IOPscience iopscience.iop.org

Home Search Collections Journals About Contact us My IOPscience

The system-wide economics of a carbon dioxide capture, utilization, and storage network: Texas Gulf Coast with pure CO_2-EOR flood

This content has been downloaded from IOPscience. Please scroll down to see the full text.

2013 Environ. Res. Lett. 8 034030

(http://iopscience.iop.org/1748-9326/8/3/034030)

View the table of contents for this issue, or go to the journal homepage for more

Download details:

IP Address: 198.216.9.15
This content was downloaded on 22/06/2016 at 20:08

Please note that terms and conditions apply.

OPEN ACCESS
IOP PUBLISHING ENVIRONMENTAL RESEARCH LETTERS
Environ. Res. Lett. **8** (2013) 034030 (16pp) doi:10.1088/1748-9326/8/3/034030

The system-wide economics of a carbon dioxide capture, utilization, and storage network: Texas Gulf Coast with pure CO_2-EOR flood

Carey W King[1], **Gürcan Gülen**[2], **Stuart M Cohen**[3,5] **and Vanessa Nuñez-Lopez**[4]

[1] Center for International Energy and Environmental Policy, The University of Texas at Austin, 2275 Speedway, Stop C9000, Austin, TX 78712, USA
[2] Center for Energy Economics, Bureau of Economic Geology, The University of Texas at Austin, 1801 Allen Parkway, Houston, TX 77019, USA
[3] Mechanical Engineering Department, The University of Texas at Austin, 204 E Dean Keeton Street, Stop C2200, Austin, TX 78712, USA
[4] Bureau of Economic Geology, The University of Texas at Austin, 10100 Burnet Road, Building 130, Austin, TX 78758, USA

E-mail: careyking@mail.utexas.edu, gurcan.gulen@beg.utexas.edu, stuart.cohen@nrel.gov and vanessa.nunez@beg.utexas.edu

Received 28 March 2013
Accepted for publication 15 August 2013
Published 9 September 2013
Online at stacks.iop.org/ERL/8/034030

Abstract
This letter compares several bounding cases for understanding the economic viability of capturing large quantities of anthropogenic CO_2 from coal-fired power generators within the Electric Reliability Council of Texas electric grid and using it for pure CO_2 enhanced oil recovery (EOR) in the onshore coastal region of Texas along the Gulf of Mexico. All captured CO_2 in excess of that needed for EOR is sequestered in saline formations at the same geographic locations as the oil reservoirs but at a different depth. We analyze the extraction of oil from the same set of ten reservoirs within 20- and five-year time frames to describe how the scale of the carbon dioxide capture, utilization, and storage (CCUS) network changes to meet the rate of CO_2 demand for oil recovery. Our analysis shows that there is a negative system-wide net present value (NPV) for all modeled scenarios. The system comes close to breakeven economics when capturing CO_2 from three coal-fired power plants to produce oil via CO_2-EOR over 20 years and assuming no CO_2 emissions penalty. The NPV drops when we consider a larger network to produce oil more quickly (21 coal-fired generators with CO_2 capture to produce 80% of the oil within five years). Upon applying a CO_2 emissions penalty of 60\$2009/tCO_2 to fossil fuel emissions to ensure that coal-fired power plants with CO_2 capture remain in baseload operation, the system economics drop significantly. We show near profitability for the cash flow of the EOR operations only; however, this situation requires relatively cheap electricity prices during operation.

Keywords: carbon capture and storage, CO_2, enhanced oil recovery, economics
S Online supplementary data available from stacks.iop.org/ERL/8/034030/mmedia

1. Introduction

The capture and storage of carbon dioxide (CO_2) emissions from point source locations, such as coal-fired power plants, can play a major role in mitigating greenhouse gas (GHG)

Content from this work may be used under the terms of the Creative Commons Attribution 3.0 licence. Any further distribution of this work must maintain attribution to the author(s) and the title of the work, journal citation and DOI.

[5] Present address: National Renewable Energy Laboratory, 15013 Denver West Parkway, Golden, CO 80401, USA.

emissions (IPCC 2005). While the cost of the CO_2 capture is the majority of total system cost for carbon capture and storage (CCS), possibilities for utilization of that captured CO_2 (carbon capture utilization and storage, or CCUS) can create a broader economic picture. One existing example of utilizing CO_2 for economic purposes is CO_2-based enhanced oil recovery (EOR). CO_2-EOR has been occurring since 1972 in the Permian Basin of West Texas (NETL). To date, there has been very little use of anthropogenic CO_2 for EOR (e.g., Weyburn–Midale field in Saskatchewan, Canada) due to the lack of development of at-scale CO_2 capture facilities on fossil power plants.

The state of Texas has more coal-fired power plants and consumes more coal than any other state in the US. There are many mature oil fields relatively near these coal-fired power plants. Previous work at the Gulf Coast Carbon Center of the Bureau of Economic Geology categorized many of the mature oil fields in the Texas Gulf Coast as candidates for CO_2-EOR (Holtz *et al* 1999, Nuñez-Lopez *et al* 2008). The present authors have published several previous analyses of the linkages and cash flows for integrating coal-fired power plants with CO_2 capture into the Electric Reliability Council of Texas (ERCOT) grid and using some of the captured CO_2 for EOR (Cohen *et al* 2011, King *et al* 2011, 2009). These previous CCUS studies were limited to either generalizing costs and oil recovery rates over a large number of oil fields or linking one power plant to one EOR field.

For the present analysis, we build upon our previous works to model several coal-fired power plants and ten CO_2-EOR candidate oil fields (see tables S1 and S2 in the supplemental information, available at stacks.iop.org/ERL/8/034030/mmedia) while considering individual heat rates for power plants and specific geologic characteristics of the EOR fields. This letter takes a 'system-wide' look at an entire CCUS system in Texas using:

(1) a dispatch model for the actual power plant fleet of the ERCOT grid in which we model selected coal-fired power plants as being retrofitted to capture CO_2 emissions;
(2) geologic characteristics of ten mature oil fields in the Texas Gulf Coast that are applicable for miscible CO_2-EOR;
(3) geologic characteristics of deep saline reservoirs above or below the EOR fields (a 'stacked storage' concept) in which all captured CO_2 that is not destined for EOR is injected for permanent storage; and
(4) a pipeline network that connects the selected capture facilities with the 'stacked storage' locations.

In this analysis, the 'CCUS system' is composed of the following investments:

(1) the *capital and operating costs of the retrofitting* of amine-based post-combustion CO_2 capture at selected coal-fired power plants;
(2) the *capital and operating costs of a new* CO_2 pipeline network; and
(3) the *capital and operating costs for wells* at stacked storage locations where drilling, production, and injection operating companies produce oil via CO_2-EOR and inject all excess CO_2 into saline formations.

A couple of studies provide relevant background to this present letter. Ghomian *et al* (2008) evaluates the economics of CO_2-EOR value chain in a similar fashion to our analysis. They consider costs of carbon capture, transportation of captured CO_2 to oil field and EOR operations in a discounted cash flow analysis. The most detailed part of their analysis is the reservoir simulations they conduct to differentiate across various reservoirs types, well spacing, and the use of water alternating gas (WAG) or continuous CO_2 injection methods. However, they do not conduct a system-wide analysis to test boundary conditions nor do they model the electricity sector independently. They find that CO_2 sequestration in oil fields would require additional incentives in the oil price environment of the mid-2000s. When they update their analysis with higher prices of 2007–2008, the need for incentives disappears (Ghomian *et al* 2008).

In another similar techno-economic analysis, Ravagnani *et al* (2009) evaluate the economics of capturing CO_2 from a fertilizer plant in Brazil, transporting and using it in EOR in a hypothetical oil field (Ravagnani *et al* 2009). In addition to economics, the authors also investigate energy and emission balances of the CO_2-EOR value chain. Similar to Ghomian *et al* (2008) they conclude that with higher oil prices, CO_2 sequestration is economically viable even without CO_2 credits although they also point out that credits, if high enough, would have a significant impact on the project. They also conclude that EOR-sequestration is reducing overall emissions.

Our analysis adds value to the existing literature in that we consider the costs of sequestering CO_2 in saline reservoirs in addition to costs and revenues from EOR operations. Our case study reservoirs within the Gulf Coast of Texas provide relevant context given the possible use of 'stacked storage' where oil can be produced from one geologic layer while storing CO_2 in saline formations above or below that oil reservoir (Ambrose *et al* 2009, 2011, King *et al* 2011, Zahid *et al* 2012). We describe a range of system-wide economic outcomes for linking multiple existing CO_2 sources and multiple sinks by using bounding scenarios on the deployment rate and extent of a CCUS network. In this way, businesses and government entities understand the range of possibilities regarding the system costs and benefits as well as different business relationships that are possible. Some previous work discusses CO_2 prices and business relationships among entities involved in CCUS for EOR (Agarwal and Parsons 2011, Esposito *et al* 2011). Agarwal and Parsons (2011) discuss how combinations of assumed contract oil and CO_2 sales prices between a power plant and oil field operator shifts the profits from one to the other. Esposito *et al* (2011) layout how different business models ('self-build', 'joint venture', and 'pay at the gate') provide tradeoffs in risk and reliability between electric power and oil production. Our present work adds value by providing economic information for business entities to understand their role and risk in these or other types of cooperative CCUS business models.

Table 1. Description of four scenarios run to bound the cash flow analysis for the modeled system producing oil from ten EOR reservoirs from a given number of electric generating units (EGUs).

		Economic scenarios	
		CO_2 *sales price,* EOR entities purchase CO_2 from coal-fired power plants with CO_2 capture	CO_2 *emissions penalty* on total emissions from (1) electricity from coal, natural gas (NG), and oil; (2) combustion of oil from EOR
Operational scenarios	'*Slow' EOR production,* three coal EGUs have CO_2 capture; oil is produced at a nearly constant rate over 20 years	Scenario 1	Scenario 2
	'Fast' EOR production, 21 coal EGUs have CO_2 capture; the majority of oil produced in $<$10 years	Scenario 3	Scenario 4

We realize that our target system exists effectively as a link between the ERCOT electric market and the (world) oil market. Our scenarios have impacts on electricity and petroleum product prices; they also involve large scale capital investment, which will have multiplier effects on the rest of the regional economy. We do not analyze these larger economic impacts in this research.

2. Description of CCUS network and scenarios

2.1. Scenario descriptions

Table 1 shows the four scenarios that are combinations of two *operational* scenarios and two *economic* scenarios. This approach provides a means to explore some bounding cases to provide perspective on different CO_2 price and emissions penalty scenarios such that information exists to contemplate possible business relationships and overall system economics.

The 'slow' and 'fast' *operational scenarios* describe the rate of oil production from the modeled candidate EOR fields. The 'slow' scenarios are designed such that oil is developed over a 20-year time span and the *annual needed delivery of* CO_2 is approximately constant. In this sense, the 'slow' scenarios approximate an optimal situation for a coal-fired power plant owner that must invest in CO_2 capture capital equipment and wishes that investment to be fully utilized until fully amortized. The 'fast' scenarios are defined such that all EOR fields drill all wells, install all capital, and begin operations at all wells at the beginning of the 20-year period (within the first three years). In this sense, the 'fast' scenarios approximate an extreme case for capital investment of EOR developers in that they would produce the oil as fast as possible (though not necessarily a realistic business case). These 'fast' scenarios estimate an upper bound on the total quantity of capital investment for the whole system in that much more capital is needed to deliver larger quantities of CO_2 during the first few years relative to all years in the 'slow' scenarios. The 'fast' scenarios necessitate larger capital investment for all three parts of the CCUS network: CO_2 capture, pipelines, and oil/CO_2 storage field operations. For a given injection and production well pattern, our CO_2-EOR model (using the Prophet program) models some delay in oil production relative to the delivery of CO_2 to allow for buildup of pressure.

The 'CO_2 sales price' and 'CO_2 emissions penalty' *economic scenarios* capture two commonly discussed options for reducing CO_2 emissions with different dynamics. They represent internal (CO_2 sales) or external (CO_2 emissions penalties) economic drivers to encourage investment in the CCUS network. In the 'CO_2 sales price' scenarios, there is no penalty (e.g. tax) for emitting CO_2 to the atmosphere, and the 'CO_2 sales price' is that price that an EOR operator pays to the coal-fired power plant for CO_2. Thus, the customer that buys electricity and/or oil does not (in large) notice the effect of this CO_2 sales transaction (via impacts on electricity or oil prices) that is internal to our modeled CCUS network. On the other hand, the 'CO_2 emissions penalty' cases represent the impact upon the modeled CCUS system of a penalty for the CO_2 emissions from burning fossil fuels consumed (for electricity) or produced (for oil) by our modeled CCUS system. Thus, an electricity or oil products (e.g. gasoline) customer would more directly notice price increases in the 'CO_2 emissions penalty' cases, but we do not model any price-related feedbacks on energy demand.

2.2. CO_2-enhanced oil recovery modeling and cost assumptions

To estimate the CO_2 injection and oil production profiles for an inverted five-spot pattern[6], we used CO_2-Prophet, a CO_2 flood prediction software that generates streamlines between injectors and producers and estimates displacement and recovery through a finite difference routine. One of the motivations of this work is to consider economic scenarios handling large volume flow rates of CO_2, so our EOR modeling in Prophet is based upon continuous CO_2 injection, not the more common EOR practice of WAG where both water and CO_2, the 'gas', are injected through the same wells in an alternating manner over the life of the well. The choice of EOR candidate fields comes from a coauthor's previous assessments and represents fields with a range of

[6] One injection well surrounded by four equally spaced production wells.

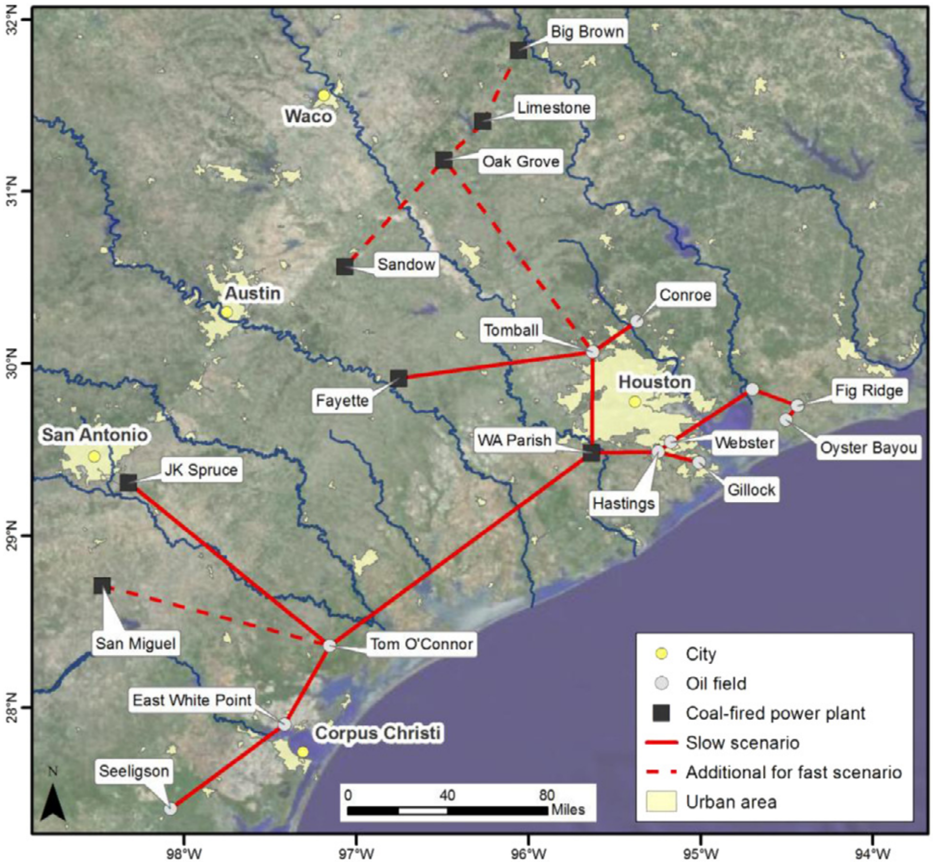

Figure 1. The pipeline network for the *slow oil production scenarios* consists of approximately 540 miles of pipe of various diameters from 8 to 20 in. The pipeline network for the *fast oil production scenarios* consists of approximately 1400 miles of pipe of various diameters from 8 to 20 in. Note that 4 segments (including the 'trunk' line connecting WA Parish and Tom O'Connor) are assumed to have 3 parallel 20 in pipelines, and 2 segments are assumed to have 2 parallel 20 in pipelines.

sizes and qualities (Nuñez-Lopez *et al* 2008). The fields are not specifically chosen to be the most or least profitable prospects. In addition, four of the EOR fields are in south Texas near the Corpus Christi area, and the other six EOR fields lie closer to Houston. Thus, we have included some geographic diversity to consider the connectivity of coal-fired plants in different regions of the state (see figure 1). Table S1 of the supplementary information (available at stacks.iop.org/ERL/8/034030/mmedia) lists the EOR fields, along with the number of wells (oil production, CO_2 injection, and water injection) assumed for each field.

The assumed profiles for CO_2 and oil flows are based upon recent CO_2-EOR activity in a Texas Gulf Coast oil field (Davis *et al* 2011). This particular oil field development is somewhat unique in that it employs continuous CO_2 injection, just like we do in our modeling. We do model some water injection wells, but these water injection wells are meant to create a 'curtain' of water and pressure at the edge of the displacement area that minimizes CO_2 loss from the targeted part of the reservoir (Davis *et al* 2011).

Based on limited CO_2-EOR experience in the US Gulf Coast, specifically related to projects where only CO_2 is continuously injected (not WAG), our main assumptions for EOR are that (i) injection continues until either 20 years is reached or a total quantity of CO_2 injected is an amount equal to 500% of the hydrocarbon pore volume (HCPV) of each reservoir (Davis *et al* 2011), (ii) approximately 12–16% of the original oil in place (OOIP) is recovered from each field, and (iii) that CO_2 injection occurs at a pressure that is 90% of the fracture pressure of the reservoir. For each well pattern, the injection pressure assumption models the oil production in a close to 'as fast as possible' manner. By staggering the dates to start each pattern of wells, we can design various plans for the development for the entire oil field over time. The supplemental information (available at stacks.iop.org/ERL/8/034030/mmedia) details the capital and operating costs models for well drilling and operation of CO_2 injection and oil production wells. Table S2 of the supplementary information (available at stacks.iop.org/ERL/8/034030/mmedia) lists the oil recovery, CO_2 delivery, and time period of oil production for each EOR field.

Major assumptions for assessing the capital and operating costs for CO_2-EOR are as follows (see the supplemental information for more details).

- *Drilling costs.* Drilling costs of both oil production and CO_2-EOR injection wells are assumed at 50% of the cost of drilling a new well. This capital cost assumption translates to our assumed use of existing oil production and water injection wells at the EOR candidate fields and that reworking and/or side-track drilling the wells is estimated at half the cost of a new well. Analysis of data in the Joint Association Survey on Drilling Costs supports the idea that wells drilled by side-tracking cost 40%–80% of the cost of a newly drilled well.

- *Lease costs.* Lease costs are a combination of costs for primary oil production and additional lease costs for CO_2-EOR. We largely follow the method described in ARI (2006) as outlined in the supplemental information.
- CO_2 *recycling capital.* We assume the full capacity capital costs ($700 000 per peak million cubic feet per day of recycled CO_2) of a CO_2 recycling plant at each EOR field occur during the year that CO_2 recycling is first required. We do not assume the CO_2 plant is upgraded or expanded at any time but it is installed a full capacity even if full capacity is not needed until several years later.
- *Electricity and lifting.* The quantity of electricity for compressing and pumping CO_2 follows the McCullom and Ogden method for CO_2 compression to supercritical and higher pressures as needed for EOR operations (McCullom and Ogden 2006). Other lifting electricity needs come from (ARI 2009).
- *General and administrative costs.* Additional costs administrative costs are added equal to 20% of lifting plus both water and CO_2 injection costs (per ARI 2006).

2.3. CO_2 storage in saline reservoirs modeling and cost assumptions

Major assumptions in assessing the capital and operating costs for CO_2 injection into saline reservoirs are as follows (see the supplemental information for more details).

- *Drilling costs.* The capital drilling costs for CO_2 saline injection wells are assumed the same as the full cost of drilling a new oil well.
- *Lease costs (capital and O&M).* Both capital and O&M lease costs are assumed equal to the additional lease costs for CO_2-EOR.
- *CO_2 pumping electricity.* The CO_2 arrives to the saline injection site in supercritical condition in the pipeline, and additional CO_2 pumping electricity is assumed at 5 kWh/BBL of supercritical CO_2 (ARI 2009).

2.4. Pipeline network configuration modeling assumptions

Because the foci of this analysis are the coal-fired power plants with CO_2 capture and EOR/CO_2 storage operations, each scenario uses a relatively simple pipeline network assumption that is not a complete analysis of the requirements for operating the pipeline network. We do not calculate needs for booster pumps or specifically estimate pipeline operating electrical demands. For the construction costs of the pipelines, and determination of the diameter of the pipeline for a given CO_2 flow rate, we follow previous methods (Herzog and Javedan 2010). The sizing and capital cost model for the pipeline is detailed in the supplemental information. Figure 1 shows the conceptual layout of the pipeline network for both the 'slow' and 'fast' scenarios.

2.5. ERCOT electric grid dispatch and CO_2 capture at coal-fired power plants

This work uses a first-order electricity dispatch model to estimate the wholesale electricity price and dispatch of power plants on the ERCOT grid. In this model, the fixed and variable operating costs for each power plant in ERCOT are used as a basis for economic dispatch. At a given load, these operating costs determine the marginal operating power plant such that all power plants with higher operating costs are not dispatched. We do not model transmission expansion or transmission constraints. Previous work has used the same model to explore the implications of flexible CO_2 capture operations in the ERCOT and Great Britain grids (Cohen 2009, Cohen *et al* 2009, 2011, Ziaii *et al* 2008). Please refer to these publications for more detail.

We do not impose retirement or fuel conversion of any ERCOT power plant over the 20-year time horizon of our scenarios. Coal-fired power plants that are likely to sign long-term contracts to provide CO_2 to EOR operators are not likely to retire. ERCOT includes many coal-fired power plants that we did not model with CO_2 capture, and these units not modeled in our scenarios are those that are (i) older, (ii) less efficient, and (iii) without as many criteria emissions controls. Thus, we chose coal-fired power plants that would be most likely to capture CO_2 within the scope of our scenarios. Most of the coal-fired generating units we model with CO_2 capture are less than 40 years old. Clearly, there is a risk of new regulations (e.g., on mercury emissions) that could force these plants to shut down. It is most likely that some coal fired and other power plants will retire during the time frame of our analysis, but considering these changes is outside of the scope of this present work.

We assume the demand for electricity in ERCOT is the same in each of our system scenarios. We ignore impacts on demand of changes in electricity price due to CO_2 sales revenues or CO_2 taxes. The ERCOT annual load for the first year (2012) is 328 TWh, and we forecast it to increase at approximately 2.3% yr^{-1} to 523 TWh in 2031 (ERCOT 2011).

For each scenario, we specifically chose the CO_2 sales price and CO_2 emissions penalty to equal the approximate level that makes the chosen subset of coal-fired power plants operate at baseload capacity factors. In other words, if the CO_2 sales price were lower, all of the chosen coal-fired power plants would operate at lower than baseload capacity over the 20-year simulation horizon, and if the CO_2 sales price were higher, they would not operate at any significantly higher capacity factor. The same rationale was used to set the level of the CO_2 emissions penalty: the penalty was chosen such that it was just at the level to enable our chosen subset of coal-fired power plants to operate at baseload conditions for the 20-year time horizon.

Table S3 (available at stacks.iop.org/ERL/8/034030/mmedia) of the supplemental information shows the chosen subset of existing ERCOT coal-fired power plants that were modeled with retrofitted amine-based post-combustion CO_2 capture. The amine capture unit is assumed to require

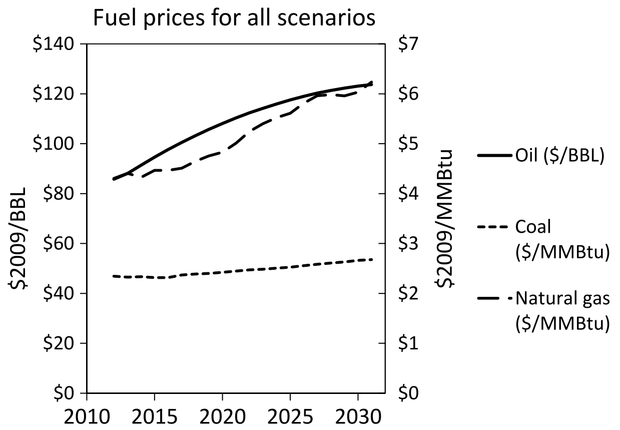

Figure 2. The fossil fuel prices assumed for the models and cash flow analysis affect electricity generation dispatch, costs, and revenues, as well as revenues and costs for EOR oil production. Low sulfur light crude oil price is used.

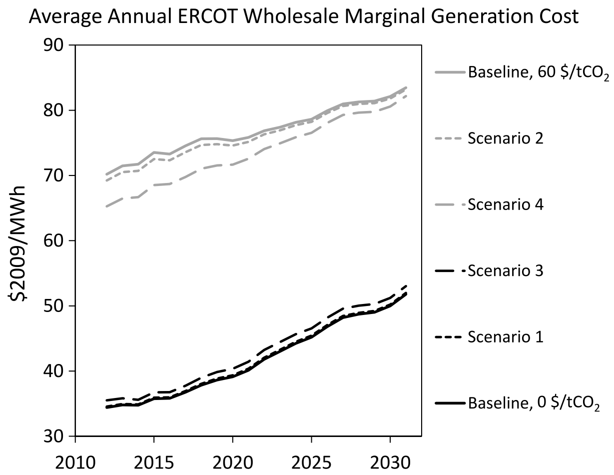

Figure 3. The average annual marginal generation cost approximates the wholesale price of energy in ERCOT. The CO_2 penalty of 60\$/tCO_2, held at constant real value for each year in scenarios 2 and 4, raises the marginal cost of electricity by 30–35\$ MWh^{-1} (approximately the emissions cost from natural gas generation). The CO_2 sales price scenarios have approximately the same marginal cost as if there were no coal-fired power plants with CO_2 capture.

0.27 MWh/tCO_2 to remove 90% of the CO_2 from flue gas, which translates to a 22–32% net power output penalty depending on the base plant efficiency (Ziaii *et al* 2008). Capacity lost to CO_2 capture energy requirements could be replaced by new generating units, demand response, or increased efficiency and conservation. Examining these options is outside the scope of this work, but other literature suggests replacement capacity might not be necessary if capture systems could be bypassed during infrequent peak demand periods. With the assumed electricity demand and power plant fleet, sufficient capacity exists to substitute for reduced coal-based generation (Chalmers *et al* 2009, Cohen *et al* 2010). For the 'slow' scenarios, fewer coal-fired generators need CO_2 capture facilities because less CO_2 is needed per year than in the first few years of the 'fast' scenarios. Thus, in the 'slow' scenarios, only the following three electric generation units are assumed to capture CO_2: Fayette Power Project unit 1, J K Spruce unit 2, and WA Parish unit 7 (see table S3).

3. Results

3.1. ERCOT grid dispatch

For the purposes of this analysis, the marginal generation cost from our dispatch model approximates the wholesale cost of electricity in ERCOT. The assumptions for fuel prices (see figure 2) and other operating costs drive the upward electricity price trends in figure 3. The projected fuel costs were taken from the EIA Annual Energy Outlook (AEO) 2011 (AEO table 1 for oil) (EIA 2011) and AEO 2012 early release (AEO table 3 for natural gas and steam coal for electricity). For all results, prices and costs are presented in constant year 2009 dollars ($2009).

We present the modeled CO_2 emissions from the ERCOT electric grid (see figure 4) during the 20-year time span of our scenarios to create context for the large flows of CO_2 by our subset of coal-fired facilities. These CO_2 emissions originate primarily from coal and natural gas combustion, with minor quantities from other fossil fuels. The total modeled 20-year CO_2 emissions from the grid for scenarios 1–4 are 4300, 2800, 3200, and 2400 MtCO_2, respectively. The baseline (business as usual) modeled emissions for the grid with no CO_2 capture and no CO_2 emissions penalty is 4500 MtCO_2 over the 20-yr time span.

Figures S1(a)–(d) (available at stacks.iop.org/ERL/8/034030/mmedia) show the electricity generation mix calculated for each scenario. Note that in all scenarios we assume that the demand for electricity in ERCOT is the same each year (e.g. the quantity of electricity generation that consumers purchase is not affected by prices). This assumption keeps the scenarios simple for straightforward comparison. In reality, the scenarios with \$60/tCO_2 emissions penalty have significantly higher wholesale prices of electricity that would reduce demand to some degree.

Due to the variations in marginal price of electricity for each scenario and the assumption of inelastic electricity demand, the total operating profits earned by all generators in ERCOT varies considerably (see figure 5). Here we define operating profits as 'operating revenues minus operating costs', and revenues to generators in ERCOT come from selling electricity. Revenues also come from CO_2 sales for those coal-fired power plants with CO_2 capture in the 'CO_2 sales price' scenarios 1 and 3. Over the modeled 20-year time span, the operating profits for scenarios 1–4 are 96, 181, 107, and 179 billion $2009, respectively. We can reasonably deduce that total ERCOT operating profits are the same between each 'CO_2 sales price' scenario and between each 'CO_2 emissions penalty' scenario.

3.2. CO_2 enhanced oil recovery

Figure 6 shows the oil production and net CO_2 delivered for EOR. One can clearly visualize the front-loaded nature

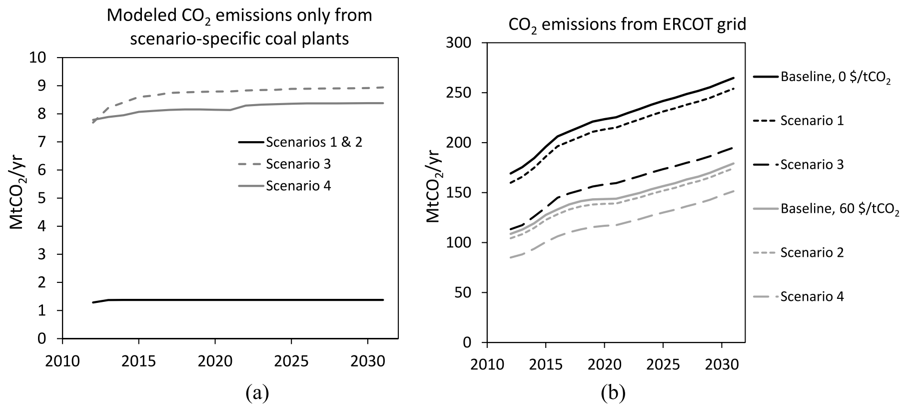

Figure 4. The CO_2 emissions from the ERCOT coal fleet (a) and total ERCOT electric grid (b) are different for each scenario. (a) The emissions from the scenario-specific coal-fired plants are highest for scenarios 3 and 4 that, by definition, include more coal-fired power plants. (b) To conceptualize the quantity of CO_2 captured in each scenario, we show two baseline results for comparison in which no CO_2 is captured. 'Baseline: no emissions penalty, no sales price, no CO_2 capture' compares to scenarios 1 and 3 in which there is no emissions penalty. 'Baseline: \$60/tCO$_2$ emissions penalty with no CO_2 capture' estimates the emissions from ERCOT generators when an emissions penalty exists but no generators have CO_2 capture.

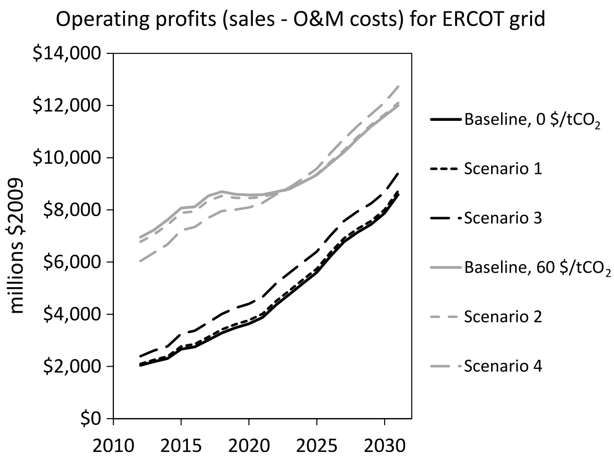

Figure 5. The operating profits (all revenues from CO_2 and electricity sales minus all operating costs) for each scenario for all electricity generators in ERCOT show a considerable jump for the 'CO_2 emissions penalty' scenarios because of the assumption that consumers will not lower consumption at higher electricity prices.

of investment for scenarios 3 and 4 where drilling and oil operations occur as early as possible. Our analysis ends after 20 years, but according to our field-specific modeling, there would still be significant oil production after 20 years for all scenarios, especially in scenarios 1 and 2. The total oil production within 20 years is 350 MMBBL for scenarios 1 and 2 and 480 MMBBL for scenarios 3 and 4. There are slight differences in the oil and CO_2 delivery profiles between scenarios 3 and 4, and these minor differences are driven by the modeled rate of CO_2 capture from the electricity dispatch model. In scenario 3, the CO_2 sales price affects dispatch of the coal-fired plants with CO_2 capture slightly differently than in scenario 4 with the CO_2 emissions penalty. The differences are minor and insignificant when interpreting cash flow results.

Table 2 lists non-discounted capital, and operation and maintenance (O&M) costs per barrel (BBL) of produced oil, over 20 years, for each of the ten EOR fields and for the aggregated system. Different values exist for scenarios 1 and 2 versus scenarios 3 and 4 because our EOR cost model calculates capital and O&M costs as a function of the assumed exogenous oil price, the drilling sequence is significantly different in the 'slow' versus 'fast' scenarios, and more oil is produced in the 'fast' scenarios 3 and 4 compared to 'slow' scenarios 1 and 2.

Table 2 summarizes capital and operating expenses for our EOR cash flow model. All values are reported in units of total (non-discounted) dollars per barrel of oil produced within our 20-year scenario. The capital costs are generally higher compared to (Kheshgi *et al* 2010) that report a range of 3–9\$/BBL capital expenditures. This discrepancy is consistent with the fact that our \$/BBL calculation is based on only 20 years of production, does not include the full expected lifetime oil production from each well pattern, and is not based on the quantity proved reserves associated with the capital investment. The O&M costs in table 2 do not include the cost of an oil producer purchasing CO_2, and the costs are all significantly higher than the ranges quoted in Kheshgi *et al* (2010) of 6–15\$/BBL.

The major parameter that affects operating costs is the cost of electricity to an operator. We assume a constant electricity price of 0.05\$ kWh^{-1} as a lower bound on electricity price. Two higher electricity price assumptions, equal to an industrial and residential price, provide medium and upper bounds on the electricity price. The industrial and residential prices are equivalent to the ERCOT average wholesale cost plus 3 and 7 cents kWh^{-1}, respectively. Even in the lowest-price case, the total O&M costs per field are 18–38\$/BBL. The main reason for our higher O&M cost is that we are modeling a CO_2-only EOR operation, instead of WAG, so a much higher quantity of electricity is required to recycle and recompress a larger flow rate of CO_2 per quantity of produced oil. For perspective on the quantity of electricity needed for our modeled scenarios we consider only the separately modeled electricity for three purposes: CO_2

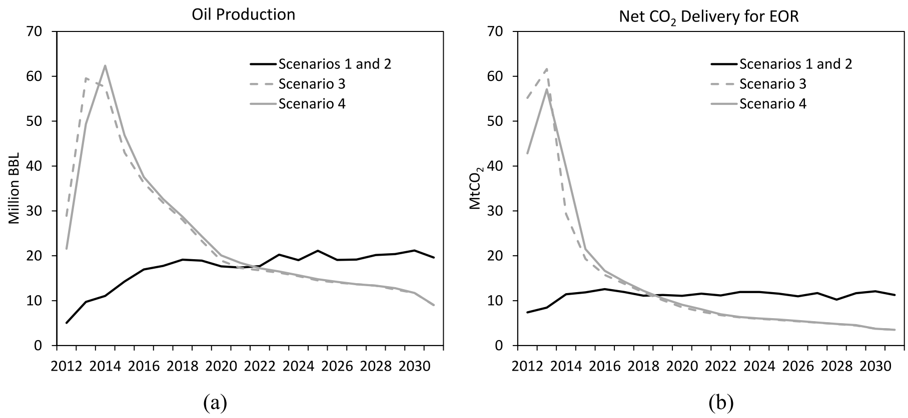

Figure 6. (a) The oil production for each scenario. (b) The quantity of CO_2 delivered specifically for EOR for each scenario.

Table 2. Capital and operating expenditures for each of the ten CO_2-EOR fields analyzed for the Texas Gulf Coast in \$/BBL. We assumed that EOR injection and production wells are drilled by side-tracking existing wells, so that capital costs are assumed at 50% of the cost of a new well.

	'Slow' scenarios 1 and 2	'Fast' scenarios 3 and 4	All scenarios (1/2/3/4)		
	Capital over 20 year (\$/BBL)	Capital over 20 year (\$/BBL)	O&M over 20 year (\$/BBL)		
			Electricity price		
			0.05\$ kWh^{-1}	Industrial	Residential
Conroe	17	12	27/27/35/35	39/55/50/50	58/74/75/75
Hastings	16	12	28/28/35/35	41/57/50/50	61/77/76/76
Webster	17	11	27/27/33/33	39/55/47/47	58/74/70/70
Tom O'connor	11	9	23/23/26/26	32/46/37/37	48/62 /56/56
Seeligson	9	7	20/20/23/22	28/40/33/32	42/54/50/48
Oyster Bayou	13	9	16/16/21/22	23/32/30/31	34/43/45/46
East white point	15	14	28/28/28/28	41/58/39/39	61/78/59/59
Tomball	24	30	38/38/38/38	55/77/50/51	81/104/77/78
Fig Ridge	41	39	28/28/31/31	38/55/39/40	57/74/61/61
Gillock	16	12	18/18/23/23	26/36/32/32	38/49/48/48
All fields	15	12	26/26/31/31	37/52/44/44	55/70/66/66

recompression during recycling, CO_2 pumping for injection for EOR and saline sequestration, and lifting of CO_2 and oil during EOR. These three needs peak at 12, 16, and 17 TWh yr^{-1} for scenarios 1 and 2 (year 19), scenario 3 (year 7), and scenario 4 (year 8), respectively. These peak annual electricity needs are significant on the scale of ERCOT as they equate to approximately 2.3%, 4.1%, and 4.3% of modeled ERCOT electricity demand in each of the respective peak years of need.

3.3. Results scenario 1: 'slow' EOR development, CO_2 sales price and scenario 2: 'slow' EOR development, CO_2 emissions penalty

In order to approximate the delivery of CO_2 for EOR at a constant rate, we aggregated each well pattern into phases of operation equal to 1/6 the total number of wells needed to develop each field. For example, we assume that there will be 211 production and CO_2 injection wells sidetracked in the Conroe field. Thus, each phase of drilling involves approximately 35 wells. In this way we stagger the operation of each phase as necessary to approximate a need for constant CO_2 delivery from the coal-fired power plants. Staggering drilling phases is done to optimize for constant CO_2 delivery, not profitability (i.e. the more profitable fields are not prioritized first with the less profitable fields later) (see figure 7). This approach is consistent with our system-wide scenario framework where we seek to understand bounding cases for a CCUS network. The cash flows for scenarios 1 and 2 are not significantly different for any ordering of EOR development phases, particularly within the accuracy of our capital and operating cost estimates. The oil production increases to 14 MMBBL yr^{-1} by year 4 and stays between 17 and 21 MMBBL yr^{-1} from years 5 to 20 (see figure 8).

For the 'sales price' scenario 1, the price starts at 15\$/tCO_2 in 2012 and increases linearly to 22\$/tCO_2 in 2031, year 20 (see figure 8(a)). This CO_2 sales price is relatively small compared to the oil price, with price ratio of (\$/tCO_2):(\$/BBL) of approximately 0.18:1 (or 3.4\$ per thousand cubic feet (Mcf) of CO_2 per \$/BBL of oil). This sales price largely offsets the increased operating costs of the coal-fired power plants with CO_2 capture and does not materially affect the marginal generation cost of the overall ERCOT grid.

Scenario 2 differs from scenario 1 in that there is an emissions penalty imposed upon CO_2 emissions from

Table 3. Economic parameters and summarized costs for calculating net present value (NPV) for each scenario. All dollars in \$2009.

Economic parameters	Slow scenarios 1 (sales) and 2 (penalties)	Fast scenarios 3 (sales) and 4 (penalties)
Enhanced oil recovery production and costs		
Oil production from EOR (million BBL)	346 (20 years)	480 (20 years)
Total EOR net CO_2 need ($MtCO_2$)	223 (20 years)	284 (20 years)
Peak annual EOR CO_2 purchase need ($MtCO_2$)	13	61 (S3), 57 (S4)
Total EOR capital costs (\$million)—30% tangible	5300 (20 years)	5600 (3 years)
Total EOR O&M costs (\$million)		
Electricity price: 0.05\$ kWh^{-1}	8800 (S1), 8800 (S2)	14 900 (S3), 14 900 (S4)
Electricity price: industrial (variable)	12 700 (S1), 17 900 (S2)	21 100 (S3), 21 000 (S4)
Electricity price: residential (variable)	18 900 (S1), 24 100 (S2)	31 700 (S3), 31 600 (S4)
Sequestration costs		
Total CO_2 sequestered over 20 years ($MtCO_2$)	240	1540 (S3)/1450 (S4)
Peak annual EOR CO_2 sequestered ($MtCO_2$)	2	77 (S3)/72 (S4)
Total sequestration capital costs (\$million)—0% tangible	300 (S1)/308 (S2)	10 000 (S3)/9300 (S4)
Total sequestration O&M costs (\$million)		
Electricity price: 0.05\$ kWh^{-1}	86 (S1), 79 (S2)	5300 (S3), 6200 (S4)
Electricity price: industrial (variable)	101 (S1), 116 (S2)	6300 (S3), 7200 (S4)
Electricity price: residential (variable)	129 (S1), 142 (S2)	7900 (S3), 9000 (S4)
CO_2 pipeline costs		
Pipeline capital cost (\$million)	880	2170 (S3), 1950 (S4)
Pipeline O&M costs over 20 years (\$million)	682 (S1)/685 (S2)	4394 (S3)/4122 (S4)
Pipeline O&M cost[a] ($\$/MscfCO_2$)	0.15	0.15
CO_2 capture installation and costs		
Number of coal generation units with CO_2 capture	3	21
Base installed capacity of units (MW)	1596	10 167
Total CO_2 captured ($MtCO_2$)	240	1542 (Scen 3)/1446 (Scen 4)
CO_2 capture capital costs (\$million)[b]	3083	19 643
Rated capacity with capture (MW)	1980	13 654
Capital investment		
Total system capital investment (\$million)	9700 (S1); 9800 (S2)	32 600 (S3); 32 300 (S4)
Tax rates and royalties		
Total tax on CO_2 capture activities (%)	0	0
Total tax on CO_2 pipeline activities (%)	37	37
State tax on EOR oil (before HB 3732 incentive) (%)	2.3	2.3
Federal tax on EOR oil (no intangible allowances) (%)	35	35
Royalty fee for landowners (%)	20	20

[a] Based on estimates by Denbury for its CO_2 pipeline from Mississippi to East Texas. This pipeline O&M cost is also consistent with O&M costs for natural gas pipelines.

[b] Based on EIA (2010). Capture plant capital costs are calculated by multiplying the difference of overnight CAPEX for new Advanced PC Single Unit with CCS and overnight CAPEX for new Advanced PC Single Unit without CCS (\$5099 kW^{-1}–\$3167 kW^{-1} = \$1932 kW^{-1}) with the base installed capacity of the generation units.

EGUs and from assumed combustion of produced oil (at 0.42 tCO_2/BBL). There is also no CO_2 sales price that EOR operators pay to coal-fired power plants. In effect, the CO_2 is delivered to the EOR fields and saline sequestration sites 'for free' to the field operators. This assumption of 'free CO_2' is a simplification based upon the choice of the emissions penalty price. We do charge EOR and saline sequestration operators a pipeline transport fee (0.8\$/Mcf = 15.2\$/tCO_2).

For the 'emissions penalty' scenario 2, we determined that a constant penalty of 60\$/tCO_2 each year incentivized the three coal-fired generators with CO_2 capture to operate (considering only electricity sales for revenue) at near baseload and capture a similar amount of CO_2 as in scenario 1. Because this emissions penalty induces the coal-fired power plants to operate while capturing CO_2, those coal-fired power plants in ERCOT that do not capture CO_2 are at an economic disadvantage having to pay for CO_2 emissions. Economic dispatch modeling does not yet include capital costs for CO_2 capture infrastructure that we include in the system-wide cash flow.

The quantity of CO_2 emissions from the modeled system is shown in figure 8(b). Over 20 years, 240 Mt CO_2 are captured from coal combustion and sequestered in EOR and saline reservoirs, 146 $MtCO_2$ are emitted from the oil

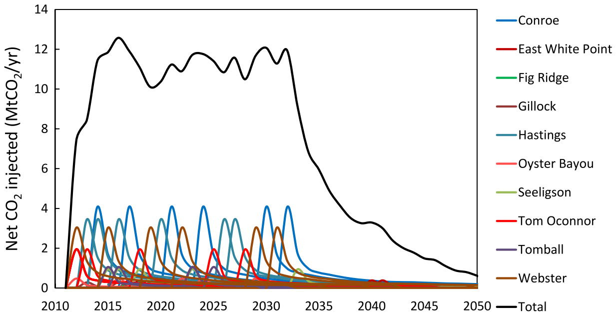

Figure 7. For ‘slow’ scenarios 1 and 2, the net amount of CO_2 injected (equal to CO_2 delivered for EOR) at each EOR field is distributed in time by assuming that each field is developed in six phases. The six phases at each field are started at different times in order to approximate a constant need for CO_2 delivery that closely matches the approximately constant rate of CO_2/yr captured at three base load coal-fired generation units.

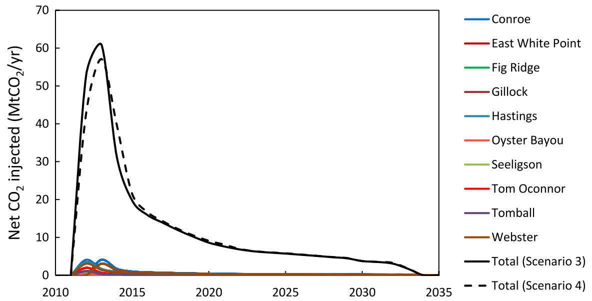

Figure 9. In the ‘fast’ scenarios 3 and 4, the net amount of CO_2/yr injected (equal to CO_2/yr delivered for EOR) at each EOR field over time is front-loaded as if all wells begin operations within the first 3 years of the analysis period.

produced from the CO_2-EOR operations, and 27 $MtCO_2$ are emitted from the power plants with capture. Thus, our modeled system stores a net amount of 66 $MtCO_2$.

3.4. Results scenario 3: ‘fast’ EOR development, CO_2 sales price and scenario 4: ‘fast’ EOR development, CO_2 emissions penalty

For the same CO_2 sales price trajectory as scenario 1, more base load coal-fired power plants are assumed to engage in CO_2 capture and deliver CO_2 for EOR to the same ten EOR fields but at a much faster rate. The EOR production is assumed to occur at a maximum rate where all phases of oil field operations engage in EOR operations within the first three years. This scenario is meant to be an extreme case indicating the shortest timescale for EOR production. CO_2 capture operations continue after EOR production, necessitating that much higher flow rates of ‘excess’ CO_2 (compared to scenarios 1 and 2) are captured and injected into saline reservoirs. Figure 9 shows the net total CO_2/yr, or delivered CO_2/yr, for EOR operations in the ‘fast’ scenarios 3 and 4. The net CO_2 delivered for EOR has a slightly different profile between scenarios 3 and 4 that accounts for the different amount of CO_2 captured in early years. This minor difference exists because coal-fired power plants are dispatched differently between the ‘CO_2 sales’ (scenario 3) and ‘CO_2 emissions penalty’ (scenario 4) scenarios.

Scenario 4 has the same CO_2 emissions penalty as scenario 2. The number of oil production and CO_2 injection wells completed each year is approximately the same as scenario 3. In scenarios 3 and 4, the field location of the saline injection wells occurs approximately in proportion to the amount of modeled oil production at each field (with some adjustment as needed). There are 566 more saline CO_2 injection wells needed in scenario 4 than in scenario 3 because the smaller oil fields (e.g. not Hastings and Conroe) start production 1 or 2 years later than in scenario 3 to better match the CO_2 delivery profile.

Figure 10 shows the annual oil production for scenarios 3 and 4, as well as the assumed oil and CO_2 prices. To continue utilizing the capital investment in CCUS infrastructure, we assume the coal-fired power plants with capture continue to capture CO_2 each year even if it is no longer needed for EOR. Figure 11 shows that the quantity of CO_2 flows for scenarios 3 and 4 are nearly the same, with 80 and 75 $MtCO_2$ yr^{-1},

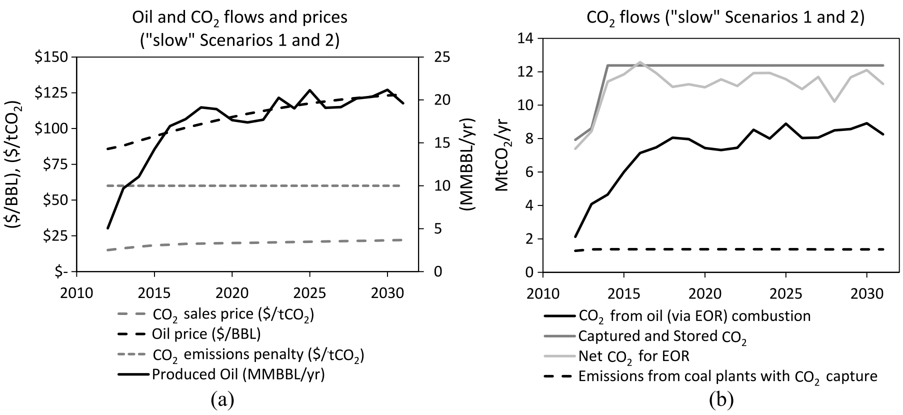

Figure 8. (a) The EOR oil production follows the delivered quantity of CO_2. The oil price taken from the EIA AEO 2011 increases over time from 85$/BBL in year 1–124$/BBL in year 20. (b) Over the 20-year span of the modeled scenarios 1 and 2 the total CO_2 emissions captured from the three coal-fired EGUs is approximately equal to that needed for EOR in the ten oil fields.

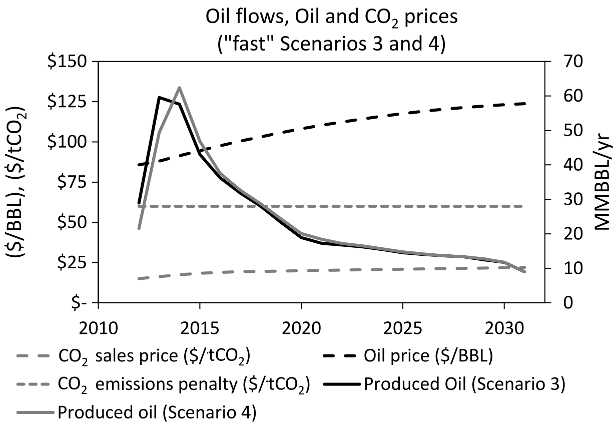

Figure 10. For the 'fast' scenarios 3 and 4, there is a much larger quantity of CO_2 captured to serve the demand for EOR in the first two years. The assumed commodity prices (oil, CO_2, natural gas, coal) are the same in scenarios 3 and 4 as in scenarios 1 and 2.

respectively. For scenario 3 and 4, respectively, 1540 and 1450 $MtCO_2$ of coal emissions are sequestered in EOR and saline reservoirs, 200 $MtCO_2$ are emitted from the oil produced from the CO_2-EOR operations, and 170 and 160 $MtCO_2$ are emitted from the power plants modeled to have CO_2 capture. Thus, our modeled system stores a net amount of 1090–1170 $MtCO_2$ over 20 years.

3.5. Integrated cash flow analysis

We developed an integrated discounted cash flow model for the CCUS system described above. We include capital investment in (i) CO_2 capture at several Texas coal plants, (ii) development of a pipeline network to transport the captured CO_2 to stacked storage locations for EOR and sequestration, and (iii) development of the stacked storage EOR and sequestration facilities. There are no revenues realized by the saline operations; saline costs are assumed to be covered by EOR operators. Our goal is not to evaluate commercial viability of each segment but rather to investigate viability of the overall system.

Nevertheless, we impose a 12% rate of return on the pipelines as these would likely be subjected to some rate control if they are accessible to third parties. If pipelines are dedicated to either power plants or EOR operators or both, their costs would be mostly internalized. In any case, the pipeline segment represents a relatively small portion of operating costs (5% in slow scenarios and 14% in fast scenarios)[7] and a small portion of capital costs in the system (8–10%).

In the 'CO_2 sales' scenarios 1 and 3, the EOR operators buy the CO_2 from the coal-fired power plants that capture it and then pay the pipeline company for transporting the CO_2 to the oil fields. In the 'CO_2 emissions penalty' scenarios 2 and 4, the EOR operators are only burdened by the cost of transporting CO_2.

In the 'CO_2 emissions penalty' scenarios, we can consider two system boundaries. One boundary does not penalize CO_2 emissions from oil combustion because these emissions can be considered to occur outside our CCUS system where oil is refined and consumed as refined products (e.g. gasoline). We also present cash flow results using a second system boundary that includes the cost of emissions from using the EOR oil. These oil emissions assume 0.42 $MtCO_2$ emissions per barrel of oil consumed at 60$/tCO$_2$, the same emission penalty used in the power dispatch model.

Table 3 shows key input values for the integrated cash flow analysis of the CO_2-EOR/sequestration value chain. The EOR cash flow model does not include operating costs for capture facilities because these costs are already included in the marginal cost calculations for power plants in our economic dispatch model of ERCOT. In that model, the power plants are dispatched only if revenues from electricity sales recover standard operating costs and the operating cost of CO_2 capture.

CO_2 sales and emission penalties produce different operating costs, especially in the 'fast' scenarios, because

[7] The share is much higher in 'fast' scenarios because EOR operations have produced more than 70% of the oil after 10 years but pipelines continue to transport CO_2 to fields for sequestration purposes.

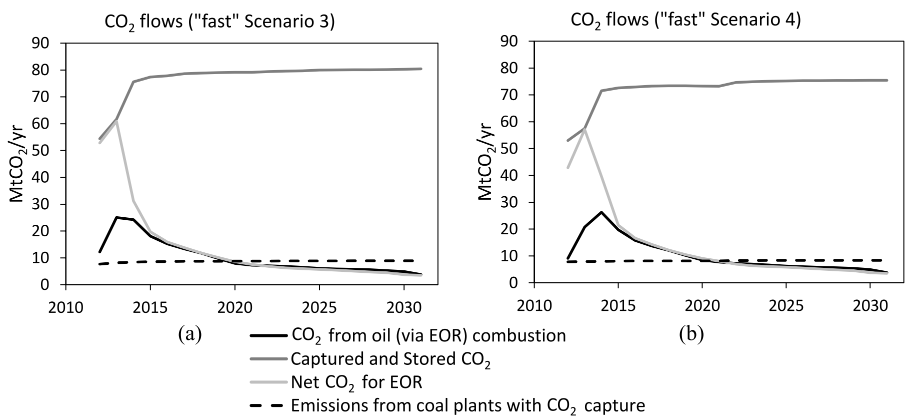

Figure 11. Both scenarios 3 and 4 have very similar total CO_2 emissions captured from the 21 EGUs at 13 coal-fired power plants with CO_2 capture.

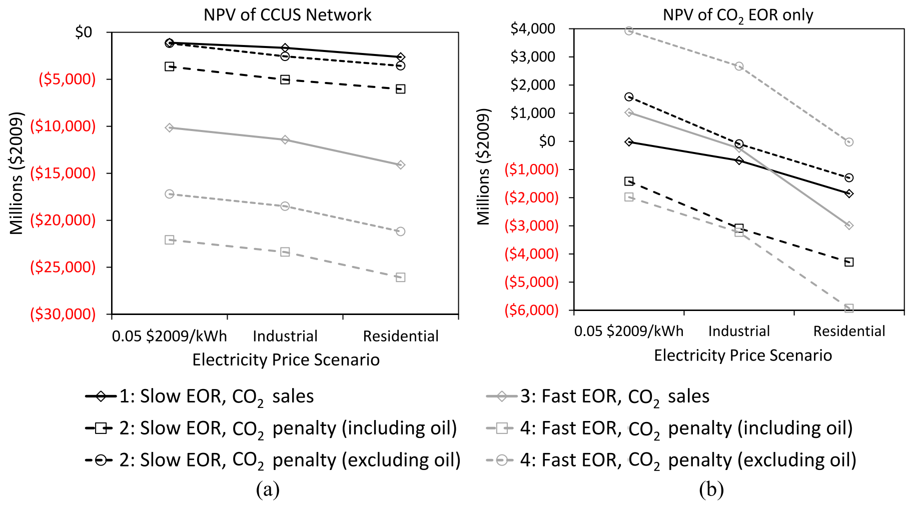

Figure 12. (a) No scenarios present a system-wide CCUS network that has a positive net present value. (b) When considering only the EOR operations, the oil production is profitable in three cases, none of which assume a CO_2 emission penalty applies to emissions from oil combustion.

emission penalties have a more indirect impact on power plant economics (via raising operating costs) than selling CO_2, which provides direct revenues to the coal-fired power plant. Accordingly, the dispatched amount of electricity, mix of generators on the ERCOT grid, and CO_2 emissions change significantly between the 'CO_2 sales price' and 'CO_2 emissions penalty' scenarios. The difference in ERCOT dispatch is less drastic between the 'slow' and 'fast' scenarios for a given 'CO_2 sales price' or 'CO_2 emissions penalty' scenario.

In addition, the financial assumptions are the following: 10% discount rate, 10-year loans at a rate of 6% (2.5% of the loan amount is paid as the up-front fee), and 0.6% interest during construction for capture plant and pipeline capital. Capital expenses in capture facilities and pipelines are realized over three years (20% first year, 60% second year, and 20% third year) and partially financed via borrowing (50% for capture facilities and 60% for pipelines).

EOR and saline sequestration expenditures are treated differently. In slow scenarios, 50% of annual capital expenditures in EOR facilities are financed for the first six years when more than 80% of total capital is spent; the remainder is not financed because relatively small amounts are needed per year for the following 14 years. In slow scenarios, there is no financing for saline infrastructure because total investment is realized via sporadic and relatively small installments over 20 years. In fast scenarios, 50% of all capital expenditures are financed since all of it is realized within the first three years; in contrast, 50% of annual saline capital expenditures are financed for the first 10 years when more than 80% of total capital is spent; the remainder is not financed because relatively small amounts are needed per year for the following 10 years.

Finally, we assume that 70% of EOR capital costs and 100% of saline capital costs can benefit from intangible drilling cost tax deductions. This is a fairly standard deduction for risky upstream oil and gas projects. There is not much history with application of such deductions to saline operations but we assume all of these costs could be eligible for intangible drilling cost allowances because the sequestration operation does not generate any revenues for the EOR operator. For most cases, these deductions provide marginal benefits in our model and are inconsequential in terms of changing an NPV from negative to positive (or an internal rate of return, IRR, from less than 10% to higher than 10%). The sole exception is when considering joint 'EOR + saline storage' operations under scenario 4 ('fast' scenario with CO_2 penalties) without emissions penalties on oil and industrial electricity rates.

3.6. Net present value summary

3.6.1. NPV summary (whole system). Figure 12(a) plots the net present value (NPV) of the CCUS network. In no modeled scenario does the total system have positive NPV (table 4). The 'slow' scenarios have higher NPV than the 'fast' scenarios. These differences in NPV are because the 'fast' scenarios have a large increase in CCUS capital expenditures to add capture to additional coal-fired power plants, drill significantly more CO_2 injection wells, and concentrate EOR capital expenditures in the first three years rather than spread them out over 20 years. Because of the electricity required to pump CO_2 at the EOR and saline sequestration sites, electricity price is also very influential in affecting the total NPV.

There is a difference between sales and emission penalty cases mainly because the CO_2 emissions penalties have a significant impact on profitability of coal-fired power plants. To have an internally consistent analysis, the CO_2 emissions penalty is applied to all generating plants using fossil fuels (coal, natural gas, and oil). Thus, our emissions penalty scenarios favor natural gas dispatch over coal generation within ERCOT (renewable generation is already favored in all scenarios due to low operating costs). Recall that we have

Table 4. Summary of system-wide economics of CCUS network ($2009 million). A 10% discount rates is used for NPV analysis. Three values for a given scenario represent the three different electricity prices assumed for sensitivity analysis (from top to bottom, 0.05$ kWh^{-1}; industrial; residential).

Scenario	Scenario name	Oil emissions *not* penalized NPV	IRR	CO_2 storage cost ($/t$CO_2$)	Oil emissions penalized NPV	IRR	CO_2storage cost ($/t$CO_2$)
1	Slow EOR, CO_2 sales	−1 100	6%	5	−1 100	6%	5
		−1 700	3%	7	−1 700	3%	7
		−2 600	—	11	−2 600	—	11
2	Slow EOR, CO_2 emission penalties	−1 200	6%	5	−3 600	—	15
		−2 600	—	11	−5 000	—	21
		−3 600	—	15	−6 000	—	25
3	Fast EOR, CO_2 sales	−10 100	—	7	−10 100	—	7
		−11 400	—	7	−11 400	—	7
		−14 100	—	9	−14 100	—	9
4	Fast EOR, CO_2 emission penalties	−17 200	—	12	−22 100	—	15
		−18 500	—	13	−23 400	—	16
		−21 200	—	15	−26 100	—	18

specifically chosen the penalty of 60$/t$CO_2$ as level that maintains base load generation for the coal-fired plants with CO_2 capture. As we have chosen only a subset of coal-fired power plants to capture CO_2 (those delivering CO_2 to EOR fields), all other coal-fired power plants shift higher in the dispatch order and earn less operating revenue (see figure S1 of the supplementary information).

One way to interpret the system costs is by calculating the present value cost of CO_2 storage as the NPV divided by the total CO_2 captured and stored (see table 4). This cost of storage is an estimate of the additional money needed to make the system break even. The NPV storage costs range from 5 to 25$/t$CO_2$. The cheapest values are for 'CO_2 sales' scenarios and the most expensive costs are for 'CO_2 emissions penalties' scenarios when oil emissions are also penalized. The highest cost of storage per tCO_2 occurs for scenario 2, the slow scenario with oil CO_2 emissions penalized. For scenario 4, the costs with oil CO_2 emissions penalized are only 3$/t$CO_2$ higher than without an emissions penalty for oil.

3.6.2. NPV of each segment of CCUS system. Given our assumptions, the analysis does not attempt to target a certain return on investment for the individual business segments (except for pipelines) within the CCUS network. It is, however, still insightful to understand the differences in economic value and returns generated across the segments of the system (tables 5–7). The pipeline will generate positive NPV in all cases since we impose a 12% return restriction on that segment (table 6); the pipeline achieves this return at a transportation tariff of about 80 cents per Mscf ($15/t$CO_2$) in the slow scenarios and just under 40 cents per Mscf (8$/t$CO_2$) in the fast scenarios.

Coal-fired power plant operating profits from CO_2 and electricity sales from the power dispatch model are not high enough to cover the large capital investment in these facilities. Thus, the CO_2 capture investment does not break even in any scenario (table 5). Although we obtain positive IRRs for the 'CO_2 sales' scenarios (based on cumulative revenues of $4.8 billion in scenario 1 and $30.8 billion in scenario 3), they are below investment levels as indicated by negative NPVs and IRRs below our assumed 10% discount rate. Revenues are not realized soon enough in the plant life to recover large investments made in capture facilities in the first 3 years of the project life (including interest, $3.2 billion in scenario 1 and $20.7 billion in scenario 3). The emission penalty cases have much lower NPV, as there are no CO_2-based revenues to capture facilities, but they incur the same capital investment costs.

Focusing only on the NPV of the EOR operations, there are four cases where NPV is positive (see figure 12(b)). These four cases are (from highest to lowest NPV): (1) 'fast' CO_2 emissions penalty (scenario 4) with no emissions penalty on oil and a 0.05$ kWh^{-1} electricity price, (2) 'fast' CO_2 emissions penalty (scenario 4) with no emissions penalty on oil and an industrial electricity price, (3) 'slow' CO_2 emissions penalty (scenario 2) with no emissions penalty on oil and a 0.05$ kWh^{-1} electricity price, and (4) 'fast' CO_2 sales (scenario 3) and a 0.05$ kWh^{-1} electricity price, (there are no emission penalties in 'CO_2 sales' scenarios).

The EOR operations can be profitable at low electricity costs. Considering EOR operations only, the present day situation in the United States is best represented by the 'CO_2 sales' scenarios that assume EOR purchases CO_2 and there are no emissions penalties. Yet only the 'fast CO_2 sales' scenario 3 has positive NPV (and 20% IRR) when assuming cheap electricity. However, the 'slow CO_2 sales' scenario 1 has a 10% IRR (and practically a zero NPV) with cheap electricity. Lower CO_2 sales prices will improve economics of these scenarios and may lead to positive NPV and 10% or higher IRR even at higher electricity prices. For example, a 40% reduction in assumed CO_2 price yields an NPV of zero and an IRR of 10% for scenario 1 with industrial electricity

Table 5. Cash flow results for the CO_2 capture capital and operation (independent of the capital and operation for electricity generation as we consider only the additional costs and revenues for CO_2 capture). Values in millions \$2009.

Scenario	Scenario name	NPV of capture plants	IRR of coal plants with capture (%)
1	Slow EOR, CO_2 sales price	−1 000	2.6
2	Slow EOR, CO_2 emission penalty	−2 400	—
3	Fast EOR, CO_2 sales price	−6 100	2.7
4	Fast EOR, CO_2 emissions penalty	−15 200	—

Table 6. Cash flow results for the pipeline capital and operation. Values in millions \$2009.

Scenario	Scenario name	NPV of pipeline	IRR of pipeline (%)
1	Slow EOR, CO_2 sales price	\$48	12
2	Slow EOR, CO_2 emission penalty	\$55	12
3	Fast EOR, CO_2 sales price	\$148	12
4	Fast EOR, CO_2 emissions penalty	\$110	12

Table 7. Cash flow results for the EOR and saline sequestration components of the CCUS network. Values in millions \$2009. If three values are present for each scenario, these represent results assuming the three electricity prices (0.05\$ kWh^{-1}, industrial, and residential).

	EOR only no CO_2 emissions penalty on oil		EOR only with CO_2 emissions penalty on oil		EOR + saline storage no CO_2 emissions penalty on oil		EOR + saline storage with CO_2 emissions penalty on oil	
Scenario name	NPV	IRR (%)	NPV	IRR	NPV	IRR	NPV	IRR
1: slow EOR, CO_2 sales price	0	10	0	10	−200	9	−200	9
	−700	3	−700	3	−800	2	−800	2
	−1900	—	−1900	—	−2000	—	−2000	—
2: slow EOR, CO_2 emission penalty	1600	22	−1400	—	1400	20	−1600	—
	−100	9	−3100	—	−200	8	−3200	—
	−1300	—	−4300	—	−1400	—	−4400	—
3: fast EOR, CO_2 sales price	1000	20	1000	20	−2600	—	−2600	—
	−200	—	−200	—	−4700	—	−4700	—
	−3000	—	−3000	—	−8800	—	−8800	—
4: fast EOR, CO_2 emissions penalty	3900	47	−2000	—	400	22	−5500	—
	2700	42	−3200	—	−1700	—	−7600	—
	0	10	−5900	—	−6000	—	−11 900	—

prices; in contrast scenario 1 with residential electricity prices does not yield positive NPV even when CO_2 is provided free. A 10% reduction in CO_2 prices is sufficient for a zero NPV in scenario 3 with industrial electricity price, but even free CO_2 does not yield a positive NPV for help scenario 3 with residential electricity prices.

The 'CO_2 emissions penalty' scenarios 2 and 4 that do not internalize costs of CO_2 emissions from the EOR oil have the highest NPV of all cases. The EOR cash flows for scenarios 2 and 4 are profitable assuming the low electricity price, even when including saline storage costs.

Integrating the cost of saline sequestration into the EOR operator cash flow prevents the 'EOR + CO_2 sequestration' operations from being profitable at industrial or higher electricity costs, especially for the 'fast' scenarios (3 and 4). This result is expected as CO_2 sequestration, a pure cost activity for the operator, would be driven by anticipated benefits outside of our modeled system, just as with any general CO_2 mitigation activity. Without emission penalties on oil, saline operations have an insignificant impact at low electricity prices for scenario 2 (22% versus 20% IRR) but are more striking for scenario 4, reducing NPV from \$4 billion to \$0.4 billion and decreasing IRR decreasing from 47% to 22%.

3.6.3. NPV of EOR with CO_2 emissions from oil internal to system boundary. If we consider consumption of oil products refined from the EOR production inside our CCUS system (e.g. passed on to the consumer), the CO_2 emission penalty on consumed EOR oil would have significant impact. We considered system NPVs with and without such penalties to guide our future work.

Our modeled CCUS system generates negative NPVs and very low IRRs in the best cases even without emissions penalties on oil products (see table 4). In the 'slow' scenarios, the NPV drops significantly lower and there is no positive IRR at any electricity cost. In the 'fast' scenarios NPVs also worsen.

Adding emission penalties on oil produced from EOR operations deteriorates EOR economics in scenarios 2 and 4 (see table 7). Including emission penalties on EOR-produced oil reduces EOR IRR from 22% to negative in the slow case with low electricity price (scenario 2) and from 47% to negative in the fast case with low electricity price (scenario 4). Combining saline storage costs into EOR operations, 'EOR + saline storage', lowers NPV and IRR further relative to considering 'EOR only', especially for scenario 4. NPVs become negative for all scenarios applying emissions penalties on oil products with or without saline operation costs.

3.7. Future work

Our current analysis provides a valid conceptualization of the 'CO_2 sales price' scenarios because the sale of CO_2 from the coal-fired power plant to the EOR operator is an internal transaction. However, because we do not consider any indirect economic impacts outside of the modeled system in the 'CO_2 emissions penalty' scenarios, a fuller interpretation is needed via an analysis that can consider these indirect impacts. A primary indirect impact to consider is the effect of higher energy (electricity and oil) prices on lowering consumer demand. Thus, future work will more effectively compare the 'CO_2 sales price' (that impacts only the parties involved in our model) and the 'CO_2 emissions penalty' (which impacts entire economy) scenarios. This approach will necessitate enlarging our scope from our well-defined CCUS system to the rest of the economy, especially the power sector and consumers of oil products. Further calculations can also estimate the necessary spacing of injection wells storing CO_2 in saline reservoirs such that we can incorporate the associated capital costs of a distribution network. Recent papers indicate the costs can be several $\$/tCO_2$, and there are different well-spacing configuration and designs to consider (Eccles *et al* 2012, Pooladi-Darvish *et al* 2011).

4. Conclusions

The scenarios presented in this analysis provide some bounding cases for the cash flow of a CCUS system in the Texas Gulf Coast and ERCOT grid. The benefits of the analyses are that they use information and data related to Texas geography, geology, and electricity market in an integrated manner. The scenario results are not necessarily meant to present one scenario as more probable or preferable than another, yet most realistic scenarios for development of a CCUS network should fall within the boundaries of the four scenarios. Our system-wide perspective is meant to demonstrate the economics as viewed from outside the system versus inside the system. In this way, any business and government players that could be part of a similar CCUS network in Texas can use this study as a basis for understanding realistic possibilities for cooperation (e.g. sharing of costs and revenues under uncertain future conditions).

The major conclusions from the NPV analyses are:

- The scenarios show a system-wide NPV range from $-\$23$ billion (scenario 4: fast EOR development with CO_2 emissions penalty) to $-\$1.0$ billion (scenario 1, slow EOR development with CO_2 sales price). These two scenarios sequester large quantities of CO_2 of 1450 $MtCO_2$ and 240 $MtCO_2$, respectively, over 20 years.
- Because our system-wide net present values are all negative, our results can be broadly interpreted as the additional costs of sequestering large quantities of CO_2 while using oil revenues to pay for a large portion of the costs. These additional 'NPV costs' range from 5 to $25\$/tCO_2$.
- The more CO_2 is captured, the lower the NPV of the system. This result stems from our assumption that a similar amount of EOR oil is produced no matter how much CO_2 is available. It is quite feasible that more CO_2-EOR oil would be produced in a scenario with more available CO_2.
- The 'CO_2 emissions penalty' scenarios generate less NPV than the 'CO_2 sales price' cases, especially in the fast development scenarios.
- If the cost of purchasing, recycling, and reinjecting CO_2 is low enough, it seems feasible for pure CO_2-EOR operations to have positive NPV in the present economic environment with no CO_2 emissions penalty.

Acknowledgments

The authors CK, GG, and VN-L thank the Gulf Coast Carbon Center at the Bureau of Economic Geology of The University of Texas at Austin for funding this research. SC also acknowledges support from the United States Environmental Protection Agency (EPA) Science to Achieve Results (STAR) Graduate Fellowship Program and the Luminant Carbon Management Program.

References

Agarwal A and Parsons J 2011 Commercial structures for integrated CCS–EOR projects *Energy Procedia* **4** 5786–93

Ambrose W A, Breton C, Holtz M H, Nunez-Lopez V, Hovorka S D and Duncan I J 2009 CO_2 source-sink matching in the lower 48 United States, with examples from the Texas Gulf Coast and Permian Basin *Environ. Geol.* **57** 1537–51

Ambrose W A, Breton C, Hovorka S D, Duncan I J, Gulen G, Holtz M H and Nunez-Lopez V 2011 Geologic and infrastructure factors for delineating areas for clean coal: examples in Texas, USA *Environ. Earth Sci.* **63** 513–32

ARI 2006 *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: East & Central Texas* (Washington, DC: Advanced Resources International, Inc.)

ARI 2009 *Electricity Use of Enhanced Oil Recovery with Carbon Dioxide (CO_2–EOR)* (DOE/NETL-2009/1354) (Pittsburg, PA: National Energy Technology Laboratory, US Department of Energy)

Chalmers H, Lucquiaud M, Gibbins J and Leach M 2009 Flexible operation of coal fired power plants with post combustion capture of carbon dioxide *J. Environ. Eng.-ASCE* **135** 449–58

Cohen S M 2009 The implications of flexible CO_2 capture on the ERCOT electric grid *Masters Thesis* Mechanical Engineering, The University of Texas at Austin, Austin

Cohen S M, Chalmers H L, Webber M E and King C W 2011 Comparing post-combustion CO_2 capture operation at retrofitted coal-fired power plants in the Texas and Great Britain electric grids *Environ. Res. Lett.* **6** 024001

Cohen S M, Fyffe J, Rochelle G T and Webber M E 2009 The effect of fossil fuel prices on flexible CO_2 capture operation *ASME 3rd Int. Conf. on Energy Sustainability (San Francisco, CA)*

Cohen S M, Rochelle G T and Webber M E 2010 Turning CO_2 capture on and off in response to electric grid demand: a baseline analysis of emissions and economics *Trans. ASME, J. Energy Resour. Technol.* **132** 021003

Davis D, Scott M, Roberson K and Robinson A 2011 Large scale CO_2 flood begins along Texas Gulf Coast *SPE Enhanced Oil Recovery Conf. (Kuala Lumpur, Malaysia)* Paper SPE 144961-PP

Eccles J, Pratson L F and Chandel M K 2012 Effects of well spacing on geological storage site distribution costs and surface footprint *Environ. Sci. Technol.* **46** 4649–56

EIA 2010 *Updated Capital Cost Estimates for Electricity Generation Plants* (Washington, DC: Energy Information Administration) (www.eia.gov/oiaf/beck_plantcosts/index.html, accessed on 15 May 2012)

EIA 2011 *Annual Energy Outlook 2011* (Washington, DC: Energy Information Administration)

ERCOT 2011 *2012 Long-Term Demand and Energy Forecast* (Taylor, TX: Electric Reliability Council of Texas)

Esposito R A, Monroe L S and Friedman J S 2011 Deployment models for commercialized carbon capture and storage *Environ. Sci. Technol.* **45** 139–46

Ghomian Y, Urun M, Pope G A and Sepehrnoori K 2008 Investigation of economic incentives for CO_2 sequestration *2008 SPE Annu. Technical Conf. and Exhibition (Denver, CO)* SPE 116717

Herzog H and Javedan H 2010 *Development of a Carbon Management Geographic Information System (GIS) for the United States: Final Report* (*DOE Award No.* DE-FC26-02NT41622) (Cambridge, MA: Massachusetts Institute of Technology)

Holtz M H, Nance P K and Finley R J 1999 *Reduction of Greenhouse Gas Emissions through Underground CO_2 Sequestration in Texas Oil and Gas Reservoirs* (*EPRI Technical Report No.* WO4603-04, *GCCC Digital Publication Series* # 99-01) (Palo Alto, CA: EPRI)

IPCC 2005 *IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change* ed B Metz, O Davidson, H C de Coninck, M Loos and L A Meyer (Cambridge: Cambridge University Press)

Kheshgi H S, Bhore N A, Hirsch R B, Parker M E, Teletzke G F and Thomann H 2010 Perspectives on CCS cost and economics *SPE Int. Conf. on* CO_2 *Capture, Storage, and Utilization* (*New Orleans, LA*) Paper SPE 139716

King C, Coleman S, Cohen S and Gülen G 2011 The economics of an integrated CO_2 capture and sequestration system: Texas Gulf Coast case study *Energy Procedia* **4** 2588–95

King C, Gülen G, Essandoh-Yeddu J and Hovorka S 2009 Economic analysis of an integrated anthropogenic carbon dioxide network for capture and enhanced oil recovery along the Texas Gulf Coast *ASME 3rd Int. Conf. on Energy Sustainability (San Francisco, CA)* Paper ES2009-90415

McCullom D L and Ogden J M 2006 *Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity* (*Report* UCD-ITS-RR-06-14) (Davis, CA: Institute of Transportation Studies, University of California)

NETL 2010 *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution* (Pittsburg, PA: National Energy Technology Laboratory, US Department of Energy) (www.netl.doe.gov/technologies/oil-gas/publications/EP/CO2_EOR_Primer.pdf)

Nuñez-Lopez V, Holtz M H, Wood D J, Ambrose W A and Hovorka S D 2008 Quick-look assessments to identify optimal CO_2 EOR storage sites *Environ. Geol.* **54** 1695–706

Pooladi-Darvish M, Moghdam S and Xu D 2011 Multiwell injectivity for storage of CO_2 in aquifers *Energy Procedia* **4** 4252–9

Ravagnani A, Ligero E L and Suslick S B 2009 CO_2 sequestration through enhanced oil recovery in a mature oil field *J. Pet. Sci. Eng.* **65** 129–38

Zahid K M, Hosseini S A, Nunez-Lopez V and Hovorka S D 2012 Characterizing CO_2 storage reservoirs and shallow overburden for above-zone monitoring in Texas Gulf Coast EOR fields *Greenhouse Gases-Sci. Technol.* **2** 460–73

Ziaii S, Cohen S M, Rochelle G T, Edgar T F and Webber M E 2009 Dynamic operation of amine scrubbing in response to electricity demand and pricing *Energy Procedia* **1** 4047–53