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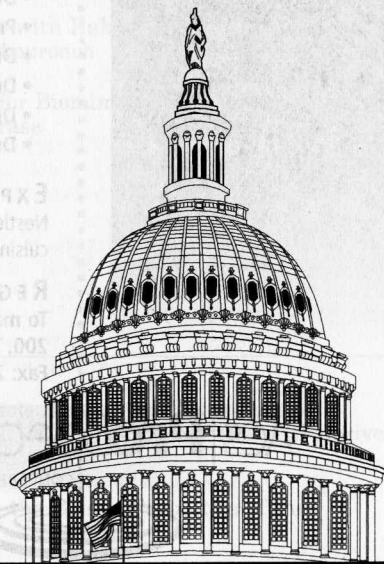
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Reducing Carbon Dioxide Emissions with Enhanced Oil Recovery Projects: A Life Cycle Assessment Approach

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A wide range of industries are investigating methods of reducing their emissions of greenhouse gases, such as carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). Several options have been identified ranging from energy efficiency and reforestation to capture and storage in oceans, aquifers, or underground. Although greenhouse gases are not yet regulated, the power generation and petroleum industries are already considering greenhouse gas capture and storage methods to reduce their emissions to the atmosphere. Preferred options are the ones utilizing CO₂ as a product and therefore providing an additional economic benefit to the oil and gas production process. Currently, CO₂ is widely used for enhanced oil recovery (EOR) projects to extract more oil out of aging reservoirs. Thus, storage of CO₂ in active reservoirs does not require technology advances and offers the advantage of reducing greenhouse gas emissions to the atmosphere. The present research conducted a life cycle assessment to determine the benefits derived from storing CO₂ in active reservoirs while enhancing the extraction of oil and the impacts on the environment over the process lifetime. The potential for CO₂ storage in a specific oil reservoir in Texas was demonstrated, as well as the mass balance of greenhouse gas emissions generated from the energy-intensive process. Our findings suggest that the storage capacity of this reservoir is huge, the process emissions are minimal in comparison, and the EOR activity is almost carbon-neutral when comparing net storage potential and gasoline emissions from the additional oil extracted.

Introduction

Anthropogenic emissions of greenhouse gases (GHG) to the atmosphere are growing and involve every sector of the economy. In 1996, 86% of total anthropogenic greenhouse gas U. S. emissions originated from energy-related activities ranging from power generation to transportation¹. More specifically, the industrial end-use sector alone accounted for one-third of total U. S. CO₂ emissions, mainly from fossil fuel combustion¹. Although scientific uncertainties remain concerning the nature and the extent of the impacts of GHG emissions, efforts have begun to reduce these emissions in order to lessen potential impacts on the global ecosystem. The petroleum industry as a user and provider of fossil fuels contributes to the increase of greenhouse gas concentrations in the atmosphere. The worldwide emissions of greenhouse gases from all activities of the petroleum industry account for about 8% of anthropogenic CO₂ and approximately 15% of CH₄.² The contribution of the upstream sector (exploration and production) of the oil and gas industry accounts for about 3% of the total greenhouse gas emissions worldwide.³

Reducing greenhouse gas emissions to the atmosphere can be accomplished by improving the efficiency of equipment and processes to reduce energy consumption, by developing renewable energy sources, by shifting to lower carbon content fuels, or by implementing storage projects in geologic formations where CO₂ may potentially remain for many decades. While each approach has benefits and drawbacks, the present study focused on geologic storage of CO₂.

Both depleted and active fossil fuel reservoirs can be used for storage of CO₂ in underground formations, and it is estimated that the storage capacity of these formations could be as high as 900 billion metric tonnes of carbon dioxide equivalent worldwide.⁴ Depleted oil fields and EOR fields offer a storage capacity of approximately 130 Gt of CO₂.⁵ Injection in geologic formations is technically mature. The power industry has used geologic formations for natural gas storage to respond

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to peak demand periods.⁶ The petroleum industry has been injecting CO₂ in underground formations for many years to improve oil recovery.⁷ Technically, injection in reservoirs has proven to be feasible, but these formations are just starting to be studied for purposes of CO₂ storage over long periods. If these formations prove to be effective trapping sites, the storage capacity will be enormous compared to the 6.6 billion metric tons of anthropogenic CO₂-equivalent emissions worldwide in 1997⁸ (This figure includes CO₂, CH₄, and the other greenhouse gases by taking into account their global warming potentials compared to those of CO₂).

Carbon dioxide under supercritical conditions acts as a powerful solvent and is routinely used for extracting more oil out of aging reservoirs in a process called enhanced oil recovery (EOR). Supercritical CO₂ dissolves in the crude oil, effectively reduces the viscosity of the oil, and increases oil bulk. Therefore, it enables the oil to flow more readily to the producing wells, thus increasing production as described by Darcy's law.

EOR with CO₂ cannot be applied to all types of reservoirs and is most efficient for crude oils with a gravity greater than 22° API,⁹ and its implementation is very dependent on oil and CO₂ prices. However, it has been used in the United States for more than two decades and accounts for about 12% of the total US oil production.¹⁰ Thermal recovery is the most widespread EOR method, but the contribution from miscible CO₂ injection represents approximately 25% of EOR production in the U. S. and is rising every year.¹⁰ Many examples of CO₂ injection for EOR purposes can be found in the literature.^{11, 12}

Injection of supercritical CO₂ in active reservoirs offers intuitive economic benefits over depleted oil or gas reservoir injection, which are also being discussed as storage options. The interest in using CO₂ injection for EOR in productive reservoirs lies in the valuable production of oil, which would be unrecoverable otherwise. Hence, the CO₂ injected in active EOR formations fills a dual purpose: extraction of additional oil and repressurization of the formation, thus avoiding ground collapse that could follow the depletion of the reservoir. Another benefit, and the subject of this study, could be the long-term storage of part of the CO₂ in the formation. The economics of CO₂ capture, compression, and transport for injection have been discussed by several

authors, and their work can be used to assess the benefits derived from using CO₂ as a product in EOR projects.^{13, 14}

The magnitude of CO₂ required in an EOR field is great, and several sources can be used to provide the necessary amounts. Currently, about 80% of the CO₂ used commercially is for EOR purposes¹⁵ and originates from natural CO₂ reservoirs for the most part. Three natural CO₂ reservoirs, Sheep Mountain, Bravo Dome, and Mc Elmo Dome, provide CO₂ for the EOR fields in New Mexico and West Texas through a set of pipelines. Other potential sources for CO₂ EOR include byproducts from ammonia plants, other chemical plants, and oil-field acid gas separation plants. The supply available from ammonia plants is 98% pure but very limited.¹⁶ Power plant stacks also contain CO₂ but at low concentration, and therefore, separation and compression of the CO₂ are required.¹⁶

The duration of storage, and how it relates to safety,¹⁷ is a very important issue, and will be the subject of a subsequent paper. Moreover, the present paper does not discuss the performance of the CO₂ miscible production process, nor the special consideration arising from the injection of acid gas in the formation. Rather, we demonstrate the application of a lifecycle assessment framework to determine the benefits arising from storing carbon dioxide in an active reservoir. This analysis uses, as a case study, an active reservoir in the Permian Basin of West Texas, currently undergoing enhanced oil recovery with injection of CO₂. A life cycle assessment approach enabled us to investigate the storage capacity of this reservoir, the emissions generated by this energy intensive process, and the amount of CO₂ needed to maintain optimal recovery throughout the lifetime of the process. The facility investigated was initially partly owned and/or operated by the Atlantic Richfield Company (ARCO) and is now owned by BP.

Methods of Approach

Life cycle assessment (LCA) can be used to determine the environmental burden for a process or product during the relevant lifetime.¹⁸ The LCA identifies and quantifies energy, material usage, and environmental releases, assesses the impacts on the environment, and evaluates and implements opportunities for improvements if feasible.¹⁹ These objectives are achieved by dividing the process into smaller elements for which input and output streams are more readily identifiable. In the present study, the focus was on the identification and quantification of the emissions and resources needed over the lifetime of the investigated process.

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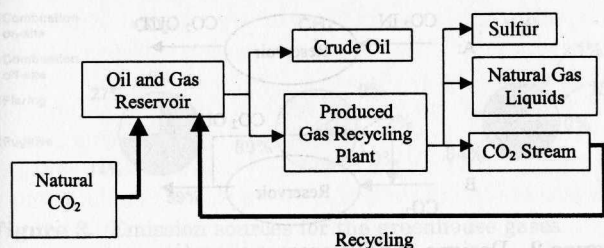


Figure 1. Schematic of processes investigated in the case studies.

Although all emissions and discharges should be included in a full LCA, this study focused on greenhouse gas emissions (CO_2 , CH_4 , and N_2O) only. The analysis was limited to the boundary of the facility and included the extraction of the oil and associated gas from the oil reservoir, the processing of the associated gas for separation of the different components (water, hydrogen sulfide H_2S , CO_2 , CH_4 , natural gas liquids), the compression of the separated CO_2 stream destined for injection, and the transport and injection of the CO_2 in the oil reservoir for extraction of additional oil and for long-term storage. Figure 1 shows a schematic of this process. The extraction and transport of the CO_2 from the natural reservoir is not part of the analysis.

The reservoir we investigated in this study is situated in the Permian Basin of West Texas. It is a layered dolomite with an average porosity of 8.5% and an average permeability of 1.5 md. Production is from the San Andres dolomite at an average depth of 1585 m, and the thickness of the producing layer varies from 15 to 70 m. The unit contains 13 130 producing acres, which have already undergone waterflooding and are now under enhanced oil recovery production using CO_2 . The minimum miscibility pressure to be maintained for injection of CO_2 is 85 atm.²⁰

The production of oil is driven by extraction wells positioned throughout the surface of the field. Water is injected alternately with CO_2 in a process called water-alternating-gas (WAG) to divert the CO_2 to different areas, sweep additional oil, and help maintain reservoir pressure. Some of the CO_2 and water injected travel from the injection point to the producing wells and are produced along with the oil. Each production well is controlled by a power source for pumping and compressing the extraction-produced fluids (oil, water, and a mix of compounds in the gas phase). The pressure differential allows the liquid and gas phases to move from one point to the next in decreasing pressure.

The separation of gas and oil/water is a simple process assisted by heat, chemicals, and retention time in the vessels and relies on phase separation. The liquid phase undergoes further separation to recover the crude oil for sale, while the gas phase is directed to the gas processing plant. The water is recycled for injection in the WAG process. The gas processing stage is the most complex stage of the system. The gas is dried to avoid pipeline corrosion arising from the association of CO_2 and water. In addition, because typical sales gas specifications require low acidic concentration, the H_2S and CO_2 have to be removed before the sale of the gas.²¹ The sales fuel-gas, whose main component is methane, can only contain 2% CO_2 and 5.7 mg of H_2S per cubic meter of gas to pass safety requirements.

The separation of CO_2 from hydrocarbons and H_2S can be achieved by using the Ryan/Holmes process. This technology is a distillation separation relying on the relative volatility of the gas components and using an additive introduced at the

top of the distillation tower.^{21,22} The additive is then regenerated and reused in the same process. The Ryan/Holmes process is highly compound-specific and will only separate CO_2 from the remaining gas stream. To separate H_2S from the natural gas liquids, we used a nonselective chemical absorption amine process, in which acidic elements are removed by countercurrent contact with an amine solution. The separated H_2S is then either transformed to elemental sulfur or incinerated.

The separation of the produced gas stream does not isolate all compounds perfectly, and the CO_2 stream destined for reinjection also contains some methane and C_2 (hydrocarbons with two carbons). We assumed that the amount of methane reinjected in the formation was a constant 10 mol % of the stream and CO_2 that represented over 87 mol %. Finally, the injection step consists of sending the gas phase under supercritical conditions (CO_2 in this case) down the injection well to the reservoir. This ultimately improves the recovery of oil at the producing wells.

Because we analyzed the storage potential for CO_2 in an existing reservoir under EOR conditions, we utilized the estimated 40-year lifetime of active EOR production of the reservoir as the duration for injection and accumulation of the CO_2 . This lifetime corresponds to the duration of the analysis and is independent of the residence time of the CO_2 in the reservoir for storage. Since the valuable commodity is the quantity of oil produced, we selected the total crude oil production volume, during the same lifetime, as a functional throughput unit and normalization factor. Hence, the emissions, storage quantities, and resources used are all presented relative to 1 kg of oil produced.

The reservoir was still in operation and provided activity data from the beginning of the EOR activity to the period of the present study. Data were generated as a result of the continuous monitoring of the process for safety and performance purposes. Forecasting models were used for projections of data concerning future activity until the termination of production. To estimate emissions, we used emission factors publicly available from regulatory bodies or research entities, or from direct sampling. For the most part, however, we estimated the emissions on the basis of applicable emission factors from AP-42, the EPA,¹ the Exploration and Production (E and P) Forum,²³ and the IPCC.²⁴ The E and P Forum emission factors²³ were specifically developed as conservative factors for the petroleum industry's operations and thus gave consistently the highest emissions. Therefore, we preferentially used these emission factors to remain conservative in our estimates. When no emission factors existed in the E and P Forum²³ for a specific activity, we used the EPA¹ emission factors and combined the E&P Forum²³ and EPA¹ estimates to obtain the final emission results. The associated gas used to fire on-site equipment was assumed to have a density of 1 ton/1000 m³.²³ Table 1 displays the emission factors used in the study and the details of sources considered for emissions. We assumed that the emissions generated by the system remain constant every year and that the facility operated at full capacity throughout the 40 years of the study. The power company, generating electricity for part of the unit, provided us with their CO_2 emissions, and we do not know how they were calculated.

Results and Discussion

As noted above, the production of oil through enhanced oil recovery requires large quantities of CO_2 .

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Table 1. Emission Factors

	CO ₂	CH ₄	N ₂ O
Field			
energy requirements			
coal (kg/kWh)	a	3.6×10^{-5}	5.04×10^{-6}
natural gas (kg/kWh)	a	1.8×10^{-5}	3.60×10^{-7}
fugitive emissions	72		
(kg/well/yr)			
routine maintenance		0.15	
(kg/well/yr)			
Recycling Plant			
energy requirements			
coal (kg/kWh)	a	3.6×10^{-5}	5.04×10^{-6}
natural gas (kg/kWh)	a	1.8×10^{-5}	3.60×10^{-7}
equipment (tons/tons of			
gas burnt)			
boiler	2.75	4.2×10^{-4}	2.2×10^{-4}
CO ₂ heater	2.75	4.2×10^{-4}	2.2×10^{-4}
flare purge and pilot	2.75	4.2×10^{-4}	2.2×10^{-4}
glycol reboiler	2.75	4.2×10^{-4}	2.2×10^{-4}
SRU heat medium	2.75	4.2×10^{-4}	2.2×10^{-4}
heater			
SRU incinerator	2.75	4.2×10^{-4}	2.2×10^{-4}
flaring (tons/tons gas burnt)			
tank VRU to flare	2.61	3.5×10^{-2}	8.1×10^{-5}
off gas compressors	2.61	3.5×10^{-2}	8.1×10^{-5}
to flare			
flare pilot	2.61	3.5×10^{-2}	8.1×10^{-5}
acid gas to flare	2.61	3.5×10^{-2}	8.1×10^{-5}
inlet gas to flare	2.61	3.5×10^{-2}	8.1×10^{-5}
process gas flare	2.61	3.5×10^{-2}	8.1×10^{-5}

^a Data from electric company.

Typically, the CO₂ comes from natural CO₂ reservoirs where the infrastructure for distribution is already present, providing easy delivery without involving major additional capital costs. In the EOR field under investigation, the CO₂ came in part from natural reservoirs and in part from the produced-gas recycling plant, which capture and separate the different components present in the produced-gas stream. Initially, the CO₂ came exclusively from natural CO₂ reservoirs, and as gas broke through in producing wells, the CO₂ was recycled through the plant. The produced and recycled carbon dioxide was compressed and reinjected into the formation as part of the solvent supply to achieve oil production. To sustain optimal production over a 40-year time frame, we estimated that this reservoir requires injection of 5.5 kg of CO₂ to recover 1 kg of oil. This number is the cumulative CO₂ utilization expected, representing past daily injection and future daily forecasts, normalized to the 40-year life-span of this EOR oil production project. This quantity is important because it shows how much CO₂ needs to be supplied for the duration of the oil recovery. It ultimately emphasizes the CO₂ demands of an EOR project and, retrospectively, what sources are able to maintain CO₂ delivery for such an extended period and in such quantities. However, this selection is made at the beginning of an EOR project, by dimensionless analysis, specific to each reservoir, which depends on percent of pore space occupied by oil and projected to be swept by the CO₂.

The EOR process can be linear (Figure 2 A) or it can be a cycle (Figure 2 B). In the case of a linear process, the CO₂ produced along with the oil is vented to the atmosphere and amounts to 2.6 kg for every kilogram of oil produced. If the injected CO₂ comes exclusively from natural CO₂ reservoirs, the EOR process would

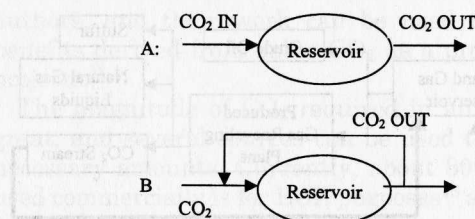


Figure 2. Designs of EOR process operations.

just displace the CO₂ from one sealed location to another, without leading to an offset of anthropogenic emissions.

In the reservoir we studied, a recycling process took place as shown in Figure 2 B, and all the produced CO₂ was reinjected in the reservoir as solvent. We calculate that during the 40-year lifetime of this active EOR reservoir, approximately 43% of the cumulative CO₂ needed for injection will be supplied by the recycling plant. Without capture and reinjection through this recycling plant, the produced CO₂ would be vented to the atmosphere, and the CO₂ needed for injection would come exclusively from natural CO₂ reservoirs, which is not economic.²⁵ Recycling the produced CO₂, therefore, effectively eliminates the purchase and release to the atmosphere of about 2.6 kg of CO₂ for each kilogram of oil produced. The benefits drawn from the recycling process include greater independence from CO₂ prices, greater potential for reducing emissions, and reduction in the depletion of natural CO₂ reservoirs.

As previously described, CO₂ is injected in the reservoir to improve oil production. Along with the oil, some but not all of the CO₂ injected is extracted from the reservoir. The remaining CO₂ is trapped in the formation (called CO₂ retention). The quantity of CO₂ stored in the reservoir is the difference between the amount of CO₂ injected and the amount of CO₂ produced, and these data are obtained from continuous monitoring and forecasting information. Because natural reservoirs can effectively trap gas (such as CO₂ or CH₄) for thousands of years, potential leakage through the rock formation or at the injection point over decades should be small compared to the process emissions and output flow.¹⁷ Nevertheless, potential leakage will be estimated as part of a later study.²⁶

We estimate that the reservoir studied has a capacity to store about 3 kg of CO₂ and 0.1 kg of CH₄ per kg of oil produced. This highlights the storage potential of an oil reservoir, and the important contribution of EOR to offset the emissions from the power intensive system, by storage in the formation. In fact, the storage capacity of the reservoir studied is much greater than the emissions generated by supporting activities such as fuel combustion, flaring, and fugitive emissions, as discussed below. Furthermore, if a reservoir with average production of 1.4×10^{10} kg (7000 bbl/d for 40 years)-is taken as an example, the final storage obtained would be 4.2×10^{10} kg of CO₂. This capacity corresponds approximately to storing the emissions of a 5 MW power plant emitting 65 tons of CO₂ per day for almost 1800

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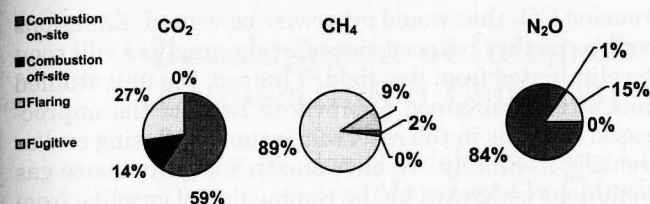


Figure 3. Emission sources for the greenhouse gases.

years²⁷ or 14 years from a 300 MW coal power plant where 8000 tons of CO₂ is captured per day.²⁸

Because the compression and separation of CO₂ from the throughput stream after produced-gas recycling require the use of energy-intensive engines and compressors, significant amounts of fossil fuels are used, which in turn lead to incremental emissions of greenhouse gases. In the system analyzed and using the emission factors from Table 1, the CO₂, CH₄, and N₂O, emissions amounted to 0.36, 1.5×10^{-3} , and 2.1×10^{-5} kg per 1 kg of oil produced, respectively.

The greenhouse gases emitted in this case study are divided into direct and indirect emissions. Indirect emissions are attributable to electricity generated by a power generation company outside of the facility boundaries. In this study, we found that indirect emissions accounted for 13.5% of total CO₂ emissions, about 0.1% of CH₄ emissions, and approximately 0.8% of N₂O emissions.

Direct emissions originate from the use of on-site equipment powered by natural gas, from flaring, and process equipment leakage and routine maintenance that could result in greenhouse gas emissions. Emissions are from both point sources as well as nonpoint sources (fugitive) emission sources. These intentional or unintentional releases of gases arise from the production, processing, transmission, and storage of fossil fuels. They include releases associated with venting, leaks, or discharges from process vents, along with emissions during maintenance activities, accidents, and system upsets—with or without flaring. Methane is the most important gas emitted from fugitive sources. Flaring is used only when absolutely necessary and with permit approval.

In this study, on-site fired equipment accounted for about 60% of CO₂ emissions, approximately 2% of methane emissions, and 84% of N₂O emissions. Flaring, maintenance, and leakage made up the remainder of the total emissions. Figure 3 shows the origin of the emissions as they relate to the system investigated over a 40-year lifetime. The analysis did not include emissions originating from extraction and transport of the natural resources needed for the generation of electricity by the off-site power generating company.

The process flow for carbon dioxide is presented in Figure 4. Emissions to the atmosphere are almost always present with industrial activity and are fixed quantities dependent on the system's energy requirement and process. Similarly, the injected CO₂ needed for optimal production of oil depends on reservoir and process characteristics but, in this case study, should

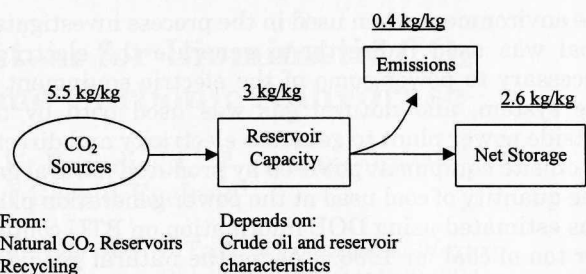


Figure 4. Process flows for CO₂ (in kg of CO₂/kg of oil produced).

Table 2. Summary of Findings (kg/kg of oil produced)

	CO ₂	CH ₄
injected	5.5	0.29
emitted	0.4	1.5×10^{-3}
emissions avoided (Figure 2 A)	2.6	0.29
storage capacity	3	0.1
net storage	2.6	0.1

be maintained at 5.5 kg per kg oil, notwithstanding the origin of the CO₂. The amount of CO₂ that can be stored in the studied reservoir was calculated to be 3 kg per kg oil. When emissions from auxiliary equipment are used to drive the process and fugitive and flaring emissions are factored in (0.36 kg CO₂ per kg oil produced), the net storage of CO₂ in the reservoir is reduced to 2.6 kg per kg oil. Table 2 presents the summary of findings from this research. In the example used previously with the power plant, accounting for emissions reduced the capacity of the storage but still corresponded to about 1500 years of storage for the 5 MW power plant or 12 years from the 300 MW coal power plant.

We were also interested in determining the magnitude of emissions resulting from the additional oil the reservoir produced using the enhanced oil recovery production method. An average car equipped with an oxidation catalyst emits approximately 380 g of CO₂ per km traveled.¹ This corresponds to about 4.8 kg of CO₂ emitted for every kilogram of gasoline consumed by the vehicle. On the other hand, the system studied in this research contributed to storing 2.6 kg of CO₂ per kg of crude oil produced, which is equivalent to about 4.5 kg of CO₂ per kg of gasoline produced (using the crude oil-to-gasoline production ratio from the BP Los Angeles refinery). These results suggest that the emissions of CO₂ versus storage in the formation balance, even when the added emissions from combustion of the gasoline by vehicles, is taken into account. This calculation provides a reference for the magnitude of storage available compared to gasoline consumption. However, from a conservative approach, the crude oil extracted from a reservoir is refined into multiple products, including gasoline, diesel, bunker, and jet fuels. Combustion of these products and intensive energy needs of a refinery lead to greenhouse gas emissions. The results presented reflect only gasoline consumption but do not take into account the additional emissions that would originate from the refining process, nor the emissions arising from the combustion of the other products of crude oil such as diesel, bunker or jet fuels.

Finally, natural resources usage is an integral part of an LCA. This information is necessary to comprehend the associated depletion of nonrenewable resources from SCOUT and CHEVRON EXHIBIT 1005, Page 8

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the environment when used in the process investigated. Coal was used indirectly to generate the electricity necessary to power some of the electric equipment in the system, and natural gas was used both by the outside power plant to generate electricity and directly by on-site equipment powered by produced natural gas. The quantity of coal used at the power generation plant was estimated using DOE information on BTU content per ton of coal for 1996.²⁹ As for the natural gas used, we knew the amount used at our facility and estimated the usage of the power generation plant by assuming a density of the gas of 0.8 ton/1000 m³ and a heating value of 1000 BTU/scf.²³ We found that 6.5 g of coal and 65 g of natural gas per kg of oil produced was used during the 40-year lifetime. These combustion rates are quite high compared to the quantity of oil produced, but because the process recovers oil as a marketable product, the storage of CO₂ through this means remains advantageous.

Conclusions

This analysis demonstrated the CO₂ storage potential of an oil reservoir in the Permian Basin of West Texas through the use of enhanced oil recovery. Concurrent with the storage possibilities in an active reservoir, we estimated the greenhouse gas emissions originating from the range of equipment used and from flaring practices and fugitive emissions. The results suggest the EOR process is not only a major CO₂ user but could also provide a significant means to storing the CO₂ underground. This study also illustrates that utilizing captured and recycled CO₂ instead of using CO₂ exclusively from natural reservoirs reduces greenhouse gas emissions to the atmosphere from EOR. The sources of CO₂ could be advantageously diversified to include CO₂ from vents at natural gas processing plants or from power plants, therefore preventing depletion of naturally occurring CO₂ reservoirs and significantly reducing the emissions of greenhouse gases to the atmosphere by

reusing CO₂ that would otherwise be vented. Emissions will be further reduced since flaring practices will soon be eliminated from this field.³⁰ Indeed, the unit studied has already obtained approval to reinject the unprocessed sour gas in the reservoir instead of flaring and/or venting it. Finally, we have shown the greenhouse gas emissions generated by the combustion of gasoline from the additional oil produced by the EOR process would almost be offset by CO₂ storage in the reservoir.

An important consideration for implementing this system is economics, which will dictate the final fate of the CO₂. Currently, while part of the retained CO₂ is flushed out of the reservoir for reuse in other EOR projects, there will be much CO₂ left in the reservoir at the end of the field life. Maximizing CO₂ retention depends on economics and technology, which dictate how much CO₂ ultimately remains in the reservoir. Thus, high oil prices are more conducive to using CO₂ in EOR projects because of the favorable ratio between oil prices and CO₂ cost. Similarly, low CO₂ prices would be more conducive to leaving the CO₂ in the reservoir for permanent storage. Currently, EOR projects are designed to maximize oil production. If the emphasis shifts to maximizing CO₂ storage, the EOR design concept will have to be changed accordingly. Notwithstanding the ultimate objective of EOR projects, they offer storage for CO₂ and lower the impacts of oil production activities on the environment by promoting a better utilization of resources technologically recoverable. Future research needs to include evaluating the residence time of the stored CO₂ in the formation and comparing the results presented here with storage in depleted reservoirs. These studies are presently underway.²⁶

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