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Life Cycle Inventory of CO_2 in an Enhanced Oil Recovery System

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Enhanced oil recovery (EOR) has been identified as a method of sequestering CO_2 recovered from power plants. In CO_2-flood EOR, CO_2 is injected into an oil reservoir to reduce oil viscosity, reduce interfacial tension, and cause oil swelling which improves oil recovery. Previous studies suggest that substantial amounts of CO_2 from power plants could be sequestered in EOR projects, thus reducing the amount of CO_2 emitted into the atmosphere. This claim, however, ignores the fact that oil, a carbon rich fuel, is produced and 93% of the carbon in petroleum is refined into combustible products ultimately emitted into the atmosphere. In this study we analyze the net life cycle CO_2emissions in an EOR system. This study assesses the overall life cycle emissions associated with sequestration via CO_2-flood EOR under a number of different scenarios and explores the impact of various methods for allocating CO_2 system emissions and the benefits of sequestration.

Introduction

Injection of CO_2 to increase oil recovery from mature fields, known as CO_2−flood enhanced oil recovery (CO_2−EOR), has been practiced commercially for nearly 40 years in the United States (*1*). As of 2008, there were approximately 100 CO_2−EOR projects operating in the U.S. producing close to 250 000 barrels of oil per day (BOPD), slightly less than 5% of total U.S. domestic oil production (*2, 3*). Recent assessments of the U.S. potential for CO_2−EOR vary somewhat in their assumptions and final estimates (*4*−*6*), but in general, conclude that if crude oil prices are between \$40 and \$60 per barrel incremental production from CO_2−EOR could be on the order of tens of billions of barrels of oil. As a result, billions of metric tons of CO_2 will be consumed and, if derived from anthropogenic sources and properly managed, could result in permanent sequestration of this CO_2 in oil reservoirs.

EOR is primarily motivated by the economic benefit of increased oil recovery. However, as concerns about climate change increase, CO_2−EOR is being suggested as a means of geologic CO_2 sequestration (*7*). Currently, approximately 50 million metric tons of CO_2 are consumed annually for EOR, the majority of which is produced from natural CO_2 accumulations, such as McElmo Dome (*3, 8*). The five largest accumulations of CO_2 in the U.S. originally contained approximately 5130 million metric tons of CO_2 and there remains large amounts of CO_2 available from these and other accumulations (*9*). Although these natural sources of CO_2 could provide the anticipated needs for CO_2−EOR, climate change could motivate the use of captured CO_2 from industrial facilities, such as power plants. It is likely that, under a cap-and-trade system, such as those being considered by the U.S. Congress (*10*), industrial facilities or oil producers will seek credit for CO_2 injected for EOR.

There have been a number of prior studies estimating the emissions associated with producing oil from CO_2 injection (*11*−*13*). These studies generally conclude that EOR projects using CO_2 captured from power plants can store significant amounts of CO_2 thus reducing the greenhouse gas impacts of power generation and oil production. These studies, however, have, for the most part, used boundaries that exclude emissions associated with the life cycle of power generation and downstream processing of produced crude oil. This study assesses the overall life cycle emissions associated with sequestration via CO_2−EOR under a number of different scenarios and explores the impact of various methods for allocating CO_2 system emissions and the benefits of sequestration.

Scope, Boundary, and Functional Unit. The goal of this study is to estimate the greenhouse gas emissions associated with using CO_2 captured from power plants for CO_2−EOR. We used guidelines set forth by the International Standards Organization in ISO 14040 (*14*). We include within the boundaries of our analysis the emissions associated with the: life cycle of the electricity generated within the power plant for CO_2 capture; transport of the CO_2 from the power plant to the field; oil extraction; transport of the crude oil produced in the field; crude oil refining; and, combustion of the refined petroleum products (Figure 1).

The boundaries of our analysis exclude transport of petroleum products from the refinery to the consumer. United States' refiners produce a number of products having different characteristics such as liquid fuels like gasoline and distillates, and solid materials like asphalt and coke. The transport needs of the refined products differ greatly bringing large uncertainties associated with calculating the total transport emissions of all the refined products. According to the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model emissions from transporting gasoline and diesel fuel derived from conventional sources represent a small percentage (approximately 1%) of the life cycle emission factors of these fuels (*15*), so ignoring these transport emissions may slightly underestimate the emissions associated with an EOR system, but is not expected to significantly affect the results or the interpretations presented in this paper. Our study's boundary also excludes any emissions associated with the construction of the physical infrastructure needed for these projects.

This paper explores a number of different alternatives for determining the impact of the CO_2−EOR. As such the functional unit varies. It is defined as the entire project when looking at net emissions, a barrel of oil when analyzing allocation by energy and price or using system expansion and oil as the primary product, and a kWh of electricity when using system expansion with electricity as the primary product.

Methods and Data Sources

CO_2−EOR Projects Modeled. For this study five CO_2−EOR projects are used as case studies (Table 1). Data for four of these cases—Northeast Purdy, SACROC, Ford Geraldine, and

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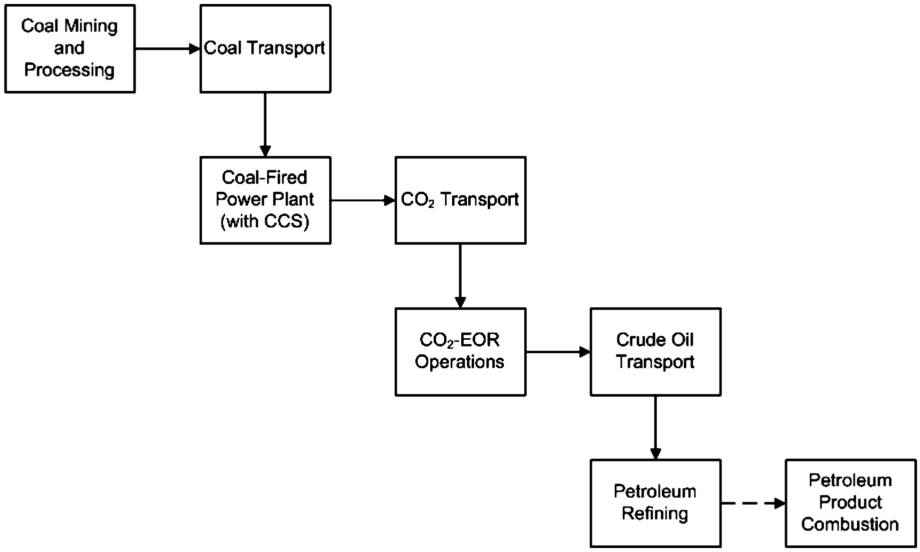

FIGURE 1. Boundary of EOR system.

TABLE 1. CO_2−EOR Project Performance Characteristics

case	Northeast Purdy Unit	SACROC Unit, Kelly Snyder Field	Ford Geraldine Unit	Joffe Viking Unit	Weyburn Unit
reference	*13*	*13*	*13*	*13*	*14*
project lifetime (yrs)	9[a]	21[a]	8	17[a]	15[a]
incremental oil recovered (million STB)	36	402	13	23	130
total CO_2 purchased (million metric tons)	6.2	87.5	2.37	3.6	20

[a] Currently operational.

Joffre Viking—were taken from McCoy (*1*) and the fifth from Suebsiri et al. (*11*). Three of these cases studied by McCoy—Northeast Purdy, SACROC, and Joffre Viking—are operating projects. McCoy applied a semianalytical model to estimate the amount of incremental oil recovered, CO_2 injected, and CO_2 purchased at the end of the project life in four cases, based on the field's published geology and oil properties (e.g., permeability, porosity, depth, oil gravity, and viscosity, etc.) (*1*). The actual performance of these four projects may differ somewhat from the modeling results due to assumptions about each field's development schedules and economics. The fifth field, the Weyburn Unit, is a CO_2−EOR project in the province of Saskatchewan, Canada that uses CO_2 captured from production of synthetic natural gas in North Dakota (*11*). We used published values for the incremental oil recovered, CO_2 injected, and CO_2 purchased but substituted CO_2 captured from electricity generation for the CO_2 currently used at Weyburn.

None of these projects are currently using CO_2 captured from electric power plants. However, the CO_2 source will have little bearing on the overall performance of the project. Most power generation processes will produce streams, which are predominantly CO_2 when dried. Trace impurities, such as H_2S and N_2, will have an effect on the minimum miscibility pressure for the reservoir oil, and the CO_2 capture process will have to provide CO_2 of acceptable quality (see, for example Yellig (*16*)). Thus, in some cases, this will require additional gas cleanup after CO_2 capture to remove trace impurities (*17, 18*). It is also important to note that the lifetime of the projects and the amount of oil recovered varies greatly case-by-case, and that the lifetime is a function of the prevailing oil price, CO_2 cost, and operating cost for a project. The CO_2 emissions presented in the following sections will be the total CO_2 emissions during the lifetime of each case as shown in Table 1.

Life Cycle Emissions of Fuels Used within the System Boundary. Many different fuels are used as energy within the system boundary. This energy is used to operate machines, equipment and vehicles for operations used to mine coal or drill oil wells. The fuels include coal, natural gas, electricity, residual oil, etc. It was assumed that the electricity used during operational activities (CO_2 transport, CO_2 compression during transport, etc.) was derived from the U.S. grid since "use" could be spatially separated from the electricity generator providing the CO_2. From a previous analysis we determined the life cycle emissions factor for average U.S. electricity, including a penalty of 9% for transmission losses, to be 712 kg CO_2e/MWh (*19*),. The development of the emissions factor for the electricity generated at the power plant where the CO_2 for the EOR projects is captured is described in the next section. Supporting Information (SI) Table S1presents the life cycle GHG emission factors of other major fuels used within the system boundary.

Electric Power Plant with CO_2 Capture, and CO_2 Transport via Pipeline. We assumed that the CO_2 used in the projects was produced at a integrated coal gasification combined cycle (IGCC) power plant that uses eastern U.S. bituminous coal and that captures 90% of the CO_2 emissions via a water shift reactor and a Selexol unit. This plant is assumed to have an efficiency of 32% (HHV) (*20, 21*). Details about the capture process and costs of this plant can be found in Rubin et al. (*21*). The upstream GHG emissions are associated with the coal life cycle from coal mining, processing, and transport (Figure 1). According to Jaramillo et al. (*19*), average emissions from coal mined, processed, and transported in the U.S. is 4.99 g CO_2e per MJ. These emissions include methane emissions released from coal mining. The coal was assumed to be a U.S. bituminous coal with a combustion emission factor of 88 g CO_2 per MJ (*22*). As

TABLE 2. GHG Emissions from Coal Upstream, Coal Power Plant, and CO_2 Transport Associated with the Production of Injected CO_2

process	case				
	Northeast Purdy Unit	SACROC Unit, Kelly Snyder Field	Ford Geraldine Unit	Joffe Viking Unit	Weyburn Unit
electricity[a] (million MWh)	7.0	99.7	2.7	4.1	22.7
CO_2 from coal power plant (million metric tons CO_2e)	6.9	97.1	2.6	4.0	22.1
power plant upstream emissions (million metric tons CO_2e)	0.4	5.5	0.15	0.23	1.25
CO_2 transport (million metric tons CO_2e)	0.03	0.41	0.01	0.02	0.09

[a] The electricity attributed to the CO_2−EOR project is calculated based on the amount of CO_2 purchased.

TABLE 3. GHG Emissions from Oil Production, Transport, Refining, and Combustion

case	crude oil production emissions (million metric tons CO_2e)	crude oil transport emissions (million metric tons CO_2e)	refinery emissions (million metric tons of CO_2e)	petroleum product combustion emissions (million metric tons of CO_2e)
Northeast Purdy Unit	2.03	0.09	1.80	14.2
SACROC Unit, Kelly Snyder Field	22.7	0.98	20.1	159
Ford Geraldine Unit	0.73	0.03	0.65	5.12
Joffe Viking Unit	1.30	0.05	1.15	9.07
Weyburn Unit	7.35	0.32	6.51	51.2

previously mentioned, a 32% (HHV) plant efficiency was assumed for the coal plant, resulting in 55 kg CO_2e/MWh for upstream emissions and 975 kg CO_2/MWh produced at the power plant. Assuming a 90% carbon capture rate (*20, 21*), 97.5 CO_2/MWh are emitted to the atmosphere, and 878 kg CO_2/MWh are captured for CO_2 EOR use. Based on the CO_2 consumption needed for the CO_2−EOR projects previously presented, Table 2 provides details for the total CO_2e emissions associated with the power plant where CO_2 is captured. The amount of CO_2 used in the Northeast Purdy, Ford Geraldine, and Joffre Viking fields is less than 20% of the projected CO_2 sequestered from a coal power plant (with 90% CCS) with a 500 MW nameplate capacity operating at 85% for the duration of the EOR projects. We assume, however, that these plants are capturing 90% of their CO_2, and the excess CO_2 not sent to the EOR projects is being sent to aquifer sequestration projects (thus these excess CO_2 is not accounted in our system boundary). The Weyburn and SACROC fields would use 50% and 115% (respectively) of the CO_2 captured in such a coal power plant for the projected duration of the EOR projects.

The coal power plant efficiency (32% HHV) includes energy used to capture and compress CO_2 to a pressure sufficient for pipeline transport. The efficiency of the reference power plant (without CCS) is 37% (HHV), which constitutes a 14% reduction in power output per unit of energy input (*20, 21*). From the power plant, the CO_2 is then transported to the EOR project via pipeline. For pipeline transport over short distances (less than 100 km), we assume that no additional energy from what is used at the power plant to compress the CO_2 (and which is included in the efficiency of the power plant) is required for pumping (*23*). For longer pipeline transport (1000 km), 6.5 kWh of electricity are needed per metric ton of CO_2 transported for pumping (*1*). We assumed that CO_2 for the analyzed projects travels between 100 and 1000 km and that the life cycle emission factor of the electricity used is 712 kg CO_2e/MWh, including a 9% transmission loss penalty (*19*). The emissions associated with the transport of the CO_2 are estimated, as presented in Table 2.

Emissions from EOR Field Operations, Crude Oil Transport, Crude Oil Refining, and Petroleum Product Transport. Emissions from the production of crude oil in the U.S. average 9 g CO_2e per MJ (*24−26*). Managing the CO_2 used in the field (that is, injecting it and then separating it from the oil extracted so it can be reinjected) requires 1.78 kWh of electricity per bbl of oil recovered (*27*), which results in additional emissions associated with the oil recovered in EOR fields. These additional emissions were calculated using and average life cycle emission factor of 712 kg CO_2e/MWh for the electricity used (as previously described) (*19*). Adding these emissions results in the total emissions associated with the operation of the fields, as shown in Table 3.

Crude oil is transported via pipeline from the field to the refinery with an energy intensity of 181 J/kg-km. This transport energy is supplied by diesel (20%), residual oil (50%), natural gas (24%), and electricity (6%) (*28*). The life cycle emission factors for the fuels used can be seen in SI Table S1. The life cycle emission factor for electricity used is 712 lb CO_2e/MWh (*19*). It is also assumed that crude oil travels an average of 1200 km from the field to the refinery (*28*), which is the average distance crude oil travels in the U.S.

The Energy Information Administration (EIA) maintains records of crude oil throughput and fuel use during operations (*29*). Refinery hydrogen, not reported by EIA, is used in significant amounts and is generally produced from fossil fuels. Wang (*30*) estimated the amount of natural gas needed to produce the hydrogen required for refining. Based on EIA's refinery input data, and the natural gas for hydrogen production data, fuel use per barrel of crude oil input was calculated as shown in SI Table S2. Furthermore, these fuel consumption data, combined with the life cycle emission factors of the fuels, presented in SI Table S1, was used to determine total emissions from refining the crude oil produced in the EOR projects, as shown in Table 3.

Using EIA refinery output data (*31*), it was estimated that 93% of the carbon contained in crude oil refined in the U.S. is converted into CO_2, through the combustion of petroleum products sold by refineries. The remaining 7% of the carbon remains in noncombustible products (such as asphalt, and petrochemical feedstocks). The average carbon content and

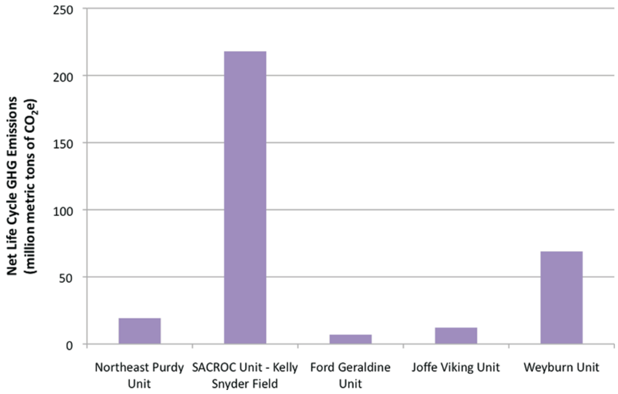

FIGURE 2. Net life cycle GHG emissions during project lifetime.

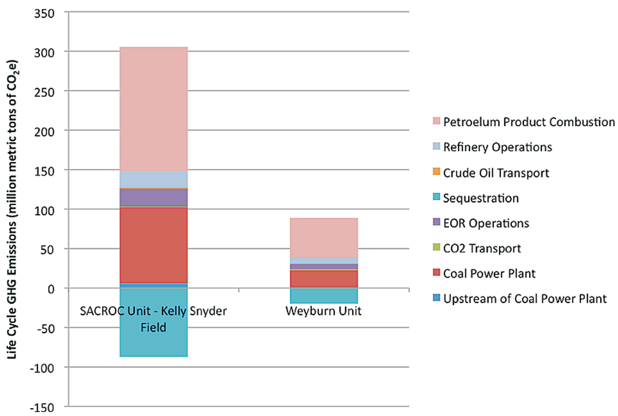

FIGURE 3. Sources of GHG emissions for SACROC Unit and Weyburn Unit.

heat content of crude oil going into U.S. refineries is 19.17 Tg C/EJ and 6120 MJ/bbl respectively (*22*). Using these numbers the total emissions from the combustion of petroleum products derived from the crude oil produced in the different EOR projects are estimated, as shown in Table 3.

Results and Discussion

First we look at the overall CO_2 emissions for the CO_2−EOR projects. Here we are viewing the system as a stand-alone project to determine if the "atmosphere" will ultimately see a reduction is CO_2 from sequestration. Allocation of these emissions will be discussed below. Figure 2 shows the net GHG emissions for each modeled CO_2−EOR project and includes the life cycle of the electricity generated at the coal power plant where CO_2 is captured; transport of the CO_2 from the power plant to the field; oil extraction; transport of the crude oil produced in the field; crude oil refining; and combustion of the refined petroleum products. The net emissions from the systems are positive meaning that the GHG emissions are larger than the CO_2 injected and stored in the reservoir. The SACROC Unit, Kelly Snyder and the Weyburn Unit cases have the largest net emissions.

Figure 3 shows the sources of these emissions for the two larger fields. The largest source of CO_2 emissions is related to the ultimate combustion of petroleum-derived products and by itself is larger than the emissions offset by CO_2 sequestration. The relative contribution of each emissions category shown in Figure 3 is consistent with the other three cases, as can been seen in SI Figure S1.

We calculated that between 3.7 and 4.7 metric tons of CO_2 are emitted for every metric ton of CO_2 injected. The fields currently inject and sequester less than 0.2 metric tons of CO_2 per bbl of oil produced. In order to entirely offset system emissions, e.g., making the net CO_2 emissions zero, 0.62 metric tons of CO_2 would need to be injected and permanently sequestered for every bbl of oil produced. The only way to sequester this amount of CO_2 would be to operate a sequestration project concurrently with the CO_2−EOR project. For example, instead of recycling produced CO_2, as in typical CO_2−flood EOR projects, produced CO_2 could be reinjected into the water leg of the same formation (as practiced at the In Salah project (*32*)) or into another nearby appropriate geological formation.

Allocation of Emissions. In the previous section, the total project lifetime emissions were presented. Allocation of the emissions to the different products produced within the system boundary (crude oil and electricity) is a common element of the life cycle assessment framework and is explored here. Allocation becomes important in determining who gets credits or debits for the emissions and prevents double counting. In this case coal-fired power plants produce CO_2 used by oil companies to recover petroleum. Some CO_2 remains in the reservoir and these amounts can be credited to the product life cycle for either electricity or crude oil, lowering the product's CO_2 emissions.

Several allocation methods are described: allocation by energy content of the products, economic value of the products, and by system boundary expansion. The SACROC case, which had the largest oil production and associated GHG emissions of the CO_2−EOR projects assessed, was chosen to investigate the utility of these allocation methods.

For the economic value allocation two cases were analyzed. For the first case, the average 2008 refiner acquisition price of crude oil ($95/bbl) and the average price paid by all electric consumers in 2008 ($98/MWh) were used (*33*). Oil prices are highly volatile, so a second economic value allocation case was analyzed with price data for January of 2009: $37.5/bbl oil and $98/MWh electricity (*33*).

For the system boundary allocation method, two cases are presented: one in which oil is the primary product and receives emission credits for electricity displaced; and another where electricity is the primary product and receives emission credits for oil displaced. System expansion requires all CO_2 emitted from within the system boundary to be allocated to the primary product. The coproduct, now carbon free, can offset an equivalent product produced in another way. Whatever CO_2 would have been emitted in the displaced process can be subtracted from the CO_2 allocated to the primary product if the displacement efficiency is 1, i.e., a 1 to 1 replacement. If the displacement efficiency is different than 1 then the amount of CO_2 credit can be scaled appropriately. In the cases discussed here the displacement is equivalent, a kWh of electricity replaces a kWh of electricity produced by a variety of means shown in Table 4 or a bbl of crude oil replaces another bbl of crude oil. The emission factors of the energy sources displaced (which were used to give an emission credit) are presented in SI Table S3.

The current U.S. electricity mix has an estimated life cycle GHG emission's factor of 655 kg CO_2e/MWh, not including the penalty for transmission loses (*19*). The U.S. average life cycle emission's factor for crude oil, excluding petroleum product transport is 530 kg CO_2e/bbl (*26*). Using energy content allocation, the electricity generated within the study's system boundary has almost 60% lower emissions than current electricity, whereas oil produced within the system boundary has 10% lower emissions than current oil. Economic value allocation is more complicated due to the volatile nature of oil prices. When oil prices are higher, more emissions are allocated to oil than when oil prices are low. It can be seen in Table 4 that using economic allocation oil can have emission factors between 20% lower than current oil (when oil is cheap) and 40% lower than current oil (when oil is more expensive). Similarly, electricity can have emission

TABLE 4. Life Cycle GHG Emission Factors for Electricity and Crude Oil Under Different Allocation Scenarios

allocation method		electricity emission factor (kg CO_2e/MWh)	crude oil emission factor (kg CO_2e/bbl)
current emissions (*19, 26*)		655	530
allocation by energy		280	475
allocation by $ ($95/bbl oil and $98/MWh electricity)		450	430
allocation by $ ($37.5/bbl oil and $98/MWh electricity)		860	330
Allocation by System Boundary Expansion: Oil as Primary Product			
electricity displacement	current mix	NA	380
	low carbon sources[a]	NA	540
	pulverized coal	NA	330
	IGCC	NA	320
	NGCC[b]	NA	440
Allocation by System Boundary Expansion: Electricity as Primary Product			
oil displacement	U.S. domestic crude oil	44.3	NA
	Canadian crude oil	77.1	NA
	Saudi crude oil	86.2	NA
	Canadian SCO[c] (in situ)	−230	NA
	Canadian SCO[c] (mining)	−190	NA
	Venezuelan crude	1.86	NA
	Mexican crude	−52.2	NA

[a] Low carbon sources include wind, solar, nuclear, and other renewables. [b] Natural gas was domestically supplied. [c] Synthetic crude oil derived from oil sands.

TABLE 5. Comparison of Emission Produced in EOR System and Emissions from Producing Oil and Electricity with Other Sources

field		Northeast Purdy Unit	SACROC Unit, Kelly Snyder Field	Ford Geraldine Unit	Joffe Viking Unit	Weyburn Unit
net EOR System Emissions (million metric tons CO_2e)		19	220	7.0	12	69
emission from oil and electricity produced with other sources	current oil, current electricity emissions (million metric tons CO_2**e**)	24	280	8.6	15	84
	IGCC and Canadian SCO (in-situ) (million metric tons CO_2**e**)	30	330	10	17	98
	low carbon electricity and Saudi Arabian oil (million metric tons CO_2e)	19	210	6.8	12	68

factors between 30% lower than current electricity (when oil is expensive) and 30% higher than current electricity (when oil is cheap).

When system expansion is used and oil as the primary product the CO_2 allocated to the oil can be offset by a variety of sources of electricity ranging from low carbon electricity to carbon intensive coal-based (Table 4). If low carbon electricity is displaced, then the CO_2 intensity would actually increase by 3% compared to current oil CO_2 intensity. If pulverized coal or IGGC were displaced then the life cycle emissions could be reduced by about 40%, resulting in a "low carbon" crude oil.

The second system expansion assumes that the electricity generated is the primary product and is allocated all of the system emissions. The CO_2 reductions for the electricity could range from an 82% compared to the current average electricity CO_2 emissions factor if Saudi crude oil is displaced, to basically carbon free electricity if unconventional sources are displaced. Negative emissions factors that appear in Table 4 using this allocation method simply indicate that there is greater offset potential than the CO_2 generated within the system boundary.

Allocation methods are "accounting tools." It is obvious from the results in Table 4 that changes in approach can result in completely different results. However, with the exception where system expansion using crude oil as the primary product and offsetting a low carbon electricity source, all of the methods result in electricity and/or crude oil with reduced CO_2 emissions.

It is important that both power generators and oil producers use a consistent method when using allocation. Additionally, allocation by system boundary expansion seems to be more problematic than allocating energy content of the products, especially since it requires assumptions about the displacement of a byproduct: there is uncertainly as to what electricity generation or oil source would be displaced.

Previous studies have shown significant amounts of CO_2 could be stored with enhanced oil recovery (*11−13*). These studies, however, use a limited system boundary and ignore the significant emissions that produced upstream of the power plant that captures the CO_2 used in the project, as well as the emissions associated with transporting, refining and combusting the recovered petroleum and petroleum products. This study shows, that including all life cycle stages results in significant net emissions. It is important to realize the atmosphere sees these significant GHG emissions and only a small amount of sequestration.

Energy Displacement. The key argument for CO_2−EOR as a sequestration method is that the electricity and oil produced within the system boundary displaces oil or electricity from other sources. Table 5 shows the net emissions from our study as previously described. Also shown are the life cycle CO_2 emissions resulting from producing an equivalent amount of electricity and oil produced to that within the system boundary of each CO_2−EOR project. For example, the SAROC Unit produces 402 million bbls of oil and 99.7 million KWh of electricity. Recall that all the captured CO_2 injected into reservoir has already been taken into account in the net calculations. Thus, the difference between the "emissions from oil and electricity produced with other sources" and the "net EOR system emissions" is the actual amount of CO_2 sequestered within the CO_2−EOR project of the life cycle of the project if product displacement is claimed. The difference between the SACROC Unit net emissions and "current oil, current electricity emissions" is 60 million metric tons of CO_2e and is approximately $^2/_3$ of the CO_2 injected. Offsetting IGCC and Canadian SCO results in 110 million metric tons of potential sequestration, a 30% greater than the actual injected CO_2. Interesting, there are combinations of offsets such as low carbon electricity and Saudi crude oil that actually results in increases in CO_2 emissions, more than offsetting any stored carbon. For the SACROC unit 10 million metric tons more CO_2 would be produced. The other CO_2−EOR projects follow the same trends.

Without a detailed economic model that captures the complexity of oil use or electricity production and management it is difficult to be certain what sources, if any, will be displaced. A thorough understanding of ultimate displacement is necessary before anyone can suggest that CO_2−EOR is a sequestration technique. Certainly it is intuitive that a bbl produced by the use of anthropogenic CO_2 could replace a bbl of oil recovered using natural CO_2. The link to other conventional and unconventional crude oil displacements is much more tenuous. Also, any displacement argument must take into account the overall continual increases of demand of energy to make certain that within a relative time frame important to climate change the displaced energy source remains displaced. It is clear, that without displacement of a carbon intensive energy source, CO_2−EOR systems will result in net carbon emissions.

Supporting Information Available

Tables S1−S3 and Figure S1. This material is available free of charge via the Internet at http://pubs.acs.org.

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