injected CO_2 that remains in the subsurface (% OOIP)

$UF_{CO2,recycle}$ = volume of CO_2 recycled per barrel of oil (kg/bbl)

Based on this analysis, we determined the P_{10}, P_{50}, and P_{90} recycle rates at 3.0 HCVP to be 4.8, 8.8, and 13.8 Mscf CO_2/bbl (248, 458, and 718 kg CO_2/bbl), respectively. In essence, at approximately 50% CO_2 retention, the recycle rate is equivalent to the net CO_2 utilization rate. These recycle rates are incorporated into our gate-to-gate model. Our CO_2 recycle rates are less than half of those used by Cooney et al. (2015) under their crude oil recovery scenario of 2 bbl/t CO_2 (recycled CO_2 flow rate of 1223 kg CO_2/bbl). The main impact on the gate-to-gate model is that our model has lower electricity and natural gas demands associated with gas processing and the compression of recycled CO_2 prior to reinjection into the reservoir.

2.4.3. Brine production

The gate-to-gate model captures emissions from the electrical uses of pumps for brine injection associated with the WAG flood and injection of excess brine into disposal wells. While this represents a small fraction of the CO_2-EOR field GHG emissions (<3% of total emissions), we use correlations to capture brine mass and derive these electrical demands. DOE NETL (2013a) provides brine production and injection rates in units of kg brine/kg crude oil for crude oil recovery ratios of 2.0, 3.0, and 4.35 bbl/t CO_2. These estimates were derived using the CO_2 Prophet modeling by DOE NETL (2010b). We do not attempt to rerun the CO_2 Prophet model in this work. Instead, over this range of interest, the relationships between brine production and injection rates and crude oil recovery ratios were determined to fit power-law functions:

$$y = Cx^k \quad (7)$$

where:

y = brine production or injection rate (kg brine/kg crude)

x = crude oil recovery ratio (bbl/t CO_2)

C, k = coefficients determined by fitting the power-law function

Values of C and k for the brine production and brine injection were determined to be (56.7 and −1.0) and (52.2 and −1.0), respectively. These power-law functions were used in our model to estimate the brine mass for a given crude recovery ratio. For example, a crude oil recovery ratio of 2 bbl/t CO_2 would result in a brine production rate of $56.7 \times 2^{-1.0} = 28.3$ kg brine/kg crude oil and a brine injection rate of $52.2 \times 2^{-1.0} = 26.1$ kg brine/kg crude oil.

2.4.4. Hydrocarbon gas production

Hydrocarbon gas produced with the crude oil affects the gas recovery calculations and emissions from flaring. The mass of hydrocarbon gas produced per mass of crude oil as presented by DOE NETL (2010b) was also determined to fit a power-law function, with values of C and k of 0.62 and −1.0, respectively. This power-law function was used to estimate the mass of hydrocarbon gas produced for a given crude recovery ratio. For example, a crude oil recovery ratio of 2 bbl/t CO_2 would result in $0.62 \times 2^{-1.0} = 0.31$ kg hydrocarbon gas/kg crude oil.

2.4.5. Additional assumptions

We make two additional assumptions that affect the fluid balance for the gate-to-gate model. First, we assume a 2% loss of purchased CO_2 associated with surface losses (Melzer, 2012). Second, for consistency with DOE NETL (2010b, 2013a) and Cooney et al. (2015), we assume a 0.5% leakage rate of stored CO_2 from the reservoir over a 100-year period, with a range from 0% to 1%.

2.5. Downstream segments

Downstream segments include crude oil transport from the CO_2-EOR field to the refinery, refining of the crude oil, fuel transport and distribution from the refinery to point-of-sale, and combustion of the refined petroleum fuel. Analogous to Cooney et al. (2015), we use the baseline NETL petroleum-based transportation fuel model to account for the GHG emissions (DOE NETL, 2008), with exceptions as noted in the remainder of this section. DOE NETL (2008) includes five life-cycle stages: (1) raw material acquisition, (2) raw material transport, (3) liquid fuels production, (4) product transport and refueling, and (5) vehicle/aircraft operation. We effectively replace stage one with our gate-to-gate model and then apply GHG emission factors from DOE NETL (2008) for the remaining downstream segments.

2.5.1. Crude oil transport from the CO_2-EOR field to the refinery

Crude oil transport from the CO_2-EOR field to the refinery equates to DOE NETL's stage two (DOE NETL, 2008). The one-way energy intensity for crude oil transport by pipeline assumes 188 J/kg-km (5.2×10^{-5} kWh/kg-km) (DOE NETL, 2008; Wang, 2008). All crude oil transport via pipeline is assumed to be fueled by electricity. Pipeline distances are assumed to range from 800 to 1000 km, depending on whether the crude oil is transported from the Permian Basin in West Texas to the Cushing, Oklahoma, or Houston, Texas, areas for refining. The emission factor is again based on the delivered 2010 U.S. grid mix which has an emission factor of 660 kg CO_2e/MWh (DOE NETL, 2015b). Oil density assumes a range of API values for the Permian Basin from DOE NETL (2010b) of 32.5°–37.5° (863–837 kg m^{-3}), which is also consistent with the database used by Azzolina et al. (2015). These inputs result in an average emission factor for crude oil transport from the CO_2-EOR field to the refinery of 4 kg CO_2e/bbl.

2.5.2. Crude oil refining

Crude oil refining equates to DOE NETL's stage three. The DOE NETL (2008) life cycle model for stage three is complex. Rather than attempt to reproduce this model, we use summary data for domestic refineries to estimate CO_2, CH_4, and N_2O emissions per barrel of refined crude. These summary data are categorized by seven different refined fuel products (gasoline, diesel, kerosene and kerosene-based jet fuel, residual fuel oil, coke, light ends, and heavy ends) along with the fraction of the total refinery production associated with each type of product. We weighted each emission factor by the fraction of the total refinery production to derive the product-weighted average refinery emissions per barrel of crude oil. Emissions are expressed in CO_2e/bbl using the 100-year global warming potential (GWP) coefficients of 34 for CH_4 and 298 for nitrous oxide (N_2O) (IPCC, 2013). These inputs result in a product-weighted average emission factor for crude oil refining of 46 kg CO_2e/bbl.

2.5.3. Fuel transport and distribution from the refinery to point of sale

Liquid fuels are transported within the United States via five primary mechanisms: pipeline, ocean tanker, barge, railcar, and truck (DOE NETL stage four). We use the transport-weighted summary emission factor of 5 kg CO_2e/bbl, which includes CO_2 and 100-year GWP-adjusted CH_4 and N_2O emissions (DOE NETL, 2008).

2.5.4. Combustion of the refined petroleum fuel

Emissions from combustion of petroleum fuel are a complex interplay between fuel efficiency, the heating value of the fuel, vehicle use profiles, and several other factors. DOE NETL (2008) stage five focuses on gasoline, diesel, and kerosene/kerosene-based jet fuel. However, these fuels only account for approximately 77% of the total refined production, leaving out other fuels that are also combusted. Rather than analyze each fuel type and derive an emission factor for combustion, we assume that the carbon contained in crude oil is converted into CO_2 through the combustion of the fuel. We use the U.S. Environmental Protection Agency (EPA) Greenhouse Gas Equivalencies Calculator (EPA, 2015), which assumes the average heat content for crude oil of 6120 MJ/bbl, the average carbon coefficient for crude oil of 1.93×10^{-2} kg carbon/MJ, and 100% oxidation to derive an emission factor of 430 kg CO_2/bbl. Jaramillo et al. (2009) assume that 7% of the carbon per barrel of oil remains in noncombustible products (such as asphalt and petrochemical feedstocks). We, therefore, explore a range from 93% to 100% (400–430 kg CO_2/bbl), where the upper bound assumes that the organic content in the noncombustible products gets completely oxidized within the time frame of the study.

Assuming that the carbon content of the crude oil is oxidized to yield CO_2 emissions per barrel does not properly account for the combustion of fuels produced from the crude oil, as the refined products have different heat contents and, therefore, different amounts of energy per barrel of refined fuel. End use fuel efficiencies for combustion also differ, further complicating the comparisons. Therefore, we also evaluate the emissions specific to gasoline and diesel combustion to allow for direct comparison with conventional sources of these two fuels. We compare the CO_2-EOR life cycle GHG emissions per MJ of gasoline or diesel combusted against DOE NETL's baseline for conventional gasoline and diesel. Gasoline and diesel represent 45% and 23%, respectively, of the total refinery production in our model, so these liquid fuels make up the majority (68%) of refinery production in the United States (DOE NETL, 2008). For direct comparison between DOE NETL (2008) and our model, in calculating the life cycle GHG emissions for conventional gasoline and diesel, we use DOE NETL's results for stage one (raw material acquisition) but retain our CO_2-EOR life cycle model results for stages two (raw material transport) and three (liquid fuels production). We then use DOE NETL's stage four (product transport) and stage five (vehicle operation) to estimate GHG emissions from product-specific transport and combustion of the fuels in vehicles. These stage five calculations apply vehicle fuel efficiencies from the 2005 average U.S. fleet. Conversion from barrels of fuel to MJ of fuel combusted assumes 5159 MJ/bbl gasoline and 5813 MJ/bbl diesel (DOE NETL, 2008).

2.6. Coproduct displacement

There are two primary coproducts associated with our CO_2-EOR system: (1) electricity from the coal-fired power plant and (2) NGLs produced from the gas separation phase of the CO_2-EOR process.

Our allocation approach for electricity agrees with Cooney et al. (2015), who note that a MJ of electricity accounts for the efficiency losses of power generation, while, within the boundaries of this analysis, 1 MJ of combustion heat does not account for the efficiency of converting heat to useful work (i.e., 1 MJ electricity ≠ 1 MJ fuel combustion). We, therefore, allocate the electricity coproduct via displacement and assume 100% displacement of electricity, meaning that each new MWh produced displaces an existing MWh (i.e., a one-to-one replacement). The source of the existing MWh that is displaced is the average 2010 U.S. electricity grid mix, which has an emission factor of 660 kg CO_2e/MWh (DOE NETL, 2015b). We choose the 2010 U.S. mix as opposed to more current versions to maintain consistency with the natural gas and electricity grid mix used in the gate-to-gate model. As previously discussed, the coal plant that provides CO_2 to the oil field is decoupled from the electricity used by the field.

As previously noted, the generated CO_2 of the coal plant is 1053 kg CO_2/MWh and the CO_2 emitted to the atmosphere at the coal plant is 158 kg CO_2/MWh (under the 85% capture scenario). The avoided GHG emissions are then calculated by multiplying the electricity production of the coal plant by the average 2010 U.S. grid mix emission factor of 660 kg CO_2e/MWh and then performing the same calculation with the lower emission factor of 158 kg CO_2/MWh. The difference of approximately 502 kg CO_2/MWh is the amount of CO_2 emissions avoided. Since the primary product from our model is oil and not electricity, these avoided CO_2 emissions are then divided by the barrels of oil produced to express the displacement as an emission factor in units of kg CO_2/bbl.

There is an energy penalty and, therefore, a commensurate GHG emission penalty in moving from refrigeration/fractionation to Ryan–Holmes to membrane/amine gas separation technologies at the CO_2-EOR field. However, these processes recover increasing amounts of NGLs from the gas-processing output. These NGLs represent another coproduct of the CO_2-EOR process, which should be incorporated into the overall life cycle GHG emission balance. Our initial evaluation of displacement for NGLs suggests that it is de minimis; and, therefore, we do not include NGL displacement in the current version of the model.

2.7. Spreadsheet model

The individual components are combined in an Excel workbook. None of the cells are locked, and thus the user may modify all inputs to the model; however, the entire model runs off of two user-defined inputs: (1) coal type and (2) OOIP. The coal type is entered using a drop-down menu. The coal type determines the HHV and carbon content of the coal, which determines the CO_2 emissions per MWh of electricity generated at the plant. The OOIP may be entered as a continuous variable between 0 and +infinity. OOIP and the incremental oil recovery factor drive the volume of incremental oil produced, which determines the purchased CO_2 requirement, which, in turn, drives the MWh required from the coal-fired power plant (i.e., the entire upstream life cycle). Downstream emissions from crude oil transport, refining, and combustion are all directly related to the barrels of oil produced, which comes from the product of OOIP and the incremental oil recovery factor. Therefore, OOIP plays a significant role in the model.

The spreadsheet model works from upstream to downstream segments using line-by-line calculations in an accounting-style ledger to derive the component CO_2 emission factors expressed as both mass of CO_2 (kg) and mass of CO_2 per barrel of crude oil produced (kg CO_2/bbl). These summary statistics are pulled into a "dashboard" tab that summarizes the key outputs in a table and graph. The complete Excel model is available on the EERC's Web site at https://www.undeerc/pcor/technicalpublications/CO2-EOR-Life-Cycle_Analysis.aspx.

The base case model uses the expected value for each parameter input. This base case represents an estimate of the average CO_2-EOR site from Azzolina et al. (2015) and literature-based assumptions about average upstream and downstream emission factors. In addition to this base case, we include low and high estimates to bracket the plausible range given the underlying uncertainty in key input variables. By "low" we refer to low-end estimates of up- and downstream emission factors, higher CO_2 capture at the coal plant (90% capture), low power estimates for equipment that is used in the gate-to-gate model, and higher CO_2 storage in the reservoir (i.e., higher net CO_2 utilization [545 kg CO_2/bbl]), which together result in a lower-end member for life cycle GHG emissions. By "high" we refer to the opposite scenario, with high-end estimates of up- and downstream emission factors, low CO_2 capture at the coal plant (80% capture), higher power estimates for equipment in the gate-to-gate model, and low net CO_2 utilization (249 kg CO_2/bbl). The low and high estimates of net CO_2 utilization (249 and 545 kg CO_2/bbl, respectively) represent the P_{10} and P_{90} estimates, respectively, from Azzolina et al. (2015).

In addition to summarizing the low, expected, and high scenarios, we also conduct a sensitivity analysis to explore the change in the life cycle GHG emission estimates as a function of changing different input parameters in the model. We focus our sensitivity analysis on several key inputs, including type of coal, CO_2 capture rate, U.S. electricity grid mix emission factor, fugitive emission factor from CO_2 pipeline leakage, OOIP, incremental oil recovery factor, net CO_2 utilization, fugitive loss rate of purchased CO_2, and leakage rate of CO_2 from storage. Our sensitivity analysis modifies these inputs by ±5%, ±10%, and ±20% and then records the life cycle GHG emission factor of the model.

3. Results and discussion

3.1. CO_2-EOR GHG emission summary

We use an OOIP of 2.475 MMbbl in our base case so that an incremental oil recovery of 12.2% OOIP yields 302,000 bbl and therefore allows direct comparison to Cooney et al. (2015). A tabulated summary of the GHG emissions for key life cycle stages is provided in Table 1. The full dashboard output for the model, which itemizes the subsegments within each life cycle segment, is provided in the Excel spreadsheet model. In the base case model, upstream processes account for 117 kg CO_2e/bbl (17%–18% of the total emissions); the gate-to-gate process produces 77–117 kg CO_2e/bbl (12%–17% of the total emissions), depending on which gas-processing technology is used; and downstream processes account for 470 kg CO_2e/bbl (67%–71% of total emissions). The majority of these downstream emissions (88%) come from combustion of the oil. Total emissions from these three segments range from 664 kg CO_2e/bbl for refrigeration/fractionation to 704 kg CO_2e/bbl for membrane/amine recovery, with the Ryan–Holmes gas-processing technology falling in the middle at 685 kg CO_2e/bbl (Table 1).

3.2. CO_2 storage in the reservoir

In this electricity–oil system, the mass of CO_2 stored in the reservoir is equivalent to the mass of CO_2 captured from the coal-fired power plant minus fugitive losses and leakage from the reservoir. Adjusting for fugitive surface losses of purchased CO_2 (9 kg CO_2e/bbl) and leakage of CO_2 from the reservoir over a 100-year time frame (2 kg CO_2e/bbl), the net CO_2 stored in the reservoir for the base case is 441 kg CO_2e/bbl (Table 1). This net storage is directly proportional to the average net CO_2 utilization of 452 kg CO_2/bbl.

Table 1
Life-cycle summary of GHG emissions for CO_2-EOR showing key upstream, gate-to-gate, and downstream stages.

Model Segment	Low	Expected	High
Key Inputs			
Incremental oil produced (bbl)	302,000		
Net CO_2 utilization (kg CO_2/bbl)	545	452	249
Upstream (kg CO_2e/bbl)			
Coal mining, processing, and transport + coal-fired power plant + pipeline transport of CO_2	89	117	116
Gate-to-Gate (kg CO_2e/bbl)			
Land use + construction + well operations + oil, gas, and water separation + crude storage + brine storage	50	72	97
Gas processing via refrigeration/fractionation	3	5	7
Gas processing via Ryan–Holmes	14	26	41
Gas processing via membrane and amine recovery	26	45	69
Downstream (kg CO_2e/bbl)			
Crude transport by pipeline to refinery + crude oil refining + fuel transport to point of sale	55	55	56
Fuel combustion	400	415	430
Total Emissions Factor (kg CO_2e/bbl)			
Gas processing via refrigeration/fractionation	597	664	706
Gas processing via Ryan–Holmes	608	685	740
Gas processing via membrane and amine recovery	620	704	768
Reservoir Storage (kg CO_2e/bbl)			
CO_2 stored in the reservoir	545	452	249
CO_2 leakage from reservoir over 100-year time frame	0	2	3
Fugitive surface losses of purchased CO_2 over the project life cycle	6	9	10
Net CO_2 stored in the reservoir	539	441	236
Electricity Displacement			
Electricity generated (MWh)	210,676	155,595	90,007
U.S. 2010 grid electricity GHG emission factor (kg CO_2e/MWh)	660	660	660
Coal plant emission factor (with CO_2 capture) (kg CO_2e/MWh)	88	158	218
CO_2 emissions avoided (kg CO_2e)	120,506,672	78,108,690	39,783,094
CO_2 emissions avoided (kg CO_2e/bbl)	399	259	132
Net Life Cycle GHG Emission Balance (kg CO_2e/bbl)			
CO_2 emission factor, refrigeration/fractionation	204	416	587
CO_2 emission factor, Ryan–Holmes	215	438	621
CO_2 emission factor, membrane and amine recovery	227	456	649

3.3. Electricity coproduct displacement

Under the base case, approximately 156,000 MWh of electricity is generated to produce the purchased CO_2 requirements of the CO_2-EOR field over 25 years (Table 1). The electricity generated is directly proportional to the OOIP, incremental oil recovery, and net CO_2 utilization, which together drive the purchased CO_2 requirement. Using the emission factor for the 2010 U.S. electricity grid mix of 660 kg CO_2e/MWh and the emission factor of the base case coal plant with CO_2 capture of 158 kg CO_2e/MWh yields avoided CO_2 emissions of 502 kg CO_2e/MWh, which saves over 78 million kg CO_2 over the 25-year operational period, or 259 kg CO_2/bbl. This electricity displacement may then be subtracted from the total emissions described above to yield a net GHG emission factor ranging from 416 to 456 kg CO_2e/bbl, depending on the gas separation technology (Table 1). The life cycle emission factor for U.S. domestic crude oil is approximately 500 kg CO_2e/bbl (DOE NETL, 2008; Mangmeechai, 2009); therefore, on average, the incremental oil produced by CO_2-EOR where the CO_2 is sourced from a coal-fired power plant has a lower emission factor than conventional oil.

3.4. Comparison to gasoline and diesel from other sources

The preceding comparisons express life cycle GHG emissions normalized to the barrels of crude oil produced. The net results of comparing life cycle GHG emissions for gasoline and diesel fuel combustion are shown in Fig. 2. Life cycle GHG emissions for conventional gasoline and diesel are 92 and 90 g CO_2e/MJ fuel combusted, respectively. Despite the higher emissions associated with diesel, the higher energy content of the fuel (5813 MJ/bbl as compared to 5159 MJ/bbl for gasoline) results in nearly equivalent life cycle GHG emissions on an energetics basis. The life cycle GHG emissions for both gasoline and diesel produced from crude oil that is derived from CO_2-EOR with Ryan–Holmes gas separation are 78 g CO_2e/MJ fuel combusted (Fig. 2). These results are comparable to the per-barrel results shown in Table 1, but are now specific to the two liquid fuels that dominate U.S. refinery production and transportation.

3.5. Comparison to Cooney et al. (2015)

Our results are comparable to those of Cooney et al. (2015), which is to be expected because we use many of the same inputs and assumptions, particularly in the gate-to-gate and downstream segments of the model. Among their scenarios, Cooney et al. (2015) compare life cycle emissions for gasoline generated from crude oil that is derived from CO_2-EOR where the CO_2 is sourced from a supercritical pc plant. This scenario is directly comparable to our work. Cooney et al. (2015) show total emissions of ~125 g CO_2e/MJ gasoline combusted and displacement for electricity coproduct of ~40 g CO_2e/MJ gasoline combusted for a net life cycle emission factor of 86 g CO_2e/MJ gasoline combusted (Fig. 3 in Cooney et al., 2015). These results are very comparable to our model results for these components, which derive average total emissions of 128 g CO_2e/MJ gasoline combusted and displacement for electricity coproduct of 50 g CO_2e/MJ gasoline combusted for a net life cycle emission factor of 78 g CO_2e/MJ gasoline.

3.6. Uncertainty analysis

The low- and high-end estimates for the life cycle GHG emissions (including electricity coproduct displacement) for the

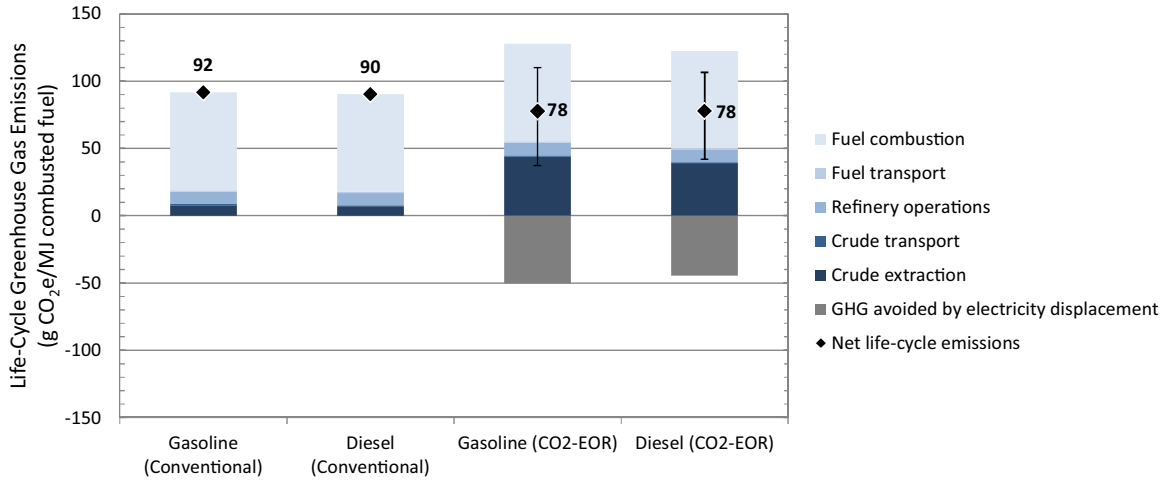

Fig. 2. Life cycle GHG emission summary factor expressed in g CO_2e/MJ combusted fuel for gasoline and diesel. Conventional gasoline and diesel emissions are taken from DOE NETL (2008). CO_2-EOR gasoline and diesel emissions use the outputs from the CO_2-EOR life cycle model for the Ryan–Holmes gas separation technology. GHG emissions avoided by electricity displacement are subtracted from the total emissions to yield the average net life cycle emissions (black diamond symbol). Error bars represent the low- and high-end member boundaries, as described in the text. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

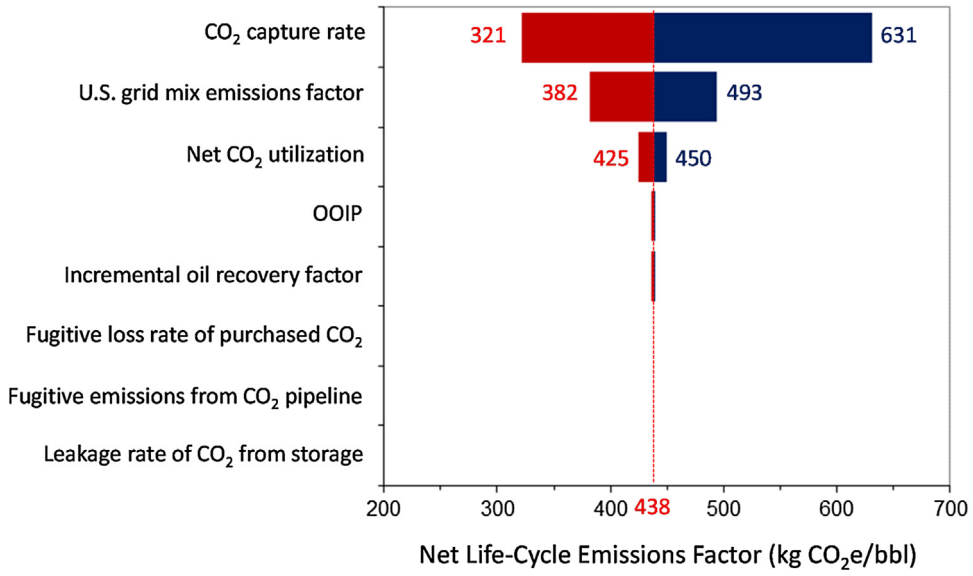

Fig. 3. Tornado diagram of the sensitivity analysis results for the life cycle GHG emission factor assuming a Ryan–Holmes gas separation technology for the CO_2-EOR field. The input variables on the *y*-axis are sorted from the most sensitive inputs at the top to the least sensitive inputs on the bottom. The base case model yields a net life cycle GHG balance of 438 kg CO_2e/bbl (red vertical dashed line). The *x*-axis shows the change in the net life cycle GHG emission factor as a function of a percent change in the input parameter from −20% to +20%. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Ryan–Holmes gas separation technology are 215 and 621 kg CO_2e/bbl, respectively (Table 1). These estimates are meant to illustrate extreme lower and upper bounds, recognizing that the most likely value is closer to the expected base case.

One counterintuitive result for the high-end estimate is that even though the emission factors of the unit processes are higher, the upstream emissions for the high estimate are commensurate with the base case. The reason for this is that the CO_2-EOR field is using less CO_2 in the high case (lower net CO_2 utilization); therefore, the upstream emissions decrease because the system does not need to generate as much electricity, which, in turn, means that the coal plant emissions and coal mining, processing, and transport are reduced as compared to the base case. This type of result underscores the importance of using a fully integrated life cycle model in this assessment, as the upstream, gate-to-gate, and downstream segments are interconnected and one segment cannot be modified without producing an effect on another.

3.7. Sensitivity analysis

Fig. 3 provides a tornado diagram summarizing the results of the sensitivity analysis assuming a Ryan–Holmes gas separation technology for the CO_2-EOR field. The input variables on the *y*-axis are sorted from the most sensitive inputs at the top to the least sensitive inputs on the bottom. The base case model yields a net life cycle GHG emission factor (including electricity coproduct displacement) of 438 kg CO_2e/bbl (red dashed vertical line). The *x*-axis of Fig. 3 shows the net life cycle GHG emission factor as a function of a percent change in the input parameter from the base case of −20% to +20%.

The most sensitive inputs are CO_2 capture rate, U.S. electricity grid mix emission factor, and net CO_2 utilization. A lower CO_2 capture rate means that the coal plant will have greater GHG emissions for each MWh of electricity produced. In addition, a lower CO_2 capture rate means that more electricity must be produced to supply the purchased CO_2 needs of the oil field, thus increasing upstream emissions. Lastly, a lower CO_2 capture rate yields less coproduct displacement, because there is a smaller difference between the electricity grid mix emission factor and the emission factor of the coal plant with CO_2 capture. Altogether, these effects result in higher life cycle GHG emissions when the CO_2 capture rate is low and vice versa when it is high. For example, a lower CO_2 capture rate of 68% produces oil with an emission factor of 631 kg CO_2e/bbl, whereas a higher CO_2 capture rate of 100% produces oil with an emission factor of 321 kg CO_2e/bbl (Fig. 3).

The electricity grid mix emission factor plays a significant role in coproduct displacement. When this electricity grid mix emission factor is low, there is a smaller difference between the electricity grid mix emission factor and the emission factor of the coal plant with CO_2 capture. As a result, a lower electricity grid mix emission factor results in higher life cycle GHG emissions and vice versa. A lower electricity grid mix emission factor of 528 kg CO_2/MWh produces oil with an emission factor of 493 kg CO_2e/bbl, whereas a higher electricity grid mix emission factor of 792 kg CO_2/MWh produces oil with an emission factor of 382 kg CO_2e/bbl (Fig. 3).

When the net CO_2 utilization is low, the oil field requires less CO_2 per barrel of oil produced. This results in less CO_2 storage in the reservoir which, therefore, offsets a smaller fraction of the total emissions produced by the electricity–oil system. As a result, lower net CO_2 utilization results in higher life cycle GHG emissions and vice versa when net CO_2 utilization is high. A lower net CO_2 utilization of 7 Mscf CO_2/bbl (364 kg CO_2/bbl) produces oil with an emission factor of 450 kg CO_2e/bbl, whereas a higher net CO_2 utilization of 10.4 Mscf CO_2/bbl (542 kg CO_2/bbl) produces oil with an emission factor of 425 kg CO_2e/bbl (Fig. 3). The primary reason why the system is not as sensitive to an increase in the net CO_2 utilization as it is to an increase in the CO_2 capture rate is that the additional CO_2 demand at the CO_2-EOR field increases upstream electricity generation and, therefore, overall upstream emissions, which offsets the additional CO_2 storage in the reservoir. The effect of net CO_2 utilization is, therefore, also sensitive to the CO_2 capture rate.

The model is largely insensitive to the other parameters: OOIP, incremental oil recovery factor, fugitive loss rate of purchased CO_2, fugitive emission factor from CO_2 pipeline leakage, and leakage rate of CO_2 from storage. Over the ±20% range used in the sensitivity analysis, changes to these parameters did not result in significant changes to the life cycle GHG emissions of the electricity–oil system.

Lastly, the coal type does affect the life cycle GHG emission balance, but only slightly. For the Ryan–Holmes gas separation technology, the life cycle GHG emissions for Pittsburgh No. 8, Illinois No. 6, Wyoming PRB, and ND lignite were 438 (base case), 440, 449, and 451 kg CO_2e/bbl, respectively. Although the Pittsburgh No. 8 has the highest carbon content (73.8%), it also has the highest HHV, which means that it takes less coal to generate the purchased CO_2 volume and combustion of that coal yields greater electricity coproduct. Conversely, while the ND lignite has the lowest carbon content (35%), it also has the lowest HHV, which means that it takes more coal to generate the purchased CO_2 volume and combustion of that coal yields less electricity coproduct. The net effect of coal type is approximately ±13 kg CO_2e/bbl. These results suggest that sourcing CO_2 for CO_2-EOR from a coal plant, regardless of the coal feedstock that is used at the plant, still produces incremental oil that has a lower emission factor than conventional oil.

3.8. Optimizing CO_2 capture and storage

As shown in Fig. 3, the three most sensitive parameters are the CO_2 capture rate, net CO_2 utilization, and U.S. electricity grid mix emission factor. In our base case model, we use an 85% CO_2 capture rate for the coal plant. However, design specifications of 90% CO_2 capture are often cited in the literature (Rubin et al., 2007; Jaramillo et al., 2009; Cooney et al., 2015); therefore, an argument could be made for exploring a higher CO_2 capture rate. With respect to net CO_2 utilization, an important point of clarification is that the 31 CO_2-EOR sites used by Azzolina et al. (2015) were designed to minimize CO_2 utilization to lower oil production costs. Most of these CO_2-EOR fields began flooding with CO_2 in the early 1980s. Therefore, the net CO_2 utilization estimates used in the current model represent lower-end estimates of CO_2 storage. Research suggests that CO_2 storage can be increased by making operational changes, leading to a higher net CO_2 utilization and an increase in the storage of CO_2 per barrel of oil produced (Ettehadtavakkol et al., 2014; Leach et al., 2011; van't Veld et al., 2013, 2014).

CO_2 capture rate and net CO_2 utilization and their interplay are important optimization design parameters in scoping-level studies of electricity–oil systems. For example, when the CO_2 capture rate is 90%, net CO_2 utilization rates of 10, 15, and 20 Mscf/bbl yield incremental oil with emission factors of 379, 317, and 256 kg CO_2e/bbl, respectively (assuming the base case U.S. electricity grid mix emission factor). Therefore, at high CO_2 capture and net CO_2 utilization rates, the electricity–oil system produces lower-emission oil; 256 kg CO_2e/bbl is approximately 50% of conventional oil. These model results show that the electricity–oil systems can be operated to produce both products (electricity and oil) at significantly reduced life cycle emission factors as compared to the status quo.

4. Conclusions

Our modeling results, which are informed with real-world reservoir performance data, show that crude oil produced from CO_2-EOR where the CO_2 is sourced from a coal plant results in lower-emission oil than conventional methods. As a result, CO_2-EOR provides one potential means for addressing the energy demand–climate change conundrum by simultaneously producing oil to meet growing energy demand and reducing GHG emissions to abate global warming.

It is likely that net CO_2 utilization for CO_2-EOR varies regionally by geologic basin and lithology (e.g., carbonate formations versus clastic reservoirs). Additional work is needed to quantify region- or geology-specific storage metrics such that national and global estimates of the CO_2-EOR potential may be calculated using the methods outlined in this paper. Further uncertainty quantification is also needed to provide statistical interval estimates (e.g., prediction intervals) for the likely performance ranges under specific design scenarios. Lastly, real-world data should be collected and used wherever possible in lieu of modeled results for more accurate estimates of GHG emissions associated with the life cycle upstream, gate-to-gate, and downstream processes for a particular oil field or geologic basin.

The model presented here provides a scoping-level evaluation of a combined electricity–oil system. These modeled results show that the optimization of key parameters such as CO_2 capture and net CO_2 utilization can produce oil with significantly lower emission factors than conventional oil. As projects move through the feasibility study and design stages, more site-specific data may be incorporated into the model to reflect actual coal supply chains, pipeline distances, and reservoir performance, all of which combine to provide more accurate estimates of the net reduction in GHG

emissions per MWh of electricity and barrel of crude oil produced by the electricity–oil system.

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Acknowledgment

This material is based upon work supported by the Department of Energy National Energy Technology Laboratory under Award Number DE-FC26-05NT42592.

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