A cash flow model of an integrated industrial CCS-EOR project in a petrochemical corridor: A case study in Louisiana

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Abstract

Petroleum refineries and petrochemical plants are major CO_2 sources, however, they are also significant capital and employment assets that are unlikely to be replaced in the near term. As a result, nations and states that are interested in reducing the carbon intensity of their economies will need to find ways to reduce the emissions of their existing industrial capacity. Industrial carbon capture provides one potential mechanism for reducing the carbon intensity of existing industrial facilities, however, an economically feasible capture system requires that the captured CO_2 be integrated into a system of transport and storage with income generated either through tax credits, enhanced oil recovery (EOR), or both. Here, we present a cash-flow model of an integrated system with industrial capture, pipeline transport, and EOR, and we parameterize the model with data from Louisiana. Given a \$50/bbl oil price, an integrated capture, transport and EOR system that uses ethylene oxide production, ammonia production, or natural gas processing as sources is predicted to have a net present value of about \$500 million; hydrogen-based capture has a cash flow of −\$214 given the same assumptions. Further, we find that the recent 45Q Tax Credit expansion has a positive impact on the cash flow of the system but does not change the overall profitability of the systems under the specified assumptions such that without the tax credits natural gas processing, ammonia production and ethylene oxide production-based capture systems remain cost-effective, while hydrogen-based capture remains unprofitable with or without the tax credit.

1. Introduction

While renewables, nuclear power, and energy storage provide a plausible foundation for a carbon neutral electricity sector (Jacobson et al. 2015), industrial processes such as petroleum refining, fertilizer and cement manufacturing, and chemical feedstock production may be harder to decarbonize. As a result, other low carbon technologies will be required for deep decarbonization (Ahman and Nilsson 2015; Ahman et al. 2017). Industrial carbon capture and storage (CCS) is one potential tool for reducing the carbon intensity of the industrial sector. Although a great deal of attention has focused on CCS from coal-fired power plants (Singh et al. 2003; Haszeldine 2009; Edge et al. 2011), industrial CCS may offer a lower-cost alternative because it typically involves carbon capture from non-combustion exhaust streams with higher concentrations and pressures of CO_2. Combustion exhausts usually have CO_2 concentrations of 3 to 14%, with partial pressures of 0.03 to 0.14 atm (0.4 to 2.1 psi), while "high-purity" industrial sources can have CO_2 concentrations of over 95% with partial pressures of 1 – 20 atm (4.5 to 290 psi; Table 1). Note that not all emissions from a specific industrial facility will be from high-purity sources, as many large industrial facilities contain both combustion and non-combustion emissions.

Once captured, CO_2 can be stored in saline reservoirs or mature oil reservoirs. Saline reservoirs allow for permanent storage but financial benefits of the system are dependent on tax or other governmental incentives. In contrast, depleted oil reservoirs may be used for enhanced oil recovery (EOR) which creates an independent cash flow but reduces the net carbon benefit (Jaramillo et al. 2009; Cuellar-Franca and Azapagic 2015). In the present study, we focus on EOR storage, but the economically preferred storage solution will depend on tax incentives for EOR and saline storage, oil prices, transportation costs, and other factors.

The development of widespread integrated CCS-EOR will depend on the geographic proximity between sources of high purity CO_2 and EOR sinks. While there is some existing CO_2 transportation infrastructure in the U.S., it is generally not collocated with industrial CO_2 sources. In addition, since demand for purchased CO_2 in an EOR project typically lasts about a decade (Jarrell et al. 2002; Dilmore 2010; King et al. 2013), a network of neighboring EOR fields and/or other storage reservoirs is likely to be required in order to continue to create cash flow from the initial capital investment.

For both historical and geological reasons, many declining petroleum and natural gas plays are located in close proximity to refining and petrochemical production. For example, oil and gas exploration and production in South Louisiana developed relatively early in the industry's history with the discovery of the Jennings field in 1901 (Harris 1910). Due to this new production and the proximity to the Gulf Coast and the Mississippi River, a refining industry grew up around the exploration and production industry, including the construction of the now ExxonMobil Baton Rouge refinery in 1909. As refineries grew in sophistication, they began to both produce and demand specialized petrochemicals, and an industry developed in the region to capitalize on abundant natural gas supplies, transportation infrastructure, and existing industrial suppliers and customers. Because of this history, there is a large concentration of both declining oil fields and industrial CO_2 sources along the Mississippi River between Baton Rouge and New Orleans, Louisiana. Due to this industrial concentration, this area is known as the Louisiana Chemical Corridor (LCC). A similar collocation of high-purity industrial CO_2 emissions and potential EOR fields occurs around Lake Charles, Louisiana, Southern California, Western Pennsylvania, Northwestern Ohio, and Coastal Texas (Figure 1).

Due to its history, the LCC is an industrial ecosystem in which firms commonly exchange steam, electricity, hydrogen and various hydrocarbon coproducts, however, CO_2 is not included as part of the existing industrial ecosystem. The addition of a CCS-EOR component to this ecosystem has the potential to convert a major waste stream (CO_2) into an input for local oil production. This would create a potentially unique industrial ecosystem and would represent an example of the continuing evolution of industrial systems (Ayers 1989).

The purpose of this paper is to analyze the economic potential of an integrated CCS-EOR project in the LCC as a case study to inform industrial CCS-EOR projects elsewhere. The model envisions a joint venture project composed of a CO_2 capture operator, CO_2 pipeline operator, and EOR operator. We begin with background information on the history of the industry and the spatial distribution of CO_2 sources and potential EOR fields. We then describe available CCS-EOR cost models and data and parameterize these models to develop capital and operational costs for the capture, transport, and injection components of the model.

2. History and Status of CO_2 EOR

2.1 EOR History

By the 1970s, declining oil production, geopolitical concerns associated with new sources of foreign oil, and the technical difficulty associated with geologically deep or subsea plays led to the development of new technologies for producing onshore oil in the U.S. One of these technologies was CO_2 EOR. The earliest CO_2 EOR tests in the Mead-Strawn and Scurry Area Canyon Reef Operators Committee (SACROC) units of West Texas in the early 1970's demonstrated that CO_2 EOR could produce up to 50% more oil than water flooding alone (Holm and O'Brien 1971; Dicharry et al. 1973).

In the late 1970s and early 1980's, several Louisiana reservoirs were injected with CO_2. In 1978, Shell began an EOR project on its Weeks Island field in South Louisiana. Shell injected approximately 44,000 tonnes of CO_2 from late 1978 to early 1980. Oil production began in 1981 and over the next six years, about 260,000 barrels of oil, or over 60% of the remaining oil in place, had been produced (ARI 2006). In 1981, Gulf Oil (now Chevron) conducted an analysis of a water alternating gas (WAG) production system in its Quarantine Bay field south of New Orleans. Gulf Oil barged 25,400 tonnes of liquid CO_2 from New Orleans and injected it into an 8,200 ft Miocene sand (Hsie and Moore 1988). In total, CO_2 injection only accounted for about 19% of the hydrocarbon pore volume (HPVC), but nearly 17% of original oil in place (OOIP) was recovered at an efficiency of 7.5 bbl/tonne CO_2. Finally, in 1982, Texaco began injecting approximately 1,500 tonnes of CO_2 per day (30 million scf) from nearby ammonia plants into the Paradis oil field (Bears et al. 1984). The CO_2 injections were into a 9,000 ft deep sand and were mixed with approximately 10% nitrogen.

While these early projects were developed using anthropogenic CO_2 captured from natural gas processing plants, discoveries of cheap and abundant non-anthropogenic[1] sources in Colorado, New Mexico and Mississippi have allowed EOR production to steadily increase (Figure 2, recreated from Kuuskraa and Wallace 2014). The Permian Basin in West Texas remains the predominant EOR-producing basin. As of 2014, the industry utilized 68 million tonnes of CO_2 in 136 separate projects and produced 300,000 bbl/d of total oil (Kuuskraa and Wallace 2014).

2.2 Current Status in Louisiana

[1] Non-anthropogenic CO_2 is CO_2 that is derived from fossil reservoirs that would, in the absence of EOR, stay underground. Anthropogenic CO_2 is produced by combustion of hydrocarbons, some other industrial hydrocarbon oxidation process, or stripping CO_2 from natural gas reservoirs.

Capture Projects

As of 2017, there were 17 operating, large-scale carbon capture systems in the world, and all but two relied on industrial sources of CO_2 (Global CCS Institute 2017). While there are no large-scale (defined as over 400,000 tonnes/year) systems currently operating in Louisiana, there is one large-scale system in development in Lake Charles, Louisiana, and another mid-sized facility operating in the LCC. In 2013, LCC ammonia producer PCS Nitrogen contracted with EOR specialist Denbury Resources to deliver approximately 365,000 tonnes/year (20 MMcf/day) CO_2 into Denbury's newly built Green Pipeline. The CO_2 flows to EOR operations in Denbury's Hastings field south of Houston, TX. Note that PCS Nitrogen emits significantly more CO_2 that is vented to the atmosphere (a total of 557,000 tonnes in 2016), however, the economic costs and benefits of the decision to capture only a fraction of emissions have not been disclosed. In addition to this operating capture project in the LCC, a petcoke to methanol project in Lake Charles, Louisiana is proposed.

EOR Projects

There are a limited number of enhanced oil recovery operations in Louisiana. Denbury operates the Delhi Field in central Louisiana, which injects non-anthropogenic CO_2 from Jackson Dome in Mississippi. Tertiary production began in 2010 and in 2016 the Delhi Field produced 2.6 million barrels of oil (SONRIS 2017). Denbury also operates a smaller field called Lockhart Crossing in South Louisiana which also receives non-anthropogenic CO_2 from Jackson Dome; Lockhart Crossing produced 445,000 barrels of oil in 2016 (SONRIS 2017). Marlin Resources conducts EOR at the Buckhorn field which is also connected to Denbury's pipeline system. In 2016 Marlin Resources produced 7,283 barrels of oil from the Buckhorn Field (SONRIS 2017).

3. Industrial CO_2 Emission Sources in Louisiana

While CO_2 capture and EOR are both currently limited in Louisiana, there is a significant resource of CO_2 emissions that could be captured for EOR uses. The Environmental Protection Agency collects detailed data on all large stationary emission sources in the U.S. because of the Greenhouse Gas Reporting Program (GHGRP). These data are available through the Envirofacts website (https://www3.epa.gov/enviro/greenhouse-gas-customized-search). All data are from the 2015 reporting year.

Due to opportunities for low-cost capture, we were specifically interested in emissions from ammonia production, hydrogen production, natural gas processing, and ethylene oxide production (recall Table 1). Therefore, data for all industrial emissions as well as data from ammonia production (GHGRP Subpart G), hydrogen production (GHGRP Subpart P), natural gas processing (GHGRP Subpart W) were collected. Locations of ethylene oxide production were collected from EPA's ChemView database; emission quantities from ethylene oxide production as well as production quantities are considered confidential business information and are not reported. Figure 3 shows all point sources of emissions in Louisiana while Figure 4 shows the emitters of the four target industrial CO_2 streams.

Most of the large, high purity CO_2 sources are located along the LCC. Ammonia, hydrogen production, and ethylene oxide production are the most attractive sources in the LCC while natural gas processing is more dispersed throughout the state. Although natural gas processing creates a highly pure CO_2 stream, emissions at each plant are typically far lower than emissions from other industrial processes because natural gas processing is dispersed into a large number of small facilities due to the challenges of transporting unprocessed gas over long distances; this could create commercialization problems associated with economies of scale. Further, the volumes of CO_2 produced from natural gas processing will follow the geographic distribution of natural gas production which changes over time as fields mature. Thus, while emissions from natural gas processing may be an attractive target for early commercialization in some areas, the larger sources along the LCC may be of more sustained potential.

4. Model

We created a cash flow model implemented in MS Excel to provide a first-order approximation of the economic feasibility of a system in which a single-owner captures CO_2 from selected industrial processes, transports the CO_2 via pipeline to one of 120 selected declining oil fields in Louisiana, and produces some incremental oil volume which is sold to finance the system[2]. Captured and injected CO_2 accrues a tax credit consistent with the 2018 CO_2 tax credit expansion ($35 per tonne). We treat the tax credit as revenue despite the fact that it is a tax credit and not a direct subsidy. Thus, we assume that the firm either has sufficient taxable earnings to claim the full value of the tax credit, or that tax credits are transferable. As of late 2019, the Internal Revenue Service has not finalized the 45Q regulations.

All parameters are on an annual basis, and all capital costs are incurred in year zero and all operating expenses and revenues begin in year 1. The model is composed of three main sub-models that estimate costs for capture, transport, and the EOR system, and an additional calculation that uses assumptions about the cumulative 30-year oil production and the rate of decline based on data from existing EOR operations. The purpose of the analysis is to determine the overall cash flow to the system, and as a result, we model the entire system as a single unit; therefore, CO_2 does not transfer ownership and the net cash flow is not distributed amongst

[2] The entire spreadsheet model will be made available by request to the corresponding author.

multiple parties. Thus, the model is similar to the cash flow to a hypothetical joint venture company composed of CO_2 source, CO_2 transport, and CO_2-EOR firms[3].

In the following sections, we describe the three main cost sub-models that estimate capital and operational expenses for CO_2 capture, transport, and injection (Figure 5). The total capital costs are the sum of the capture, transport and injection (EOR) capital costs:

$$CAPEX_{TOTAL} = CAPEX_{CAPTURE} + CAPEX_{TRANSPORT} + CAPEX_{EOR} \quad \text{Eq. 1}$$

Capital costs occur in year 0 and do not reoccur. Total operating costs are also the sum of the operating costs of capture, transport and injection (EOR) systems, and reoccur annually. Therefore:

$$OPEX_{TOTAL\_t} = OPEX_{CAPTURE\_t} + OPEX_{TRANSPORT\_t} + OPEX_{EOR\_t} \quad \text{Eq. 2}$$

where t indicates the year of operation.

Revenue is generated by the sale of oil at a given price, plus tax credits of $35 per tonne generated in the first 12 years of injection[4]. Thus, the total revenue in year t (REV_{TOTAL_t}) is the sum of oil production (q) in year t times the oil price (p) plus the CO_2 injected in year t (C_t) times the fixed $35 per tonne tax credit for $t < 12$:

$$REV_{TOTAL\_t} = q_t p + 35C_t \quad \text{Eq. 3}$$

Equation 3 assumes that the CO_2 injected is equal to the CO_2 stored (e.g. CO_2 leakage is ignored). In year 0, revenues and OPEX are zero, and are first incurred in year 1.

Annual costs for all three sub-models are summed and subtracted from the revenue generated by CO_2 tax credits and oil recovery to generate an annual cash flow for the overall

[3] We are interested in the profitability of the entire system because if the entire system is profitable, then profits may be split among multiple parties. If the system is not profitable, it is unlikely that a business case for development can be made.

[4] Note that the model is denominated in 2011$, but the 45Q tax credit is denominated in 2019$. This could create some error, but given the overall uncertainties in the model, we expect the difference to be small.

system. Once the net annual cash flow is estimated, annual cash flows are discounted and summed to determine the Net Present Value (NPV) according to:

$$NPV = CAPEX_{TOTAL} + \sum_{t=0}^{30} \frac{REV_{TOTAL\_t} - OPEX_{TOTAL\_t}}{(1+i)^t} \qquad \text{Eq. 4}$$

Where i is the discount rate, assumed to be 10%.

Two of the models (capture costs and transport costs) were denominated in 2011$; the third model (EOR costs) was denominated in 2008$ and inflated to 2011$ using the Producer Price Index for oil and gas field machinery and equipment manufacturing (PCU333132333132)[5]. To inflate to more recent denominations, model users could inflate model output using the relevant PPI data. Figure 6 presents a detailed depiction of the model structure and Table 2 describes selected model parameters.

4.1 Capture Costs

Normalized capital and operational expenses (CAPEX and OPEX) developed by Summers et al. (2014) for retrofit carbon capture systems are depicted in Table 3, along with the facility design size on which they are based. To our knowledge, Summers et al. provide the most detailed engineering-based analysis of industrial carbon capture retrofit costs available. While the normalized capital cost from Table 3 could be input directly to the model, normalized costs assume a linear relationship between facility size and facility cost. However, there are economies of scale between the facility size and the capital cost that may be non-linear and this would make the use of normalized costs inappropriate. Summers et al. did not provide cost curves for CAPEX, but they did provide cost curves that related total breakeven cost per tonne to facility

[5] Alternatively, the PPI for crude petroleum and natural gas extraction could be used (PCU211111211111), however, due to the high demand for oil drilling in the 2008 period, the use of this index would dramatically deflate the 2008$. In contrast, the PPI selected results in a slight inflation from 2008$ to 2011$.

size across a range of facility sizes (Figure 8). Summers et al. also provide information on the proportion of the breakeven costs[6] that are attributable to capital and operating expenditures, and we use these data as a means of adjusting the normalized CAPEX.

From the graphs provided by Summers et al. (Figure 7), we derived exponential curves of the form:

$$Breakeven\ CO_2\ Cost = M * E^{-n} \quad \text{Eq. 5}$$

Where *M* and *n* are best-fit constants, the *Breakeven Cost* is the price, in dollars per tonne CO_2, at which Summers et al.'s capture model breaks even, and *E* is the CO_2 emissions captured in tonnes per year. Values of *M* and *n* are provided in Table 3 for each industrial process studied. In order to adjust the CAPEX, we first derived a predicted breakeven CO_2 cost using Eq. 5 and the emissions input, then multiplied by the percentage of the breakeven costs that were associated with CAPEX in Summers et al.'s data. This approximates the breakeven CAPEX in the Summers et al. model given a specific emissions quantity; however, for our model, we were not interested in the breakeven costs, but the actual capital costs. Therefore, we used the known relationship between the CAPEX cost and the breakeven capex cost reported by Summer et al. to inflate (or deflate) the estimate:

$$CAPEX_{CAPTURE} = [(M * E^{-n}) * (B_C/(B_C + B_O)] * (R_C/B_C) \quad \text{Eq. 6}$$

Where *M*, *E* and *n* are as in Eq. 5, B_C and B_O are the breakeven CAPEX and OPEX respectively reported by Summers et al. for the design case, and R_C is the retrofit CAPEX estimate from Summers et al. for the design case. In each capture system, the Summers et al. model includes

[6] Breakeven costs are the price of CO2 required for a system to be financially viable. As in all techno-economic modelling, breakeven cost estimation requires a number of financial assumptions. Summers et al.'s major financial assumptions include a 1-year capital expenditure period, a 50:50 debt to equity ratio, a 30 year economic life, a 8% interest rate on debt, a return on equity of 20% and a 15.2% capital charge factor.

compression that increases the pressure of the CO_2 to 2215 psi consistent with the input for the transportation cost model. We used the normalized OPEX (in $ per tonne) in the last column of Table 3 as model input ($OPEX_{CAPTURE\_t}$); this assumes that the relationship between operating expenditures and facility scale is linear.

4.2 EOR System Cost

We used an engineering-based model (Godec 2014) to estimate the capital ($CAPEX_{\_EOR}$) and operating ($OPEX_{\_EOR\_t}$) costs of an EOR system. The model includes four components of capital costs: the costs to drill new wells, the costs to build a CO_2 recycling plant, the costs to build a CO_2 distribution system, and the costs of the CO_2 compression system. Other equipment for fluids and water management were modeled as annualized leases and incorporated into operating costs. All other capital costs associated with field development including production well construction costs, intra-field and export production pipeline construction cost, and other equipment costs are considered sunk and are not included. The model also includes operating costs for the CO_2 recycling plant as a function of oil price and the maximum CO_2 injection volume[7], workover costs, energy costs for compression, and energy costs for lifting water and liquids. See Supplementary Information for the equations employed.

Equations for all of these cost components were taken from Godec (2014), but critical input parameters were the number of wells needed, the drilling cost per well, well depth, oil price, distribution system mileage, electricity price, and oil production. Many of these variables are difficult to estimate with confidence. The number of wells needed will depend on field geology, the number of existing wells that may be reused, and operator strategy, and in our base

[7] We use the maximum injection volume as a proxy for the CO_2 recycle rate in all years. This is a simplification and it is more likely that CO_2 recycle rates will be an increasing function with the average approximately equal to the initial injection rate.

parameterization we assume that 10 new wells are drilled. Drilling cost per foot was taken from EIA (2016), and well depth was assumed to equal the depth of the reservoir taken from Nunez-Lopez et al. (2008). In-field distribution lines were assumed to require 20 miles of new pipeline. Electricity prices were assumed to be 0.10 $/kWh. Oil production estimates are discussed in Section 4.5, below.

4.3 Transportation Costs

A viable CCS system will consist of a number of capture facilities linked to a number of storage reservoirs via a pipeline network. We employed a model developed by the National Energy Technology Laboratory (Morgan et al. 2014) to estimate the costs of building a CO_2 pipeline in southern Louisiana. The model first calculates the appropriately sized pipe and the number of booster pumps needed based on fluid dynamics and using a least cost approach. Once the model calculates the basic characteristics of the system, it calculates total capital and operational expenses based on data from natural gas transmission data, supplemented with other data sources (Morgan et al. 2014).

We assume that most CO_2 EOR projects will take place within 100 miles of the CO_2 point source because distances greater than 100 miles are increasingly uneconomic (Dooley et al. 2006, Middleton et al. 2014) and because Louisiana offers a number of sources and sinks at distances less than 100 miles. Therefore, we evaluate transport distances between 10 and 100 miles. The quantity of CO_2 transported is set by the maximum amount of CO_2 injected, C_{max}, which is defined in the next section. All other input parameters were set at their default values, including the pressure drop (1000 psi; from 2215 to 1215 psi), elevation rise (50 ft, consistent with flat Southern Louisiana terrain), and contingency allowance (15%). Capital costs relations from McCoy and Rubin (2008) were used and a Southwest U.S. location was assumed.

Given these input parameters, we set $CAPEX_{TRANSPORT}$ equal to the "Total Investment (capital expenses or Capex) with project contingency in real $" given by the NETL model (Morgan et al. 2014). For the purposes of its own internal cost calculations, the NETL transport model assumes that capital costs of pipeline construction are spaced over three years; for simplicity, we assumed $CAPEX_{TRANSPORT}$ was incurred in year 0. Likewise, we used the "Total Annual Operating Expense" output from the NETL model as input for $OPEX_{TRANSPORT\_t}$.

4.4 CO_2 Purchase over Time

Total CO_2 purchased for injection into the reservoir over the life of the project, C_{total},, is estimated as:

$$C_{total} = OOIP * RF * \frac{1}{EF} \qquad \text{Eq. 7}$$

where *RF*, the recovery factor, is quantity of oil recovered as a percent of OOIP, and *EF* is the efficiency factor in bbls of oil produced per tonne of CO_2 purchased. However, the timing of CO_2 injection and oil production is also important because it determines the timing of costs and revenues. We assumed that purchase of captured CO_2 occurred for a period of *n* years with a maximum purchase tonnage in the first year of operation[8]. Purchase tonnage declined linearly to zero through the *n* year purchase time. Thus, purchase tonnage in year *t* is given by:

$$C_t = \left(1 - \frac{t}{n}\right) C_{max} \qquad \text{Eq. 8}$$

[8] It is possible that the maximum CO_2 injection would occur sometime after year 1 as it takes time for injection patterns to come online. The model could be modified to take this into account, but for simplicity we assume a decreasing CO_2 injection that peaks in year 1.

where C_t and C_{max} are the annual CO_2 purchase quantities in year t and the initial year of operation, respectively.

However, C_{total} is also the summation of C_t over the period zero to *n.* Thus, the sum of the sequence of CO_2 injections is:

$$C_{total} = n\frac{(C_{max} + 0)}{2} \qquad \text{Eq. 9}$$

Solving for C_{max}:

$$C_{max} = \frac{2 * C_{total}}{n} \qquad \text{Eq. 10}$$

In the remainder of the paper, we assume[9] that n = 10. King et al. (2013) assumed that CO_2 injection into Texas Gulf Coast reservoirs occurred over 7 to 20 years, thus our use of a 10-year CO_2 purchase period may be reasonable. Note that we assume a linear decline in CO2 injection. A nonlinear decline is also plausible and may lengthen the duration of injection while keeping the quantity injected relatively constant (e.g. Dilmore 2010). Such a change would be expected to have small changes in net cash flows. Likewise, we could incorporate a long-term purchase and injection of "make-up" CO_2 to account for CO_2 loss. We ignored this as we assumed it would have a minor impact on net cash flows.

The size of the capture, pipeline, and injection sub-models are then scaled based on C_{max} while operating costs are scaled to C_t. Note that the model assumes that some industrial source capable of producing C_{max} is within 100 miles of the field. In Louisiana this will generally be

[9] King et al. (2013) assumed that CO_2 injection into Texas Gulf Coast reservoirs occurred over 7 to 20 years, thus our use of a 10-year CO_2 purchase period may be reasonable. Note that we assume a linear decline in CO2 injection. A nonlinear decline is also plausible and may lengthen the duration of injection while keeping the quantity injected relatively constant (e.g. Dilmore 2010). Such a change would be expected to have small changes in net cash flows. Likewise, we could incorporate a long-term purchase and injection of "make-up" CO_2 to account for CO_2 loss. We ignored this as we assumed it would have a minor impact on net cash flows.

reasonable but may not be defensible elsewhere. In these cases, the maximum transportation distance would need to be increased.

The efficiency factor, *EF*, is a critical unknown parameter. Six EOR fields have a sufficient operating history and data availability to allow for an approximation of the oil production per unit of CO_2 injected (Table 4). These six fields (Weeks Island, Northeast Purdy Unit, Kelly Snyder Field, Ford Geraldine Unit, Joffre Viking Field, and Weyburn Unit), all produced between 4.7 and 6.7 barrels of oil per tonne of CO_2 purchased over project lifespans of 8 to 21 years. (Jaramillo et al 2009; Dilmore 2010). Likewise, the WAG system used for the Miocene Quarantine field in South Louisiana produced about 7.5 bbls per tonne of CO_2 (Hsie and Moore 1988). However, these high recovery ratios from early EOR projects have been challenged by Azzolina et al. (2015). Using confidential data on 31 reservoirs under EOR, Azzolina et al. estimated the crude recovery rate varied from 1.8 to 4 bbl/t CO_2. Data reported by Murrell and DiPietro (2013) suggest similar efficiencies, while estimates by King et al. (2013) range from 1.4 to 3.3 bbl/t CO_2. Thus, a large range of efficiencies are defensible. In reality, efficiency will vary over space and time, changing with different geological conditions and technological development. For our baseline model, we select an intermediate value of 3 bbl/t CO_2, but explore the effect of variable efficiencies.

4.5. Oil Production

Oil production from EOR reservoirs will be dependent on the geology of the reservoir and its history of exploitation, and it is difficult to make generalizations about oil production via EOR. We estimated the total oil production (Q) over the 30-year life of the project as a fraction of the original oil in place (OOIP).

$$Q = OOIP * RF \qquad \text{Eq. 11}$$

Other authors have assumed *RF* to be 15% of OOIP (Nunez-Lopez et al. 2008), and empirical measurements of *RF* are generally between 5 and 25% of OOIP (Oleas 2017). For our baseline parameterization, we select a value of 17.5%.

Nunez-Lopez et al. (2008) provided data on the estimated OOIP for 120 Louisiana reservoirs that passed geotechnical screening criteria as being amenable to EOR and the OOIP and depth of these reservoirs become input to the model. The model is geologically simple and only requires information on reservoir OOIP and depth. This allows the model to be generalizable to nearly any reservoir, however, the oil production values are unlikely to be accurate if the model is applied to reservoirs that have not been screened for geotechnical parameters. See Nunez-Lopez et al. (2008) for details on the geotechnical screening process.

4.6 Production Volumes over Time

Tertiary oil production from EOR reservoirs follows a decline curve as in other hydrocarbon production systems. Following Jahediesfanjani (2017), we assumed a standard exponential decline where

$$q_t = q_i e^{-D_i t} \qquad \text{Eq. 12}$$

Where q_t is oil production in bbls per year at year t, q_i is the initial oil production (bbls/year), and D_i is the decline rate per year. Equation 12 was used to calculate oil production in year t. From Equation 11, the integral of q_t from year zero to year 30 is Q which is also given by (Poston and Poe 2008):

$$Q = \frac{q_i}{D_i}(1 - e^{-D_i n}) \qquad \text{Eq. 13}$$

And rearranging for q_i gives:

$$q_i = \frac{QD_i}{1 - e^{-D_i n}} \qquad \text{Eq. 14}$$

Jahediesfanjani (2017) estimated decline curve parameters from CO_2-EOR systems based on 15 reservoirs for which production data were available. While there were only 15 reservoirs in the analysis, small reservoirs had higher decline rates than large reservoirs (Table 5) and we therefore estimated D_i based on the OOIP of the reservoir according to Table 5.

4.7 Cash Flow Calculations

The cash flow was evaluated in a single integrated model in which carbon was captured from one of four sources (ammonia production, ethylene oxide production, natural gas processing, or hydrogen production). Capital and operational costs of the capture system were determined from section 4.1, above. CO_2 was transported some distance via pipeline and injected, incurring capital and operational costs as described in sections 4.2 and 4.3, respectively. Data on original oil in place and reservoir depth were input to the model based on the analysis of Nunez-Lopez et al. (2008). All revenue in the model is generated by the production of oil, which is sold at a $50 per barrel in the baseline parameterization, and the generation of EOR tax credits. In 2019$, a barrel of oil would be $57, roughly equivalent to late 2019 oil prices; nonetheless, oil prices are highly variable, and other values could be justified. The tax credits are assumed to be $35 per tonne consistent with the 2018 45Q expansion and are treated as normal income.

We calculated cash flows assuming either no discount rate or a 10% discount rate and a project lifetime of 30 years. Tax rates and depreciation were not considered. While these financial assumptions are highly unrealistic for actual financial planning purposes, the present interest is on techno-economic feasibility and identifying sources of costs and opportunities for economies rather than parameterizing actual decision-making. For simplicity, we also assumed that oil production began in year 1 of injection and followed a single year (year 0) of capital expenses. In reality, there will be a multi-year investment period in the capture, transport and injection systems such that the capital expenses we model as occurring in year 0 will actually be spread among the prior two to four years. Future models may take this more realistic distribution of capital expenses into account.

5. Results and Discussion

For simplicity, we discuss the costs and production from a single representative reservoir, Paradis. Paradis is a Miocene sand discovered in 1939. There are a number of reservoirs in the field, including a 9,000 ft reservoir that was the target of previous EOR injections, but we assume that this 40-year-old equipment is not used. We model an 11,000 ft reservoir with an estimated OOIP of 206 MMbbls. Paradis is relatively close to the LCC, approximately 9 miles from the nearest major industrial facilities in Norco, Louisiana, and approximately 60 miles from the most distant facilities in the LCC. Therefore, we assume a conservative 50-mile transport distance. We assume *RF* is 17.5 and *EF* is 3 bbl/t CO_2. Given these assumptions, the initial oil production was estimated to be approximately 3 million bbls in the first year.

5.1 CO_2 Accounting

Figure 8 shows the modeled oil production from the Paradis reservoir and CO_2 purchases along with the CO_2 emissions from the combustion of the produced oil, assuming an emission of 0.43 tonnes CO_2 per bbl (EPA 2018). Oil production and CO_2 purchases decline rapidly over the first decade of the project. While a thorough life cycle analysis is beyond the scope of the present paper, the total CO_2 purchased over the life of injection is about 15% less than the CO_2

emitted through the combustion of the produced oil (12 million tonnes purchased versus 14 million tonnes emitted). Note that estimates of life-cycle CO_2 emissions are highly dependent on assumptions about the efficiency factor; when the efficiency factor is cut in half (from 3 to 1.5), the amount of CO_2 purchased doubles so that it significantly exceeds the CO_2 emissions from oil production (24 million tonnes purchased versus 14 million tonnes emitted)[10].

5.2 Cash Flows

The summed, non-discounted cash flows for the ammonia ($919 million), ethylene oxide ($969 million) and natural gas processing ($998 million) systems are quite similar and positive while the cash flow for the hydrogen capture system ($41 million) is more negative (See Supplementary Figure 1). Cash flow becomes negative late in the life of all four system types as the costs of operating the reservoir exceed the oil revenue. Table 6 depicts the net present value by source type for various oil prices. At $50 per bbl oil prices and given a modest 10% discount rate, the cash flow from the hydrogen-based capture system becomes negative (-$214 million) while the net cash flow of the other source types remains positive. CO_2 capture from hydrogen production only generates a positive NPV at oil prices above $70 per bbl, while the other three industrial source types remain cost effective even at low oil prices.

Figure 9 shows discounted cash flows from an ammonia-based EOR system with and without the tax credits established by the February 2018 amendments to section 45Q of the 2005 Energy Policy Act. Using a 10% discount rate, the tax credit increases the net present value from $158 million to $453 million. The inclusion of the tax credits in non-discounted cash flows has a similar effect.

[10] This illustrates that the meaning of the "efficiency factor" depends on the aim of the system. Paradoxically, if the aim of the system is to sequester carbon, a low efficiency factor is preferred. If the aim of the system is to produce hydrocarbons, a higher efficiency factor is preferred.

The efficiency factor (*EF*) is a critical unknown parameter and values from approximately one to five are defensible. In the default parameterizations discussed so far, we have utilized an intermediate value of three. See supplementary Figure 2 for non-discounted cash flows given efficiency factors of 1.5, 3, and 4.5 tonnes CO_2/ bbl at \$50 per bbl oil. Higher efficiency factors improve cash flows, but even an efficiency factor of 1.5 generates a net non-discounted cash flow of \$347 million and a net discounted cash flow of \$252 million.

To this point, we have only discussed results from a single reservoir, Paradis. However, the model is easy to parameterize with alternative reservoirs given their original oil in place and reservoir depth. Table 7 shows the net discounted cash flow for an ammonia capture system supplying selected Louisiana oil fields at 50- or 100-mile transport distances. While there is relatively little effect of increasing transportation distance, small fields have low or negative net cash flows, suggesting that there are significant economies of scale associated with field development costs.

5.3 Model Limitations

The model is relatively simple to parameterize and this allows for a significant degree of generality. However, the generality of the model implies a loss of realism, and this is especially true for the geological processes. The model estimates the oil production based only on the original oil in place. While the analysis is constrained to reservoirs that have passed geotechnical analysis for suitability to EOR (e.g. mature, water drive fields that declining after secondary recovery), the model does not take into account the wide variety of factors that could impact recovery volumes. However, many of these factors are either not known for all fields or not publicly disclosed, and the model is intended to provide a mean estimate of cash flows given limited data. For example, King et al. (2013) used hydrocarbon pore volume to constrain CO_2 injection while we based CO_2 injection on OOIP because hydrocarbon pore volume was not available for Louisiana's potential EOR fields. As a result of these simplifications, the model may be more useful for high-level planning and policy purposes than for decision-making for any individual EOR system.

The simplistic treatment of several financial parameters, especially taxes and depreciation, may also be critiqued. The model was built to examine the system-wide feasibility of a capture-transport-inject EOR system, however, in practice, this system may be operated by three separate corporate entities. Thus, the tax regime is not obvious and would depend on the allocation of cash flows among firms. Nonetheless, the incorporation of taxes will likely serve to reduce net cash flows to the EOR system.

While we assumed that the development of an EOR system in Paradis would not rely heavily on the existing infrastructure, this assumption is not consistent with the previous development of an EOR facility in Paradis. As discussed above, a shallower reservoir in the Paradis field was flooded with CO_2 in the early 1980's. For the sake of comparison to other fields, we ignored this development in our cost models, however, the details of the original EOR development of Paradis may be instructive for future development of Paradis and other fields in the LCC. When Paradis was developed for EOR in the early 1980's, CO_2 was supplied by two nearby ammonia facilities. To transport this CO_2, an existing 14-inch diameter natural gas pipeline was converted to CO_2 service and the CO_2 was transported as a low-pressure gas in a pipeline with a maximum allowable operating pressure of 814 psia. This pipeline was able to transport approximately 570,000 tonnes of CO_2 per year without the need for construction of a new supercritical line as envisioned in our model. Likewise, for the injection of the CO_2, the operator was able to adapt three existing compressors with a combined 3,980 hp, thereby avoiding significant capital costs for compression (Bears et al. 1984). Similarly, in the Quarantine project, the operator drilled one new production well and recompleted six other wells including one producer well that was converted for injection (Hsie and Moore 1988). While each project is unique and opportunities for reuse will vary, it is likely that the models may conservatively overstate some capital expenditures because it is not possible to know which wells, pipelines, and compressors can be repurposed at each potential EOR field.

Similarly, it is likely that other capital expenditures may be underestimated for some fields. The number of new wells is user input, but it is difficult to generalize because it depends both on the geology of the field and the condition of the existing infrastructure. In our default parameterization of Paradis, we assumed 10 new wells would be drilled for the injection system, but this may not be sufficient.

Finally, the model ignores the possibility that a single capture system might be built to supply an increasing number of EOR fields. As EOR fields mature, their needs for CO_2 decrease. While we discounted the operating costs of the capture facility to account for the reduced CO_2 capture, the capture facility represents a large capital cost and a firm that has invested in a capture facility is likely to seek other CO_2 buyers to make use of its capital investment. Future modelling should take this into account as it will have significant effects on the cost effectiveness of the system.

6. Conclusions

An integrated carbon capture-EOR system in Louisiana has the potential to generate positive discounted cash flows at modest oil prices, however, this applies only to high purity sources.

Hydrogen production, which produces exhaust that has a CO_2 concentration intermediate between combustion exhaust and ethylene oxide production, ammonia production, and natural gas processing, returns negative cash flows in most circumstances. This suggests that anthropogenic EOR may, at present, be a plausible means to reduce the carbon intensity of industries with high-purity emissions, but that other options will be necessary for more general industrial utilization.

The inclusion of the 45Q tax credits add significant cash flow to the model, however, we did not study which projects are expected to be stimulated by the passage of the tax credit. Presumably, the purpose of the passage of the tax credit was to provide an incentive so that projects that fell below profitability would generate positive NPV. In our cursory analysis, the profitability of the system was driven by the capture component such that hydrogen capture generated negative NPV with and without the tax credit, while the other capture types generated positive cash flows with and without the tax credit. Thus, a future analysis could use the model presented here to identify the marginal projects whose NPV becomes positive with the inclusion of the tax credit. Similarly, our analysis was limited to a single oil price environment. Future oil prices may change our conclusions.

A functional EOR market requires integration across multiple CO_2 sources, pipeline operators, and EOR operators with each player in the market generating a sufficient return to justify operations, but without creating costs that make operations unprofitable for the other players. Because of these conflicts, partnerships and joint ventures may be more feasible methods for development. The model presented here is essentially a cash flow model of a joint venture between capture, transportation, and EOR operators and suggests that in at least some circumstances, such a joint venture may be profitable. Our results suggest that joint ventures that include high-quality sources, transport firms, and EOR operators may be profitable today, but that capture for lower quality CO_2 sources may require either the purchase of CO_2 by the EOR firm (e.g. a subsidy) and/or a network of EOR and saline storage options that improve the economics of the capture investment.

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Table 1. CO_2 concentrations in exhaust streams from power and industrial sources. (sources: Metz et al. 2005; Summers et al. 2014; Munson 2016)

Process	*Capture Concentration (mole %)**	*Partial Pressure (psia)*
Coal Fired Power Plant	3 to 14	2
Natural Gas Processing	99	23.3
Coal to Liquids	100	265
Gas to Liquids	100	265
Ethylene Oxide	100	43.5
Ammonia	97	22.8
Hydrogen	44.5	8.9

Table 2. Parameters and their default model values

Parameter	*Description*	*Value*
Field	Potential EOR Field	Selected from 120 LA fields identified by Nunez-Lopez et al. 2008
n	Duration of CO_2 purchase in years	10
OOIP	Original Oil in Place	Determined from Nunez-Lopez et al. 2008
RF	Recovery Factor; % of OOIP recovered	17.5%
EF	Efficiency factor; bbls of oil produced per tCO_2 purchased	3
Distance	Source to sink distance in miles	10-100
Capture system	Type of industrial system	Hydrogen; Natural gas processing; Ethylene oxide; Ammonia
Wells	Number of new injection wells	10
Distribution length	Length of the distribution system, in miles	20
Drilling cost	Cost to drill and complete injection wells, $/ft	150
Injection pressure	Pressure of supercritical CO_2 required for injection, psi	2200
Oil price	Price of oil, $/bbl	50
C_{max}	Maximum quantity of CO_2 purchased in year 1, tonnes	Derived from model input
C_t	CO_2 purchased in year $_t$, tonnes	Derived from model input

Table 3. Capital and operational costs of retrofit industrial CCS systems, and best-fit parameters used for scaling capital costs; data from Summers et al. 2014

Process	*Retrofit CAPEX* $(R_c; \$\ tonne^{-1})$	*Design case emissions* $(t\ CO_2/yr)$	*Breakeven CAPEX* $(B_c; \$\ tonne^{-1})$	*Breakeven OPEX* $(B_o; \$\ tonne^{-1})$	*Best Fit Parameters*		*OPEX Cost* $(OPEX_{CAPTURE\_t}; \$\ tonne^{-1})$
					M	*n*	
Natural Gas Processing	42	551,818	6.2	11.36	1191	0.317	11.36
Ethylene Oxide	67	103,276	9.95	14.57	1445	0.351	14.57
Ammonia Production	71	389,639	10.55	15.97	3235	0.371	15.97
Hydrogen Production	271	273,860	43.43	74.84	15,571	0.392	74.84

Table 4. CO_2 injection and incremental oil production at selected EOR fields in North America

Field/reservoir	*Total CO_2 purchased (million tonnes)*	*Incremental oil production (million bbls)*	*Bbl produced per tonne CO_2 purchased*	*Reservoir geology*	*State or province*	*Source*
Northeast Purdy unit	6.2	36	5.8	Pennsylvanian sandstone	Oklahoma	McCoy 2009; Fox et al. 1988
Kelly Snyder field	87.5	402	4.6	Pennsylvanian carbonate	Texas	McCoy 2009; Grigg and McPherson 2007
Ford Geraldine unit	2.37	13	5.5	Permian sandstone	Texas	McCoy 2009; Phillips et al. 1983
Joffre Viking unit	3.6	23	6.4	Albian sand	Alberta	McCoy 2009; Pyo et al. 2003
Weyburn unit	20	130	6.5	Mississippian carbonate	Saskatchewan	Jaramillo et al. 2009; Whittaker 2005
Weeks Island field	0.044	0.26	5.9	Miocene sand	Louisiana	ARI 2006
Quarantine field	0.028	0.188	7.5	Miocene sand	Louisiana	Hsie and Moore 1988

Table 5. Decline curve parameters used in the cash flow model

Field category	*Category definition (MMbbls OOIP)*	*Number of fields*	*Average D_i (yr^{-1})*
Small	<100	3	0.092
Medium	100-1,000	5	0.076
Large	>1,000	7	0.055
All fields		15	0.069

Table 6. Net present value (in million $) of the baseline parameterization for the Paradis field

Oil Price ($/bbl)	*Nat Gas Processing*	*Ammonia*	*Ethylene oxide*	*Hydrogen*
30	316	254	299	-413
50	571	509	553	-158
70	826	764	808	97

Table 7. Variation in NPV by EOR field assuming ammonia capture system

			NPV (million $)	
Field	***OOIP (million bbls)***	***Depth (ft)***	***50 miles***	***100 miles***
Paradis	206	11,000	509	484
Avery Island	155	9,000	358	333
Bayou Sale	290	14,000	763	717
Delhi	334	3,135	915	880
Hackberry West	166	7,360	394	369
Lake Pelto	32	13,200	10	-8
Clovelly	17	11,900	-26	-44
Erath	28	8,695	10	-8

Figure 1. Industrial sources (red circles) and potential storage locations (dark grey) in the U.S. Data from NETL 2015

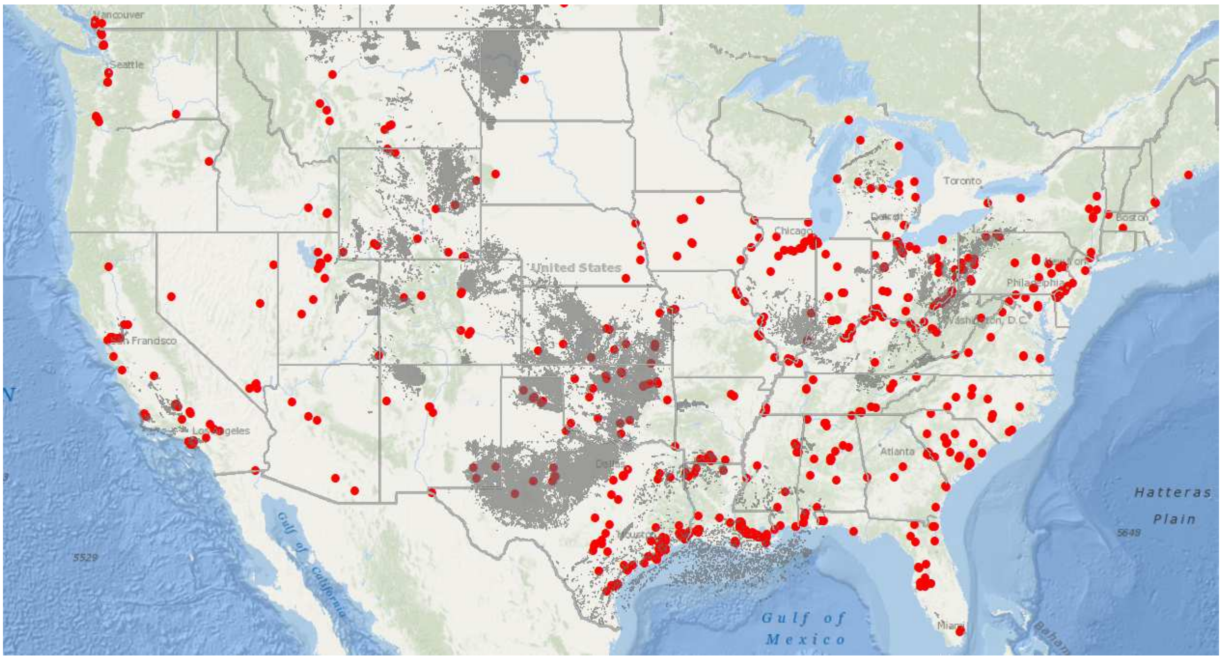


Figure 2. Crude oil production via EOR in the U.S., 1986-2014. Data from Kuuskraa and Wallace 2014

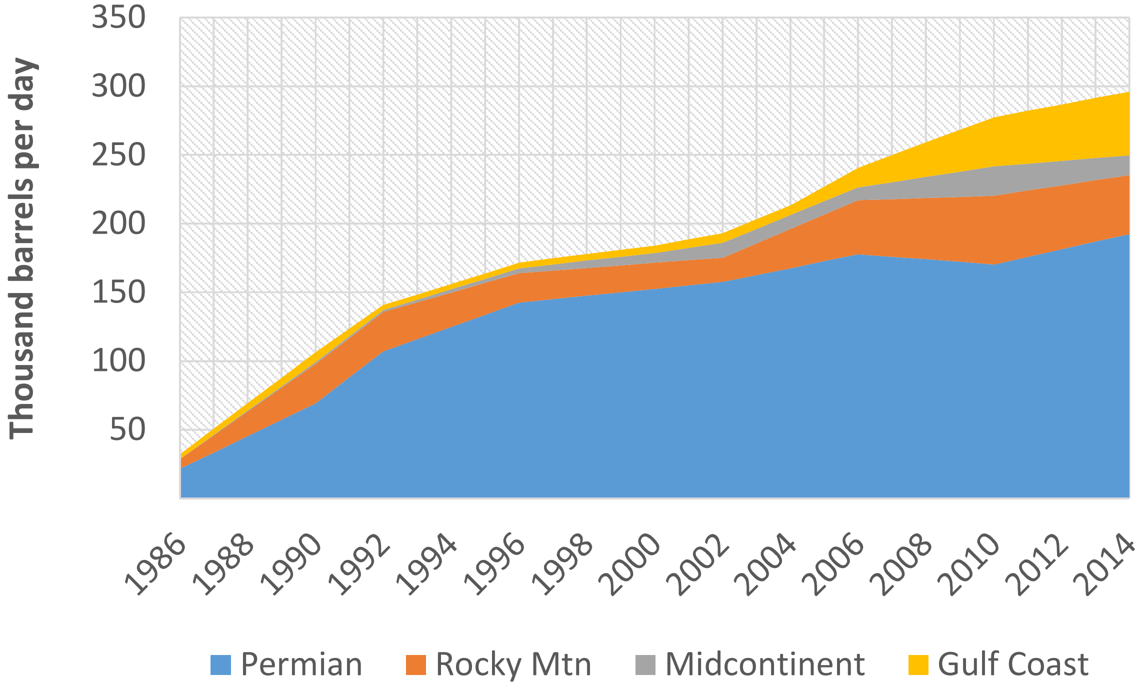


Figure 3. Annual emission and from point sources of CO_2 emissions in Louisiana (2015). Data from EPA 2017

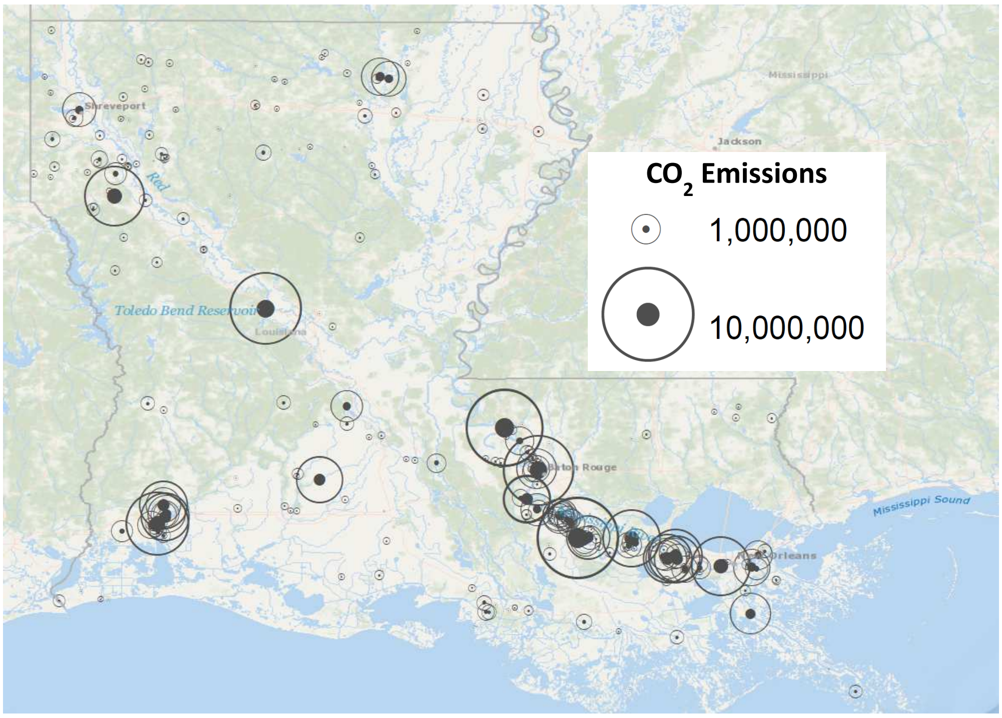


Figure 4. Point sources of high purity CO_2 in Louisiana by annual emissions (top) and high purity source production processes (bottom)

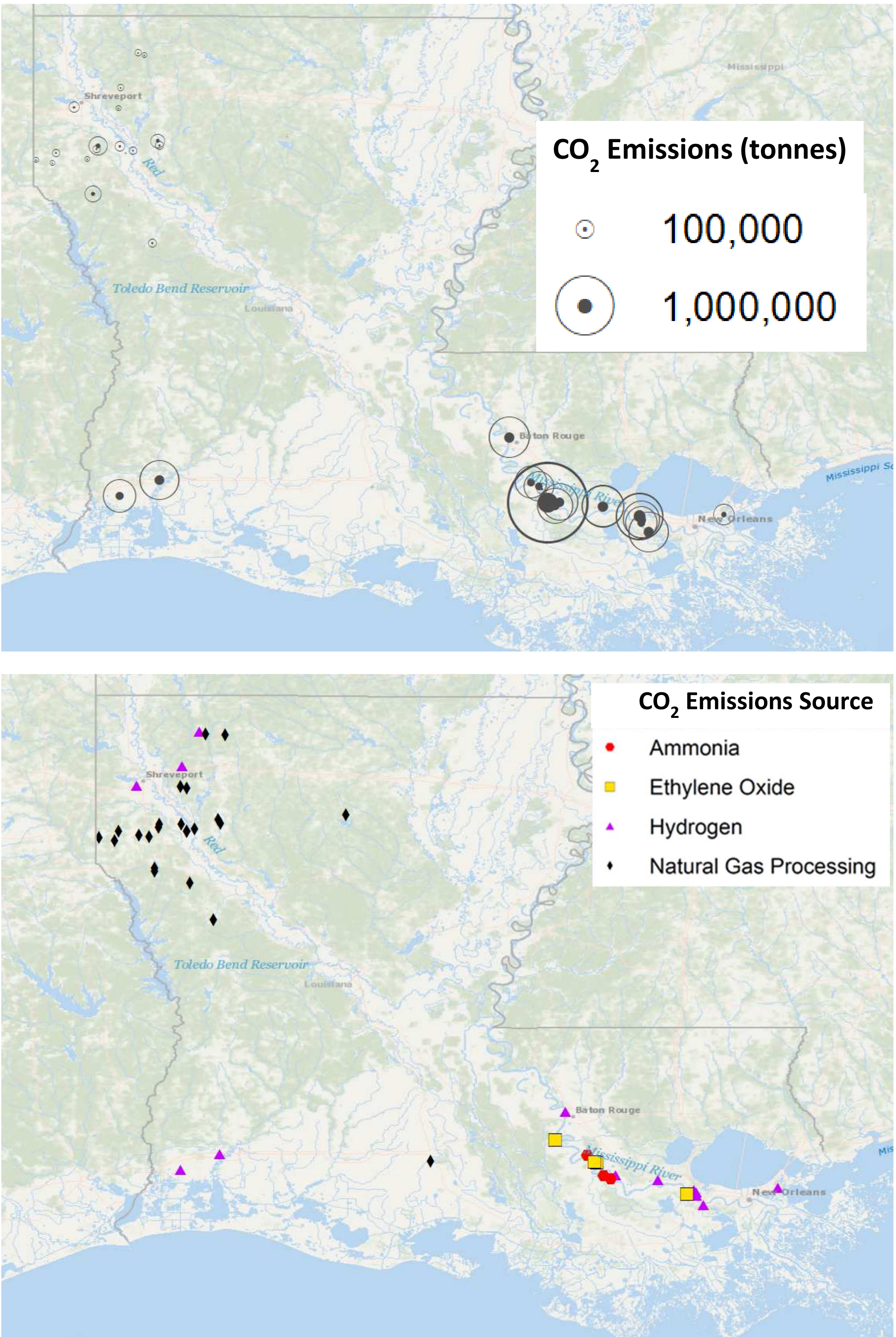


Figure 5. Diagrammatic depiction of the model system

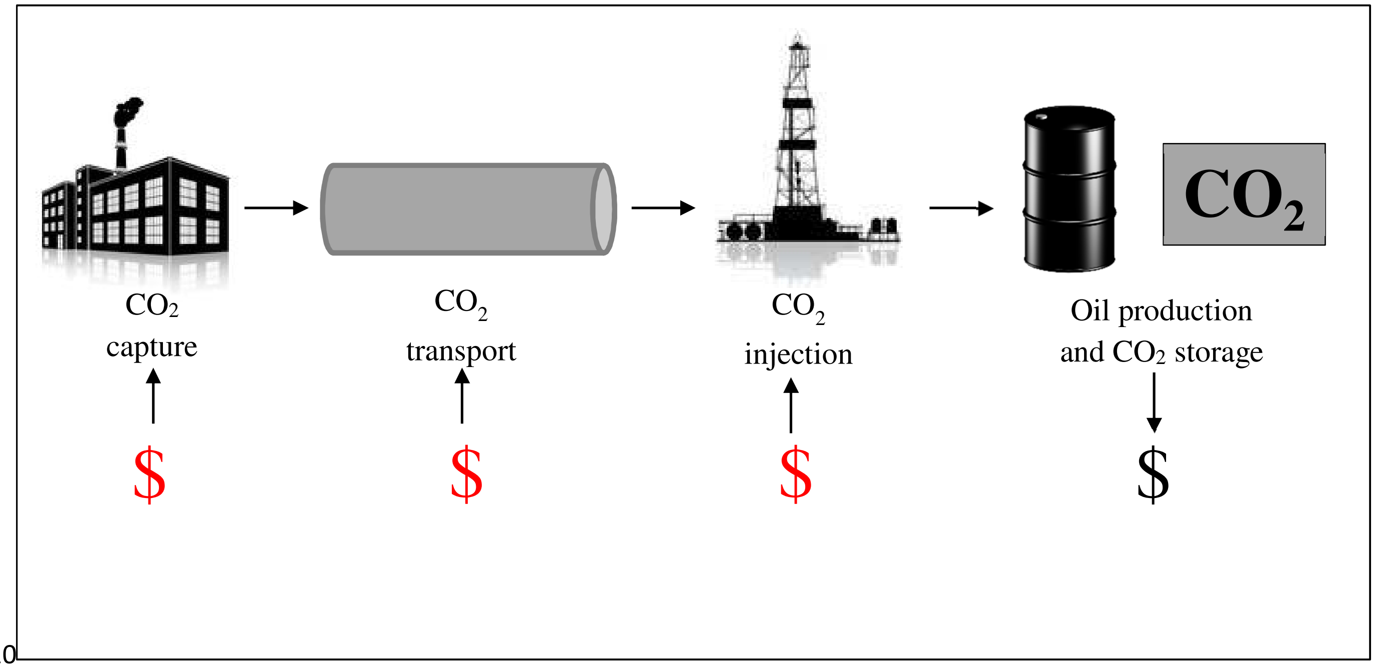
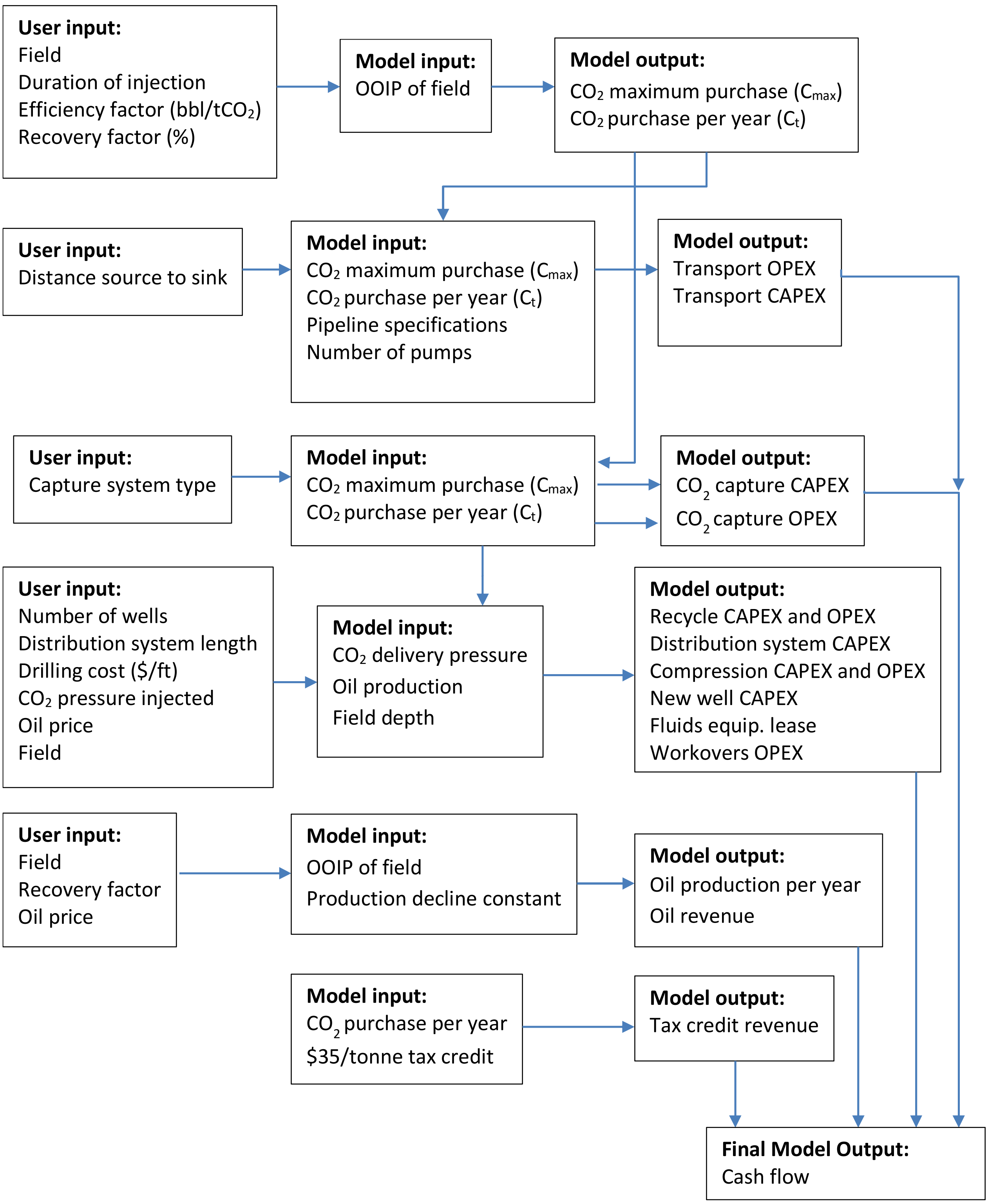


Figure 6. Schematic depiction of the integrated techno-economic model



722 **Figure 7.** Nonlinear relationships between facility emissions and the breakeven cost in the
723 Summers et al. (2014) model.

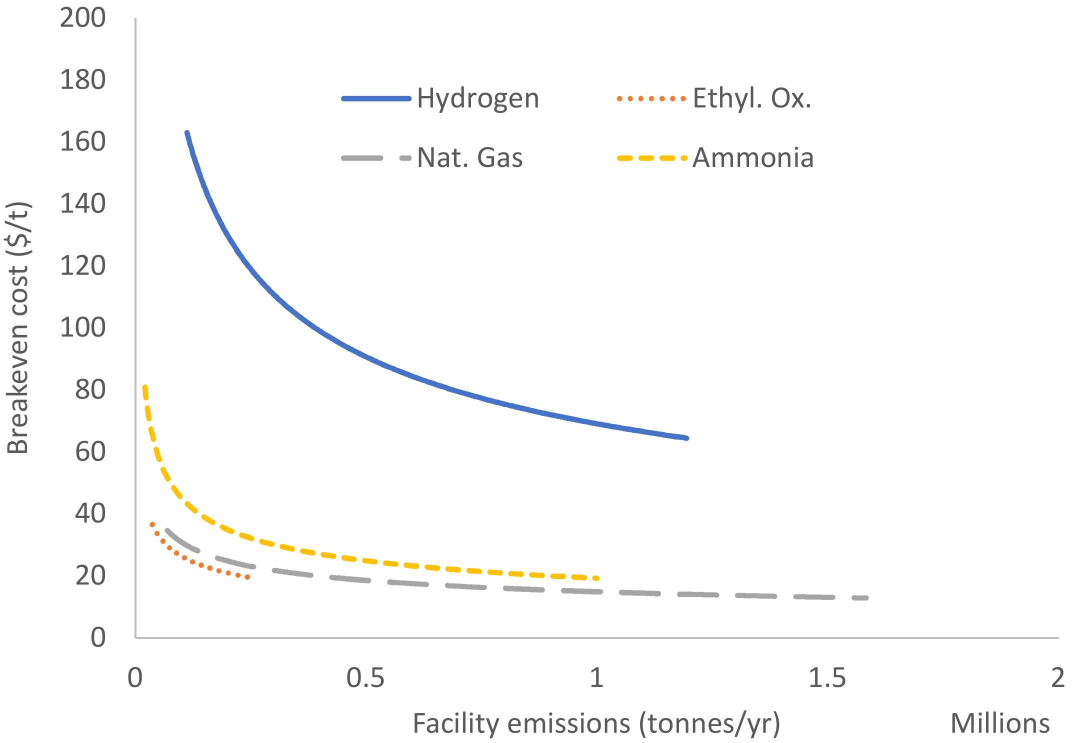


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Figure 8. Modeled oil production, CO_2 purchases, and CO_2 emissions from combustion of produced oil from the Paradis oil field

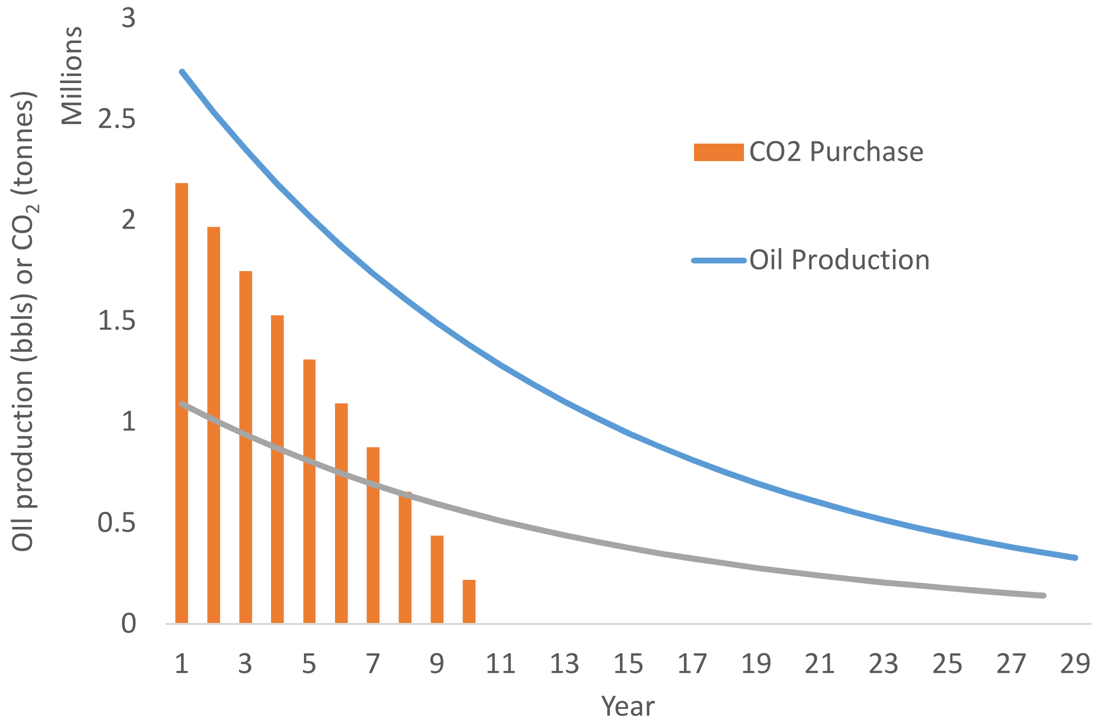

Figure 9. Discounted cash flows from an ammonia-based EOR system with and without the EOR tax credit