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SUSTAINABILITY ASSESSMENT OF LARGE-SCALE CARBON CAPTURE AND SEQUESTRATION DEPLOYMENT OUTSIDE THE SYSTEM BOUNDARIES - OPPORTUNITIES AND CHALLENGES

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SUSTAINABILITY ASSESSMENT OF LARGE-SCALE CARBON CAPTURE AND SEQUESTRATION DEPLOYMENT OUTSIDE THE SYSTEM BOUNDARIES - OPPORTUNITIES AND CHALLENGES

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Mohammad Abotalib

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of

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To my sponsor, Kuwait University, my family, and friends. Thanks for your support along the way.

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LIST OF ABBREVIATIONS

AEO Annual Energy Outlook

BBL Barrel of Oil

Btu British Thermal Unit

CED Cumulative Energy Demand

CCS Carbon Capture and Sequestration

°C Degree Celsius

CH4 Methane

CO Carbon Monoxide

CO_2 Carbon Dioxide

CO_2-e Carbon Dioxide Equivalent

COE Cost of Electricity

DOE Department of Energy

EIA Energy Information Administration

EOR Enhanced Oil Recovery

EPA Environmental Protection Agency

°F Degree Fahrenheit

FG Flue Gas

FGD Flue Gas Desulfurization

GHG Greenhouse Gases

GWP Global Warming Potential

HCL Hydrogen Chlorid

H_2S hydrogen Sulphide

HF Hydrogen Fluoride

Hg Mercury

HHV Higher Heating Value

I-6 Illinois No. 6

IGCC Integrated Gasification Combined Cycle – a technology that converts coal to gas and then burn it to produce electricity

IPCC Intergovernmental Panel on Climate Change

ISO International Organization of Standardization

kg Kilogram

kWe Kilowatt of Electricity

kWh Kilowatt-Hour

lb. Pound

LC Life Cycle

LCA Life Cycle Analysis

LCC Life Cycle Cost

LCI Life Cycle Inventory

LCI&C Life Cycle Inventory and Cost Analysis

LCIA Life Cycle Impact Assessment

LCOE Levelized Cost of Electricity

MEA Monoethanolamine

MDEA Methyl Diethanolamine

MW Megawatt

MWe Megawatts (electric)

MWh Megawatt Hours

N Nitrogen

N2O Nitrous Oxide

NETL National Energy Technology Laboratory

NGCC Natural Gas Combined Cycle

NH3 Ammonia

NOX Oxides of Nitrogen

O&M Operations and Maintenance

O3 Ozone

P Phosphorus

Pb Lead

PM Particulate Matter

PM10 Particulate Matter (diameter 10 micrometer)

PM2.5 Particulate Matter (diameter 2.5 micrometer)

ppm Parts per Million Volume

PC Pulverized Coal

R&D Research and Development

SCPC Supercritical Pulverized Coal

SF6 Sulfur Hexafluoride

SO_2 Sulfur Dioxide

SO_x Sulfur Oxides

VOC Volatile Organic Chemical

ABSTRACT

Abotalib, Mohammad. Ph.D., Purdue University, December 2016. Sustainability Assessment of Large-scale Carbon Capture and Sequestration Deployment Outside the System Boundaries – Opportunities and Challenges. Major Professors: Fu Zhao and Larry Nies.

Most power generation in the United States is derived from the combustion of fossil fuels, primarily coal and natural gas. As a result, greenhouse gases (GHGs) are generated, and they act to trap radiant heat from the Earth. When GHGs are discussed, attention is usually concentrated on carbon dioxide (CO_2) because it is believed to be the most manageable anthropogenic GHG. Therefore, introducing new technologies, primarily those which deal with CO_2 capture and storage, is seen as a potential option for managing GHGs. Oil and gas reservoirs, saline formations, and un-mineable coal beds are examples of underground CO_2 storage sites. In the United States, it has been estimated that these sites together have the potential capacity to store the country's CO_2 emissions for the next 500 years. For this reason, carbon capture and sequestration (CCS) has become a very attractive approach by several industries, including the coal-fired power industry, to reduce their GHG emissions. However, the implementation of CCS on a broad scale will require an enormous input of resources and energy, which will be used during the CCS production, installation, and operation phases. The eventual result of this implementation will be an increased demand for fuel, which in turn will lead to further

mining activities to provide the additional energy required. Input materials such as pipelines, water, and chemicals are also required throughout the technology's life cycle. According to the literature, CCS with a post-capture system reduces the total CO_2-equivalent (CO_2-e) emissions of a coal power plant by 65% to 87%. The magnitude of this reduction depends on the study boundaries that are considered in the life-cycle assessment (LCA), and on other parameters considered in the study, such as the plant's power-generation thermal efficiency and capacity, fuel type, raw material transportation method, distance to power plants, distance to storage sites, and depth of storage sites.

This dissertation address this issue and uses the LCA harmonization approach with the aim of reducing the variability observed in the published literature, particularly, for amine-based post- combustion CCS technologies on coal-fired power plants. The levels of GHG reduction, both the published and harmonized results indicated a large decrease in global warming potential (GWP) for the various coal-fired technologies examined. However, because of the requirements of energy and other input materials, there was a notable increase in cumulative energy demand (CED), which would subsequently increase the footprint of the technology in term of resources.

To expand the foreseen benefits of CCS and widen it applications, CCS integration with EOR was investigated from an LCA-GIS perspective in which the CO_2 is utilized from ethanol, coal-fired, and natural gas power plants in the lower 48 states of the U.S. the results indicated that that crude oil with lower carbon intensity can be produced from EOR reservoirs that are less efficient in terms of crude recovered per ton of CO_2 injected. However, it should be acknowledged that using less efficient reservoirs would be associated with greater CO_2 supply which has a parasitic energy requirement and would in turn entail a higher cost burden. With a focus of future CCS deployment in the U.S., the game-theory approach was applied to determine the impacts of possible changes in carbon policies, the carbon market, and the cost of CCS technologies on the decisions of industrial carbon emitters.

In conclusion, CCS have great potential to reduce the carbon intensity of electric or transportation fuel. However, under existing carbon policies and at the current cost of CCS deployment, the strategy of the ethanol industry would be dominated by CCS deployment. By contrast, coal power plants would not have sufficient governmental or economic incentives to deploy CCS because of the gap between the cost capturing and transporting CO_2 and the price of CO_2.

CHAPTER 1. INTRODUCTION

1.1 Statement of the Problem

The growing global population and the economic growth in industrialized and developing countries give rise to a continuous increase in demand for energy. Energy production worldwide depends on the combustion of fossil fuels, which produces greenhouse gases (GHGs) and other undesired emissions. GHGs such as carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3) trap heat in the atmosphere by absorbing infrared radiation. The term “global warming potential” (GWP) refers to the potential that GHGs have to trap heat in the atmosphere over a certain time period and is generally based on their cumulative radiative forcing (IPCC, 2007). GWP is typically calculated for various GHGs over a span of 20, 100, or 500 years and expressed in the form of CO_2-equivalent (CO_2-e) (Metz, Davidson, de Coninck, Loos, & Meyer, 2005; Solomon, 2007).

Discussion of GHGs is usually focused on carbon dioxide because (1) CO_2 is the largest contributor to radiative forcing, and (2) human beings are adding CO_2 to the atmosphere at a historically high rate (Chen, 2005). In the United States, the electricity generation sector is the largest source of anthropogenic GHG emissions, accounting for 30% of the total GHG emission as of 2013, followed by the transportation sector (U.S. EPA, 2015).

Coal is the primary fossil fuel used for power generation, and it produces more than 40% the country's electricity (EIA, 2014b). Coal is the predominant fuel for electricity generation not only in the U.S., but also worldwide, generating 30% of global anthropogenic CO_2 emissions and about 40% of energy-related CO_2 emissions (EIA, 2016; Epstein et al., 2011). In the future, coal will continue to be a major source of energy, both in the United States and around the world, because of its abundance and low cost (EIA, 2011).

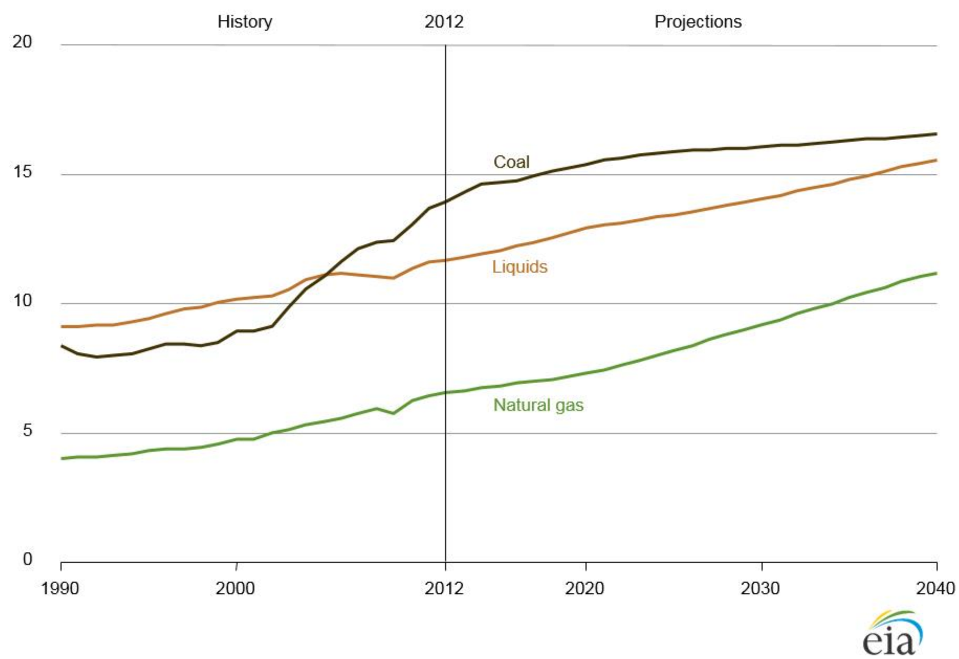


Figure 1.1 Historical and projected global energy-related CO_2 emissions [in billion metric tons] by fuel type between 1990 and 2040

Source: (EIA, 2016)

According to the Intergovernmental Panel on Climate Change (IPCC), preventing the catastrophic impacts of climate change will require maintaining the global average temperature at 1.1 ^{o} C/2 ^{o} F below the present level (IPCC, 2007). To avoid an increase in temperature, the atmospheric concentrations of CO_2 would need to be stabilized within the range of 400-450 ppm at maximum, and they could not exceed 400 ppm in the long term (IPCC, 2007). Achieving these targets requires that global CO_2 emissions be reduced by approximately 60% by 2050 in comparison to 2010 levels (Kasibhatla & Chamedies, 2007). Kasibhatla and Chamedies (2007) have found that industrialized countries, including the U.S., would need to decrease their GHG emissions by 80% in the same time period. In theory, this goal could be achieved with an annual reduction of only 2%, which would be approximately 136 million metric tons of CO_2-e per year.

In view of making substantial CO_2 reductions, the IPCC has explored various technological options for generating low-carbon energy. Among the most promising options is carbon capture and sequestration (CCS). In brief, CCS collects and compresses CO_2 from point sources, including those in the power-generation industry, and then transports the CO_2 by pipeline, truck, ship, or train to suitable geological formations. A detailed description of CCS is presented in Chapter 2. CCS technologies have the potential to become a widely-used means of providing low-carbon energy. For example, CCS could be used in the power-generation industry in general, and more specifically in the coal-fired power industry, to produce low-carbon electricity (UK DECC, 2012). The most applicable CCS technology for existing industrial facilities, including coal-fired power plants, is post-combustion capture, in which an amine-based solvent such as monoethanolamine (MEA) or methyl diethanolamine (MDEA) is used as an absorbent. Furthermore, integration of CCS with CO_2-enhanced oil recovery (EOR) could allow the production of transportation fuel that is less carbon-intensive than conventional petroleum-based fuels such as gasoline and diesel (De Oliveira, Marcelo E Dias, Vaughan, & Rykiel, 2005). In CCS-CO_2-EOR, carbon dioxide is sequestered and compressed from point sources, and subsequently transported and injected into mature oil reservoirs to enhance the recovery of trapped oil (ARI, 2010b).

Although the fundamentals of CCS are well understood, the technology has not been strongly endorsed by a number of environmentalists and scholars because of their limited experience with it. The implementation of CCS on a broad scale would require an enormous input of resources and energy during the operation phase (Gibbins & Chalmers, 2008; Marx et al., 2011). The eventual result of this implementation would be an increased demand for fuel, which in turn would lead to further mining activities to provide the additional energy required. Input materials such as pipelines, water, and chemicals are also required throughout the technology's life cycle. Random application of CCS without clear guidance could have undesirable environmental and economic consequences. Therefore, a comprehensive understanding of the environmental impacts of CCS technologies is critically needed. The discussion is already turning to practical challenges in the application of CCS. Large-scale implementation of CCS must include an in-depth assessment of these technologies from a life-cycle perspective.

1.2 Objective

The primary objective of this research is to enrich the current understanding of the sustainability of CCS, first, by use of the life cycle assessment (LCA) approach; second, by extending the value of LCA through integration with region-specific geospatial information using a geographic information system (GIS); and finally, by assessing the potential application of CCS in line with the existing and future carbon market and policies.

In the first component of the research, the LCA harmonization method is used to deal with variations in recent LCA results for coal power plants. Although the literature in this field has continued to mature, some variations in LCA results exist for legitimate reasons, such as the assumptions made, the definitions of system boundaries, and the methodologies followed (Heath & Mann, 2012). A similar challenge existed when the LCA approach was used to assess the environmental footprint of biofuels (Farrell et al., 2006).It is assumed here that LCA harmonization can provide more consistent estimates by adjusting published results to common gross system boundaries (Whitaker, Heath, O'Donoughue, & Vorum, 2012). Chapter 4 of this dissertation focuses on the use of LCA harmonization in assessing the GWP and cumulative energy demand (CED) of post-combustion CCS in a coal-fired power plant in terms of input and output resources. The analysis identifies these resources, their environmental impacts, and their associated emissions in terms of GWP by harmonizing the LCA results from relevant published literature. In addition to producing varied results, most of the published CCS LCA studies have had an "attributional" framework that focuses primarily on the environmental impacts within the system boundary, independently of other systems. The second and third components of this research, rather than following the approach of attributional LCA (ALCA), involve a consequential life cycle assessment (CLCA) in order to anticipate the effects of CCS adoption on market responses and current policy (Helin, Sokka, Soimakallio, Pingoud, & Pajula, 2013). The deployment of CCS-EOR in various industrial sectors has been investigated through the lens of the system expansion method and the game-theory approach to facilitate the decision-making process.

This document is organized into seven chapters. Chapter 1 introduces the research problem and expands on the objective of the research. Chapter 2 defines CCS and comprehensively describes various CCS technologies. This chapter also presents current CCS demonstration projects and highlights knowledge gaps. Chapter 3 briefly explains the methodology that will be used for each research component in order to achieve the objectives. Chapter 4 applies the LCA harmonization approach for various coal-fired technologies in order to reduce variability in the results and provide more consistent estimates. Chapter 5 extends the value of LCA by integrating the tool with GIS, and explores the use of the system expansion approach in coal power plants, natural gas plants, and ethanol facilities in the lower 48 states of the U.S. Chapter 6 establishes a framework for assessing CCS-EOR deployment in industrial sectors, with a specific focus on coal power plants and ethanol facilities, from a game-theory perspective under various carbon market and policy scenarios. Finally, Chapter 7 summarizes the previous chapters, highlights the existing gaps in knowledge, and provides recommendations for future work. The research outline and the subjects to be investigated in this dissertation are presented in Figure 1.2.

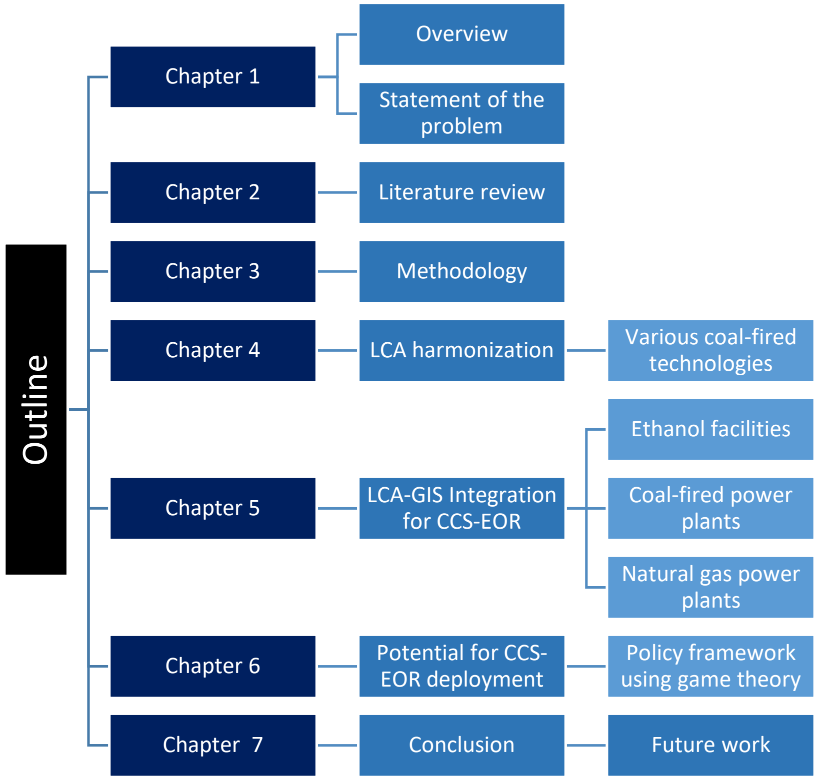


Figure 1.2 Dissertation outline

Chapter 1 is an introduction to the topic with the following objectives:

Objective I: Present the current and proposed CO_2 emissions under the business-as-usual scenario.

1. What are the problems with existing business-as-usual electricity generation?
2. How can a reduction in the current level of CO_2 emissions be achieved?

Objective II: Underscore the potential role of CCS in mitigating anthropogenic CO_2 emissions from major industrial sectors.

3. How can we mitigate CO_2 emissions from power plants?
4. How can we reduce CO_2 emissions from the transportation sector?

Objective III: Define the scope and state the problem to be investigated.

5. Why is it important to use the LCA approach when assessing CCS as an option for CO_2 mitigation?

Chapter 2 discusses various CCS techniques, and presents current CCS demonstration projects worldwide and U.S. efforts in further deployment. This chapter will address the following:

Objective I: Describe the main principles of CCS technology and the available CO_2 capture techniques.

1. What is CCS?
2. How can CO_2 be captured from power plants? What types of technologies are currently available?
3. What types of geologic formation are suitable for CO_2 storage? What is the CO_2 storage capacity in the U.S.?

Objective II: Highlight U.S. efforts in further deployment of CCS.

4. Why does post-combustion CCS have potential for implementation in coal-fired power plants in the U.S.?
5. What is the current status of CCS in the U.S. and its application?

Objective III: Discuss the current knowledge gaps.

6. Why should the LCA approach be used to assess the sustainability of CCS technology?
7. What are some of the issues that are encountered in the use of LCA?
8. What are the knowledge gaps in existing CCS LCA analysis?

Chapter 3 describes the research methodology and data collection process, as well as the computer software used in the assessment. This chapter will address the following:

Objective I: Provide a framework for the research strategy.

Objective II: Highlight the tools that have been used in the pursuit of the research goals.

The subsequent chapters will address diverse objectives in order to provide a comprehensive understanding of the potential for large-scale CCS deployment from environmental, technical, and political perspectives:

Chapter 4: Analytical assessment of LCA studies in peer-reviewed scientific journals and government publications, and LCA harmonization of the GWP and CED from previous studies of post-combustion CCS technology in coal-fired power plants.

Objective I: Present the results of various LCA studies in the field.

Objective II: Provide a reasonable estimate of GWP and CED and improve the range of variability among different sets of LCA results.

Chapter 5: Integration of LCA with GIS in order to compare GHG emissions in the EOR process, utilizing CO_2 from three industrial pathways (i.e., ethanol refineries, coal power plants, and natural gas power plants).

Objective I: Explore the use of the system expansion approach from life-cycle and geospatial perspectives for each source (pathway).

Objective II: Rank pathways geospatially in terms of their net life-cycle carbon intensity for supplying the CO_2 required to produce a barrel of crude oil via EOR.

Chapter 6: Framework for assessing CCS-EOR deployment in industrial sectors, with a specific focus on coal power plants and ethanol facilities, from a game-theory perspective.

Objective I: Highlight current and future challenges under various carbon policy scenarios.

Objective II: Explore CCS-EOR deployment in industrial sources, with a specific focus on coal power plants and ethanol facilities, and a strategy for existing and future carbon policy approaches and incentives in terms of potential variations in carbon market conditions.

Chapter 7: Conclusions and recommendations.

Objective I: Summarize the findings of this dissertation.

Objective II: Identify knowledge gaps and provide recommendations for future work.

CHAPTER 2. LITERATURE REVIEW

2.1 Background

Current energy consumption trends show a continuous increase in energy demand that is driven by economic and population growth in both developing and developed countries. The U.S. Energy Information Administration (EIA) predicts a 48% increase in the world energy consumption by 2040 as compared to 2012 (EIA, 2016). The main factor in this increase is the world's basic need for electricity, which is generate by the combustion of fossil fuel, produces GHGs. Therefore, energy experts, non-government organizations (NGOs), international organizations, and scholars have studied the effectiveness of CCS as a solution that will meet environmental, social, and political goals for CO_2 reduction. This subject has also attracted the attention of several environmental NGOs, including the World Wildlife Fund (WWF). In 2007, the WWF developed a model to examine the global technical and economic feasibility of a variety of GHG emissions-mitigation technologies by utilizing the knowledge of experts in the field. The exercise assessed promising technologies with maximum permissible CO_2 emissions of 400 GtC – 500 GtC (billion metric tons of carbon) between 2004 and 2050. The study concluded that implementation of CCS in 25% of the global energy supply by 2050 would reduce worldwide CO_2 emissions by approximately 8 GtC per year.

This conclusion was found to be valid even when radical improvements in energy efficiency and contributions of renewable energy sources were taken into account (WWF, 2007). Similarly, the United Kingdom Department of Trade and Industry (UK DTI) studied the potential role of CCS in achieving a UK CO_2 emissions reduction target of 60% by the year 2050. The study concluded that this target was realistic and that it could be achieved only if CCS were implemented in at least 50% of fossil-fuel power plants (UK DTI, 2005). The conclusion assumed that no new nuclear power stations would be constructed. CSS has gained strong acceptance by different stakeholders and is widely thought to be a valid CO_2 mitigation tool, but it is critical to understand the technology in greater depth before making fundamental decisions.

2.2 Technology Description

CCS is the process of storing CO_2 underground in deep geologic formations (Metz et al., 2005). The three main steps in the process are capture, transport, and sequestration (Metz et al., 2005). Capture of CO_2 can be achieved by means of three different technological concepts: post-combustion systems, pre-combustion systems, and oxy-fuel systems (Gibbins & Chalmers, 2008). Figure 2.1 provides a generic overview of the different CO_2 capture techniques.

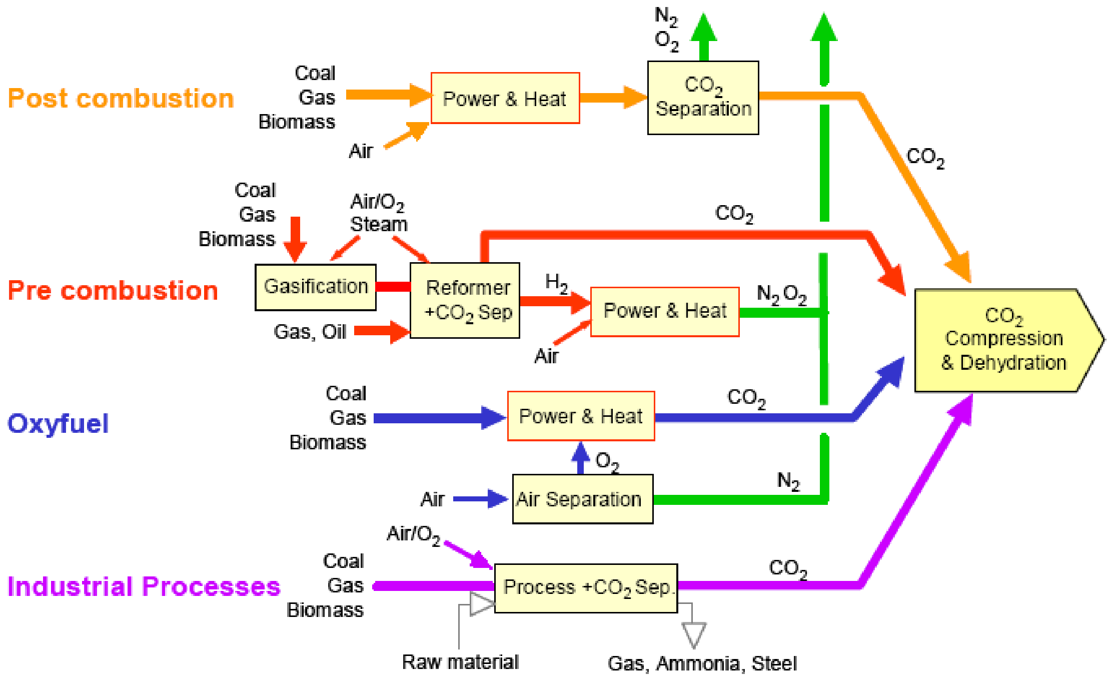


Figure 2.1 Representation of different CCS technologies

Source: (Metz et al., 2005)

2.2.1 Post-combustion Capture System

The post-combustion system captures CO_2 from the flue gases emitted by large point sources after the combustion reaction takes place, as shown in Figure 2.2.

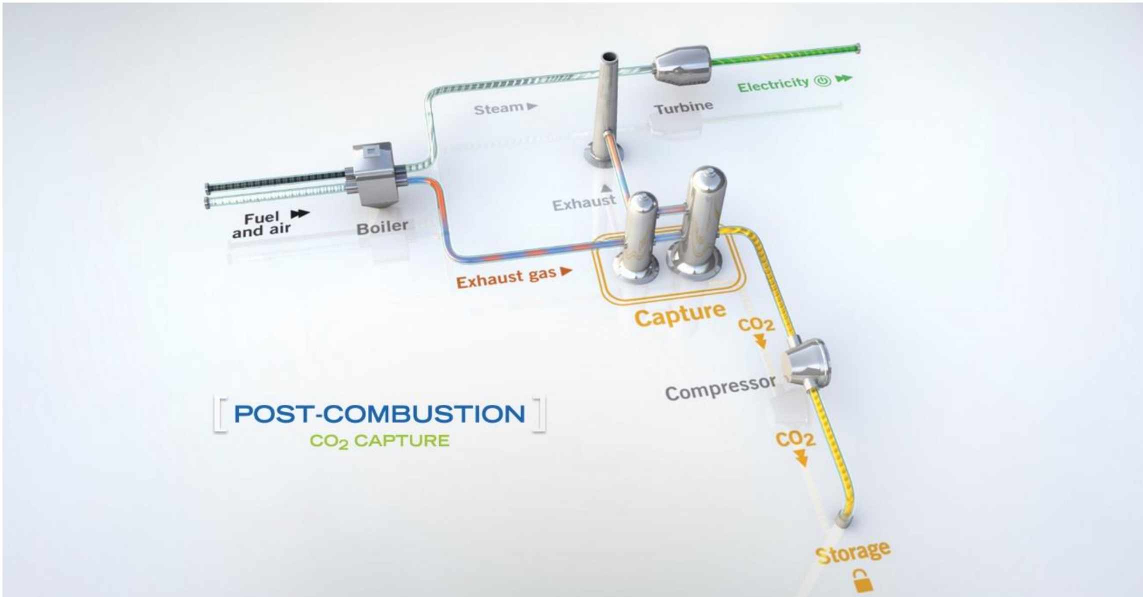


Figure 2.2 Schematic diagram of post-combustion capture
Source: (Global CCS Institute, 2014)

Post-combustion capture is an established, well-understood technology with CO_2 removal efficiency of up to 90% (Rochelle, 2009), and it is used in a number of industrial applications. The biggest advantage of the post-combustion capture system is that it permits modifications to existing plants without operational disruption (Rochelle, 2009). Therefore, this option is favored by several industries, including the power-generation industry. The name of this technique is self-explanatory, as CO_2 is removed after the process of combustion has taken place. CO_2 is captured either by liquid or solid chemical absorbents (Metz et al., 2005). In the chemical absorption method, which is the most widely used, an amine-based solvent such as MEA or MDEA is used as an absorbent. The main principle of this method is the removal of CO_2 from the flue gas using a lean amine-based solvent, which is then cleaned with water to remove any ammonia residue (Figueroa, Fout, Plasynski, McIlvried, & Srivastava, 2008). Next, the CO_2-rich solvent is sent to a stripper to be separated by the application of heat. The highly concentrated CO_2 is then compressed and transported, primarily by pipelines, to storage sites where the remaining solvent is recycled to the absorber system (Figueroa et al., 2008). This technique is very energy intensive, in that a large amount of energy is required during the stripping phase for effective separation. The technique also requires water for cooling, CO_2 absorption and stripping, and CO_2 compression (Fluor Ltd., 2005; Rao & Rubin, 2002; Zhai & Rubin, 2010).

2.2.2 Pre-combustion Capture System

The main principle of this technique is the capture of CO_2 before combustion by converting carbon to an intermediary gas mixture of hydrogen (H_2) and carbon monoxide (CO) that burns to produce heat (Metz et al., 2005), as shown in Figure 2.3.

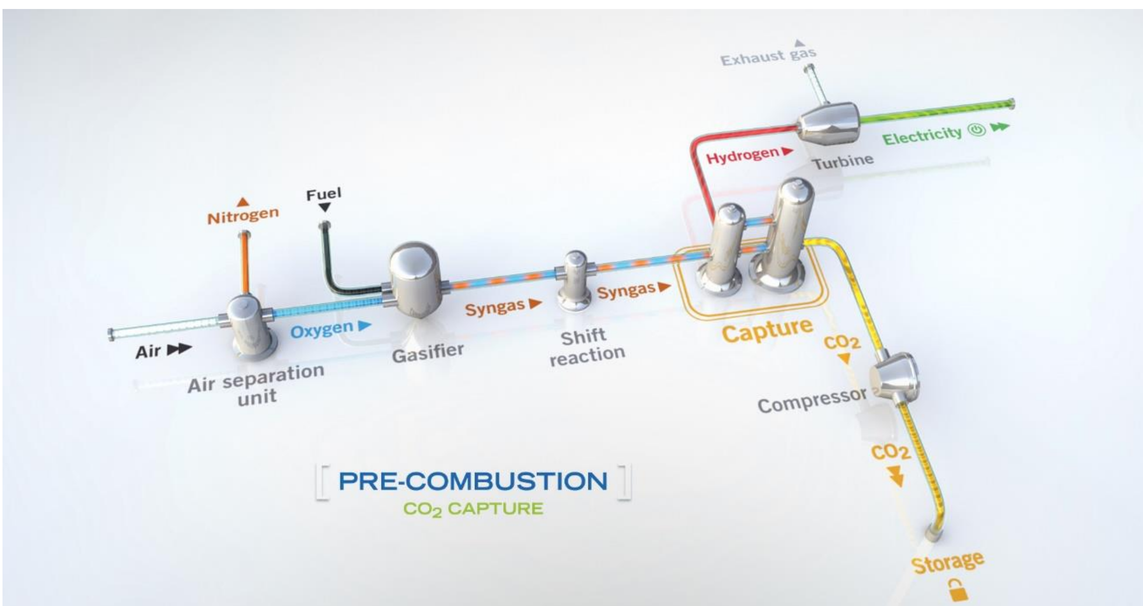


Figure 2.3 Schematic diagram of pre-combustion capture
Source: (Global CCS Institute, 2014)

In most cases, a gasifier is used to oxidize carbon. The products of this reaction are CO and H_2O, which react to form CO_2 and additional H_2. Then the CO_2 is captured, and the H_2 is used as fuel. This technology is widely applied in the production of fertilizer, chemicals, gaseous fuel (H_2 and CH_4), and power (Metz et al., 2005).

2.2.3 Oxy-fuel Capture System

In the oxy-fuel technique, an air separation unit (ASU) is used to generate oxygen, which is used in a burner instead of air (Metz et al., 2005), as shown in Figure 2.4.

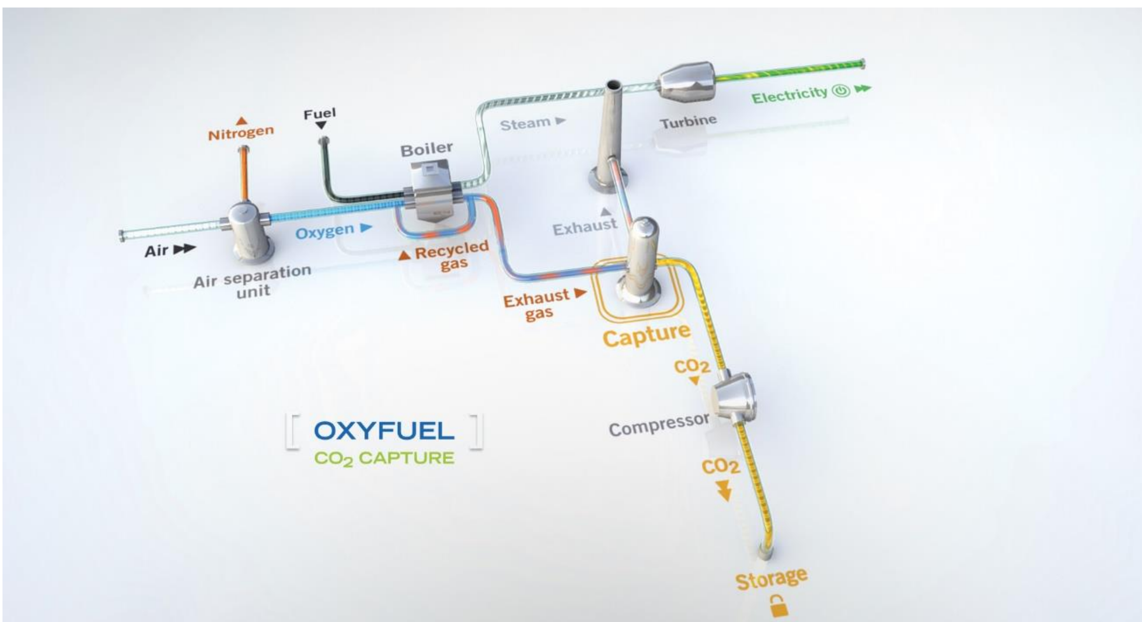


Figure 2.4 Schematic diagram of oxyfuel combustion
Source: (Global CCS Institute, 2014)

The products of this reaction are pure CO_2, which is directly transported and stored, and water vapor. Although this technique is promising, it is energy intensive, especially in the initial air-separation step, which is responsible for oxygen generation (Metz et al., 2005).

2.3 CO_2 Transportation

Another part of the CCS technology, the transportation of CO_2, is already well understood in many industrialized countries. The U.S. has the necessary infrastructure and experience to deal with transportation because CO_2 is used commercially to enhance oil recovery (Metz et al., 2005). The most challenging aspect of the transportation process would be cohesive coordination between CO_2 producers and end users. Network integrity is also a concern because of possible pipeline corrosion, but the use of appropriate corrosion inhibitors would solve this problem.

2.4 Suitable CO_2 Storage Sites

A suitable CO_2 geologic storage site must be at a minimum depth of 800 meters underground (Metz et al., 2005). At the temperature and pressure that are reached at this depth, CO_2 enters the supercritical state and behaves like a liquid (Metz et al., 2005). Greater quantities of CO_2 can be stored as the depth and temperature increase (NETL, 2010b). The relationship between depth and pressure and the volume of CO_2 to be stored is shown in Figure 2.5.

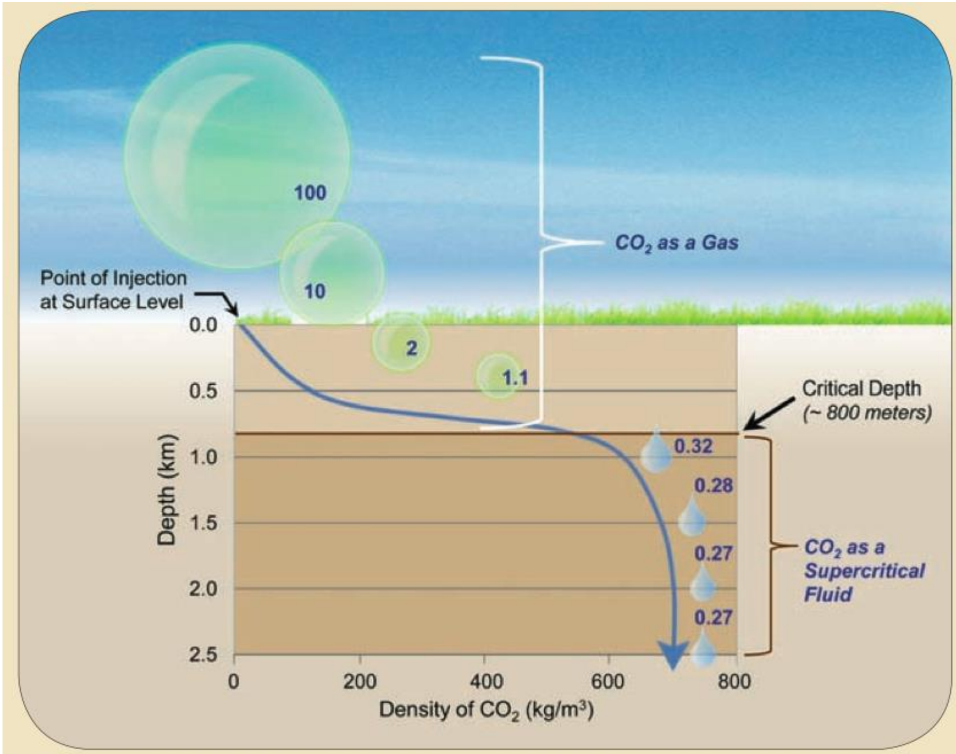


Figure 2.5 Characteristics of an appropriate CO_2 storage site
Source: (NETL, 2010b)

The blue numbers in Figure 2.5 indicate the volume of CO_2 at different depths as compared to standard atmospheric pressure. In addition to being sufficiently deep underground, a suitable site for CO_2 storage must meet the following requirements (Metz et al., 2005):

1. Sufficient **capacity**: sequestering large volumes of CO_2.
2. Sufficient **injectivity**: receiving CO_2 at an efficient and economic rate of injection.
3. **Effective** storage: retaining CO_2 safely over extended periods of time.

The third requirement is the most difficult to evaluate because the standards for storage effectiveness and duration have not been defined. According to the IPCC (2005), appropriate, well-managed geologic reservoirs are **very likely** and **likely** to retain 99% of the stored CO_2 for **100** and **1000** years, respectively. Worldwide, guidelines for 99% successful storage range from several thousand years to 5,000 years (Metz et al., 2005).

2.5 Potential Storage Sites

There are three major types of potential onshore geologic storage reservoirs for CO_2: depleted oil and gas reservoirs, un-mineable coal beds, and deep saline formations (Hendriks, 1994; Holloway et al., 1996). In 2010, National Energy Technology Laboratory (NETL) estimated that oil and gas reservoirs have the capacity to store U.S. CO_2 emissions for 21 years at the current CO_2 emission rates (NETL, 2010b).

An overview and a description of potential CO_2 geologic storage reservoirs is presented in provided in Appendix A. All these sites meet the criteria listed in the previous section. A basic illustration of the technology's principles and potential geologic storage options is provided in Figure 2.6.

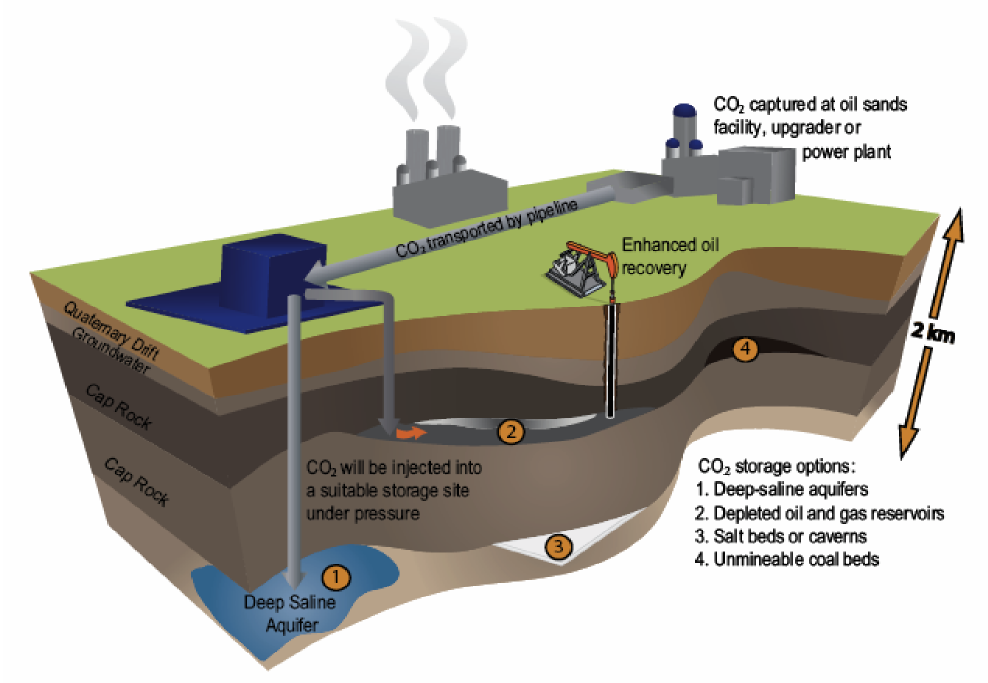


Figure 2.6 Schematic showing geological sequestration of carbon dioxide emissions from a power station with CO_2 capture system

Source: (Alberta Energy, 2011)

2.6 LCA of CCS Deployment in Coal-Fired Power Plants

Marx, Schreiber, Zapp, Haines, Hake, and Gale (2011) have suggested using the life cycle assessment (LCA) approach as a tool to evaluate the environmental impacts of CCS implementation (Marx et al., 2011). Schreiber and colleagues (2012) conducted a meta-analysis of 15 LCA studies focusing on the GHG emissions of various CCS technologies implemented in hard coal, lignite, and natural gas power plants. Such findings can be constructive when comparing CCS technologies with one another in terms of a given environmental impact category (Schreiber, Zapp, & Marx, 2012). However, when various published studies of the same CCS technology are compared, inconsistencies are observed in the results. According to Whitaker and colleagues, the use of the LCA harmonization approach reduces variability in the results and provides more consistent estimates by adjusting published results to common gross system boundaries (Whitaker et al., 2012). The LCA harmonization project managed by the National Renewable Energy Laboratory (NREL), with funding from the U.S. DOE, has covered various fossil fuel based and a number of renewable power generation technologies, but the incorporation of CCS in coal-fired power plants was not covered (NREL, 2013). Therefore, investigating this gap will complement the NREL effort in this area. The LCA harmonization approach has been applied to the amine-based post- combustion CCS with the aim of reducing the variability observed in the published literature for GWP and CED, see Chapter 4 for details.

2.7 Making CCS Attractive

Several studies have suggested the integration of CCS with CO_2- EOR as another unique approach for improving the energy outlook and reducing GHG emissions by producing crude oil with low carbon intensity (Hussain, Dzombak, Jaramillo, & Lowry, 2013; Jaramillo, Griffin, & McCoy, 2009; Khoo & Tan, 2006a; Middleton et al., 2015; Rhodes, Clarens, Eranki, & Long, 2015). Table 2-1 lists the largest operational CCS projects in the United States, with CO_2-capturing capacities ranging from 0.68 to 8.4 MMT of CO_2 per year. Most of these projects were not developed explicitly to target CO_2 storage; the decisions were instead based on economic considerations (McQuale, 2010).

Table 2-1 Commercial CCS projects in the United States as of 2013

	Project Name	Country	Stage / Status	Purpose	Transport	MMT CO_2 / Year
1	Century Plant	United States, TX	Operational / Active 2010	EOR	Onshore to onshore pipeline, 43 miles	8.4
2	Shute Creek Gas Processing Facility	United States, WY	Operational / Active 1986	EOR	Onshore to onshore pipeline, 403 km	7
3	Val Verde Natural Gas Plants	United States, TX	Operational / Active 1972	EOR	Onshore to onshore pipeline, 132 km	1.3
4	Air Products Steam Methane Reformer	United States, TX	Operational / Active 2013	EOR	Onshore to onshore pipeline, 101-150 km	1
5	Coffeyville Gasification Plant	United States, OK	Operational / Active 2013	EOR	Onshore to onshore pipeline, 112 km	1
6	Enid Fertilizer CO_2-EOR Project	United States, OK	Operational / Active 1982	EOR	Onshore to onshore pipeline, 225 km	0.680
7	Lost Cabin Gas Plant	United States, WY	Operational / Active 2013	EOR	Onshore to onshore pipeline	1

Notes: MMT = million metric tons, EOR = enhanced oil recovery

Source: (Global CCS Institute, 2012) personal analysis

As shown in Table 2-1, most of the CCS projects were developed to enhance oil recovery, in which case it was possible to recover the initial capital cost (McQuale, 2010). In depleted oil and gas reservoirs, CO_2 has been commercially used to increase pressure and recover residual oil and gas (Lokhorst & Wildenborg, 2005). In CCS- CO_2-EOR, carbon dioxide is sequestered and compressed from point sources, and subsequently transported and injected into mature oil reservoirs. CO_2-EOR is a tertiary oil recovery method that has been employed by the oil industry for more than 40 years to increase pressure and recover residual oil from depleted reservoirs (ARI, 2010b; Hussain et al., 2013).

In the United States, about 60 million metric tons (MMT) of CO_2 are injected per year in EOR, which produces more than 90 million barrels of oil (MMbo) annually. In addition to natural CO_2 supply, anthropogenic CO_2 has been recovered from gas processing and fertilizer production facilities in Texas and Wyoming for EOR projects (MITEI, 2016). In 2013, the CO_2-EOR technology produced, on average, 276000 barrels of crude oil per day (bbl/d) (EIA, 2014a).

Advances Resources International (ARI) estimates that productive use of CO_2 for EOR could produce approximately 3.0-3.6 million additional barrels of oil per day (MMbo/d) by 2030 and play an important role in reducing U.S. reliance on imported oil (ARI, 2010b). In addition to current CO_2-EOR production, it is estimated that there are more than 24 billion barrels of economically recoverable oil, with the use of current EOR practices in the lower 48 states of the U.S., with approximately 24% in East/Central Texas, 22% in the Permian Basin of West Texas, and 30% split between California and the Mid-Continent (Kuuskraa, Van Leeuwen, Wallace, & DiPietro, 2011a).When considering the application of next generation EOR technologies, those estimates could nearly triple (Kuuskraa et al., 2011a). It is important to highlight that about 70% of the CO_2 utilized in current CO_2-EOR practices is from natural CO_2-dedicated wells (Middleton, Clarens, Liu, Bielicki, & Levine, 2014a). More than 83% of the remaining 30% of the CO_2 used in EOR is supplied from acid gas processing plants such as natural gas and oil refineries (Xu, Isom, & Hanna, 2010). Because the supply of natural CO_2 is at capacity, the role of CO_2-EOR can be extended if combined with other innovative methods such as utilizing CO_2 from various industrial sources (Kuuskraa et al., 2011a). An overview of the U.S. CO_2 merchant market and the CO_2 demand by EOR is presented in Appendix A. Among industrial sources that have potential CO_2 supply are ethanol refineries, natural gas plants, and coal-fired power plants. Besides the potential CO_2 supply from these sources, the geographical distribution of the plants makes them good candidates as suppliers of CO_2 and as substitutes for natural CO_2 wells (Middleton et al., 2014a). Figure 2.7 shows the distribution of corn ethanol plants (green dots), pulverized coal-fired plants (grey hexagons), and natural gas power plants (yellow circles) in the U.S., along with the various EOR fields. This map will be further refined in order to identify viable CO_2 sources in Chapter 5

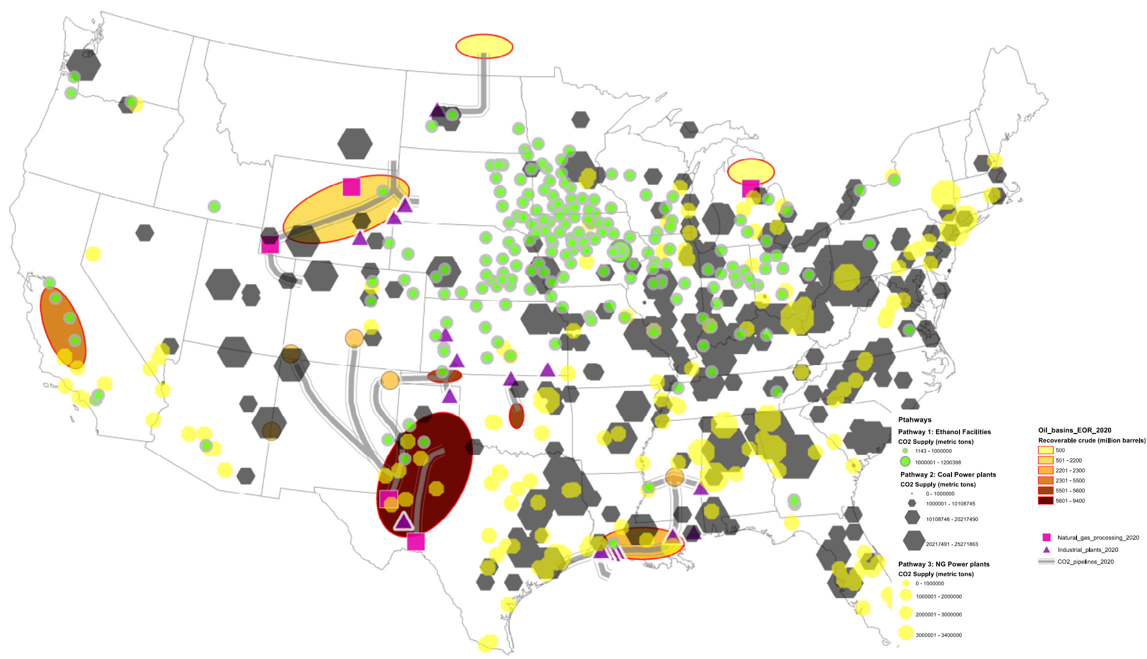


Figure 2.7 Spatial distribution of pathways and CO_2-EOR infrastructure in the lower 48 states of the U.S.

Source: (Abotalib, Zhao, & Clarens, 2016)

However, it is important to consider the environmental ramifications of CO_2 capture from each source (pathway) by accounting for the net GHG impacts on the basis of upstream, direct, and downstream impacts (i.e., from a life cycle perspective). Capturing CO_2 from ethanol plants, coal-fired power plants, and natural gas facilities would increase the demand for primary fuel, chemicals, and infrastructure materials and would subsequently increase indirect emissions throughout the value chain of each industry. In contrast to ethanol plants, which produce a pure CO_2 stream (i.e., biogenic CO_2 from the fermentation process), coal-fired and natural gas power plants produce a stream with low CO_2 concentration, between 10 to 17% by volume, with higher associated energy and economic penalties.

2.8 Challenges for CCS Deployment

Recently developed geotechnical solutions have made it possible to capture CO_2 emissions from industrial point sources by means of carbon capture and storage (CCS) technologies (Metz et al., 2005). In this context, CCS can be applied directly to the power generation sector or other industrial sources, and the captured CO_2 can be utilized for enhanced oil recovery (EOR). As discussed in the literature, CCS integration with CO_2-EOR has significant potential to reduce the carbon footprint of the U.S. transportation sector by producing crude oil with lower carbon intensity than in conventional crude recovery (Abotalib et al., 2016; Hornafius & Hornafius, 2015; Rhodes et al., 2015; U.S. DOE, 2013; U.S. EPA, 2015). Finding an alternative and consistent CO_2 supply would allow the expansion of EOR projects and further the objectives of the Energy Policy Act of 2005 (Energy Policy Act, 2005). However, current carbon policies do not provide sufficient economic incentives for major carbon emitters to invest in CCS projects (Mills, 2014). Under the existing Federal 45Q Tax Credit, anthropogenic CO_2 emitters that capture at least 500,000 metric tons of CO_2 during a taxable year receive a tax credit of \$10 per metric ton of CO_2 captured (IRS, 2011). This allocated carbon credit creates a huge gap between the costs associated with capturing and transporting CO_2 from major sources such as power plants under current market conditions and carbon price (Mills, 2014). Furthermore, the 45Q provision excludes potential biogenic CO_2 sources such as ethanol facilities (IRS, 2011). Although finding the right set of incentives can be a complex and time-consuming process, establishing a framework that is more inclusive and attractive for various industrial CO_2 emitters would motivate more players to participate and compete in order to maximize their benefits.

To determine the effects of polices on the decision-making of stakeholders, game theory has been applied to a wide range of disciplines including the social sciences, international relations, economics, ecology, and climate science (Başar, 2015; Dong, Li, Li, Wang, & Huang, 2010; Kutasi, 2010; Morbee, 2014; Turocy & von Stengel, 2001). Game theory can be defined simply as a mathematical decision-making tool. Participants in a game (called "players") aim to maximize their benefits or payoffs or, in some situations, minimize their losses, regardless of the consequences for other players (Başar, 2015; Dong et al., 2010). This type of game is considered non-cooperative, meaning that the players tend to act independently because they do not benefit from unilaterally altering their choices when the strategies of other players stay the same. As a result, players' decisions are based on rational factors. Their optimal strategy in such a game is referred to as a non-cooperative equilibrium or Nash equilibrium, a concept first proposed by John Nash (Turocy & von Stengel, 2001). Recently, the literature has presented climate policy in the form of game theory, with a focus on encouraging the development of clean technologies, carbon price, and carbon-abatement-related policies and on creating international negotiation frameworks among major carbon economies

(Helm, Hepburn, & Ruta, 2012; Knox-Hayes, 2012; Kutasi, 2010; Urpelainen, 2013). Chapter 6 presents a framework for assessing CCS-EOR deployment by industrial emitters, with a specific focus on coal power plants and ethanol facilities, from a game-theory perspective under various carbon policy scenarios, in the United States, with a focus on the Illinois Basin.

CHAPTER 3. METHEDOLOGY

3.1 Overview

This chapters provides a brief description of the methodologies followed in chapters 4, 5, and 6. In this chapter, section 3.1 describes the method of the LCA harmonization. Section 3.2 describes the framework used for integrating LCA with GIS for EOR. Section 3.3 describes the methodology implemented for establishing a framework for assessing the CCS-EOR deployment from a game theory perspective.

3.1.1 Method for LCA Harmonization

In Chapter 4, the LCA harmonization approach to post-combustion CCS has been implemented with an emphasis on GWP and CED to adjust variations in previously published LCA studies and provide more robust and consistent conclusions. Data for this analysis has been collected primarily from secondary sources, such as recent national and international studies in the field as reported in peer-reviewed journal articles and technical papers. Publications from intergovernmental organizations and governmental departments were also used as resources for assessing the results of various LCAs in the field:

3.1.2 Method for LCA GIS Integration

The LCA-GIS model has been designed to calculate the carbon intensity of CO_2-based enhanced oil recovery, where CO_2 is utilized from three different industrial sources, which are referred to as “pathways” throughout the analysis. The first pathway is a corn-based ethanol plant with CCS (EtOH-CCS). The second and third pathways are a coal-fired (PC-CCS) and a natural gas (NG-CCS) power plant, respectively; both use amine-based post-combustion CO_2 capture technology. Geospatial data for pathways was obtained from the National Renewable Energy Laboratory’s (NREL) interactive mapping tool, the National Energy Technology Laboratory’s (NETL) NATCARB database in addition to the U.S. EPA Facility Level Information on Greenhouse Gases (FLIGHT) to denote the CO_2 emissions of 2014 (NETL, 2016; U.S EPA, 2015).

3.1.3 Method for LCA GIS Integration

The future of CCS-EOR deployment in ethanol refineries and coal power examined using the game theory approach. The framework has been designed the impacts of possible changes in carbon policies, the carbon market, and the cost of CCS technologies on the decisions of industrial carbon emitters.

CHAPTER 4. LCA HARMONIZATION

4.1 Background and Motivation

The identification of more representative results requires a careful assessment of the technology's footprint during its entire life cycle. This chapter focuses on assessing the GWP and CED of post-combustion CSS in a coal-fired power plant in terms of input and output resources, by following the principles of the ISO-14040: 2006/14044:2006 standard, titled "Life-Cycle Assessment -- Principles and Framework," to identify resources, energy flows, and the potential impact of CCS deployment (ISO, 2006b). According to ISO (14040:2006), an LCA should include four phases. The focus of Phase I is to describe the aim of the LCA, define the functional unit to be compared, and draw the system boundaries. In Phase II, the system's input and output flows are identified to generate life cycle inventories (LCIs) for all life cycle stages or processes. In Phase III, life cycle impact assessment (LCIA), the LCI flows are converted into environmental impact indicators targeting important local/global environmental concerns such as global warming, cumulative energy demand, etc. The final phase (Phase IV) consists of analytical interpretation of the LCIA results and addresses the questions posed in Phase I. Data for this analysis has been collected primarily from secondary sources, such as recent national and international studies in the field as reported in peer-reviewed journal articles and technical papers.

Publications from intergovernmental organizations and governmental departments were also used as resources for assessing the results of various LCAs in the field. This analysis uses 1 kWh of electricity generated by a power plant with post-combustion CCS as a functional unit. The selected power plants range in size from 400 to 800 MW prior to the addition of CO_2 capture. The system boundaries in this analysis incorporate the processes shown in Figure 4.1.

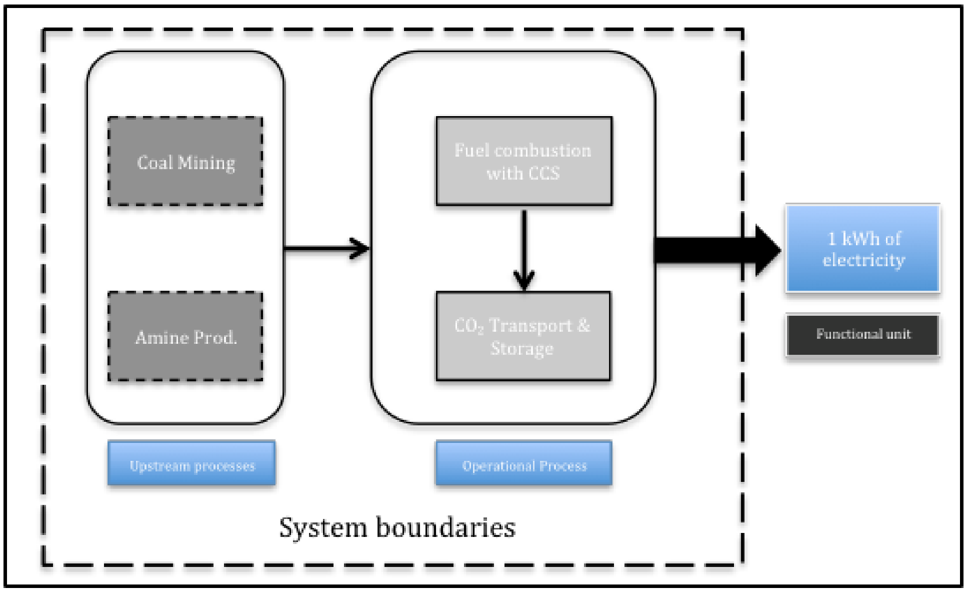


Figure 4.1 Generalized system boundaries of post-combustion CCS technology
Source: (Abotalib & Zhao, 2015)

As illustrated in Figure 4.1, processes can be grouped as upstream and operational processes:

1. Upstream processes

   (I) Coal mining, including extraction, processing, and transportation of coal required for plant operations.

(II) Amine production, including raw material, energy consumption, and transportation.

2. Operational processes

   (I) Coal combustion (direct emission from the stack, waste generated from plant operations), and the CCS capture system operations (energy requirement for amines regeneration and CO_2 compression).

   (II) CO_2 transport and storage including CO_2 transportation infrastructure and energy required storing CO_2 in deep geologic formations.

On the basis of the above considerations, the analysis focuses on GWP and CED. GWP has been selected to assess the effectiveness of achieving the objective of CCS throughout the technology life cycle. Whereas CED has been considered because it accounts for the cumulative energy consumption during the life cycle of a product or service, including the energy used in the production phase, use, and disposal phases of the process. Therefore, CED can be used as an environmental as well as an economic indicator. Although it is considered that all LCA studies follow the ISO standards, some variations have been observed in the existing literature in the results for GWP and CED. Therefore, the LCA harmonization approach has been implemented in order to adjust variations in previously published LCAs and thus provide more robust and consistent results, as described by Whitaker et al. (Whitaker et al., 2012). The following section describes in further detail the approach that has been adopted.

4.2 Harmonization Method

The LCA harmonization in this research was conducted in accordance with a harmonization project managed by the National Renewable Energy Laboratory (NREL), with funding from the U.S. DOE, which consists of (1) system harmonization and (2) technical harmonization (NREL, 2013). Because the NREL harmonization method has been followed, the outcomes of this work will be more relevant to the NREL objective of identifying representative estimates of the GWP and CED of CCS post-combustion power generation technologies.

1. System Harmonization

System harmonization was applied to data from 42 studies representing 57 environmental impact estimates, according to the procedure in Figure 4.2.

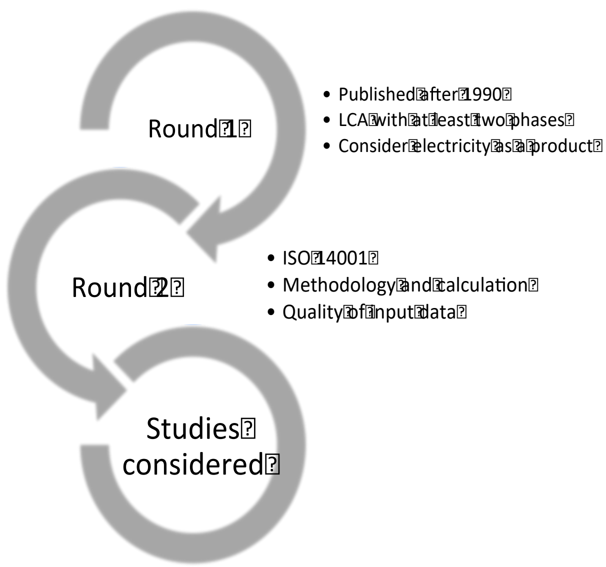


Figure 4.2 System screening procedure
Source: adapted from (NREL, 2013)

Each LCA study went through two rounds of screening to ensure consistency and comparability. The initial screening round eliminated publications that met any of the following criteria:

- ❖ Published prior to 1990;
- ❖ LCA with fewer than two phases
- ❖ Did not consider electricity as a product of the technology;
- ❖ Presentation, abstract, or poster;
- ❖ Trade journal article of three or fewer published pages; or
- ❖ Conference paper of five or fewer double-spaced pages (or equivalent).

After the first screening round, a second, more comprehensive, screening exercise was carried out for the remaining publications to ensure the quality of the frameworks used and the outcomes of each publication, on the basis of:

- ❖ Adherence to the ISO-14040 framework for conducting LCA, as described above;
- ❖ Methodology used for calculating the investigated indicators; and
- ❖ Quality of the input data used (i.e., whether or not both empirical and theoretical).

System harmonization was applied to data from 42 studies representing 57 environmental impact estimates, according to the procedure in Figure 2 in main manuscript. This screening exercise yielded 44 environmental impact estimates, which were then used in the technical harmonization phase. (see Table 4-1 for details).

Table 4-1 Published LCA studies that passed the LCA harmonization screening requirements with key performance parameters

No.	Author/s	Tech.	Eff.	Eff. (CCS)	Country	Decrease in power output	Increase in Fuel	Distance (km)	Depth (m)
1	(Muramatsu & Iijima, 2002)	PC	41%	31%	Japan	24%	32%	20	1250-2000
2	(Spath & Mann, 2004)	PC	41%	31%	USA	24%	31%	300	800
3	(IEA GHG, 2006)	USPC	44%	35%	Netherlands	21%	27%	NA	NA
4	(Viebahn et al., 2007)	PC	49%	40%	Germany	18%	23%	300	NA
5	(Viebahn et al., 2007)	PC (L)	46%	34%	Germany	26%	35%	300	NA
6	(Odeh & Cockerill, 2008)	SPC	40%	30%	UK	24%	32%	300	800
7	(Dones, Bauer, Heck, Mayer-Spohn, & Blesl, 2007)[min]	USPC	43%	31%	Europe	28%	34%	200	800
8	(Dones et al., 2007)[max]	USPC	43%	31%	Europe	30%	36%	400	2500
9	(Dones et al., 2007)[min]	PC (L)	43%	31%	Europe	27%	38%	200	800
10	(Dones et al., 2007)[max]	PC (L)	43%	31%	Europe	30%	43%	400	2500
11	(UKERC, 2008)	PC	44%	35%	UK	21%	26%	300	NA
12	(Koornneef, van Keulen, Faaij, & Turkenburg, 2008)	USPC	46%	35%	Netherlands	24%	31%	100	3000
13	(Fripp, 2009)	PC	33%	25%	USA	24%	31%	NA	NA
14	(Pehnt & Henkel, 2009) [RC]	PC (L)	45%	27%	Germany	39%	65%	325	NA
15	(Pehnt & Henkel, 2009)[SD]	PC (L)	46%	28%	Germany	40%	65%	325	NA
16	(Schreiber, Zapp, Markewitz, & Vögele, 2010) [2010]	SPC	46%	36%	Germany	23%	30%	300	NA
17	(Korre, Nie, & Durucan, 2010)	PC	40%	30%	USA/global	25%	33%	NA	NA
18	(NETL, 2010c)	PC	35%	24%	USA	31%	45%	160	1236
19	(Schreiber et al., 2010)[RETRO]	PC	46%	33%	Germany	29%	41%	400	800
20	(Schreiber et al., 2010)[ND_after_2020]	PC	49%	38%	Germany	23%	31%	400	800
21	(Schreiber et al., 2010)[2010-2020 retrofit]	PC (L)	45%	30%	Germany	33%	49%	400	800
22	(Schreiber et al., 2010)[ND_after_2020]	PC (L)	48%	35%	Germany	26%	36%	400	800
23	(Singh, 2010)	SPC	43%	33%	USA	23%	30%	500	1000
24	(Ziębik, Hoinka, & Liszka, 2010)	PC	44%	33%	Unknown	25%	33%	NA	NA
25	(Nie, Korre, & Durucan, 2011)	PC	45%	34%	USA	25%	33%	300	1000
26	(Suebsiri & Wilson, 2011)	PC (L)	31%	22%	Canada	30%	43%	NA	NA

Table 4-1 Continued

27	(Marx et al., 2011) (Min.)	PC	50%	40%	Global	20%	25%	NA	NA
28	(Marx et al., 2011) (Max.)	PC	50%	30%	Global	40%	66%	NA	NA
29	**(Marx et al., 2011) (Min.)**	**PC (L)**	**49%**	**40%**	**Global**	**25%**	**18%**	**NA**	**NA**
30	(Marx et al., 2011) (Max.)	PC (L)	46%	28%	Global	65%	40%	NA	NA
31	(Singh, Strømman, & Hertwich, 2011a)	SPC	43%	33%	USA	24%	31%	500	NA
32	(Sathre, 2011)	PC	44%	33%	Global	25%	33%	NA	NA
33	(Sathre, 2011)	PC (L)	46%	32%	Global	30%	44%	NA	NA
34	(U.S. DOE, 2011)	SPC	44%	33%	USA	25%	33%	300	NA
35	(Singh, Strømman, & Hertwich, 2011b)	SPC	43%	33%	USA	24%	31%	500	NA
36	(Wangen, 2012)	SPC	43%	33%	Europe	24%	32%	250	1000
37	(Castelo Branco, Moura, Szklo, & Schaeffer, 2013)	PC	30%	25%	Brazil	17%	21%	200	NA
38	(Śliwińska & Czaplicka-Kolarz, 2013)	PC	37%	25%	Poland	32%	48%	NA	NA
39	(Śliwińska & Czaplicka-Kolarz, 2013)	SPC	39%	27%	Poland	30%	44%	NA	NA
40	(Śliwińska & Czaplicka-Kolarz, 2013)	PC	37%	25%	Poland	32%	48%	NA	NA
41	(Śliwińska & Czaplicka-Kolarz, 2013)	SPC	39%	27%	Poland	30%	44%	NA	NA
42	(Liang et al., 2013)	USPC	43%	33%	China	23%	30%	100	3000
43	(Koiwanit et al., 2014)	PC (L)	31%	21%	Canada	33%	49%	NA	NA
44	(Zhang et al., 2014)	SPC	46%	34%	Norway	26%	35%	200	800

Table 4-1 presents studies passed the two-harmonization screening rounds. Some studies provided more than one estimates based different scenarios and assumptions made. In Table 4-1, each estimate is presented in a separate row to include the followings:

1. Author and year,
2. Coal-fired technology,

3. Thermal efficiency before CCS deployment (Eff.),
4. Thermal efficiency with CCS deployment (Eff. CCS),
5. Country or region,
6. Decrease in plant's power output,
7. Increase in fuel demand,
8. Distance to CO_2 storage sites,
9. Depth of CO_2 storage formations

Some studies, in Table 4.1, have passed the system and technical screening rounds, but did not cover all the processes defined within the system boundaries as illustrated in Figure 4.1.

2. Technical Harmonization

Coal-fired technologies can be classified into four groups: pulverized coal (PC), pulverized coal (lignite) (PC) (L), supercritical pulverized coal (SPC), and ultra-supercritical pulverized coal (USPC). It was found that some of the studies that passed the two screening rounds did not cover all the processes defined within the system boundaries in Figure 4.1. Therefore, an emission profile, which expresses the relative impact of each process on the LCIA results, was established for each technology, and an adjustment was made for those estimates with incomplete system boundaries. After the estimates had been adjusted to common system boundaries by incorporating the effects of missing processes, the outliers, i.e., any estimates that were outside the "whiskers" in box-and-whisker plots of the data, were eliminated. In other words, estimates that were greater or less than 1.5 times the interquartile (IQ) range were omitted from the harmonized results. In Figure 4.3, the LCA studies considered in this analysis are presented in a geographic map in order to highlight the regions that have shown interest in researching the topic and to aid in interpretation of results in relation to regional differences.

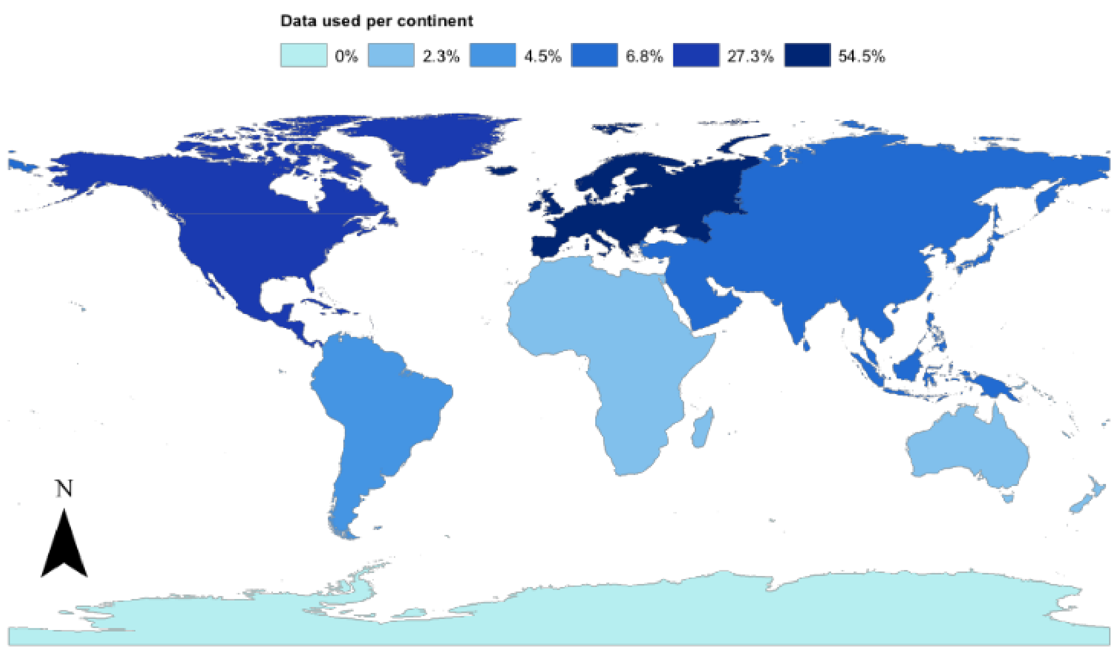


Figure 4.3 Geographic map showing the spatial distribution of data analyzed
Source: (Abotalib & Zhao, 2015)

It can be seen that most of the studies have focused on Europe as a baseline, followed by North America (USA and Canada). Details of each study and their underlying assumptions are provided in Table 4-1. The results, henceforth, are presented in the form of relative changes in GWP and CED per 1 kWh of electricity generated with the use of CCS. Two statistical indicators are employed: (1) the arithmetic mean, which refers to the average value of the data, and (2) the Q_3 value, which refers to the 75th

percentile, where 75% of the data fall at or below that value. As can be seen in Figure 4.4, the published estimates show a significant reduction in GWP, ranging from 65% to 85% for all coal-fired technologies.

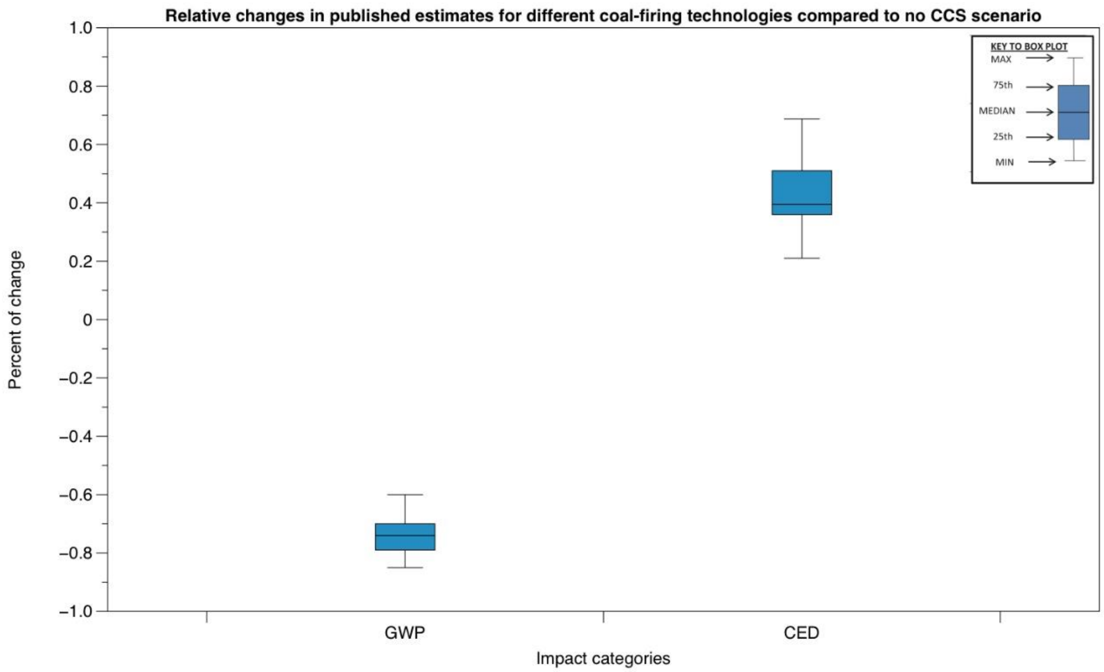


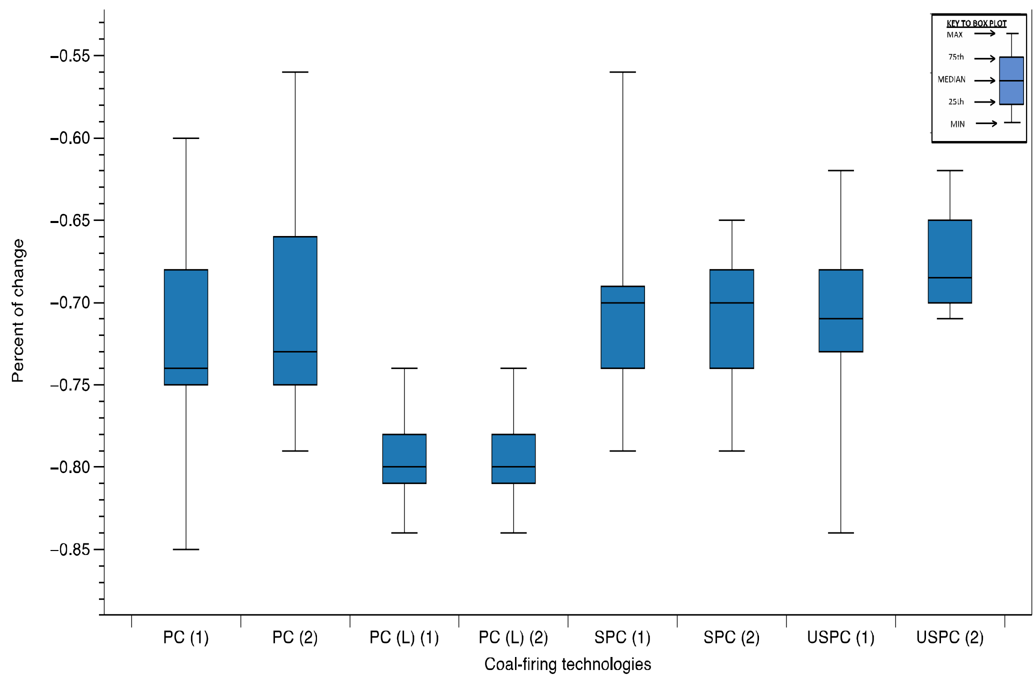
Figure 4.4 Box plot of published estimates considered in the analysis

In regard to CED, the Q3 and mean values indicate a considerable increase input resources. The results in Figure 4 were further refined by breaking down coal-fired technologies into four groups: pulverized coal (PC), pulverized coal (lignite) (PC) (L), supercritical pulverized coal (SPC), and ultra-supercritical pulverized coal (USPC). This classification allows a comparison of various coal-fired technologies in terms of the environmental impact categories considered.

Figures 4.5 and 4.6 show published estimates and harmonized estimates of GWP and CED, respectively, for each technology with CCS, compared to the same technologies without CCS. The mean and Q_3 values are again used as general representative indicators for the impact categories that were investigated in each case.

4.3 Results

4.3.1 Global Warming potential



Note: (PC) = pulverized coal, (PC) (L) pulverized coal (lignite), (SPC) = supercritical pulverized coal, and (USPC) = ultra-supercritical pulverized coal. 1 = published estimates, and 2 = harmonized estimates.

Figure 4.5 Box plots of studies considered in the analysis, illustrating the percentage of change in GWP for each evaluated coal-firing technology compared to the no-CCS scenario, using technology-specific information

Source: (Abotalib & Zhao, 2015)

Figure 4.5 confirms the general assumption that CCS can provide a signification reduction in GWP in all coal-fired technologies. The level of decrease in GWP is affected primarily by the fuel production process and direct emissions from plant operations. Fuel production process and direct emissions from plant operations are accountable for about 40% and 50% of the overall GWP respectively. However, lignite has a different emission profile, and in this case the fuel production process contributes 25% and direct emissions from the plant 60%, due to lower efficiency, of the overall GWP. The remaining GWP for all fuel types is generally distributed between amine production and CO_2 transport and storage processes. Technology-specific emission profiles of the GWP for each process are provided in Table 4-2.

Table 4-2 Share of life-cycle process to the total impacts for GWP for each coal-fired technology

Process	***Upstream***		***Operational***	
Technology	Coal mining & transport	Amine production	Fuel combustion	CO_2 transport & storage
Averaged PC	48%	6%	40%	5%
Averaged PC (L)	25%	9%	60%	6%
Averaged SPC	40%	4%	54%	3%
Averaged USPC	45%	5%	44%	5%

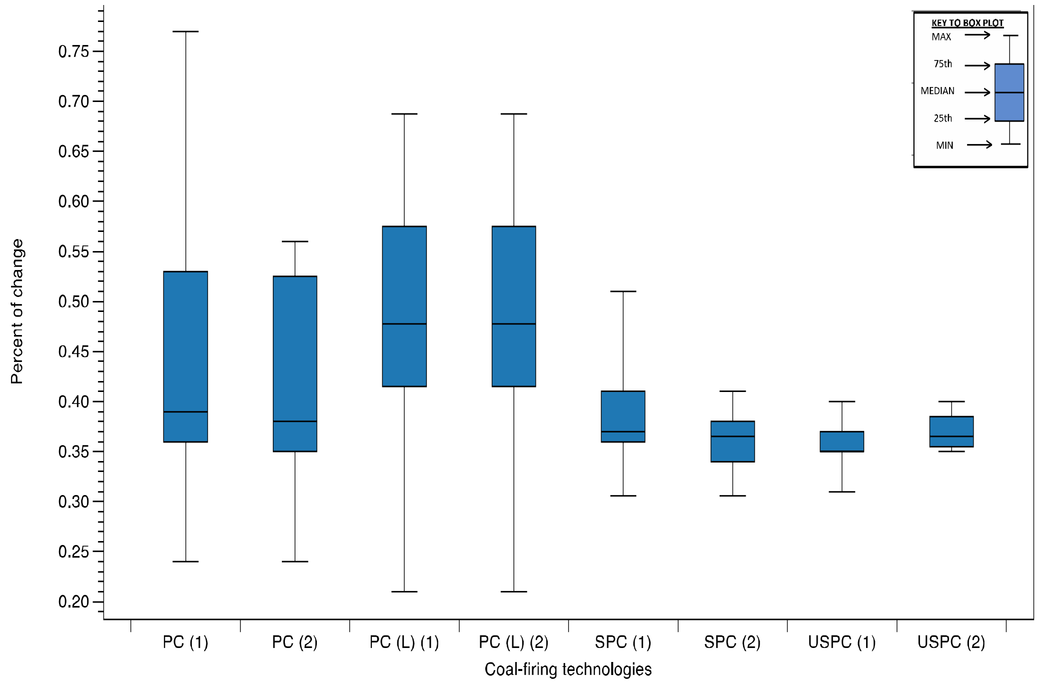
Averaged and 75th percentile results

In the GWP category, the estimates suggest a significant reduction regardless of the coal-fired technology considered. The mean reduction in GWP was 80% for the PC (L) technology, 72 % for SPC, 70% for PC, and 68% for USPC. The results indicate that the Q_3 values for PC, USPC, and SPC were nearly equal, with a reduction in GWP of 66%, 67%, and 68%, respectively. For example, a conventional pulverized coal power plant (PC) without CCS and a thermal efficiency of 38% would emit 960 g of CO_2 per kWh of electricity generated from a life cycle standpoint (UChicago Argonne, 2014). When CCS to be applied to same plant, the net GWP would be 288 g of CO_2 per kWh of electricity. The PC (L) technology shows a possible additional reduction in GWP of 10%, with a Q_3 value of 78%. This conclusion indicates that the type of fuel used is an important factor in the level of change in GWP. The PC (L) technology uses lignite, which has a lower heating value and higher GWP from fuel combustion, as this fuel type shows the highest achievable reduction in GWP on average compared to other types of coal. Although lignite has higher CO_2 emission per unit of electricity generated than do other hard coals, the fuel production process has a lower GWP impact, and therefore lignite has a lower overall GWP.

Sensitivity analysis and outliers

To ensure data quality, the harmonization process excluded from the analysis three estimates that indicated a 56%, 68%, and 80% reduction in GWP. To ensure data quality, the harmonization process excluded from the analysis three estimates that indicated a 56%, 68%, and 80% reduction in GWP. These estimates were outliers, i.e., they were found to be outside the “whiskers” in the box-and-whisker plots shown in Figure 4.3. The first result (56%) was reported by Wangen (2012) and represents SPC technology. In that study, the author assumed that 70% of the overall GWP originates from direct plant emissions which is moderately high, especially for SPC, where the averaged value from published literature was 50% contribution from this process. Because CCS has the ability to capture 90% of CO_2 from plant’s direct emissions, the study reached the 56% reduction in GWP. Another reason for this result may have been the choice of offshore storage of CO_2, which could have an additional impact on GWP as compared to onshore storage CO_2. Similarly, Suebsiri and Wilson (2011) assume a 66% contribution by direct plant emissions from a PC (L) plant to the overall GWP reduction of 68%. This share is not significantly higher than the averaged estimate of 59% for PC (L), but the system boundaries in the study excluded the impact of two processes: amine production and CO_2 transport and storage. When the effects of these processes were incorporated, the reduction in GWP decreased from 80% to 68%, which is outside the whisker box for PC (L), as shown in Figure 4.3. The third outlier removed from the harmonized GWP category was the IEA GHG (2006) estimate for the case of USPC, which suggests an overall reduction of 79%. Although that study focused on the USPC coal-fired technology, lignite was the main type of coal considered. The study's conclusion of a 79% reduction is not within the harmonized reduction range for USPC, although it may be valid for PC (L). Furthermore, the study addresses a European case in which lignite is typically surface mined and transported over a relatively short distance to the power plant via conveyors, with the result of a lower GWP impact in the upstream processes (IEA GHG, 2006).

4.3.2 Cumulative Energy Demand



Note: (PC) = pulverized coal, (PC) (L) pulverized coal (lignite), (SPC) = supercritical pulverized coal, and (USPC) = ultra-supercritical pulverized coal. 1 = published estimates, and 2 = harmonized estimates.

Figure 4.6 Box plots of studies considered in the analysis, illustrating the percentage of change in GWP for each evaluated coal-firing technology compared to the no-CCS scenario, using technology-specific information

Source: (Abotalib & Zhao, 2015)

As shown in Figure 4.6, CCS deployment causes an increase in CED without regard to the specific coal-fired technology. The increase in CED occurs because more auxiliary energy is needed for CO_2 capture and compression, and this higher energy requirement will eventually increase the demand for natural resources throughout the technology's life cycle. For example, a conventional pulverized coal power plant (PC) without CCS and a thermal efficiency of 38% would require about 11 MJ of natural resources (i.e. CED including fossil and non-fossil resources) per kWh of electricity produced (UChicago Argonne, 2014). The PC (L) and PC technologies, which are less efficient, have exhibited a larger increase in CED, which is primarily due to corresponding increases in fuel consumption of as high as 65% and 66%, respectively. In contrast, SPC and USPC are more efficient technologies and have exhibited an increase in fuel demand of only 30-38%. Therefore, they would have a smaller effect on the overall CED impact category. Technology-specific emission profiles of the CED for each process are provided in Table 4-3.

Table 4-3 Share of life cycle process to the total impact for CED for each coal-fired technology

Process	***Upstream***		***Operational***	
Technology	Mining and transport	Amine production	Fuel combustion	CO_2 transport & storage
Averaged PC	97%	3%	1%	2%
Averaged PC (L)	100%	5%	0%	0%
Averaged SPC	97%	3%	1%	2%
Averaged USPC	97%	3%	1%	2%

Averaged and 75th percentile results

In Figure 4.6, the averaged estimates of CED for PC, PC (L), SPC, and USPC indicate increases of 41%, 49%, 36%, and 37% respectively. The harmonized Q_3 estimates show a similar trend, with an increase in CED of 52% for PC, 57% for PC (L), and 38% for SPC and USPC. These findings indicate that PC and PC (L) technologies have a higher energy penalty than SPC and USPC.

Sensitivity analysis and outliers

While there is a consensus in the literature in regard to an increase in CED for all technologies, Marx and colleagues (2011), Pehnt and Henkel (2009), and Śliwińska and Czaplicka-Kolarz, (2013) determine either a lower or higher increase in CED compared to published literature. Therefore, these estimates were not included in the harmonized results. Marx and colleagues (2011) evaluated the worst-case CCS scenario and a scenario for a PC plant that used the best available CCS technology (BAT CCS). In the worst-case scenario a significant drop in the plant's efficiency is anticipated, from 46% to 28%. This prediction represents a skeptical view of the technology, in which CED increases by 77% because of the reduction in efficiency. In contrast, the second scenario assumes an efficient CCS system, which represents a very optimistic view of the technology, with an increase in CED of 21%. This finding was also omitted from the harmonized results because it was far outside the IQ range for PC power plants. The other estimate removed from the analysis that reported by Pehnt and Henkel (2009) for the PC (L) coal-fired technology. Their study used a relatively high net efficiency of 46% for a lignite plant without CCS, which would drop to 28% with the deployment of CCS. This drop represents a decrease in plant efficiency of about 40% and is two times the estimated values in the literature for similar plants. The final omitted estimate, reported by Śliwińska and Czaplicka-Kolarz (2013), is that of 56% increase in CED. The study used a slightly lower net plant efficiency of 39% for SPC, whereas other SPC studies have assumed net plant efficiency in the range of 40% to 46%. This lower efficiency led to a 52% increase in the CED category, which appears to be reasonable for conventional power plants but not for SPC coal-fired technologies.

4.4 Summary

The LCA approach has been suggested as a holistic tool for evaluating the environmental impact of CCS implementation. CCS is a relatively new technology, and various LCA studies have provided differing results. In this analysis, the LCA harmonization approach has been applied to post-combustion carbon capture and sequestration with the aim of reducing the variability observed in the published literature, and with a focus on GWP and CED. Despite the observed variations among various LCAs studies, they agree in regard to a significant reduction in GWP and a considerable increase in CED. The CED category mainly increases due to an increase in energy demand, which results in greater exploitation of natural resources throughout the life cycle of the technology. Therefore, more efficient technologies have less environmental impacts. Assuming the deployment of amine-based post-combustion CCS technology with 90% CO_2 capture efficiency, two processes recognized to have substantial impacts on the results are the coal combustion process (operational phase) and the fuel production process (upstream phase). Furthermore, it has been demonstrated that MEA production and CO_2 transport and storage have marginal effects on GWP. The harmonized results for the CCS amine-based post-combustion technology indicate a potential reduction in GWP ranging from 56% to 80%. Although the results from the published literature were adjusted to common system boundaries, variations in the harmonized results still existed because of differences in the underlying assumptions made by each study, such as fuel type and characteristics, boiler type, methods of transporting fuel and chemicals, transportation distance, MEA requirements and losses due to chemical regeneration, and distance to CO_2 storage sites. Lignite provides a good example of the impact of coal type on emissions profiles for each process. Lignite has a lower heating value than that of sub-bituminous and bituminous coal and therefore a greater GWP impact during combustion. However, lignite is normally surface-mined and transported to the power plant over a relatively short distance and hence has a lower impact on GWP. To improve the level of consistency in the results, it is essential to establish standardized values for key parameters, such as the development of plant efficiencies and energy penalties, capture efficiency, purity of the CO_2, and location of the fuel source and composition (Marx et al., 2011). In addition to the above considerations, with the acknowledged environmental trade-offs associated with CCS deployment for all coal-fired technologies, it is crucial to make a distinction between global and regional consequences. For example, global warming has global significance, whereas the effects of CED are observed on a more regional level. Hence, any potential increase in these categories should be carefully evaluated on a case-by-case basis, taking into account the potential impacts on the regional ecosystem. Such an evaluation can be accomplished by integrating LCA findings with a region's specific spatial and temporal records in order to better evaluate the significance of each impact category independently.

CHAPTER 5. LCA-GIS INTEGRATION

5.1 Background and Motivation

In the United States, the transportation sector is the second largest source of greenhouse gas (GHG) emissions, after the electricity generation sector, accounting for 27% of the total GHG emissions as of 2013 (U.S. EPA, 2015). In 2007, California introduced the Low Carbon Fuel Standard (LCFS), which was the world's first regulation aimed at reducing carbon intensity in transportation fuels. The U.S. Department of Energy (U.S. DOE) has also examined the future of transportation fuel through the lens of the Transportation Energy Futures project, which addressed multiple futuristic approaches, such as controlling the growth of the transportation sector, increasing the use of biofuels, and escalating electric and hydrogen-power vehicle technologies (U.S. DOE, 2013). Similarly, the U.S. Environmental Protection Agency (U.S. EPA) has initiated the Renewable Fuel Standard (RFS) Program with the objectives of reducing the GHG emissions of transportation fuel as well as reducing the nation's reliance on foreign oil. Under the RFS legislation, the U.S. biofuel industry is projected to produce 36 billion gallons of biofuels (primarily ethanol), which would be equivalent to 16% of transportation fuels consumed in the U.S., by 2022 (Hornafius & Hornafius, 2015). In 2010, the ethanol production capacity in the U.S. was 13.9 billion gallons, which was equivalent to 10% of the country's gasoline consumption (RFA, 2012).

Although the proposed strategies can play important roles in reducing GHG emissions from the transportation sector, a combined set of strategies can achieve better outcomes (Rhodes et al., 2015). Integrating CCS with CO_2-EOR could be a unique prospect, leading to escalate the deployment of commercial CCS projects, increased local oil supply, and the production of less carbon intensive transportation fuel as an alternative to conventional petroleum-based transportation fuels such as gasoline and diesel (De Oliveira, Marcelo E Dias et al., 2005). Recently, the literature has examined the life cycle GHG emissions of CO_2-EOR deployment from various anthropogenic (e.g., coal or natural gas (NG) power plants and NG processing plants) and biogenic (e.g., ethanol plants) industrial sources. For example, the life cycle GHG emissions of pulverized coal with CCS (PC-CCS) and CO_2-EOR applications have been examined in previous studies (Cooney, Littlefield, Marriott, & Skone, 2015; Jaramillo et al., 2009; Khoo & Tan, 2006b; Kuuskraa et al., 2011a). Other studies have examined the GHG emissions of crude oil produced via EOR using the CO_2 from natural gas power plants (Rhodes et al., 2015; Zapp et al., 2012). Rhodes et al. (2015) analyzed emissions in California and used a crude production rate of 2.5 bbl/tCO_2 injected. According to data for 2012, the crude oil CO_2-EOR production rate is a site-specific parameter and varies by oil basin, ranging from 0.9 to 3.8 bbl/tCO_2 (NETL, 2014b). This point was partially addressed by Cooney et al (2015) by using two different crude recovery rates of 2 and 4.35 bbl/tCO_2 for current EOR and advanced EOR technologies, respectively (Cooney et al., 2015). Therefore, this parameter would play an important role in the life cycle assessment (LCA) results for EOR geospatially. Hussain et al. (2013) evaluated switchgrass and livestock manure biogas as biogenic CO_2 sources; they did not consider corn ethanol plants as candidates despite ethanol's wide-spread use. Furthermore, the analysis compared CO_2 sources on the basis of their net GHG emissions without taking into account their geospatial distribution in relation to candidate EOR basins (Hussain et al., 2013). The life cycle GHG emissions of EOR using biogenic CO_2 from biomass and corn ethanol refineries have been addressed in other studies (Hornafius & Hornafius, 2015; Laude, Ricci, Bureau, Royer-Adnot, & Fabbri, 2011). Hornafius and Hornafius (2015) assigned a monetary carbon credit based on reduced carbon content in fuel rather than reporting the carbon intensity of the CO_2-EOR crude. In another study, Laude et al. (2011) focused on a gate-to-gate LCA approach that excluded the biofuel's upstream emissions as well as emissions associated with crude refining and combustion.

In summary, these studies have used inconsistent system boundaries, different functional units, and different LCA allocation methods. In addition, some studies rely on site-specific assumptions, which are not representative for other locations. The objective of the present analysis is to extend the value of LCA by integrating the LCA tool with geospatial information using GIS. This analysis also explores the use of the system expansion approach (for details, see the Method section) from life cycle and geospatial perspectives for each source (pathway). The scenario examined represents a cradle-to-grave case, which accounts for the upstream GHG emissions associated with CO_2 supply from each pathway and subsequently allocates carbon emissions credit on the basis of other products produced in parallel. The combined LCA-GIS approach integrates LCA results from each CO_2 pathway (coal power plants, natural gas plants, and ethanol refineries) with site-specific geospatial data for potential recoverable crude oil basins and information about existing/proposed CO_2-EOR infrastructure in the lower 48 states of the

United Sates. Coupling LCA with GIS can be a powerful environmental decision-making tool for deepening our understanding of the overall carbon footprint of each pathway with respect to potential EOR crude oil basins. Subsequently, the pathways can be ranked geospatially in terms of their net life cycle carbon intensity for supplying the CO_2 required to produce a barrel of crude oil via EOR. The analysis covers the processes of CO_2 capture and sequestration from potential sources (pathways), crude recovery and transport to a U.S. petroleum refinery, crude refining, and end-use consumption of refined products.

5.2 Method and Model Description

The model has been designed to calculate the carbon intensity of CO_2-based enhanced oil recovery, where CO_2 is utilized from three different industrial sources, which are referred to as “pathways” throughout the analysis, as illustrated in Figure 5.1. Geospatial data for pathway one was obtained from the National Renewable Energy Laboratory’s (NREL) interactive mapping tool and CO_2 form ethanol fermentation process was calculated using the generalized stoichiometric ratio approach based on annual ethanol production, as approached by Middleton et al. (2014) (Middleton, Clarens, Liu, Bielicki, & Levine, 2014b; NREL, 2016). For pathways 2 and 3, we used the National Energy Technology Laboratory’s (NETL) NATCARB database in addition to the U.S. EPA Facility Level Information on Greenhouse Gases (FLIGHT) to denote the CO_2 emissions of 2014 (NETL, 2016; U.S EPA, 2015).

In order to identify viable CO_2 candidates for existing and planned EOR fields, ArcGIS, a geographical mapping software developed by ESRI, was used to perform spatial analysis on the basis of two key parameters: 1) minimum power generating capacity of 400 MW for sources in pathways 2 and 3 (ESRI, 2011; IEA, 2011), and 2) maximum distance of 100 miles between a CO_2 pathway and an EOR oil basin. We understand that current CO_2 EOR pipelines exist from Colorado to West Texas for EOR at much greater distance (about 600 miles) (Middleton et al., 2015). However, using similar value or even half the distance would have significant economic implications on CO_2 transport, as illustrated by the FE/NETL model (NETL, 2014a). The NETL model uses a default CO_2 transport distance of 62 miles to eliminate the needs for additional pumps to transport the CO_2 from the source to EOR reservoirs. We examined increasing the distance to cover more CO_2 candidates and at the same time keep cost attractive for EOR operators. At 100-miles transport distance, cost would only increase by 40% as opposed to 300% when the distance was increased to 300 miles. No minimum capacity restriction was placed on pathway 1, as it produces a pure CO_2 stream. This consideration yielded a total of 76 CO_2 candidates consisting of 21 ethanol plants (pathway 1), 22 coal power plants (pathway 2), and 33 natural gas power plants (pathway 3). Using the CO_2 supply from each pathway, we generated a map that illustrates recoverable crude oil in each EOR basin with respect to region-specific CO_2 to crude oil recovery rates, as shown in Figure 5.1.

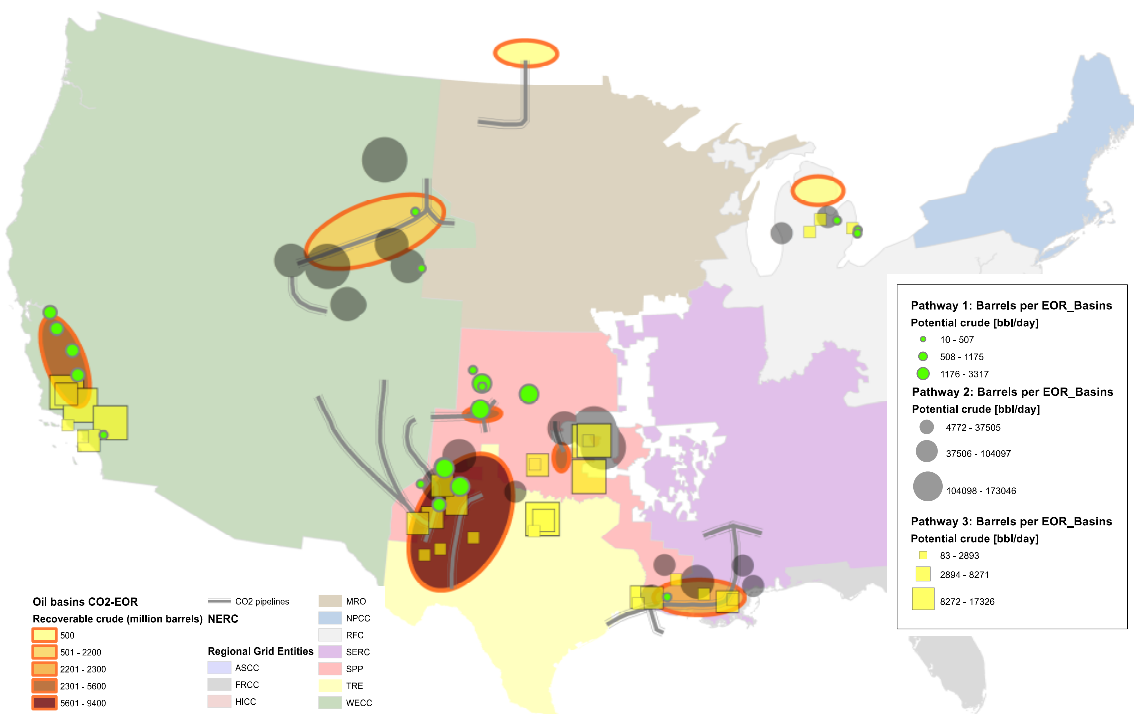


Figure 5.1 Map of CO_2 pathways within 100 miles of EOR fields in the lower 48 states of the U.S. Quantities of CO_2available from the pathways were converted to barrels of crude oil to be recovered via EOR

Source:(Abotalib et al., 2016)

To illustrate possible future CCS directions, the LCA scenario examined applies the system expansion approach, which accounts for upstream emissions of co-products, such as electricity and ethanol fuels, produced within the CO_2 supply process from the pathways, as well as credits displacement values for these co-products. In this model, the entire credit goes to the functional unit defined, which is a barrel of crude oil recovered and consumed via EOR, based on the GHG emissions emitted by conventional ethanol and electricity production in pathways 1,2, and 3. Table 5-1 highlights the key assumptions made in the pathways and the scenario examined in this analysis. Because this analysis aimed at comparing the carbon intensity of crude oil extracted via EOR for each pathway, GHG emissions is the primary environmental indicator used throughout the analysis; other environmental impact categories were considered to be outside the scope of this work. We used the calculation method of the IPCC (2007) to express GHG emissions in the form of CO_2-e over a span of 100 years (Solomon et al., 2007).

Table 5-1 Processes included in the scenario and pathways examined in the present analysis

System process	Pathway 1	Pathway 2	Pathway 3
CO_2 supply	*Includes LCA GHG emissions stages related to ethanol manufacturing with CO_2 capture:* ▪ Corn farming (including land use change) ▪ Corn transport to ethanol facility ▪ Ethanol manufacturing (i.e., fermentation) Regional electricity grid mixes supply required energy for CO_2 compression.	*Includes LCA GHG emissions stages related to electricity generation from coal with CO_2 capture:* ▪ Coal mining ▪ Coal transport ▪ Coal combustion ▪ Amine production The same plant provides necessary energy for CO_2 separation from flue gas (CCS system) by increasing fuel input.	*Includes LCA GHG emissions stages related to electricity generation from natural gas with CO_2 capture:* ▪ Natural gas production ▪ Natural gas transport ▪ Natural gas combustion ▪ Amine production The same plant provides necessary energy for CO_2 separation from flue gas (CCS system) by increasing fuel input.

Table 5-1 Continued

<table>
<tr><td>CO_2 transport</td><td colspan="3">Includes LCA GHG emissions of CO_2 transport:

Regional electricity grid mixes to supply required energy for CO_2 transport.</td></tr>
<tr><td>CO_2 injection (oil recovery)</td><td colspan="3">Includes LCA GHG emissions of CO_2 injection (oil recovery):
▪ Regional electricity grid mixes to supply required energy for CO_2 transport.
▪ Conventional oil recovery and transport to U.S. refineries.</td></tr>
<tr><td>Crude oil consumption</td><td colspan="3">Includes LCA GHG emissions of crude refining and refined products combustion:
▪ Crude oil refining.
▪ Refined petroleum products combustion such as gasoline, diesel, and fuel oil.</td></tr>
<tr><td>CO_2 accounting</td><td>Systems expansion
▪ Functional unit receives credit based on avoided GHG emissions from of corn ethanol fuel production without CCS.</td><td>Systems expansion
▪ Functional unit receives credit based on avoided GHG emissions from pulverized coal electricity generation without CCS.</td><td>Systems expansion
▪ Functional unit receives credit based on avoided GHG emissions from natural gas combined cycle electricity generation without CCS.</td></tr>
</table>

Table 5-1 Continued

Possible credited entities	At least two of the following three entities 1. Operating facility as the party responsible for preventing escape into the atmosphere. 2. CO_2 operator as the party responsible for injecting the CO_2 underground. 3. Oil refinery for purchasing crude oil of lower CI.

Notes:

- Pathways 1, 2, and 3 are compared to the business-as-usual (BAU) baseline, which is conventional crude recovery.
- The BAU case includes LCA GHG emissions stages related to crude oil recovery, transport to U.S. refineries, and combustion (see appendix B for details).

As mentioned earlier, the LCA model expands the system boundaries in order to account for negative emission credits for co-products using the system expansion or displacement method in accordance with ISO standards 14040-14044 (ISO, 2006a; ISO, 2006b). Appendix B provides additional information about the technical performance parameters for each pathway. A schematic of the system boundaries for pathways 1, 2, and 3 is shown in Figure 5.2, where the grey boxes represent co-products. As shown in Figure 5.2, all pathways generate a common product, which is crude oil, and two distinct co-products, which are ethanol in pathway 1 and electricity in pathways 2 and 3.

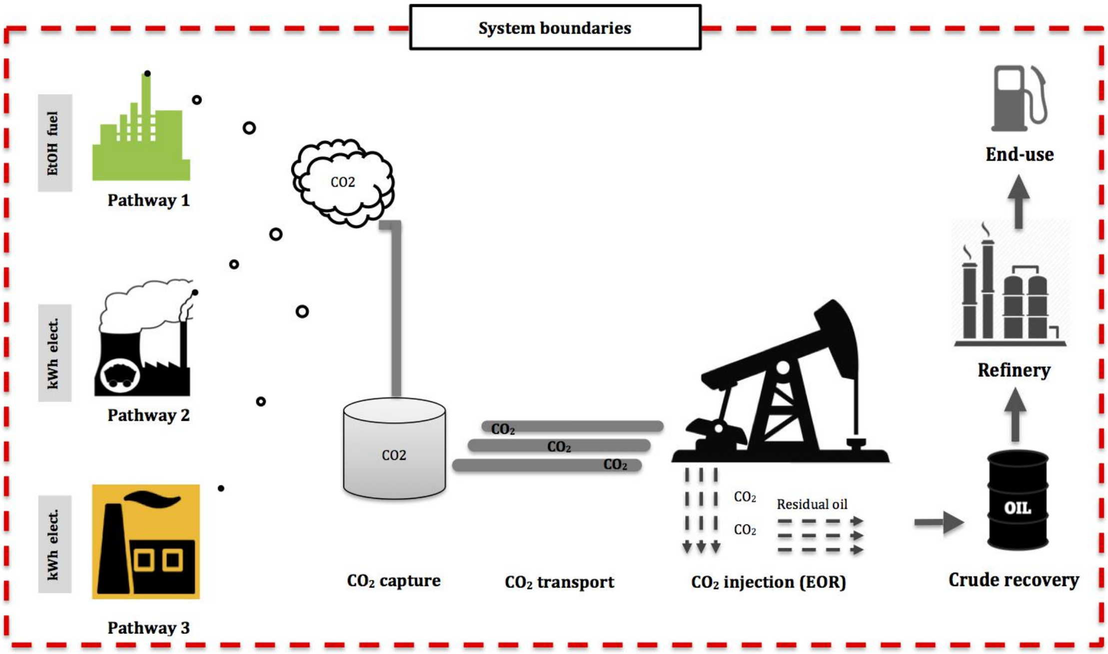


Figure 5.2 Model system boundaries for pathways 1, 2, and 3
Source: (Abotalib et al., 2016)

In Figure 5.2, the system boundaries for each pathway are shown as multiple system processes, where each system process is treated as a discrete black box. The GHG emissions for each system process were calculated separately and then combined on the basis of the specific pathways examined. For example, in pathway 1, the "CO_2 supply" system process accounts for the life cycle GHG emissions throughout the corn ethanol production process, which includes corn farming, transport to the ethanol facility, fermentation, and ethanol delivery to end users as well as the energy requirement for CO_2 capture from the fermentation process. A detailed description of each system process is provided in Appendix B. The system boundaries for the pathways excluded the physical infrastructure required in each of the system processes, and thus their associated GHG emissions were considered to be outside the scope of this analysis.

5.2.1 Functional Unit and Emission Credits

In this analysis, we use the GREET model developed by Argonne Laboratory as a reference for our LCA results for ethanol production, coal, and natural power generation (UChicago Argonne, 2014). This model has been used in regulatory compliance standards in California, such as the LCFS (Rhodes et al., 2015). The functional unit selected here is a barrel of crude oil produced via CO_2-EOR and consumed. Because CO_2-EOR fields have historically produced oil at different recovery rates (0.9 to 3.8 bbl/tCO_2), the results were calculated on the basis of geospatial characteristics of the major EOR fields in the lower 48 states of the U.S. for the pathways investigated. In this analysis, we define crude recovery rates as the amount of oil produced (in barrels) per a metric ton of CO_2 injected. The results were calculated with assigning negative emission credits for co-products, as per the system expansion approach. In the system expansion, it was assumed that the co-products would displace alternative production methods such as the production of ethanol from corn without CO_2 capture and conventional electricity generation from pulverized coal (PC) and natural gas combined cycle (NGCC) without CCS. Accordingly, the functional unit obtains a credit based on the GHG emissions emitted by conventional ethanol, in pathway 1 and electricity production in pathways 2 and 3. Table 5.2 shows some of the key results and credit values that were used for the investigated CO_2-EOR oil fields.

Table 5-2 Displacement factors for co-products in each pathway when system expansion is applied

Pathway	Oil Basin				
1: EtOH-CCS-EOR	**Permian**	**Gulf Coast**	**Rockies**	**Mid-Continent**	**California**
Co-product [gallons of EtOH]	169	395	124	91	140
Displacement Value [tCO_2-e]*	-0.87	-2.04	-0.64	-0.47	-0.72
Crude recovery rate [bbl/tCO_2]	2.1	0.9	2.8	3.8	1.8
Product [bbl. crude oil]	1 barrel of crude oil recovered via EOR				
Displaced Products	Corn ethanol via dry milling				
2: PC-CCS-EOR	**Permian**	**Gulf Coast**	**Rockies**	**Mid-Continent**	**California**
Co-product [kWh]	485	1135	355	261	402
Displacement Value [tCO_2-e] *	-0.51	-1.20	-0.38	-0.28	-0.42
Crude recovery rate [bbl/tCO_2]	2.1	0.9	2.8	3.8	1.8
Product [bbl. crude oil]	1 barrel of crude oil recovered via EOR				
Displaced Products	Electricity from coal				
3: NG-CCS-EOR	**Permian**	**Gulf Coast**	**Rockies**	**Mid-Continent**	**California**
Co-product [kWh]	1041	2434	762	560	862
Displacement Value [tCO_2-e] *	-0.56	-1.30	-0.41	-0.30	-0.46
Crude recovery rate [bbl/tCO_2]	2.1	0.9	2.8	3.8	1.8
Product [bbl. crude oil]	1 barrel of crude oil recovered via EOR				
Displaced Products	Electricity from natural gas				

Note: * Subject plants are assumed to be retrofitted with CCS as opposed to the construction of new plants without CCS.

Source: (Abotalib et al., 2016)

Equation (5.1) shows the key variables used to calculate net GHG emissions for each pathway at various EOR fields, allowing the results to be compared with one other. The findings were also compared to a business-as-usual (BAU) baseline scenario, which refers to conventional crude recovery and transport to U.S. refineries and refined crude oil combustion (see Appendix B for details).

$$\mathbf{Net\ GHG(y)_{EOR} = GHG_{EOR} + \ dc = [tCO_2e\ per\ bbl.]} \qquad \mathbf{Eq. 5.1}$$

where

$$GHG\ (y)_{EOR} = \sum_{i=1}^{n} x_i = x_1 + x_2 \ldots + x_n \quad [tCO_2e\ per\ bbl.] \qquad Eq. 5.1.1$$

$y = EOR\ field\ (region\ specific\ crude\ recovery\ rate\ and\ energy\ mix)$

$x_1 = GHGs\ CO_2\ supply$

$x_2 = GHGs\ CO_2\ transport$

$x_3 = GHGs\ CO_2\ injection\ (oil\ recovery\ and\ transport\ to\ a\ refinery)$

$x_4 = GHGs\ crude\ oil\ refinery\ and\ refined\ crude\ combustion$

$dc = displacement\ credit\ [\ tCO2e\ per\ bbl.]$

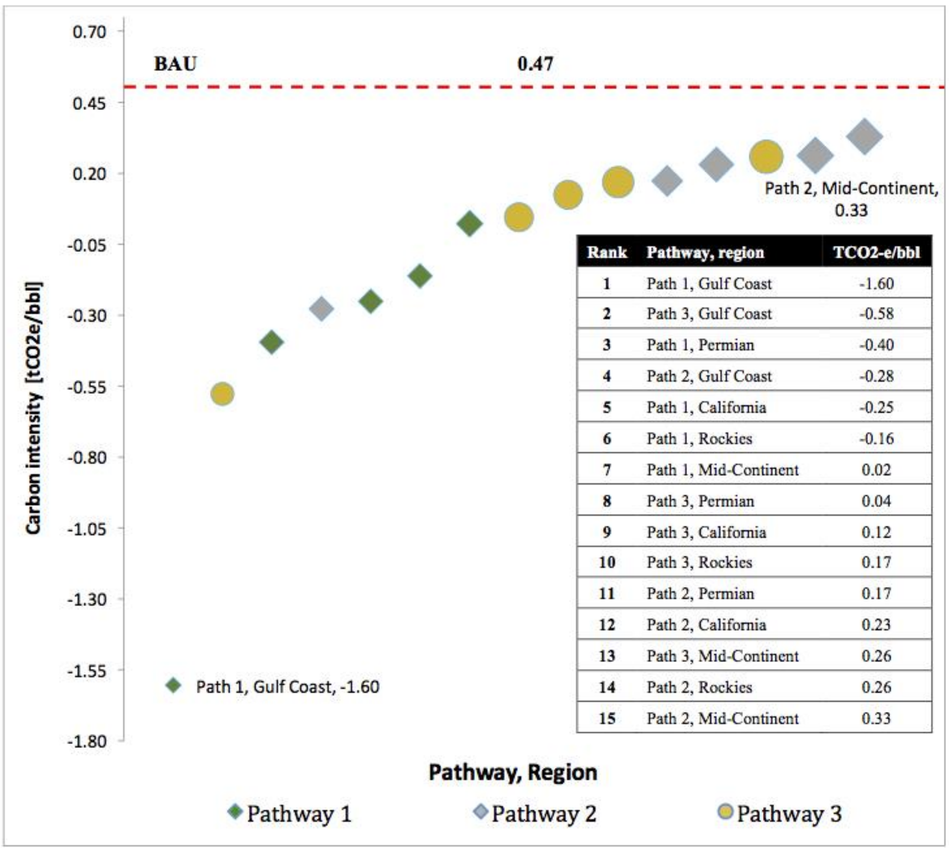
$$dc = (No.of\ units_{co-product}) * (\frac{GHGs\ displaced\ prod.}{unit}) \qquad Eq. 5.1.2$$

5.2.2 Data Sources for GHG Life Cycle Emissions for Energy

In pathways investigated, the energy required for CO_2 capture, for pathways 2 and 3 was assumed to be supplied by the same pathway. On the other hand, the energy required for CO_2 compression, for pathway 1, and for CO_2 transport via pipeline, and injection into an EOR reservoir was assumed to be supplied by an independent source using the regional electricity grid mix as defined by the North American Electric Reliability Corporation (NERC) (NERC, 2014). The life cycle GHG emissions and geographical distribution for each NERC entity are provided in appendix B. In addition, the model's technical performance parameters are highlighted in appendix B

5.3 Results and Discussion

The results, henceforth, are presented in the form of metric tons of CO_2-e emissions per barrel of crude oil (t CO2-e/bbl.) in all investigated pathways. Three pathways were examined, representing the five major EOR fields. The pathways were compared to a baseline case, which is conventional crude recovery with LCA GHG emissions of 0.47 tCO_2-e/bbl. Figure 5.3 illustrates the pathways in ascending order in terms of the carbon intensity of a barrel of crude recovered and consumed via CO_2-EOR.



Rank	Pathway, region	TCO2-e/bbl
1	Path 1, Gulf Coast	-1.60
2	Path 3, Gulf Coast	-0.58
3	Path 1, Permian	-0.40
4	Path 2, Gulf Coast	-0.28
5	Path 1, California	-0.25
6	Path 1, Rockies	-0.16
7	Path 1, Mid-Continent	0.02
8	Path 3, Permian	0.04
9	Path 3, California	0.12
10	Path 3, Rockies	0.17
11	Path 2, Permian	0.17
12	Path 2, California	0.23
13	Path 3, Mid-Continent	0.26
14	Path 2, Rockies	0.26
15	Path 2, Mid-Continent	0.33

Figure 5.3 Carbon intensity of crude oil recovered via CO2-EOR from investigated pathways in different EOR fields

Source: (Abotalib et al., 2016)

As shown in Figure 5.3, the LCA results varied among the investigated oil basins. Therefore, the impacts of individual system processes were further examined in order to identify the GHG emissions contributions from the processes included in the study system boundary, as shown in Figures 5.4. However, one key factor in the LCA variation was the crude recovery rate in each EOR field. For example, the Gulf Coast, which has a lowest crude recovery rate of 0.9 bbl/tCO_2, requires about 1.13 tCO_2 to recover one barrel of crude oil via CO_2-EOR. This is approximately double the average requirement for CO_2-EOR in the U.S. (0.54 tCO_2/bbl) and more than four times the CO_2 needed in EOR fields in the Mid-Continent basin (0. 26 tCO_2/bbl). In view of that, storing more carbon at a given oil reservoir would correspond to an increase in the displacement credit for co-products.

Figure 5.4 illustrates the carbon intensity in terms of system process, which includes the upstream emissions from CO_2 sources and allocates displacement credits on the basis of the resulting co-products. The results show that lower carbon intensive crude oil was produced via CO_2-EOR for the three pathways compared to conventional crude recovery (BAU), despite the fact that the system boundary was expanded to include upstream emissions from the three pathways.

Pathway 1 generally exhibited significant GHGs benefits than other pathways in all EOR oil basins, whereas pathway 2 had highest GHGs profile. In pathway 1, the capture of biogenic CO_2 has added value compared to the capture of non-biogenic CO_2 in pathways 2 and 3. Biogenic CO_2 capture not only enables the production of low-carbon crude oil; it also removes carbon from the natural carbon cycle. Furthermore, the model allocates displacement credits for co-products, which balance a significant amount of the

CO_2 generated in other system processes. For example, CO_2 injection plays an important role in determining the extent of co-product credits, where the magnitude of the reduction in GHGs depends on a site's specific crude recovery rate. The results show that co-product credits in pathways 2 and 3 offset at least 60% of the GHG emissions (in the Mid-continent) of the crude refinement and refined product combustion system processes.

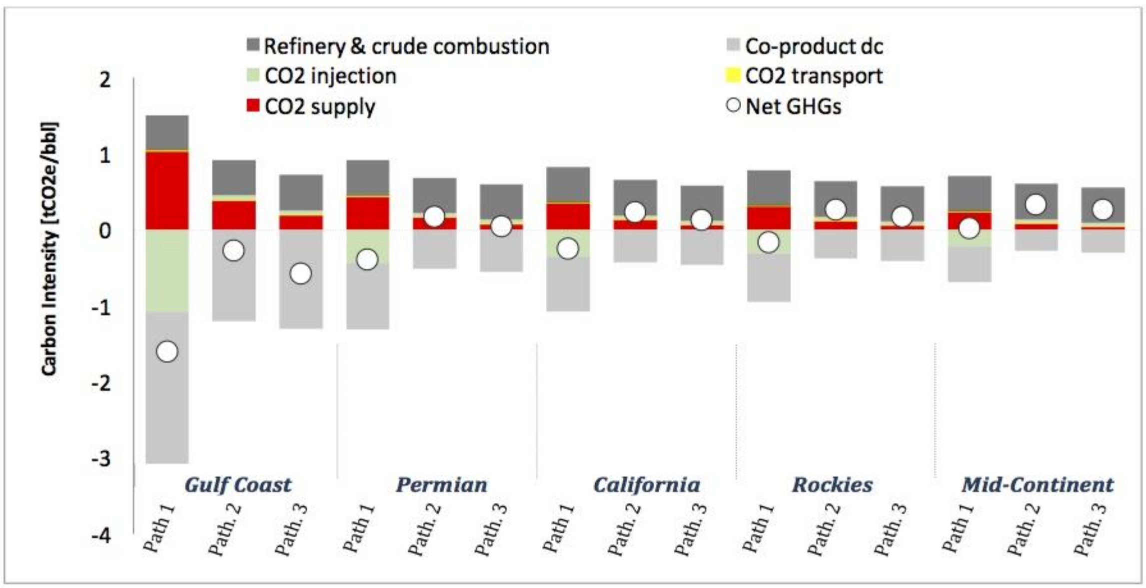


Figure 5.4 LCA net GHG emissions for major EOR fields in the three pathways
Source: (Abotalib et al., 2016)

5.4 Summary

EOR basins with a higher CO_2 requirement per incremental barrel of oil exhibit a greater reduction in the carbon intensity for produced crude oil. This finding provides a potential future direction for CO_2-EOR from a carbon mitigation perspective. However, EOR operators tend to increase the efficiency of the EOR process in order to maximize the crude yield from purchased CO_2. This point was addressed in a study by Middleton et al. (2015), which suggested that CO_2 supply cost and oil prices would determine the economic viability of CCS-EOR applications in different EOR fields (Middleton et al., 2015). The study also suggested that utilizing CO_2 from industries that produce high purity CO_2 would be an attractive financial alternative to primary crude production under certain oil market conditions (Middleton et al., 2015).

As highlighted earlier, pathway 1 illustrates greater GWP benefits as opposed to pathways 2 and 3 and would be a favorable pathway for EOR operators as it produces almost pure CO_2 stream. Next, the results indicate that pathway 3 was somehow less carbon intensive than pathway 2. However, the deployment of pathway 3 is unlikely to take place before pathway 2 because it has lower CO_2 emissions profile and considerably higher subsequent economic implications (Middleton & Eccles, 2013). In this study, recovering crude oil by use of CO_2 from pathway 1 was less carbon intensive than with the use of CO_2 from the other pathways for individual EOR basins. The results indicated that pathway 1 was the preferable option, as its carbon intensity was only 3 to 7 percent that of as pathways 2 and 3. Pathway 3 was marginally less carbon intensive than pathway 2. This difference can be explained by the displacement credit that pathway 3 receives and lower GHGs emission from the CO_2 supply system process. Although the process of CO_2 transport via pipeline, and injection into an EOR reservoir uses a different regional electricity grid mix as per the NERC classification, variations in GHG among NERC entities did not have a significant impact on the final LCA results in pathways examined. For the pathways investigated, under the technical and geospatial constraints of this study, the results indicate that 1.25 million barrels of crude can be recovered per day through the use of CO_2-EOR in five major oil regions: Permian Basin, Gulf Coast, Mid-Continent, Rockies, and California. As mentioned previously, we considered only those candidates within a distance of 100 miles from EOR oil basins. Under this assumption, coal-fired power plants alone would have the potential to supply about 88% of the CO_2 required for EOR. For example, in the Rockies, about 0.6 million barrels can be recovered per day from only eight coal-fired power plants, with potential CO_2 supply of 210,000 tCO_2 per day. Natural gas power plants would have the capacity to supply about 10%, while ethanol facilities would supply the remaining 2%.

Increasing the distance parameter alone would yield even more CO_2 candidates, providing additional CO_2 supply for EOR. For example, when we enlarged the distance restriction from 100 to 300 miles, the number of CO_2 candidates, in all oil basins, increased to 88, 105, and 193 compared to 21, 22, and 33 for pathways 1,2, and 3, respectively. However, we noticed that most of those additional CO_2 candidates were located in the Midwestern region, where CO_2 pipelines are lacking and oil deposits are not significant (See Figure S8 in the SI document for details).

Furthermore, the RFS target of increasing biofuel production to 36 billion gallons by 2022 can be seen as an opportunity to increase the CO_2 supply from ethanol facilities by expanding the ethanol industry in regions close to EOR fields, in particular in locations with favorable climatic conditions. Furthermore, the study focused on CCS-CO_2-EOR applications in the top five major oil regions, where 80% of all EOR oil is trapped and readily available for recovery. Therefore, evaluating the investment opportunities in CCS-EOR projects in these regions would be a sensible choice for EOR operators. However, additional recoverable EOR crude oil deposits do exist at fair capacities in other regions. For example, the Illinois Basin has about 220-300 million recoverable oil and at the same time reasonable ethanol capacity, producing about 3 million gallons of ethanol in 2014. Using the CO_2 supply from ethanol plants would be relatively cheap enough to recover 10 to 40 million barrels of oil every year (RFA, 2016). Therefore, the case of the Illinois basin deserves complete investigation by a separate dedicated study.

The main limitations of the model are the technical performance parameters related to the individual EOR reservoirs in the investigated oil basins. The quantity of crude oil recovered from an EOR reservoir is highly dependent on geological characteristics, crude properties, and EOR technology-specific operations. The hydrostatic pressure in an oil reservoir depends on fluid extraction rates and other geophysical parameters such as, porosity and temperature. Therefore, a reservoir pressure is variable in both space and time (Hoversten, Gritto, Washbourne, & Daley, 2002). In this study, we did not account for such variations and assumed that the pressure in each EOR reservoirs does not change over time. Instead, we used crude recovery rates for each oil basin on the basis of historic oil production rates. (See appendix B for detailed technical performance parameters). Also, it is very important to recognize that storing more carbon at a given reservoir would correspond to an increase in the displacement credit for co-products. In our model, we assumed that “like displaces like,” i.e., that the two co-products, ethanol and electricity, would displace the production of corn ethanol and electricity from coal and natural gas without CCS. However, it can be argued that the choice of substitutes for ethanol and electricity should be based on the purpose that each co-product serves. For example, the co-product in pathway 2 supplies additional electricity to the power grid mix, and therefore it may be argued that it should not be assumed to displace electricity from coal, which would yield greater displacement credit; rather, it would replace the regional electricity grid mix. The same argument applies to pathway 1, where additional ethanol produced could be assumed as a replacement for cellulosic ethanol, which has 80% less GHG emissions compared to corn ethanol. Thus, exploring alternative substitutes for co-products would have a significant impact on the displacement credits; especially if that alternative has lower LCA GHG emissions per unit produced. Finally, because of the linear relationship between energy requirements and the CO_2 to be injected to recover a barrel of oil, greater CO_2 storage in a less efficient EOR field places a cost burden on this option. Therefore, investigating the economic dimension associated with CO_2 capture from each pathway along with the reduction in fuel carbon intensity would lead to a more comprehensive understanding of industrial CO_2-EOR practices.

CHAPTER 6. CCS DEPLOYEMNT FROM GAME THEORY PERSPECTIVE

6.1 Background and Motivation

The introduction or revision of operative laws, regulations, standards, or other government incentive programs can be a time-intensive process, as it involves careful categorization of potentially affected stakeholders as well as holistic evaluation of anticipated positive and negative consequences on stakeholders, in particular, and on society as a whole (Swanson & Lin, 2009). Effective environmental regulations should apply to the existing market and also guide industries in the desired political direction. Among environmental standards and regulations are those related to controlling greenhouse gas emissions from industrial sources. Such regulations are viewed by developing countries as a constraint on economic growth and the improvement of public welfare (Li, Zhang, Shi, & Zhou, 2016). In recent years, and especially in the post-Copenhagen era, climate policy has shifted towards a new paradigm, which considers a wide range of strategies such as the green economy and low-carbon development projects between public and private sectors and encourages the involvement of potentially affected stakeholders in the decision-making process (Bäckstrand & Lövbrand, 2016). In 2016, key global CO_2 emitters including China, India, and the United States were among the committed participants in the Paris Agreement (Bäckstrand & Lövbrand, 2016; X. Yang & Teng, 2016).

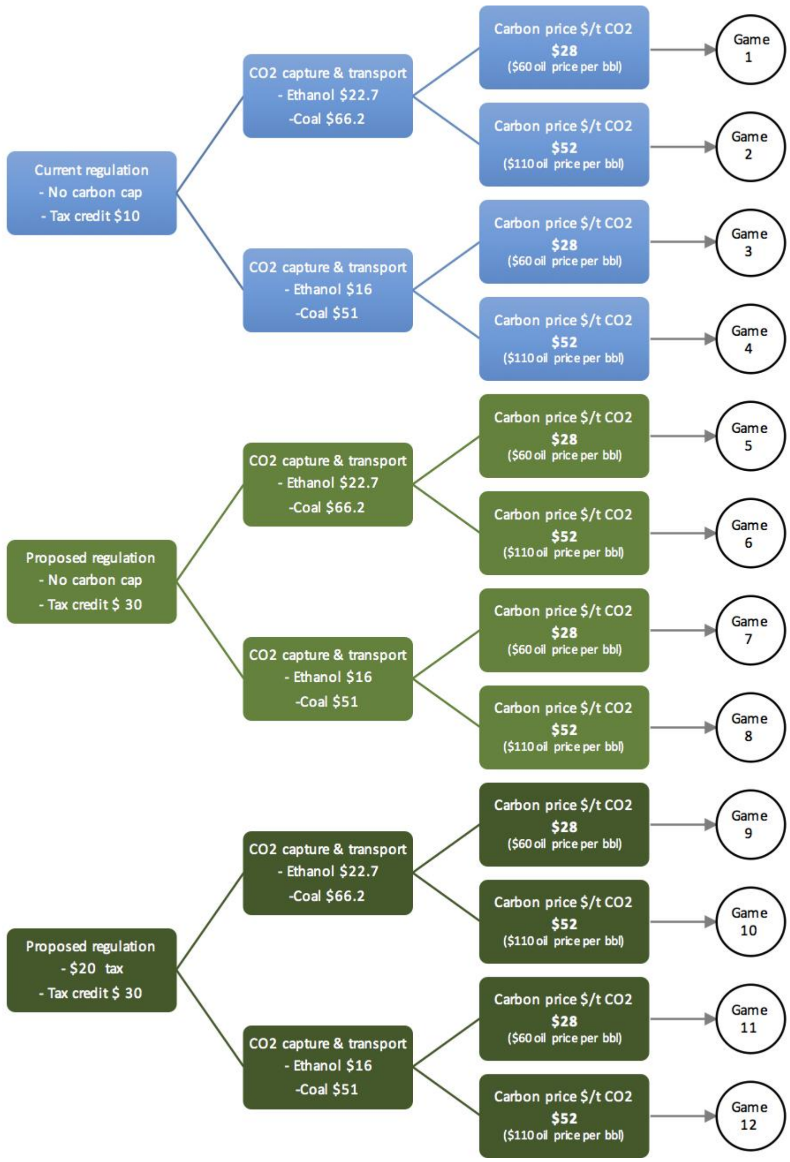
In view of substantially reducing CO_2 emissions, the Paris Agreement recognized the importance of de-carbonizing the world's leading economies by creating a balance between emission of anthropogenic CO_2 by sources and elimination by sinks (Bäckstrand & Lövbrand, 2016). In the United States, the electricity generation and transportation sectors are the two main sources of anthropogenic CO_2 emissions (U.S. EPA, 2015). One way of reducing GHG emissions from the transportation sector is the production of fuel that is less carbon intensive. Recently developed geotechnical solutions have made it possible to capture CO_2 emissions from industrial point sources by means of CCS technologies (Metz et al., 2005). In this context, CCS can be applied directly to the power generation sector or other industrial sources, and the captured CO_2 can be utilized for enhanced oil recovery EOR.

Although there is a general consensus in the literature that CCS has a parasitic energy load and increases resource consumption, the technology has shown promising reductions in GHG emissions when analyzed from a life cycle perspective (Abotalib et al., 2016; H. Herzog, Meldon, & Hatton, 2009; Hornafius & Hornafius, 2015; Hussain et al., 2013; Melzer, 2012; NETL, 2011; Rhodes et al., 2015; Singh et al., 2011b; Singh, Bouman, Strømman, & Hertwich, 2015). However, the magnitude of the reduction in GHG emissions from a source is dependent on the energy requirement for sequestering the CO_2 from the flue gas stream. For example, ethanol facilities produce a nearly pure CO_2 gas steam (from the fermentation process), whereas coal-fired and natural gas power plants produce a gas stream with low CO_2 concentration, between 10 and 17% by volume (Katzer, Moniz, Deutch, Ansolabehere, & Beer, 2007).

As discussed in the literature, CCS integration with CO_2-EOR has significant potential to reduce the carbon footprint of the U.S. transportation sector by producing crude oil with lower carbon intensity than in conventional crude recovery (Abotalib et al., 2016; Hornafius & Hornafius, 2015; Rhodes et al., 2015; U.S. DOE, 2013; U.S. EPA, 2015). In the United States, more than 90 million barrels of oil (MMbo) are produced annually via CO_2-EOR. This figure may increase significantly, as estimates suggest that there are more than 24 billion barrels of economically recoverable oil in the lower 48 states of the U.S. (Kuuskraa, Van Leeuwen, Wallace, & DiPietro, 2011b; MITEI, 2016). The majority of these oil deposits are trapped in the Permian, Gulf Coast, Mid-Continent, Rockies, and California oil basins (ARI, 2010a). Currently, about 70% of the CO_2 used in EOR projects is obtained from natural CO_2 wells. Finding an alternative and consistent CO_2 supply would allow the expansion of EOR projects and further the objectives of the Energy Policy Act of 2005 (Energy Policy Act, 2005). However, current carbon policies do not provide sufficient economic incentives for major carbon emitters to invest in CCS projects (Mills, 2014).

The first objective of this chapter is to establish a framework for assessing CCS-EOR deployment by industrial emitters, with a specific focus on coal power plants and ethanol facilities, from a game-theory perspective under various carbon policy scenarios. Second, we assess the payoffs of possible dynamic changes in climate policies and in the carbon market, and the effects of policy changes on the ethanol and coal power industries in the United States, with a focus on the Illinois Basin. The results from the games (scenarios) explored here are envisioned as the players' possible strategies, i.e., their responses to existing and futuristic carbon policy approaches and incentives, in terms of potential variations in carbon market conditions.

Based on technical and economic information from the literature (see Method section in this chapter for details), twelve combinations of game scenarios were established in order to determine players' chosen strategies and the corresponding payoffs under each scenario, as shown in Figure 6.1. The games are considered to be non-cooperative; i.e., each player tends to act independently with the aim of maximizing its payoff or, in some situations, minimizing its loss, regardless of the consequences for other players (see Table 6-2 - 6-4 for details). The best outcome of such a game is referred to as a non-cooperative equilibrium or Nash equilibrium. The outcomes or payoffs from the games can be illustrated in a classic two-player, two-strategy game matrix, as shown in the Results section.



Game	Description	Notes
1	*Existing carbon policies and current price of CCS technology at oil price of $60 per bbl.*	No change in existing carbon regulations
2	*Existing carbon policies and current price of CCS technology at oil price of $110 per bbl.*	
3	*Existing carbon policies and future price of CCS technology at oil price of $60 per bbl.*	
4	*Existing carbon policies and future CCS technology at oil price of $110 per bbl*	
5	*Future carbon policies and current price of CCS technology at oil price of $60 per bbl.*	Increasing carbon incentive from $10 to $30 per ton of CO_2 captured and used for EOR
6	*Future carbon policies and current price of CCS technology at oil price of $110 per bbl.*	
7	*Future carbon policies and future price of CCS technology at oil price of $60 per bbl.*	
8	*Future carbon policies and future price of CCS technology at oil price of $110 per bbl*	

9	*Future carbon policies and current price of CCS technology at oil price of $60 per bbl.*	$20 carbon tax for anthropogenic CO_2 emitters, and increasing carbon incentive from $10 to $30 per ton CO_2 captured and used for EOR
10	*Future carbon policies and current price of CCS technology at oil price of $110 per bbl.*	
11	*Future carbon policies and future price of CCS technology at oil price of $60 per bbl.*	
12	*Future carbon policies and future price of CCS technology at oil price of $110 per bbl*	

Figure 6.1 Schematic representation of different non-cooperative game scenarios analyzed under different policy and market conditions. A detailed description of each game is provided in appendix B

6.2 CCS Game-Theory Model

In this analysis, we use non-cooperative game theory to assess the future of CCS deployment in ethanol production facilities and coal power plants. The participants in a game are referred to as "players." Their payoffs in the game are determined by whether or not they change their business-as-usual (BAU) practices by integrating CCS into their operations and subsequently selling captured CO_2 to EOR operators. The strategy chosen by a player in a specific game scenario is determined by the payoff in that scenario. For example, for ethanol production facilities (player 1) and coal power plants (player 2), the payoffs are calculated under different carbon policies, costs of CO_2 capture technologies, and market prices of carbon as a commodity for EOR operations. Payoffs are calculated on the basis of the economic costs/benefits of capturing one metric ton of CO_2 and transporting it to an EOR operator. The cost of CO_2 capture represents the current and future costs of technology deployment in ethanol facilities and coal power plants. The CO_2 sale price is based on the amount that EOR operators are willing to pay per mass unit of CO_2. Historical market prices for oil and CO_2 indicate that an EOR operator would purchase CO_2 at 2.5% of the oil price per thousand cubic feet (Mcf) of CO_2, or at

47% of the oil price per metric ton of CO_2 (Kuuskraa et al., 2011a). Equation 1 is the mathematical formula for calculating payoffs. The variables are defined below.

$$\boldsymbol{R\ (i)^{N}(P^{n}) = \sum_{j=1}^{n} C_j = C_1 + C_2 + \ldots\ldots C_n} \qquad \textbf{Equation 6.1}$$

$R^N = Payoff\ from\ BAU\ and\ CCS\ deployment$

$i = Specific\ scenario\ of\ carbon\ regulations\ and\ advancement\ in\ CCS\ technologies$

$P^1 = Player\ 1, ethanol\ facility$

$P^2 = Player\ 2, coal\ power\ plant$

$C_1 = Cost\ to\ capture\ and\ transport\ one\ metric\ ton\ of\ CO_2\ in\ U.S.\$/tCO_2$

$C_2 = Carbon\ price\ including\ tax\ and\ credits, if\ any, in\ U.S.\$/tCO_2$

$C_3 = Commodity\ price\ of\ CO_2\ in\ U.S.\$/tCO_2$

Table 6-1 Key parameters for possible scenarios and subsequent associated cost for each player

	Parameter	Player 1: ethanol facility	Player 2: coal power plant	Notes and references
CCS technical assumptions	**CO_2 supply* [$/T$CO_2$] [a]**	22.7	66.2	▪ The cost includes CO_2 capture from source and transport to EOR operator in [$/T$CO_2$] ▪ Cost of CO_2 capture from ethanol = $12.7 (Global CCS Institute, 2012) ▪ Cost of CO_2 capture from coal = $56.2 (NETL, 2015) ▪ Cost to transport CO_2 100 miles = $10 (NETL, 2015)
	CO_2 supply* [$/T$CO_2$] [b]	16	51	▪ The cost includes CO_2 capture from source and transport to EOR operator in [$/T$CO_2$] ▪ Cost of CO_2 capture from ethanol = $6 (Global CCS Institute, 2012) ▪ Cost of CO_2 capture from coal = $41 (NETL, 2015) ▪ Cost to transport CO_2 100 miles = $10 (NETL, 2015)
Regulation	**Carbon Tax [$/T$CO_2$] [a]**	0	0	▪ Current regulations
	Carbon Tax [$/T$CO_2$] [b]	0	20	▪ Future carbon tax assumed
	Tax credit [$/T$CO_2$] [a]	0	10	▪ Section 45Q (IRS, 2011)
	Tax credit [$/T$CO_2$] [b]	0	30	▪ Proposed revision of section 45Q (NEORI, 2016)

Table 6-1 Continued

Economy	**CO_2 sale price [$/$TCO_2$]** [a]	28	28	▪ At oil price of $60 per bbl (Kuuskraa et al., 2011a)
	CO_2 sale price [$/$TCO_2$] [b]	52	52	▪ At oil price of $110 per bbl (Kuuskraa et al., 2011a)

[*] CO_2 supply includes the cost of CO_2 capture from source and transport to EOR operators, [a] current or existing cost or technology, [b] proposed or future cost.

Table 6-1 lists the key parameters used to calculate the payoff for each player examined in each game scenario. Data from the literature were used in these calculations. On the basis of the information provided in Table 6-1, twelve combinations of game scenarios were established in order to determine players' chosen strategies and the corresponding payoffs under each scenario, as shown in Figure 6.1. The games are considered to be non-cooperative; i.e., each player tends to act independently with the aim of maximizing its payoff or, in some situations, minimizing its loss, regardless of the consequences for other players (see Tables 6-2-6-4 for details). The best outcome of such a game is referred to as a non-cooperative equilibrium or Nash equilibrium. The outcomes or payoffs from the games can be illustrated in a classic two-player, two-strategy game matrix, as shown in the Results section

6.2.1 Potential CO_2 Supply

6.2.1.1 Potential Supply from Ethanol Plants

Currently, the amount of CO_2 potentially recoverable from ethanol plants is estimated at 23.4 MMT, of which less than 20% is used as a commodity by other industries in the U.S. CO_2 merchant market (Supekar & Skerlos, 2014). Ethanol plants would have the capacity to supply about half of the CO_2 required for EOR in the U.S at current EOR projects capacity. However, less than 40% of this supply is located within 100 miles from EOR fields.

6.2.1.2 Potential Supply from Coal-fired Power Plants

In 2010, anthropogenic GHG emissions in the U.S. reached a total of 6,821.8 MMT of CO_2-e. Coal-fired power plants alone are responsible for about 27% (1,840 MMT) of such emissions (U.S. EPA, 2012). In 2011, the EIA reported that coal would continue to dominate the U.S. power-generation matrix for the next 25 years (EIA, 2011). The EIA has projected a 10% increase in the concentration of CO_2-e in the atmosphere between 2015 and 2035 (EIA, 2010). A typical 500 MW coal-fired power plant emits about three MMT of CO_2 per year; if this CO_2 were captured and used for EOR, approximately 11 million incremental barrels of oil could be produced(ARI, 2010b; Katzer et al., 2007). Under the assumption of 90% efficiency in the capture of CO_2 from flue gas, a total of nearly 19 coal-fired power plants with an electric power capacity of 500 MW would be sufficient to supply all the CO_2 (50 MT) required by current EOR projects. In contrast to ethanol plants, which produce a pure CO_2 stream, coal-fired power plants produce a stream with low CO_2 concentration, about 15% by volume, with higher associated energy and economic penalties (Katzer et al., 2007).

6.2.2 Geospatial Data Sources

For geospatial analysis, we used the ArcGIS computer software developed by ESRI to visualize the potential of CO_2 CCS-EOR applications, particularly in the Illinois

Basin (ESRI, 2011). Geospatial data for players 1 and 2 were obtained from the NREL interactive mapping tool and the National Energy Technology Laboratory's (NETL) NATCARB database (NETL, 2016; U.S EPA, 2015). The CO_2 emission profiles for ethanol facilities were calculated from annual ethanol production data using the mole-to-mole stoichiometric ratio method (Middleton et al., 2014a). Figure 6.2 is a geographic map of existing/proposed EOR and CO_2 infrastructure in addition to ethanol and coal power plants in the lower 48 states of the U.S. Eighty percent of all EOR oil is trapped in the top five oil regions: Permian, Gulf Coast, Mid-Continent, Rockies, and California. However, reasonable capacities exist in other regions such as the Illinois Basin, where estimates suggest that there are about 220-300 million barrels of recoverable oil (Abotalib et al., 2016). Currently, there are no commercial CO_2-EOR projects or dedicated CO_2 pipelines in the Illinois Basin because of the absence of dedicated natural CO_2 wells or other supplies (Damico et al., 2014). However, as shown in Figure 6.2, this region has numerous industrial CO_2 sources, such as ethanol facilities and coal-fired power plants, which are potential suppliers of CO_2 for EOR projects in place of natural CO_2 wells.

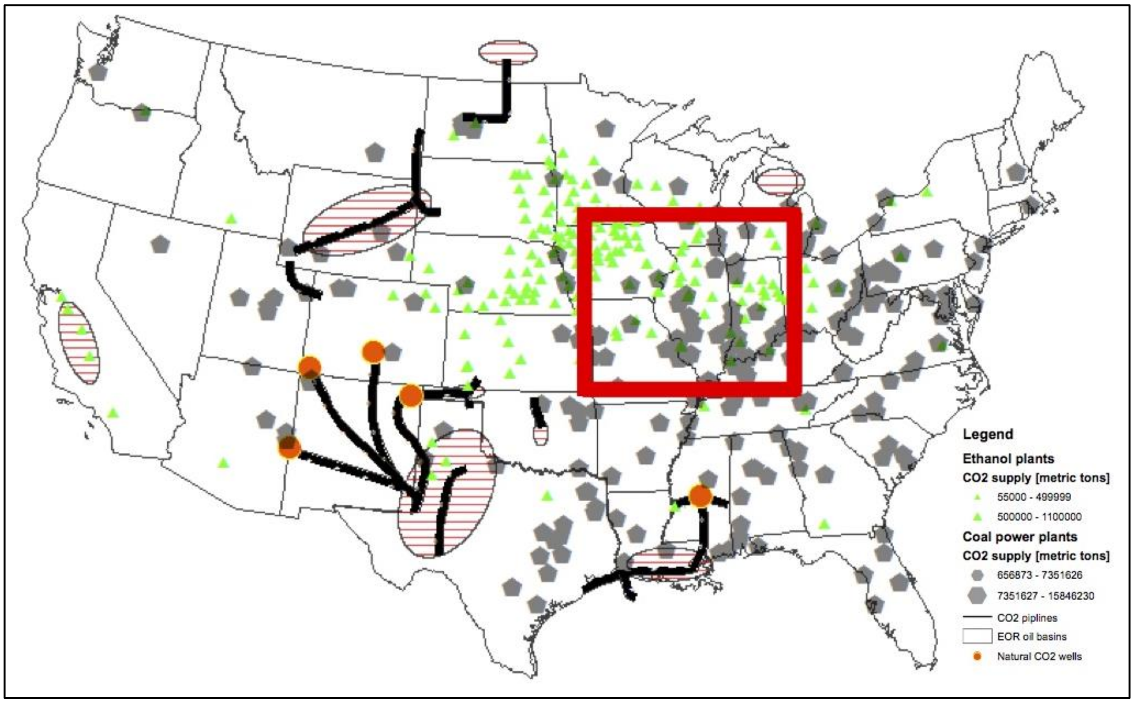


Figure 6.2 Map of EOR infrastructure and potential CO_2 supply from ethanol and coal power plants. Quantities of CO_2 are based on annual emission profiles from the sources

6.3 Results and Discussion

6.3.1 Non-Cooperative Game Scenarios

The payoffs from the game scenarios, hereafter, are presented in U.S. dollars and based on the parameters considered in the scenarios (as illustrated in Figure 6.1). The payoff matrix for a given game demonstrates the rational strategy to be followed by each player according to the expected outcome or payoff, and subsequently a Nash equilibrium (highlighted in red in Tables 6-2 to 6-4) can be determined at which each player's strategy is optimal to the game. The twelve games in Figure 6.1 represent three carbon policy scenarios with varying exogenous impacts such as changes in the cost of CO_2 technologies and the EOR operator's willingness to pay for CO_2 captured from industrial sources. The first set of game scenarios (1-4) represent four possible cases with existing carbon regulations and changes in oil prices and in the cost of CCS and delivery to EOR operators. Their payoff matrices are shown in Table 6-2. The second set of games (5-8) explore four possible cases in which the incentive credit allocated to anthropogenic CO_2 emitters during a taxable year is increased from $10 to $30 per metric ton of CO_2 captured and utilized for EOR. This set also explores two different oil prices, and the existing and future costs of CCS deployment in ethanol facilities and coal power plants and of CO_2 delivery to EOR operators, as illustrated in Table 6-3. Lastly, the third set of game scenarios (9-12) specify a carbon tax on anthropogenic industrial CO_2 emitters of $20/t$CO_2$ emitted. These scenarios also provide incentives for these entities in the form of tax credits for CCS deployment and integration with EOR under two different costs for CCS deployment and two different carbon prices. The payoffs matrices for the third set of games are shown in Table 6-4. For a detailed description of the game scenarios, see Figure 6.1 and section B3 in appendix B.

Table 6-2 Games 1-4: Payoffs for players 1 and 2 with current carbon regulations under different CCS costs and market conditions

Game 1) Current CCS tech at oil price of $60 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, -28.2)
	CCS	**(5.3, 0)**	(5.3, -28.2)

Game 2) Current CCS tech at oil price of $110 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, -4.2)
	CCS	**(29.3, 0)**	(29.3, -4.2)

Game 3) Future CCS tech at oil price of $60 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, -13)
	CCS	**(12, 0)**	(12, -13)

Game 4) Future CCS tech at oil price of $110 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, -28.2)
	CCS	(36, 0)	**(36, 11)**

Table 6-3 Games 5-8: No carbon tax. Incentive for anthropogenic CO_2 of $30 instead of $10. Changes in oil prices and CCS technologies

Game 5) Current CCS tech at oil price of $60 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, -8.2)
	CCS	**(5.3, 0)**	(5.3, -8.2)

Game 7) Future CCS tech at oil price of $60 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, 7)
	CCS	(12, 0)	**(12, 7)**

Game 6) Current CCS tech at oil price of $110 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, 15.8)
	CCS	(29.3, 0)	**(29.3, 15,8)**

Game 8) Future CCS tech at oil price of $110 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, 31)
	CCS	(36, 0)	**(36, 31)**

Table 6-4 Games 9-12: $20 carbon tax. Incentive for anthropogenic CO_2 of $30 instead of $10. Changes in oil prices and CCS technologies

Game 9) Current CCS tech at oil price of $60 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, -20)	(0, -28.2)
	CCS	**(5.3, -20)**	(5.3, -28.2)

Game 11) Future CCS tech at oil price of $60 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, -20)	(0, -13)
	CCS	(12, -20)	**(12, -13)**

Game 10) Current CCS tech at oil price of $110 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, -20)	(0, -4.2)
	CCS	(29.3, -20)	**(29.3, -4.2)**

Game 12) Future CCS tech at oil price of $110 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, -20)	(0, 11)
	CCS	(36, -20)	**(36, 11)**

According to the results, the ethanol facilities (player 1) would increase their payoffs when implementing CCS-EOR in all scenarios. In other words, the dominant strategy of player 1 would always be to switch to CCS as opposed to BAU. In games 1, 5, and 9, the payoffs for player 1 were the lowest, yet still positive. In these situations, the sale price of CO_2 was relatively low because of the low price of oil (at $60 per bbl), and there was no reduction in the cost of CCS technology deployment. The payoffs for player 1 were the highest in games 4, 8, and 12, where oil prices were at $110 and the cost of capturing and delivering CO_2 for EOR was reduced by 30%.

Next, the results show that coal power plants (player 2) would be reluctant to change their BAU strategy under existing carbon regulations and the current cost of CCS technologies (i.e., in games 1 and 2). This outcome is justified by the fact that switching to CCS would not make sense economically even if the oil price were assumed to be \$110 per bbl. Player 2 would also tend to maintain a BAU strategy in game 3, under the CO_2 price of \$28 per metric ton, despite the reduction in the cost of CCS technologies from \$66.2 to \$51 per metric ton of CO_2 captured. CCS integration in coal power plants would be a financially viable option only in game 4, with existing carbon regulations, a 23% reduction in the cost of CCS, oil prices of \$110 per bbl, and a carbon price of about \$52 per metric ton. In scenarios where the government increases the carbon tax credit (games 5-12), the payoff for player 2 becomes mostly positive (except in games 5 and 9). In other words, coal power plants would be likely to reject their BAU strategy adopt CCS. For example, if the government increased the carbon tax credit from \$10 to \$30, coal plants would increase their payoffs by applying CCS, except in the case in which the cost of CCS technologies has not decreased and oil prices are \$60 per bbl (game 5). The same outcome is expected for the coal power industry in the case where a carbon tax on anthropogenic CO_2 emitters is introduced (game 9).

6.3.2 Cooperation Opportunities

In the Illinois Basin, oil deposits that are recoverable via EOR geographically underlie some parts of the state of Illinois and extend to parts of neighboring states such as Indiana and Kentucky (REX Energy, 2012). This region has no existing commercial CO_2-EOR projects or dedicated CO_2 pipelines, as shown in Figures 6.2 and 6.3.

However, this region has the potential to establish a market for CO_2-EOR, since the CO_2 required for commercial projects could be obtained from the ethanol facilities and coal-fired power plants that are abundant in the region (Abotalib et al., 2016). This potential CO_2 supply could provide a reliable input for upcoming EOR projects in the Illinois Basin and further the objectives of the Energy Policy Act of 2005 (Energy Policy Act, 2005).

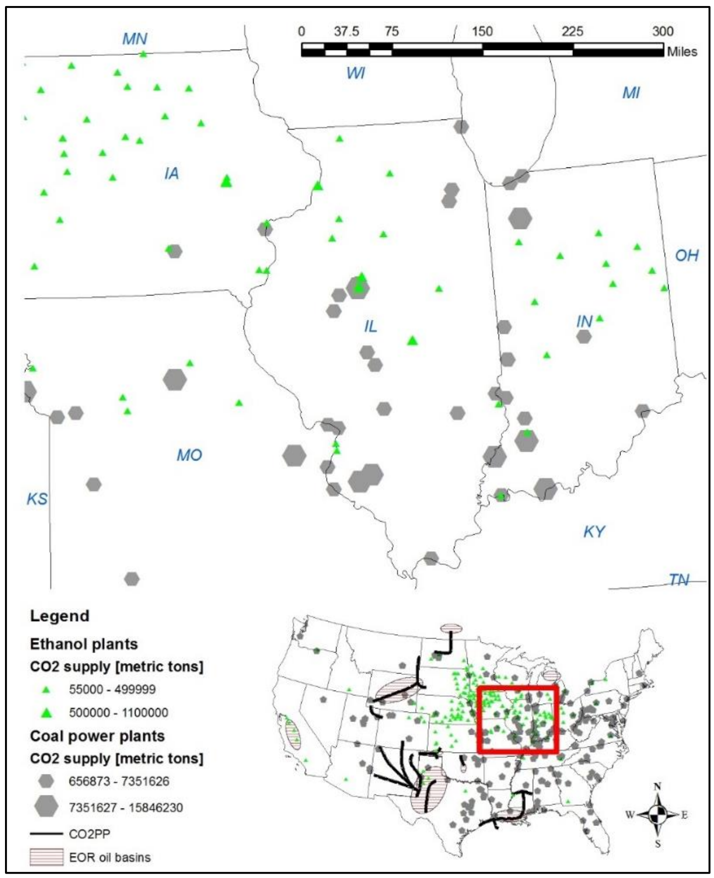


Figure 6.3 Illustrative map of potential CO_2 supply from ethanol and coal power plants near the Illinois Basin. Quantities of CO_2 are based on annual emission profiles from the sources

In game scenarios 1-12, the strategy of ethanol facilities (player 1) was dominated by rejection of BAU and adoption of CCS. However, the CO_2 supply from ethanol facilities is small compared to that from coal power plants and may not be sufficient to motivate investment in new EOR projects. For example, the ADM Decatur plant is the largest ethanol facility in the Illinois basin and has the capacity to provide about a million metric tons of CO_2 ($MTCO_2$) annually, whereas the average CO_2 supply from an ethanol facility is estimated to be approximately 260,000 metric tons per year (Middleton et al., 2014a). Meanwhile, the largest coal power plant in the region, the Gibson generating station in northwestern Indiana, emits about 16.3 $MTCO_2$ annually, whereas the average CO_2 emissions from a coal power plant is estimated to be approximately 5.6 MT of CO_2 per year (NETL, 2016; U.S EPA, 2015). In the lower 48 states of the U.S., the crude recovery rate is a site-specific parameter; it varies from 0.9 to 3.8 bbl/t CO_2 among the various CO_2-EOR fields (NETL, 2014b).

To overcome the limitation of CO_2 supply from ethanol facilities, players could cooperate with one another rather than acting independently. This cooperation would ensure that the CO_2 supply is sufficient for making capital investments in future EOR projects, and it would reduce the costs associated with establishing a dedicated CO_2 infrastructure. In other words, clustering CO_2 from various industrial sources, such as ethanol facilities and even coal power plants, might be an economically feasible way to provide the necessary CO_2 quantities, and it could motivate players to invest in commercial EOR projects in the Illinois Basin.

Cooperation would allow players to consider opportunities for minimizing some of the costs associated with CCS deployment, and subsequently their game strategies could change. Game 2 was selected for investigation of this possible change. In game 2, the payoff from adopting CCS would be negative ($ - 4.2) for player 2. In other words, adoption of CCS would entail a cost burden. Thus, player 2 would not be motivated to change its BAU strategy and invest in CCS, despite a carbon price of $52 per metric ton. However, at that price, player 1 would make a profit of $29.3 per tCO_2 sold to EOR operators, and therefore its strategy would be dominated by switching to CCS. Under a new scenario for the case of cooperation, it is assumed that both players evenly share the cost associated with establishing a joint CO_2 transport infrastructure to deliver CO_2 to an EOR operator. Without cooperation, the cost to transport CO_2 from a source to an EOR operator is $10/tCO2 for each player. With cooperation, in which this cost is evenly shared, the payoff for each player would increase by $5/tCO2. This small change would be just enough to encourage player 2 to switch to CCS, even though the payoff would not be significant in comparison to that in the BAU scenario. The payoff matrix for this new scenario (game 2R) is shown in Table 6-5.

Table 6-5 Game 2R: cooperation assumed between players, no change in current regulations, no reduction in the cost of CCS technologies, high oil prices

Game 2R) Cooperation for CO_2 transport with current CCS tech at oil price of $110 per bbl.		**Player 2: Coal**	
		BAU	**CCS**
Player 1: Ethanol	**BAU**	(0, 0)	(0, 0.8)
	CCS	(34.3, 0)	**(34.3, 0.8)**

6.4 Summary

Integrating CCS with CO_2-EOR can play an important role in the large-scale deployment of CCS by various industries under economic condition in which the returns from selling CO_2 to EOR operators exceed the costs associated with CCS deployment. Furthermore, as CCS becomes more widely applied and a reliable supply of CO_2 more readily available, a significant expansion in EOR projects is expected. In this analysis, a number of game scenarios were used to evaluate CCS-EOR deployment in the ethanol and coal power production industries, with a focus on the Illinois oil basin. We explored the impacts of possible changes in carbon policies, the carbon market, and the cost of CCS technologies on the decisions of carbon emitters regarding the integration of CCS into their operations. We did not select these scenarios in order to advocate for a specific case. Rather, they represent possible changes in carbon policies and CCS-EOR market conditions. Our framework is intended as a decision-making tool for industrial CO_2 emitters in response to dynamic changes in policy and market conditions. In this sense, the framework can provide regulatory and industrial players with a better perspective on CCS-EOR deployment from an economic standpoint.

In the absence of established carbon regulations and the necessary economic incentives, industrial CO_2 emitters will tend to avoid additional costs in order to maximize their profits. According to the game scenarios examined here, the coal power industry would not be likely to invest in CCS under the existing cost of CCS technologies and current carbon regulations. However, investment in CCS becomes an economically viable option in cases in which the cost of supplying the CO_2 for EOR is competitive with the cost of sourcing the CO_2 from other sources such as natural CO_2 wells. For example, coal power plants would consider CCS deployment if the price of carbon was above $57 per metric ton. From an economic perspective, EOR operators would not be likely to purchase CO_2 at this price unless the price of oil rose above $120 per bbl. Historically, however, oil market statistics have been fluid, and oil prices have fluctuated over the past six decades (Macrotrends LLC, 2016). Thus, there is significant financial uncertainty for potential EOR operators who are making economically based decisions about investing in the technology. Reducing the dependence of CCS deployment on oil prices by means of government carbon regulation and incentives would decrease the risk for both CO_2 emitters and end-users. Hence, tools such as a carbon tax and carbon credits can be used for incentivizing industrial CO_2 emitters to consider operating at a lower carbon footprint and start investing in cleaner technologies and practices (Tang, Shi, Yu, & Bao, 2015; J. Yang et al., 2016). In short, individual stakeholders tend to act independently: first, to maximize benefits, and second, to minimize loss. However, working with other stakeholders may open the door to a third option that is better than losing. For example, if players had the opportunity to cooperate with one another and evaluate other possible economic avenues, as highlighted in game 2R, their strategy would change

CHAPTER 7. CONCLUSION AND FUTURE WORK

7.1 Conclusion

This research addresses the potential role of carbon capture and sequestration in near-term mitigation of anthropogenic CO_2 emissions. In the United States, the electricity generation sector, which is dominated by the use of coal, and the transportation sector together account for two thirds of total anthropogenic GHG emissions (EIA, 2014b; U.S. EPA, 2015). CCS has the potential to become a widely-used option for producing low-carbon electricity. When integrated with enhanced oil recovery, CCS is also an avenue to the production of transportation fuel that is less carbon intensive than conventional petroleum-based fuels such as gasoline and diesel. Because CCS will soon be capable of storing carbon dioxide from large point sources, the technology will continue to be an attractive option for CO_2 mitigation in a fossil fuel-dependent economy.

Therefore, CCS has been evaluated here from a life-cycle perspective to provide a better understanding of its environmental and economic consequences. Although the LCAs of various studies revealed some differences in the levels of GHG reduction, both the published and harmonized results indicated a large decrease in GWP for the various coal-fired technologies investigated.

However, because of the requirements of energy and other input materials, there was a notable increase in CED, which would subsequently increase the footprint of the technology in term of resources. This energy burden is seen as the main constraint for large-scale deployment of CCS in coal-fired power generation. According to optimistic financial estimates, the implementation of CCS at an existing conventional coal-fired power plant would increase the price of delivered electricity by 40% (IEA, 2012).The integration of CCS with CO_2-EOR is seen as a more realistic approach to advancing large-scale CCS deployment and thus reducing anthropogenic CO_2 emissions. The merits of the integrated technologies are clear at each stage, from point sources such as power plants to the oil produced by EOR, in which some of the CO_2 is offset during the production phase. In other words, using mature oil wells, rather than storing CO_2 underground in saline formations, could play an important role in lowering the carbon intensity of transportation fuel. This approach would help to achieve the goal of reducing U.S. carbon emissions by 26-28% by 2025 in comparison with 2005 levels, which translates into an annual reduction target of 2.3-2.8% (White House Press, 2015). Looking at CCS from this perspective requires the identification of potential industrial CO_2 sources (pathways). In this dissertation, coal power plants, natural gas plants, and ethanol refineries were selected as potential industrial sources of CO_2 for the EOR process. These sources were investigated from a life-cycle perspective in terms of their ability to provide the CO_2 needed to produce a barrel of crude oil. The LCA scenario examined here represents a cradle-to-grave case, which accounts for the upstream GHG emissions associated with CO_2 supply from each pathway and subsequently allocates carbon emissions credit on the basis of other products produced in parallel. The model developed in this dissertation extends the value of LCA by integrating the LCA results from each CO_2 pathway with GIS using site-specific geospatial data for potential recoverable crude oil basins, and considers information about existing/proposed CO_2-EOR infrastructure in the lower 48 states of the U.S. The pathways were compared to a conventional crude recovery, transport, refinement, and end-use combustion baseline, which had net GHG emissions of 0.47 tCO_2-e/bbl. Overall, net GHG emissions from pathways 1, 2, and 3 were lower than in the baseline case. However, our results clearly indicated that ethanol-based CCS-EOR (pathway 1) was the best alternative. Still, the CO_2 supply from ethanol plants was limited; the plants would have the capacity to produce only about 25,000 bbl/d, compared to 1.1 Mbbl/d in pathway 2 and 125,000 bbl/d in pathway 3. Among the system processes that were assessed, the CO_2 injection had the greatest influence on the LCA results, where the magnitude of the reduction in GHGs depended on each site's specific crude recovery rate, and that rate determines the extent of the displacement credits for coproducts. This finding indicates that crude oil with lower carbon intensity can be produced from EOR reservoirs that are less efficient in terms of crude recovered per ton of CO_2 injected. However, it should be acknowledged that the use of less efficient reservoirs would be associated with greater CO_2 supply, which has a parasitic energy requirement and would in turn entail a higher cost burden.

The results also indicated that natural gas power plants produce a low-CO_2 stream; the energy requirement for CO_2 separation was twice that of ethanol plants and 1.12 times greater than that of coal power plants. As a result, these power plants are less attractive for CO_2 supply from an economic perspective. Therefore, the future of CO_2

supply from natural gas power plants has been eliminated when looking at the future of CCS deployment from a game-theory perspective.

In this dissertation, we adopted the game-theory approach to evaluate CCS-EOR deployment in the ethanol (player 1) and coal power production (player 2) industries, with a focus on the Illinois oil basin. Following this approach, we explored the impacts of possible changes in carbon policies, the carbon market, and the cost of CCS technologies on the decisions of industrial carbon emitters. The results were first assessed on the basis of a non-cooperative type of game, and then in terms of the opportunity for cooperation between players. In a non-cooperative game, participants (players) act independently: first, to maximize their benefits, and second, to minimize their losses, regardless of the consequences for other players. According to our analysis, under existing carbon policies and at the current cost of CCS deployment, the strategy of the ethanol industry would be dominated by CCS deployment. By contrast, coal power plants would not have sufficient governmental or economic incentives to deploy CCS because of the gap between the cost of capturing and transporting CO_2 and the price of CO_2. However, cooperation between the two players could lead to a third option that might have a greater payoff for each individual. The findings of this study have demonstrated the potential costs and benefits of CCS-EOR advancement in line with prospective changes in carbon regulations and market conditions.

7.2 Future Work

The goal of this dissertation was to develop a more inclusive approach to determining the role CCS in providing low-carbon electricity and transportation fuel in the United

States. A comprehensive, in-depth assessment of CCS from a sustainability perspective is also needed. The assessment should target three typical aspects of sustainability: environmental, economic, and social considerations. However, the latter component is very hard to quantify at this stage and is therefore considered outside the scope of this research.

- Although the results of the post-combustion studies are quite robust, other emerging CCS technologies such as chemical looping and membrane-based capture systems have also been investigated. Experimental trials with these alternatives have shown lower energy penalties and lesser economic implications than those of amine-based capture systems. The present research addressed the amine-based post combustion process because it has been deployed at existing point sources on a commercial scale. In addition, the analysis here focused mainly on the problem of global warming potential because GWP reduction is the intended purpose of CCS. In fact, region-specific constraints such as water consumption and land requirement are equally important in the consideration of post-combustion technology. Including additional environmental indicators is possible, but at this point we need to understand the possible reduction in GWP in greater depth before moving on to other impact categories. Because of our limited experience with CCS, it is not yet clear where and when these technologies can be used. Future analysis should take into account region-specific environmental conditions along with carbon policies.

- The LCA-GIS approach uses an averaged crude recovery rate for each of the major oil basins in the lower 48 states, but the recovery rate can vary considerably from well to well within the same basin. Existing data sources do not provide a specific crude recovery rate for each individual oil well that could potentially be used in EOR. Such information would enable the development of a more comprehensive LCA-CCS-EOR optimization model. Furthermore, the model could include an economic component that would indicate the return on investment for obtaining CO_2 from various industrial sources. For example, an EOR operator would be able to analyze all possible options on the basis of GWP and the ability to supply enough CO_2 at a feasible price, before making a large-scale CO_2- EOR investment.

- The game-theory framework is limited by few possible scenarios in carbon policies and CO_2 market value. Existing and potential carbon regulations and CO_2 prices are not likely to promote cooperation among the various CO_2 emitters. However, this may not be true in all situations, particularly in the cases of high carbon taxes and stringent carbon cap-and-trade scenarios. In such situations, the game-theory framework would provide more opportunities for cooperation among CO_2 emitters and among CO_2 end-users. The payoffs for each player can be calculated with the use of the Shapley value approach in order to allocate the gains from cooperation fairly among different players.

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APPENDICES

Appendix A CCS and CO2 Storage

A.1 Saline Formation

Saline formations exist at a greater depth compared to oil reservoirs and coal seams. These types of formation are globally available with great storing capacities (Lokhorst & Wildenborg, 2005). The rocks in these formations are classified as porous containing extremely salty water. There are limited encouraging projects worldwide. A famous project is the Sleipner project off the coast of Norway. In this project, over 10 million tons of CO_2 have been injected so far with no leakage noticed yet (Lokhorst & Wildenborg, 2005).

A.2 Depleted Oil and Gas Reservoirs

In depleted oil and gas reservoirs, CO_2 has been commercially used to increase pressure and recover residual oil and gas from the reservoirs. This process is known as enhanced oil recovery (EOR). According to the U.S. DOE, this option has an added-value besides CO_2 storage, as an additional 39-48 billion barrels of domestic oil could be produced prior to 2030 as a consequence of this technology (NETL, 2010d). As of 2013, there were seven large-scale CCS projects in the United States, with CO_2-capturing capacities ranging from 0.68 to 8.4 MMT of CO_2 per year (Global CCS Institute, 2014).

A.3 Un-minable coal seams

Naturally, coal seams contain gases such CH_4 that are held in pores in the coal and adsorbed on the surface of the coal (Lokhorst & Wildenborg, 2005). Certain coal seems such as those that are too deep or too thin to be economically viable can be feasible CO_2 storage sites. The UK Department of Trade and Industry (UK DTI) estimates that undisrupted coal seams can contain extensive amounts of CH_4, as much as 25 m^3 per ton of coal. CO_2 injection in this type of formation will displace the CH_4, which can then be recovered for energy generation (UK DTI, 2000).

A.4 United States CO_2 supply and demand market

Table A-1 lists a number of CO_2 end-users, where CO_2 is supplied from either natural or industrial sources. The latter are primarily industries that produce an almost pure CO_2 stream. Among these industries is the refining of ethanol, where only the dehydration and compression of CO_2 are required before its delivery to consumers (Middleton et al., 2014b). In 2014, Superkar and Skerlos published an overview of the U.S. CO_2 merchant market that listed major suppliers and buyers, as shown in Figure A.1 "merchant market" is a free market controlled by supply and demand, in which suppliers and buyers of a commodity are independent and are not owned by the same entity. Under this definition, the supply of CO_2 for enhanced oil recovery was not included in the CO_2 merchant supply portfolio for the U.S. (Supekar & Skerlos, 2014).

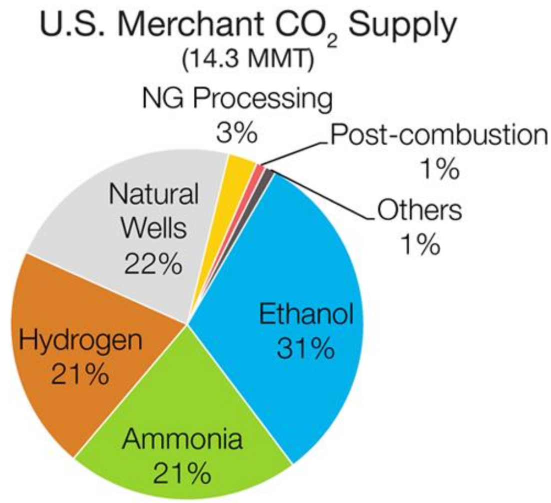

Figure A1. Sources of CO_2 supply in the U.S. merchant market excluding CO_2 used for EOR

Source: (Supekar & Skerlos, 2014)

As shown in Figure A.1, about 4.3 MMT is supplied from ethanol, 3.15 from natural CO_2 wells, and about 3 MMT each from hydrogen and ammonia. Table A-1 lists the major CO_2 consumers in the U.S. in terms of annual demand.

Table A-1: Demand for CO_2 in the U.S. market in millions of metric tons (MMT) per year

Industry	Market Demand MMT
Enhanced Oil Recovery (EOR)	50
Food Processing	6.38
Carbonated Beverages	1.98
Agriculture	0.77
Chemical Processing	0.11
Metal Fabrication	0.44
Others	1.32
Approximate Total CO_2 Annual Demand	61

Notes: EOR data is for 2007; other data represents the U.S merchant market for CO_2 in 2013.

Sources: (Middleton et al., 2014b; Supekar & Skerlos, 2014)

As shown in Table A-1, enhanced oil recovery consumes significantly more CO_2 than any other industry, followed by the food processing industry. Currently, more than 50

MMT of CO_2 are injected per year in EOR, which produces more than 90 million barrels of oil (MMbo) (Meyer, 2007). About 70% of this figure comes from natural CO_2-dedicated wells (Middleton et al., 2014b).

Appendix B Technical Parameters

B.1.0 Technical parameters for pathways for LCA-GIS integration

B.1.1 Pathway 1

Figure B.1 shows processes that have been included in the ethanol production system boundaries. We used the uses a different regional electricity grid mix as per the NERC classification for energy related requirements focusing on the ethanol drying milling process. The system boundary for ethanol production was utilized from the GREET model of Argonne Lab, which assumes natural gas as the main source of heat (about 84%). The remaining heat is supplied from coal (7%) and electricity grid mix (9%). The ethanol production process is described in detail in the Supporting Information document.

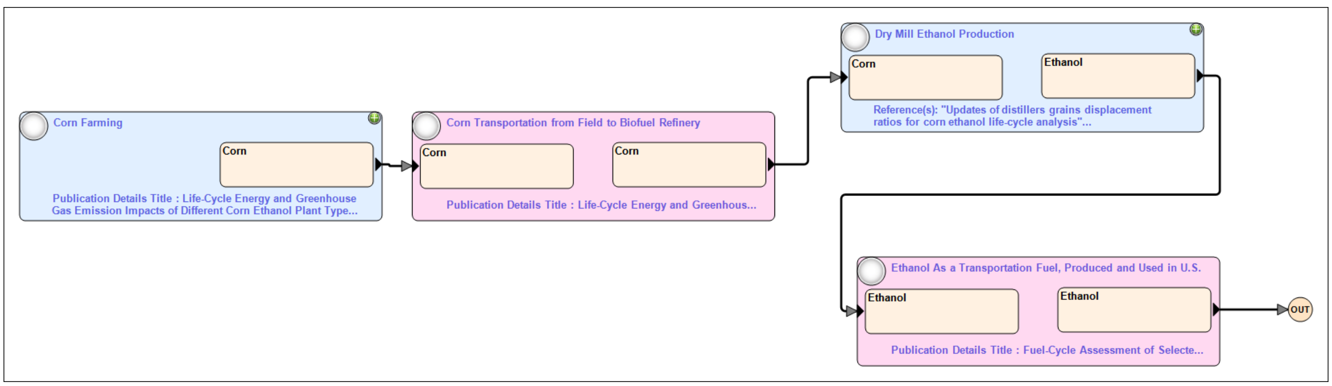

Figure B.1. System boundaries of corn-based ethanol manufacturing via dry milling.

Table B-1: GHG emission of CO2 supply from dry milling corn based ethanol including LCA emission of ethanol manufacturing.

Parameter	Value	Reference
1.0 CO_2 Supply		
1.1 Corn ethanol [g CO2-e/gallon]	4929	GREET.2014

1.2 Gallons of EtOH [gallon / bbl.]	90-395	(This is co-product generated from one bbl. of crude, region specific)
1.3 Electricity for CO2 purification [kWh / tCO2]	171.8	This CO2 is utilized fermentation (ISGS 2006, p15)

B.1.1.1 Biogenic CO_2 accounting

Capturing biogenic CO_2 would lower the upstream emission from ethanol production. In other words, subtracting captured CO_2 (from the fermentation process) from upstream ethanol production would lower the net GHG emission of ethanol production. Figure 2 illustrates the carbon flow for pathway one by considering this assumption.

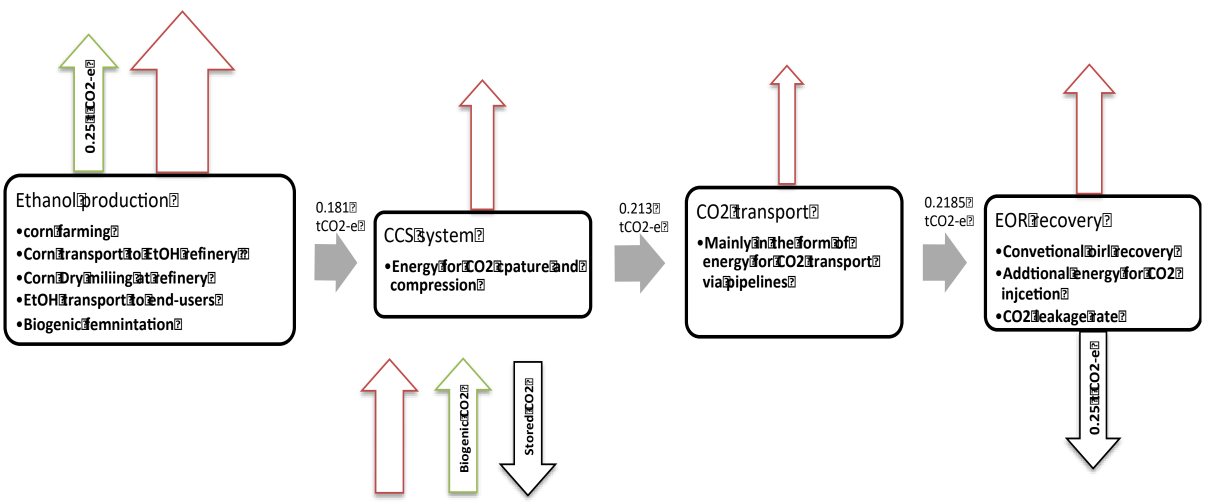

Figure B.2 Carbon flow diagram for pathway 1. The green arrow represents biogenic CO_2 captured from the fermentation process. This value is subtracted from non-biogenic CO_2 emissions associated with ethanol production

NOTE: Note: We assumed that 0.25-ton CO2 would recover one bbl. of crude via EOR as an example.

B.1.2 Pathway 2

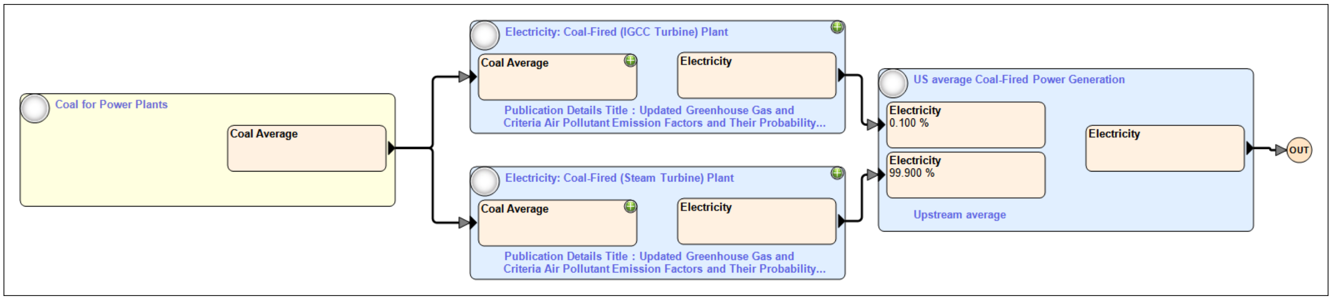

Figure B.3 System boundaries of coal-fired electricity generation via 99.9% steam power generation

The life cycle GHG emissions for a coal-fired power plant covers coal mining and cleaning, transport, amine production, and direct emission from stack (released). CO_2 transport and storage are covered separately.

Table B-2: Performance parameters of a coal-fired power plant with CCS

No.	Process	Value	Reference
1.1	CCS total energy penalty [kWh/kWh (PC-CC)]	0.25	(H. J. Herzog, 2001; H. J. Herzog, 2011)
1.2	CCS electricity requirements [kWh/tCO2 captured (PC-CC)]	317	(H. J. Herzog, 2001; H. J. Herzog, 2011)
1.3	Emission of CCS capture [tCO2e/tCO2 captured] (w/o amine production, transport & injection)	0.21003	(Frischknecht et al., 2007; Koornneef et al., 2008; Odeh & Cockerill, 2008)
1.4	Solvent Production [t CO2e/tCO2 captured]	0.00525	(Frischknecht et al., 2007; Koornneef et al., 2008; Odeh & Cockerill, 2008)

1.5	**Net GHG from CCS [tCO_2e/tCO_2 captured]**	**0.2153**	Not to be included because we capture 90%

B.1.3 Pathway 3

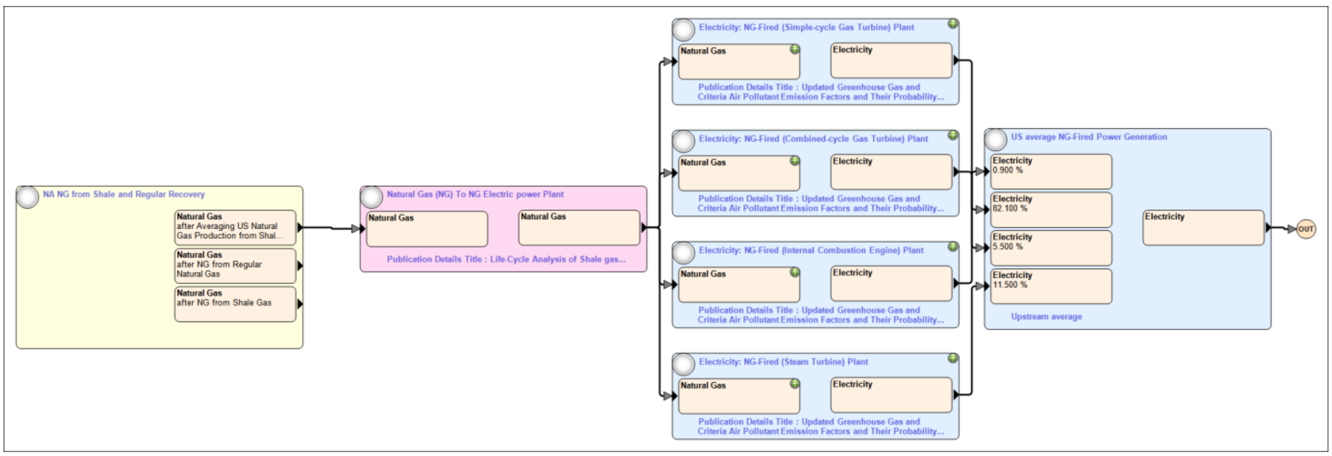

Figure B.4 System boundaries of natural gas electricity generation at 82% by natural gas combined cycle (NGCC) power generation

Table B-3 Performance parameters of CO_2 supply from a NG-fired power plant with CCS

No.	Process	Value	Reference
1.1	CCS total energy penalty [kWh/kWh (NG-CC)]	0.13	(H. J. Herzog, 2001; H. J. Herzog, 2011)
1.2	CCS electricity requirements [kWh/tCO_2 captured (NG-CC)]	354	(H. J. Herzog, 2001; H. J. Herzog, 2011)
1.3	Emission of CCS capture [tCO_2e/tCO_2 captured] (w/o amine production, transport & injection)	0.235	(Frischknecht et al., 2007; Koornneef et al., 2008; Odeh & Cockerill, 2008)

1.4	Solvent Production [t CO2e/tCO2 captured]	0.00525	(Frischknecht et al., 2007; Koornneef et al., 2008; Odeh & Cockerill, 2008)
1.5	**Net GHG from CCS [t CO2e/t CO2 captured]**	0.24	Not to be included because we capture 90%

B.2.0 CO2 Transport parameters

Table B-4: Performance parameters CO2 transport and emissions profile CO2 EOR storage location.

Process	Value	Reference
2.1 Energy intensity of pipeline transport [btu/ton-mi]	127	(Rhodes et al., 2015)
2.2 Pipeline distance [mi]	100	Assumed based on geographic information.

Using the existing CO_2 pipelines make more economic sense if capacity is not a constraint. We agree that 100-mile radius seems to be restrictive, however our choice was guided based on the information found in the literature that indicate the need for additional CO_2 infrastructure. The literature has indicated that existing CO_2 pipelines would not to support further expansion in EOR oil production and for that reason major EOR regions such as, the Permian basin, Rockies, Mid-continent and the Gulf Coast basin are planning to build additional dedicated CO_2 pipelines networks(Melzer, 2012; NEORI, 2012; Tanner, 2010). Because this study considers the opportunity of increasing the share of low carbon intensive oil production (CO_2-EOR) as opposed to conventional oil production, we think that it would be more reasonable to select a restrictive distance (100-miles) versus using the distance of existing CO_2 pipelines. This choice would help to avoid the inclusion of impractical CO_2 candidates, which could overestimate the number of potential CO_2 candidates. For the pathways investigated under this restrictive assumption, the results indicate that 1.25 million barrels of crude can be recovered per day through the use of CO_2-EOR, which more than 4 times current CO_2-EOR oil production. Therefore, we investigated different distance values using the FE/NETL CO_2 transport model which considers capital as well as operational cost of CO_2 transport infrastructure. We highlighted this point in the limitation section and mentioned the opportunity of increasing the distance parameter.

Nevertheless, reviewer's comment was taking into consideration and the use of less restrictive distance value has also been investigated. Results were shown in Figure B.5 to illustrate the potential CO_2 candidates within 300 miles from EOR regions. With the 300 miles' distance restriction, the number of CO_2 candidates increases to 88, 105, and 193 compared to 21, 22, and 33 with the 100 miles for pathways 1,2, and 3, respectively. We noticed that most of those additional candidates were located in the Midwestern region, where oil deposits are not significant, and therefore would not be able to use existing CO_2 pipelines even if capacity is not an issue.

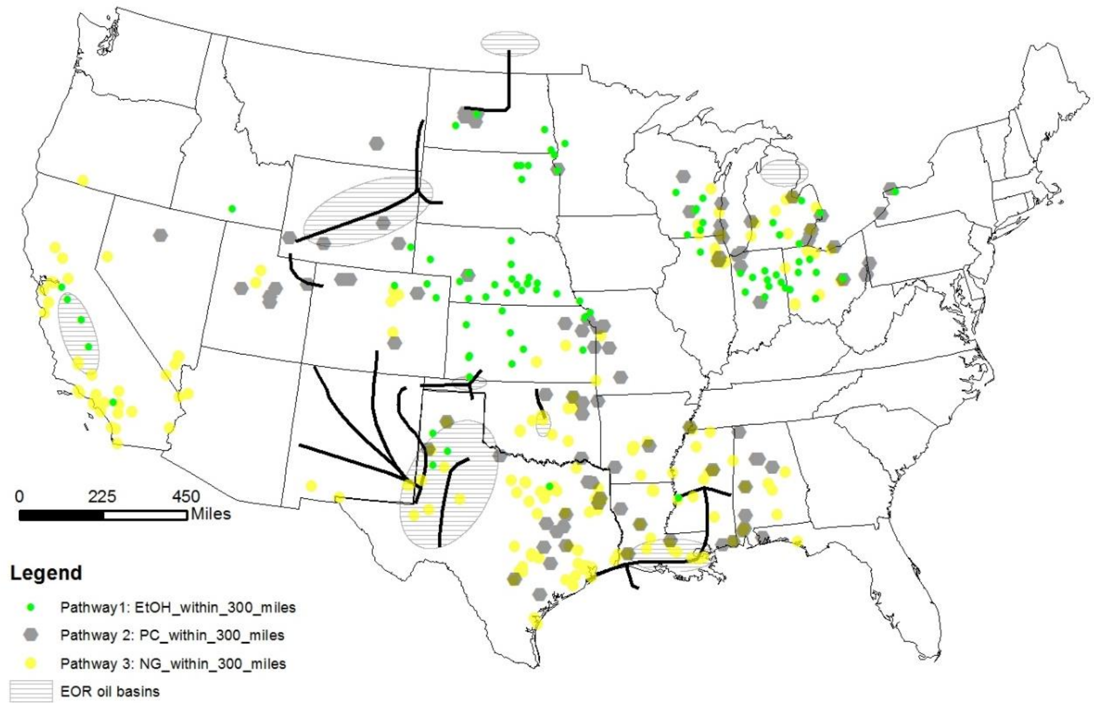

Figure B.5 Potential CO2 candidates within 300 miles from EOR oil basins

B.3.0 Crude recovery parameters

Table B-5: GHG of Enhanced oil recovery per barrel of recovered crude.

Process	Value	Reference
U.S Conventional oil recovery [g CO2/bbl.]	29911	GREET.2014
U.S Conventional transport process [g CO2/bbl.]	10889	GREET.2014
Additional energy for EOR [1.78 kWh/bbl]	1329.6	(Rhodes et al., 2015)
Total GHGs U.S EOR to Refinery (Recovery, EOR, and transport)	**42129.6**	**Calculated**

Table B-6 EOR technology parameters

Parameter	Value	Reference	Remarks

Energy for EOR [kWh/bbl.]	1.78	(Middleton et al., 2014b)	This includes energy needed for CO_2 injection into EOR reservoir and CO_2 recovery from recovered crude.
Oil production rate [bbl./ tCO_2]	4	(ARI, 2010b; NETL, 2010a)	This value represents historical EOR practices and can be adjusted based on EOR reservoir specific characteristics.
Sequestered CO_2 [tCO_2/ bbl.]	0.26-1.13	Calculated from oil production rate	Depending to oil basin (see Table 7)
CO2 sequestration rate	0.991	(Middleton et al., 2014b)	

Table B-7 Crude recovery rates from major oil basins in the lower 48 sates of the U.S.

Region	Annual bbl. produced via CO_2 EOR	TCO_2 injected per year	BBL/tCO_2	TCO_2/bbl	Reference
Permian Basin	67890000	32802597.4	2.07	0.48	(NETL, 2014b)
Gulf Coast	15695000	17728571.43	0.89	1.13	(NETL, 2014b)
Rockies	13140000	4645454.545	2.83	0.35	(NETL, 2014b)
Mid-Continent	6205000	1611688.312	3.85	0.26	(NETL, 2014b)

California	NA	NA	2.5	0.4	(Middleton et al., 2014b)

Table B-8 Operational parameters for EOR from the literature

CO_2-EOR Operational Scenario	Historical	Current Best Practices	High CO_2 Scenario[a]
CO_2 injection duration (single pattern, years)	7	**25**	36
Volume of CO_2 injected as a percent of the hydrocarbon pore volume in the target formation[b]	0.4	**1.0**	1.5
Oil recovery as a percent of original oil in place (OOIP)	12%	**17%**	21%
Percent of injected CO_2 recycled[c]	60%	**71%**	78%
CO_2 stored per barrel of oil produced (kg CO_2/bbl oil)[c]	200	**230**	210
GHG emissions per barrel of oil produced (kg CO_2e/bbl oil)[c]	51	**71**	95

[a] Assumes (1) improved technologies that enable more efficient contact between CO_2 and residual oil and (2) policy incentives for sequestering CO_2

[b] Hydrocarbon pore volume (HCPV) is the pore volume in a reservoir initially filled with oil, and is often used to describe in-formation fluid volumes and discuss normalized performance between reservoirs. HCPV is calculated as $\Sigma A{*}h{*}\varphi{*}(1-Swi)$ where: A = surface area (40 acres), h = pay thickness (76 ft.), φ = porosity (0.11), and Swi = initial oil saturation as fraction (0.8)

[c] Values are average over the duration of the flood.

Results derived from single injection well modeling of a 40 acre 5-spot tapered WAG injection in a typical formation in the Permian basin, using the CO_2 Prophet model.

Source: (NETL, 2010a)

B.4.0 GHG life cycle emissions for electricity

The energy requirement for CO_2 transport via pipeline, and injection in the EOR assumed to be supplied by regional NERC entities in all scenarios. The life cycle GHG emissions of each entity are provided in Table B-9. The U.S. electrical grid is regulated by the North American Electric Reliability Corporation (NERC), which insures the reliability of bulk power systems in the United States, Canada, and the northern part of Baja California, Mexico (NERC, 2014). The NERC delegates its authority to eight regional electric reliability entities that cover the 48 contiguous states and the District of Columbia. Each regional entity is accountable for compliance with NERC regulations and standards as well as distribution of electricity in areas under the entity's jurisdiction. Table B-9 shows the eight regional players, distribution of electricity sources and CO2e per kWh of electricity distributed for end users.

1. Florida Reliability Coordinating Council
2. Midwest Reliability Organization (MRO)
3. Northeast Power Coordinating Council (NPCC)
4. Reliability First (RF)
5. Southwest Power Pool, RE (SPP)
6. Texas Reliability Entity (TRE)

Table B-9 shows the eight regional players, distribution of electricity sources from coal and CO2e per kWh of electricity distributed for end users.

Table B-9 NERC regional entities profile and their LCA GHG emissions

Regional NERC entity	**Population served**	**Geography**	**LCA GHG (g CO2/ kWh)**	**(%) Electricity from coal**
Florida Reliability Coordinating Council (FRCC)	Over 16 million	About 50,000 square miles over peninsular Florida.	628.8	0.24381
Midwest Reliability Organization (MRO)	Over 20 million	Covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba, and all or parts of the states of Illinois, Iowa, Minnesota, Michigan, Montana,	747	0.64302

		Nebraska, North Dakota, South Dakota and Wisconsin.		
Northeast Power Coordinating Council (NPCC)	About 35 million	State of New England, New york, and Maritimes area.	329.8	0.04269
NPCC New York	About 19.4 million	State of New York		
NPCC- New England	About 14 million	New England		
NPCC- Maritimes	About 1.9 million	New Brunswick and Nova Scotia		
NPCC-Ontario	~ 13 million	Province of Ontario		
NPCC- Québec	About 8million	Province of Québec		
Reliability First (RF)	About 61 million	All or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.	705.8	0.54487
Southwest Power Pool, RE (SPP)	About 15 million	all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas and the entire state of Nebraska covering 370,000 square miles.	625.25	0.43394
Texas Reliability Entity (TRE)	About 23 million	State of Texas	662.5	0.3735

Western Electricity Coordinating Council (WECC)	Approximately 81 million people	Serving an area of nearly 1.8 million square miles It extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western states in between.	489.5	0.27323
SERC Reliability Corporation (SERC)	About 39.4 million	All or portions of Alabama, Florida, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, South Carolina, Tennessee, and Virginia. Covers an approximate area of 308,900 square miles	664.4	0.46113
US Electricity Grid Mix	About 330		628	0.41471

Source: (NERC, 2014; UChicago Argonne, 2014)

B.5.0 Co-product sensitivity impacts

In our model, we assumed that "like displaces like," i.e., that the two co-products, ethanol and electricity, would displace the production of corn ethanol and electricity from coal. However, the choice of different substitutes for ethanol and electricity based on the purpose that co-product serves can be argued. For example, the co-product, in pathway 2, supplies additional electricity to power grid mix and therefore it may be argued that it should not assumed to displace electricity from coal which would yield greater displacement credit. The same argument also applies to pathway 1, where ethanol is mostly used as a blending agent in gasoline. Thus, we chose to explore different substitutes for corn ethanol and electricity from coal, where we assumed that ethanol and electricity would displace gasoline blend stock (~ 55% less LCA GHG emissions than corn ethanol) and U.S. electricity grid mix (~ 70% less LCA GHG emissions than electricity from coal), respectively.

Table B-10 Displaced co-products in each pathway

Pathway	Product	Co-product	Displaced products	GHG displacement Value [g CO_2-e]
1: EtOH-CCS-EOR	Recovered oil	88 gallons Ethanol fuel	Ethanol production (Like-displaces-like)	-436655
1: EtOH-CCS-EOR	Recovered oil	88 gallons Ethanol fuel	Gasoline blend stock (Alternative-substitute)	-235997
1: EtOH-CCS-EOR	Recovered oil	88 gallons Ethanol fuel	Cellulosic ethanol (Alternative-substitute)	-0.077
2: PC-CCS-EOR	Recovered oil	279 kWh Electricity	Regional electricity (Like-displaces-like)	-224473
2: PC-CCS-EOR	Recovered oil	279 kWh Electricity	U.S. electricity grid mix (Alternative-substitute)	-208483

NOTE: Note: We assumed that 0.25-ton CO2 would recover one bbl. of crude via EOR as an example.

B.6.0 Sensitivity Analysis of the Results

Based on the CO_2 recovery rates in each region we estimated the potential recoverable barrels of oil per year from the pathways considered.

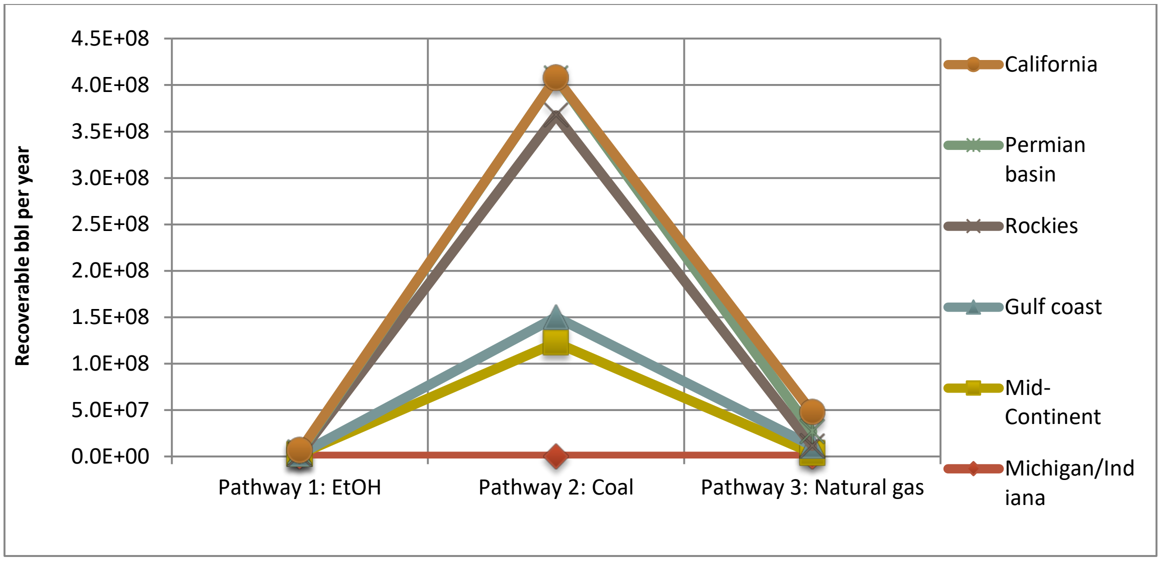

Figure B.6 The recoverable barrels of oil with respect to CO2 supply from sources and crude recover rates in each oil basin

As seen in Figure B.6, pathway 2 was the major supplier for CO_2 compared to the other two pathways. However, the LCA results have shown that pathway 2 was not the most favorable carbon intensive option. Figure B.7 illustrates pathways in an ascending order based on the CI of a barrel of crude recovered via CO_2-EOR. Figures B.8-B.11 illustrate the share of GHG emissions from various system processes in the form of tons of CO_2 equivalent per a barrel of crude produced and consumed.

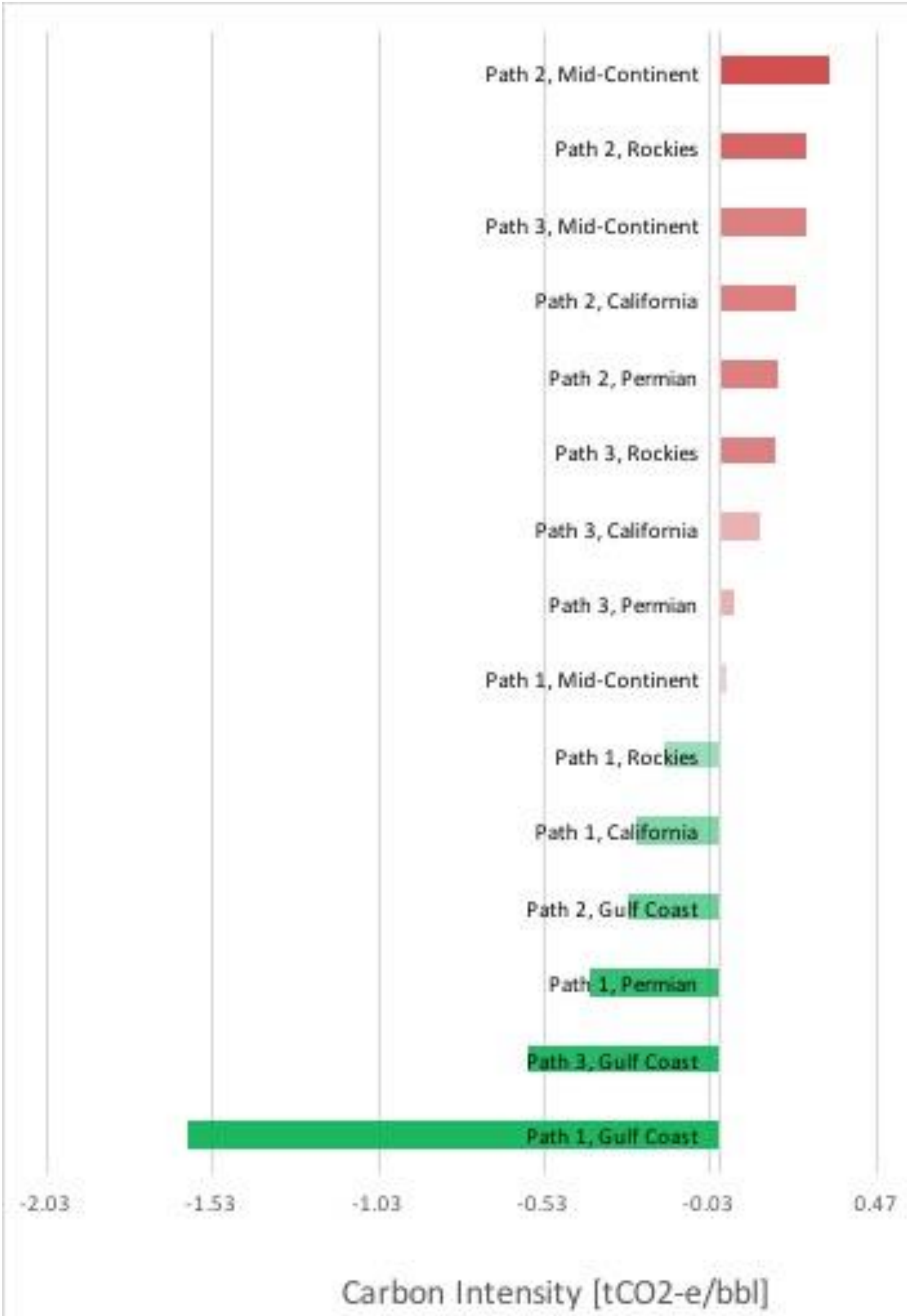

Figure B.7 Ranking of pathways in major EOR fields

B.6.1 Pathway 1

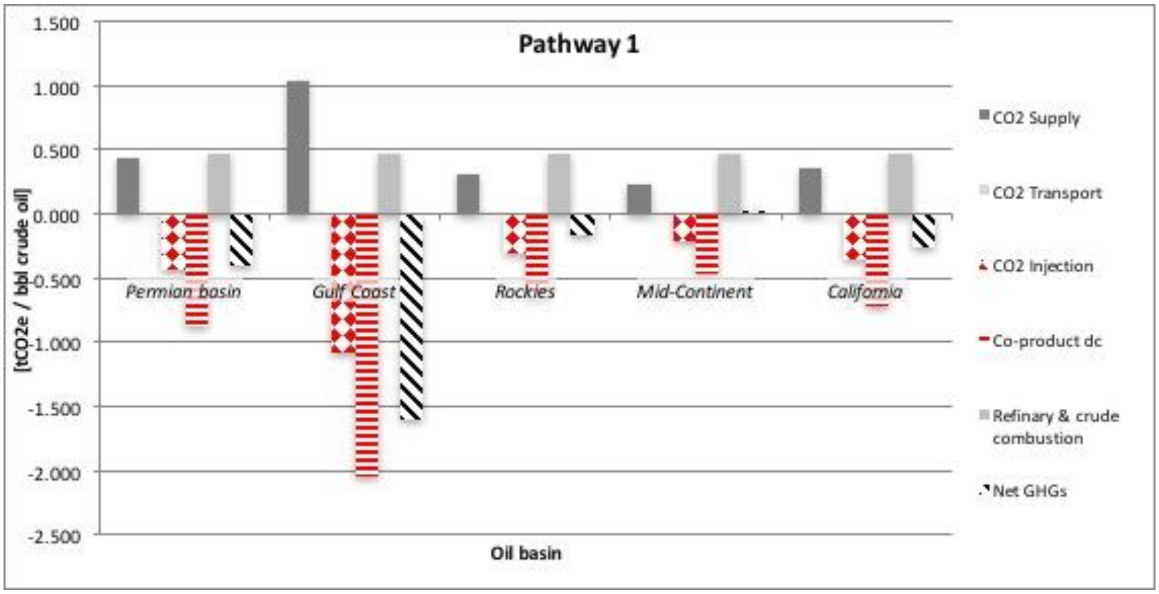

Figure B.8. Share of GHG emissions from different system processes in pathway 1

B.6.2 Pathway 2

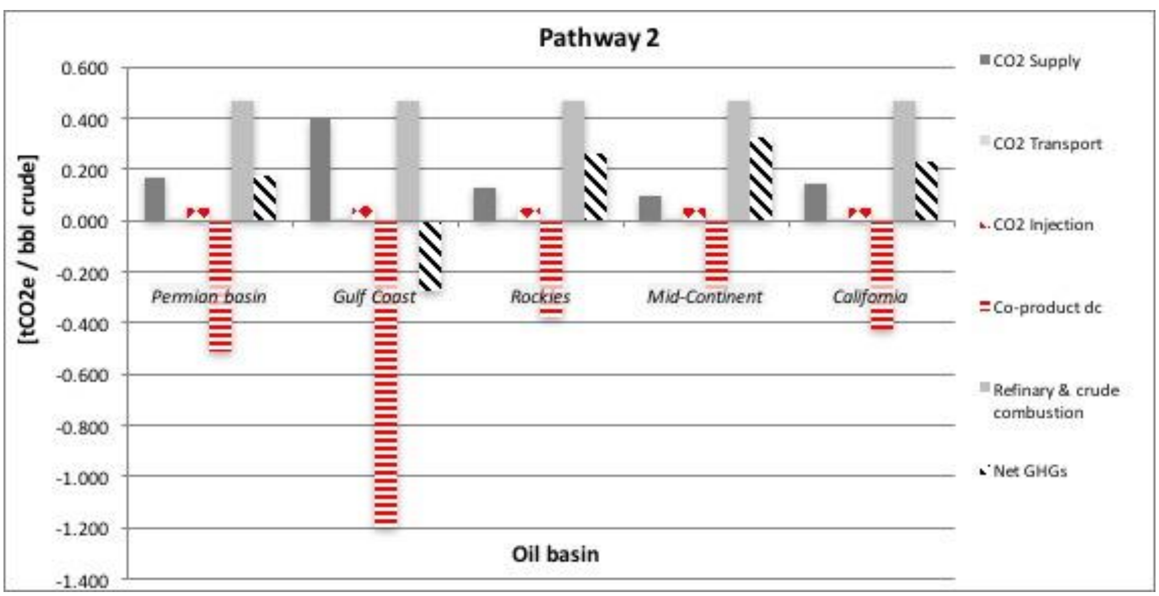

Figure B.9 Share of GHG emissions from different system processes in pathway 2

B.6.3 Pathway 3

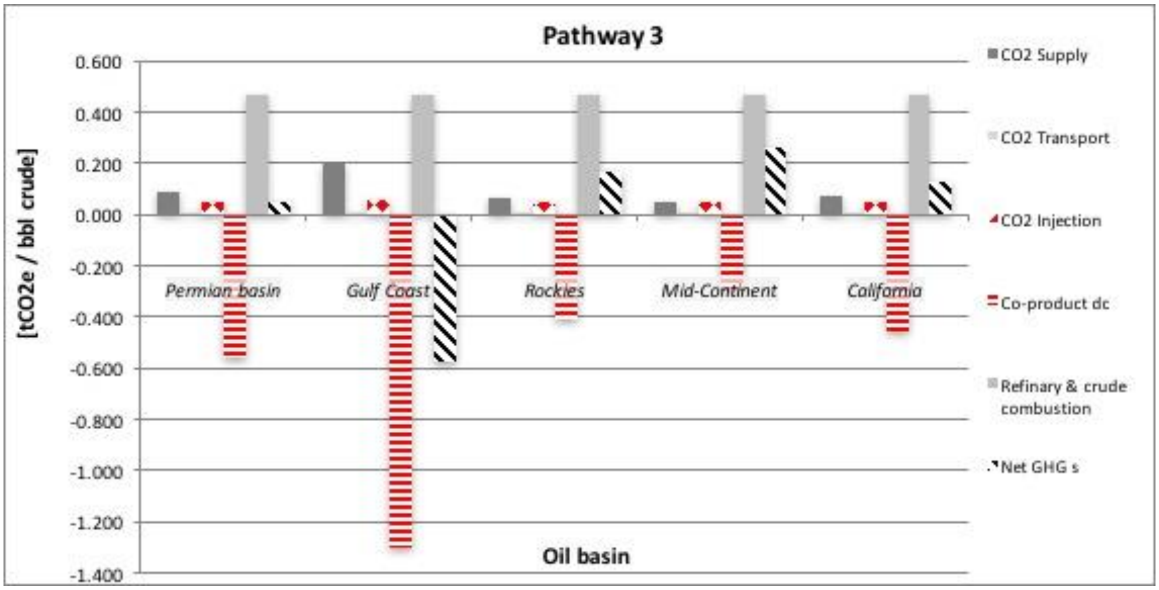

Figure B.10 Share of GHG emissions from different system processes in pathway 3

B.7.0 Details on the methodology used for game-theory assessment

Table B-11 Description of each game and parameters for calculating payoffs

scenario	Game No.	C_1 = CO_2 capture	C_2 = CO_2 regulation	C_3 = CO_2 price to EOR
1. No change in current regulation. Changes in oil prices and CCS technologies	1	• CO_2 emitters responsible for any cost associated with CCS • $22.7 for ethanol and $66.2 for coal based on current CCS technologies.	• No carbon cap regulatory limit on industries. • Carbon credit is $10 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be $28 per metric ton of CO_2. [at $60 oil price per bbl]
	2	• CO_2 emitters responsible for any cost associated with CCS • $22.7 for ethanol and $66.2 for coal based on current CCS technologies.	• No carbon cap regulatory limit on industries. • Carbon credit is $10 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be $52 per metric ton of CO2. [at $110 oil price per bbl]
	3	• CO_2 emitters responsible for any cost associated with CCS. • $16 for ethanol and $51 for coal based on future CCS technologies.	• No carbon cap regulatory limit on industries. • Carbon credit is $10 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be $28 per metric ton of CO_2. [at $60 oil price per bbl]
	4	• CO_2 emitters responsible for any cost associated with CCS. • $16 for ethanol and $51 for coal based on future CCS technologies.	• No carbon cap regulatory limit on industries. • Carbon credit is $10 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be $52 per metric ton of CO2. [at $110 oil price per bbl]

2. No carbon Tax. Change in current regulation by increasing credit to \$30. Changes in oil prices and CCS technologies	5	• CO_2 emitters responsible for any cost associated with CCS. • \$22.7 for ethanol and \$66.2 for coal based on current CCS technologies.	• No carbon cap regulatory limit on industries. • Carbon credit is \$30 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be \$28 per metric ton of CO_2. [at \$60 oil price per bbl]
	6	• CO_2 emitters responsible for any cost associated with CCS. • \$22.7 for ethanol and \$66.2 for coal based on current CCS technologies.	• No carbon cap regulatory limit on industries. • Carbon credit is \$30 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be \$52 per metric ton of CO2. [at \$110 oil price per bbl]
	7	• CO_2 emitters responsible for any cost associated with CCS. • \$16 for ethanol and \$51 for coal based on future CCS technologies.	• No carbon cap regulatory limit on industries. • Carbon credit is \$30 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be \$28 per metric ton of CO_2. [at \$60 oil price per bbl]
	8	• CO_2 emitters responsible for any cost associated with CCS. • \$16 for ethanol and \$51 for coal based on future CCS technologies.	• No carbon cap regulatory limit on industries. • Carbon credit is \$30 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be \$52 per metric ton of CO2. [at \$110 oil price per bbl]

3. \$20 carbon Tax. Change in current regulation by increasing credit to \$30. Changes in oil prices and CCS technologies	9	• CO_2 emitters responsible for any cost associated with CCS. • \$22.7 for ethanol and \$66.2 for coal based on current CCS technologies.	• Carbon cap on industrial anthropogenic CO_2 emitters. • \$ 20 carbon tax per metric ton CO2 emitted. • Carbon credit is \$30 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be \$28 per metric ton of CO_2. [at \$60 oil price per bbl]
	10	• CO_2 emitters responsible for any cost associated with CCS. • \$22.7 for ethanol and \$66.2 for coal based on current CCS technologies.	• Carbon cap on industrial anthropogenic CO_2 emitters. • \$ 20 carbon tax per metric ton CO2 emitted. • Carbon credit is \$30 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be \$52 per metric ton of CO2. [at \$110 oil price per bbl]
	11	• CO_2 emitters responsible for any cost associated with CCS. • \$16 for ethanol and \$51 for coal based on future CCS technologies.	• Carbon cap on industrial anthropogenic CO_2 emitters. • \$ 20 carbon tax per metric ton CO2 emitted. • Carbon credit is \$30 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be \$28 per metric ton of CO_2. [at \$60 oil price per bbl]
	12	• CO_2 emitters responsible for any cost associated with CCS. • \$16 for ethanol and \$51 for coal based on future CCS technologies.	• Carbon cap on industrial anthropogenic CO_2 emitters. • \$ 20 carbon tax per metric ton CO2 emitted. • Carbon credit is \$30 for coal power plants.	• EOR operator offset some of the CCS cost by purchasing CO_2 from emitters. • The price is assumed to be \$52 per metric ton of CO2. [at \$110 oil price per bbl]

VITA

VITA

Abotalib, Mohammad was born in Kuwait on May 3, 1983. At the age of 18, he decided to pursue his undergraduate studies overseas. In 2001 he received a scholarship from the Ministry of Higher Education, Kuwait to pursue his undergraduate studies at Griffith University, Brisbane, Australia. After graduation, he joined Kuwait Oil Company (KOC) as and environmental engineer and there he got exposed to several environmental problems such as air pollution, land contamination and industrial waste management. During his time at KOC, he became keenly aware of the urgency of addressing environmental challenges properly, especially for a country like Kuwait, which is highly dependent on oil.

In 2010 he received a scholarship from Kuwait University to purse his master and Ph.D. in the United Sates. In January, 2011, he started his master degree at the University of Pennsylvania and graduated in December 2012. In 2013, he joined the Ecological Sciences and Engineering Ph.D. program at Purdue University.

PUBLICATIONS

PUBLICATIONS

Abotalib, M., & Zhao, F. (2015). Life cycle harmonization of carbon capture and sequestration for coal-fired power plants. *Paper Proceedings from the LCA XV International Conference, October 6-8, 2015 Vancouver, Canada*, 76-88.

Abotalib, M., Zhao, F., & Clarens, A. (2016). Deployment of a geographical information system life cycle assessment integrated framework for exploring the opportunities and challenges of enhanced oil recovery using industrial CO2 supply in the united states. *ACS Sustainable Chemistry & Engineering, 4*(9), 4743-4751.