MIT CEEPR

MIT Center for
Energy and Environmental
Policy Research

Risk Sharing in CO_2 Delivery Contracts for the CCS-EOR Value Chain

Anna Agarwal

January 2014

CEEPR WP 2014-001

A Joint Center of the Department of Economics, MIT Energy Initiative and MIT Sloan School of Management.

Risk Sharing in CO_2 Delivery Contracts for the CCS-EOR Value Chain

Anna Agarwal*

Massachusetts Institute of Technology

Abstract

A key reason for poor performance in large capital projects is the weak incentives facing the involved entities to deliver optimal project outcomes. The weak incentives arise from misalignment of interests of the individual entities with the common interest of the project, thus resulting in sub-optimal decisions that do not maximize the overall project value. Contractual risk-sharing is key to aligning the interests of the individual entities and incentivizing them to make optimal decisions. We develop a framework to quantify the impact of the project contract terms on the financial value of large energy capital projects. We focus on a prototype carbon capture and storage (CCS) project wherein the power plant company (that captures the CO_2) is linked to the oil field company (that stores the CO_2 for enhanced oil recovery, EOR) through a long-term CO_2 delivery contract. We evaluate alternate CO_2 contract structures in terms of the incentives the contracts provide to the individual entities to respond to changes in the market risk factors (oil price, electricity price, and CO_2 emission penalty). The results show that inappropriate risk allocation, as in fixed price CO_2 contracts, leads to significant loss in project value. This loss under fixed price CO_2 contracts is due to high contracting risks associated with ex post insolvencies and weak incentives for contingent decision-making. We find that risk sharing offered by oil-indexed price CO_2 contracts significantly reduces the contracting risks and thus considerably increases the project value compared to a fixed price CO_2 contract. Analyzing the weaknesses of alternate CO_2 contract structures gives insights into the design of optimal CO_2 contracts for the CCS-EOR value chain.

Keywords: risk management, contract design, risk sharing, capital projects, CCS

---

* I would like to thank my advisor John E. Parsons for his valuable comments. This work was supported by a grant from BP Technologies Ventures Inc. as a part of the BP-MIT Advanced Conversion Research program.
Email address: annaag@mit.edu

1. Introduction

In this paper, we emphasize the importance of strong contractual risk-sharing structures in optimizing the financial value of large energy capital projects. Many of the large energy projects such as upstream oil and gas projects involve large upfront capital investment, and the project cash flows are subject to considerable uncertainty from multiple risk factors. The final project value will be determined by how the exogenous risk factors evolve during the project and how the project entities respond to the changes in the risk factors. Dewatripont and Legros (2005) classify the risks in large projects into two categories: exogenous and endogenous. Exogenous risks refer to the risks that are not under the control of the project owners and operators such as volatility in the market prices. Endogenous risks are associated with inefficient actions by the involved entities, such as poor maintenance leading to reduced economic life.

Studies find that a key reason for poor performance in large capital projects is the endogenous risk of inefficient decision-making by the involved entities (Flybjerg et al., 2003; Miller and Lessard, 2000; World Bank, 1994; Ostrom et al., 1993). Endogenous risks arise from conflict of interest among the entities, wherein the interests of the individual entities are not aligned with the common interest of the project, resulting in sub-optimal decisions that do not maximize the overall value of the project. Endogenous risks are influenced by the contract terms that link the different entities involved in the project. The contract terms determine how the project cash flows would be distributed among the involved entities, and the value captured by each entity and the resulting risk exposure will determine the incentives for optimal performance.

The design of incentives through contracts is the subject of literature on the economics of contracts and the principal-agent problem (Joskow, 1985, 1988; Grossman and Hart, 1983; Holmstrom, 1979; Mirrlees, 1975). This literature points to risk sharing among the involved entities as being at the heart of creating incentives through contracts. Optimal risk sharing aligns the interests of the entities involved so that they perform in the common interest of the overall project, resulting in maximization of the total project value.

We quantify the impact of project contract terms on the final project value through an application to carbon capture and storage (CCS) projects. CCS is a technology to reduce anthropogenic carbon dioxide (CO_2) emissions from fossil fuel power generation and other CO_2 intensive industrial processes. The CCS value chain involves three key components: CO_2 capture, CO_2 transport, and CO_2 storage. CO_2 is captured at CO_2 emitting sources (such as a coal-fired power plant), and then transported via pipelines to CO_2 storage sites (such as an oil reservoir) where the CO_2 is sequestered for long-term storage. In an integrated CCS project, the different parts of the CCS value chain are likely to be owned and operated by different entities. The power plant operations will be performed by an entity that might differ from the entity responsible for the CO_2 storage operations. The performance of one entity will affect the operations of other entities, thus affecting the overall value chain. The CO_2 delivery contracts that link the individual entities of the CCS value chain will determine the incentives the individual entities have to make optimal decisions in the common interest of the project.

We focus on a prototype CCS project wherein the CO_2 is captured at a coal-fired power plant and is transported via a dedicated pipeline to an oil field, where it is injected for enhanced oil recovery (EOR). We analyze the impact of exogenous market risks on the value of the CCS-EOR project; the market risk factors analyzed include volatility in the price of oil recovered, the wholesale price of electricity, and the CO_2 emission penalty. The results show that the market risk factors significantly affect the CCS-EOR project, and contingent decisions can considerably change the project value. In particular, we evaluate the decision to adjust the CO_2 capture and injection rate in response to change in the market risk factors. We find that there is a 22% probability that ex post it would be economical to reoptimize the CO_2 capture. The contingent optimization of CO_2 capture rate increases the net present value (NPV) of the CCS-EOR project by $14 million (1% increase), compared to continuing operations at the initially planned 90% CO_2 capture rate. All financial values in this paper are in 2017 USD unless specified; year 2017 is the t = 0 of the project. The NPV of the project under the 'First-Best' case and the 'Business as Usual' case is presented in Table 1. Financial gains from contingent optimization of CO_2 capture increase as the oil price decreases, the price of electricity increases, and the CO_2 emission penalty decreases, and can exceed $400 million, which implies a 14% increase in the ex post project value.

The CO_2 delivery contracts that link the different entities in the CCS-EOR value chain would determine the incentives of the individual entities to optimize the CO_2 capture rate in response to changes in the market risk factors. We model the CCS-EOR project ownership structure such that the power plant and the oil field are owned and operated by separate entities, and the pipeline is jointly owned by the two entities. The operation between the power plant company and the oil field company is integrated through a long-term contract for the delivery of CO_2. We evaluate two alternate standard CO_2 delivery contract structures in terms of the risk allocation between the power plant company and the oil field company and the resulting incentives for optimal decision-making. The contract structures analyzed include a fixed price contract where the CO_2 contract price is fixed for the contract term, and an indexed price contract where the CO_2 contract price is indexed to the oil price. The results, as summarized in Table 1, show that the contract terms influence the ex post decision-making by the involved entities and hence determine the value of the project.

	Net Present Value $m *(% change from 'First-Best')*	**Insolvency Risk**	**Risk of Sub-optimal Outcome**
Business as Usual [1]	$1,319 *(-1.0%)*	NA	NA
First-Best [2]	$1,332	NA	NA
Fixed Price Contract [3]	$1,204 *(-9.6%)*	6.7%	20.7%
Oil-indexed Price Contract [4]	$1,327 *(-0.4%)*	0%	9.3%

Notes:
[1] 'Business as Usual' refers to continuing at 90% CO_2 capture rate and not reoptimizing in response to change in risk factors
[2] 'First-Best' refers to optimizing the CO_2 capture rate in response to change in risk factors and thus maximizing the project value
[1] + [2] Results do not account for contracting risks and present the overall project value
[3] Results correspond to the 'optimal' fixed price contract, which minimizes the contracting risks for all negotiable fixed price contracts
[4] Results correspond to the 'optimal' oil-indexed price contract, which minimizes the contracting risks for all negotiable indexed price contracts

Table 1 Summary of results: Impact of contingent optimization of CO_2 capture and choice of contract terms

Weak risk sharing in fixed price contracts leads to a positive probability of ex post insolvency ranging from 6.7% to 26.7%, depending on the ex ante negotiated contract price. When the price of oil is below $50/bbl there is a 100% probability that the oil field company would be insolvent under fixed price contracts. Furthermore, since the power plant company is paid a fixed price, there is a high probability that the power plant would not have incentives to reoptimize and lower the CO_2 capture rate. Overall, under the 'optimal' fixed contract price (that minimizes the contractual risks) there is a 20.7% probability of sub-optimal ex post project outcomes, including operating at sub-optimal CO_2 capture rate and contractual breach due to insolvency. If the ex ante negotiated contract price is different from the optimal price, then there is an even higher probability of sub-optimal decision-making. Oil-indexed contracts offer sharing of the oil price risk, and the results show that this risk sharing eliminates the risk of ex post insolvency. Furthermore, oil-indexed contracts have stronger incentive structures that increase the probability of reoptimization of the CO_2 capture rate. There is a 9.3% probability that the optimal oil-indexed price contract will lead to a sub-optimal ex post project outcome.

We evaluate the impact of sub-optimal decision-making on the financial value of the project under the alternate optimal contract price structures. The results, as summarized in Table 1, show that the high risk of sub-optimal decision-making under the fixed price contract leads to a NPV loss of \$128 million or a 9.6% decrease, compared to the maximum achievable project NPV. The decrease in project value under the optimal oil-indexed price contract is relatively insignificant and is \$5 million (0.4% decrease). These results emphasize the importance of contractual risk-sharing in optimizing the project outcomes and maximizing the total project value. Oil-indexed contract shares the oil price risk between the power plant company and the oil field company and leads to a \$123 million increase in the NPV (10% increase) compared to the fixed price contract.

The rest of this paper is organized as follows: Section 2 describes the technical specifications of the prototype CCS-EOR project, and presents the project cost and price parameters. In Section 3, we present how we model the stochastic movement of the market risk factors, and evaluate the optimal contingent decisions that would maximize the project value in light of the change in the market risk factors. In Section 4, we evaluate the performance of alternate contract structures for the CCS-EOR value chain in terms of the risk of ex post insolvency, the incentives provided to the individual project entities to reoptimize the CO_2 capture rate, and the final project value achieved under the alternate contract structures. Finally, in Section 5, we present the conclusions.

2. The CCS-EOR Project

The prototype CCS-EOR project we focus on is an integrated project with a coal-fired power plant with CO_2 capture, a pipeline that transports the CO_2, and an oil field that injects and subsequently stores the CO_2 for EOR. This is a dedicated project such that the power plant, the pipeline and the oil field are dependent on each other for the CO_2 capture/transport/injection and there is no alternate source or sink for the CO_2. The CCS-EOR project ownership structure is such that the power plant and the oil field are owned and operated by separate entities, and the pipeline is jointly owned by the two entities. The operation between the power plant company and the oil field company is integrated through a long-term contract for the delivery of CO_2. Joint ownership of the pipeline and a long-term CO_2 delivery contract reduces the risk of ex post opportunistic behavior, which often arises from relation specificity of investments (Williamson, 1971; Klein et al., 1978) as is the case in this dedicated prototype CCS-EOR project.

This section describes the key technical specifications and the economic parameters of the different components of the prototype CCS-EOR project. The project construction is planned to begin in 2018, the operations will start in 2021 and continue for 25 years till 2045. To evaluate the project cash flows, we use a tax rate of 35%, nominal discount rate of 10%, and an inflation of 3% for all the components of the CCS-EOR project. First we describe the power plant, then the pipeline, and lastly the oil field.

2.1 Power Plant

The power plant is a 500 MW coal-fired integrated coal gasification combined cycle (IGCC) plant. This is a baseload plant with a capacity factor of 80%. The power plant is designed to capture 90% of the CO_2 generated, which amounts to 3.2 million tons of CO_2 capture every year. The heat rate of the power plant with 90% CO_2 capture is 10,000 Btu/kWh resulting in the plant efficiency of 34.1%. The costs incurred at the power plant include the capital investment, O&M costs, fuel cost and CO_2 emission penalty. Revenue at the power plant is generated through the electricity sales. Table 2 presents the unit costs (in 2010 USD) and the expected prices in 2017 used to evaluate the cash flows of the power plant. The references for the economic parameters are mentioned below Table 2; we assume that the expected value of the CO_2 emission penalty in 2017 is $5 per ton CO_2.

Power		
Overnight Cost	$/kW	5,000 [1,2]
Fixed O&M Cost	$/kW/year	80 [1]
Variable O&M Cost	mills/kWh	6 [1]
Price of Coal	$/MMBtu	3 [3]
Price of Electricity	c/kWh	10.3[3]
CO_2 Emission Penalty	$/ton	5
Oil Field		
Capital Investment	$/bbl	7.5 [4]
O&M Cost	$/bbl	12.5 [4]
CO_2 Recycle Cost	$/ton	16 [5]
Price of Oil	$/bbl	105 [3]
Royalty Payment		17.5% [5]

References: [1] GCCSI, 2011; [2] GCCSI, 2010;
[3] US EIA AEO 2013 (reference case); [4] NETL, 2008;
[5] NETL, 2011

Table 2 Power plant and oil field: Unit costs and prices

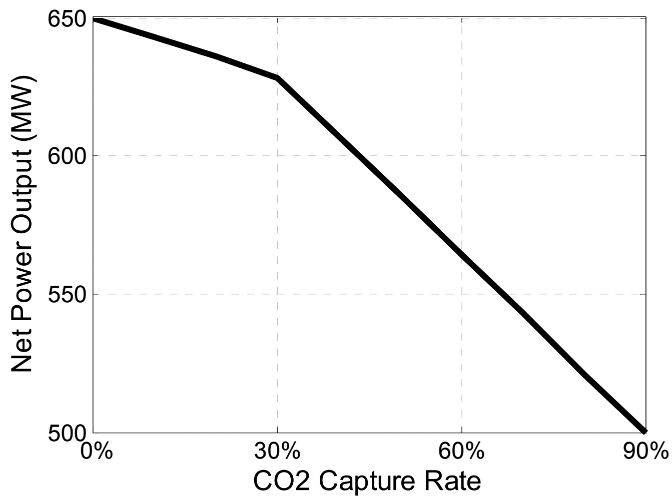


Figure 1 Net power output as a function of the CO_2 capture rate

The IGCC power plant in this project is designed to have dynamically adjustable CO_2 capture rate that can be optimized in response to change in the risk factors. The optimal capture rate will be determined by the marginal costs and benefits of CO_2 capture and injection. A significant cost of CO_2 capture is the energy penalty of applying the capture process to the power generation. MIT's Future of Coal study (2007) reports that adding 90% pre-combustion capture to an IGCC plant leads to a 7.2 percentage point reduction in the generating efficiency compared to a plant without capture. Keeping the coal feed constant, the total energy penalty of CO_2 capture leads to a 23% decrease in the net power output. This implies that if we turn off capture in a 500 MW IGCC power plant capturing 90% CO_2, the net power output will increase to 650 MW.

Figure 1 shows how we model the increase in the net power output as the CO_2 capture rate is reduced from 90% to 0%. The increase in net power output is linear as we reduce CO_2 capture rate except there is kink at 30% CO_2 capture rate. This kink reflects that 30% of CO_2 capture is achieved by "skimming" without the water gas shift (Hildebrand, 2009). Thus, the entire energy penalty from the water gas shift reaction (13% decrease in net power output) is recovered by reducing CO_2 capture rate from 90% to 30%.

2.2 Pipeline

The CO_2 is transported via a 50-mile dedicated pipeline to the oil field. The pipeline will have two streams of cash flows: the capital investment in building the pipeline and the O&M costs. The capital costs is modeled as \$1.7 million per mile, and O&M costs are \$2.5/ton of CO_2 transported (in 2010 USD, source: Al-Juaied and Whitmore, 2009).

2.3 Oil Field

The CO_2 captured at the power plant is injected and stored in the oil field for oil production. This technique of oil production through CO_2 injection is known as enhanced oil recovery or EOR. Over the 25-year life of the project, it is expected that a total of 140 million barrels of oil will be recovered by injecting 80 million tons of CO_2 from the power plant. At the end of the project, all of the CO_2 injected will be stored in the oil field.

In this section, we describe how we model the annual oil production profile for the prototype project. The amount of oil produced depends on the technical EOR efficiency (incremental oil production per unit of CO_2 injected) and the amount of CO_2 injected:

$$Amount\ Oil\ Produced\ (bbl.) = EOR\ efficiency(bbl./ton)\ *Amount\ CO_2\ injected(ton)$$

We first present how we model the annual CO_2 injection profile, and then describe the modeling of the annual EOR efficiency. Lastly in the section, we present the annual oil production curve for the prototype project.

The total CO_2 injected comprises of the 'new' CO_2 from the power plant and the 'recycled' CO_2 that is produced along with the oil and is re-injected. The amount of purchased (or new) CO_2 is constant through the life of the project and is equal to 90% of the CO_2 captured at the power plant (3.2 million tons/year). We model the CO_2 recycling to begin 3 years after the start of CO_2 injection (oil production is assumed to begin 2 years after the start of injection). Thereafter the CO_2 recycling rate increases linearly for the next 10 years: from 0% in year 3 to 40% in year 13. After year 13, the CO_2 recycling rate plateaus at 40%. The average recycling rate for the prototype CCS-EOR project is 30%. This recycling rate of 30% is at the lower end of the CO_2 recycling rates observed in traditional EOR projects (Bloomberg, 2012; Martin and Taber, 1992; Brock and Byran, 1989). We choose a low recycling rate, as unlike traditional EOR projects, the CCS-EOR projects would have a financial incentive to store CO_2 and thus the amount of CO_2 recycled might be much less in CCS-EOR projects (Hovorka, 2010; McCoy, 2008).

Next, we present how we model the technical EOR efficiency curve for the prototype project. The EOR efficiency profile combined with the CO_2 injection profile will give us the oil production profile for the project.

We model the oil field in the prototype CCS-EOR project to have heterogeneous EOR efficiency, wherein some parts of the field have higher EOR efficiency than rest of the field. Typically, the EOR operators account for the field's heterogeneous efficiency in the design of the oil field operations. For example, the operators first develop and start CO_2 injection in the more efficient part of the field and gradually develop the lesser efficient parts of the field as the amount of CO_2 available increases (with increasing CO_2 recycling rate). Furthermore, when the oil prices drop, often the EOR operations are halted first in the less efficient parts of the field. These decisions by the EOR operators would have important implications on CO_2 delivery contractual obligations with the CO_2 source company and affect the overall project economics.

For simplicity, we model the oil field as two sub-fields with different EOR efficiency. Figure 2 presents the expected EOR efficiency curve for the high efficiency sub-field, low efficiency sub-field, and the average across the overall integrated field.

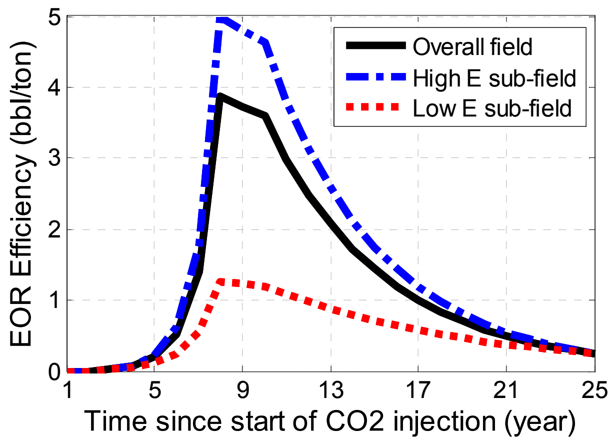


Figure 2 EOR efficiency curve in the prototype CCS-EOR project

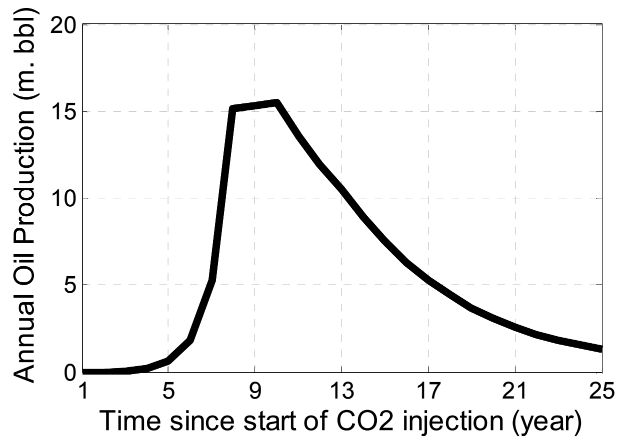


Figure 3 Oil production curve in the prototype CCS-EOR project

We model the EOR efficiency profile to reflect the typical oil production profile observed in EOR projects (GCSSI, 2012; Jakobsen et al., 2005). As we see from Figure 2, the EOR efficiency initially exponentially increases. This increase in EOR efficiency reflects the initial exponential increase in oil production observed in EOR projects. The EOR efficiency increases and reaches the peak value at 8 years from the start of CO_2 injection. Thereafter, the EOR efficiency is modeled to slowly decline. The slow decline in the EOR efficiency lasts 2 years and then there is a steep exponential decline in the EOR efficiency as seen in Figure 2. The steep exponential decline in EOR efficiency reflects the exponential decline in oil production. The EOR efficiency reduces to 0.25 bbl./ton, which reflects the end of economic life of the project.

The overall oil field is expected to have an average technical EOR efficiency of 1.23 bbl./ton CO_2 over the 25-year life of the project. The average EOR efficiency in the high EOR efficiency sub-field is 1.51 bbl./ton CO_2 and the low EOR efficiency sub-field has an average expected EOR efficiency of 0.55 bbl./ton CO_2. This average EOR efficiency in the overall oil field and in the high and low efficiency sub-fields reflects the range of EOR efficiency reported in past EOR projects (Bloomberg, 2012; Martin and Taber, 1992; Brock and Byran, 1989).

Figure 3 presents the oil production curve. The oil production starts after a lag of 2 years from the start of CO_2 injection, thereafter the oil production exponentially increases for the next 6 years. The peak oil production in the 8^{th} year is about 15 million barrels. From the 8^{th} year to the 10^{th} year the annual oil production is almost constant, as the decrease in EOR efficiency is offset by the increase in amount of CO_2 recycled. After the 10^{th} year of operations, the annual oil production exponentially declines. Over the 25-year life of the project it is expected that a total of 140 million barrels of oil will be recovered through EOR. 85% of the expected oil production will be recovered from the high EOR efficiency sub-field and the remaining 15% will be recovered from the low EOR efficiency sub-field.

The prototype CCS-EOR project's NPV is $1,319 billion (in 2017 USD); calculated based on the project specifications, costs and prices presented in this section. Next, we analyze the impact of evolution of the market risk factors on the value of the prototype project and evaluate the optimal contingent decisions that would maximize the project value.

3. Stochastic Market Price Movements and Contingent Decision-making

We model the impact of three key market risk factors on the prototype CCS-EOR project: price of oil recovered, wholesale price of electricity, and the CO_2 emission penalty. We want to evaluate the impact of these market risk factors on the project value and analyze the financial gains that can be achieved by contingent decision-making. The contingent decision we focus on is the decision to adjust the CO_2 capture and injection rate in response to change in the market risk factors. In this section, we firstly describe the modeling of stochastic price movements through the project. Then, we evaluate the financial gains that are achieved by reoptimizing the CO_2 capture rate in response to the evolution in the market risk factors.

3.1 Modeling Evolution of Market Risk Factors

The model of price movements we use is the one-factor random walk model, where the uncertain parameter is the shock to the price that follows a Brownian motion. The discrete time version of the random walk process written in terms of the log spot price is:

$$\ln(P_t) - \ln(P_{t-1}) = \mu + \sigma\varepsilon_t$$

where, each time step is 1 year, μ is the annual expected rate of growth of spot price, σ is the annual volatility in spot price. ε_t is a standard normal random variable, implying that the shocks to the log of spot price are normally distributed.

Thus, the spot price is modeled to be log normally distributed. The expected value and variance of the log of spot price is given by:

$$E[\ln(P_t)] = \ln(P_0) + \mu t \qquad \text{and} \qquad Var[\ln(P_t)] = \sigma^2 t$$

where, P_0 is the initial price at $t = 0$

As we see, the variance increases with time because in the random walk model all shocks or changes to the price are permanent. In some cases, this assumption of permanent change in prices might not be valid. Market prices can change due to many reasons, such as, change in market demand and supply, technological improvements, exhaustion of existing supply sources or discovery of new sources of supply. These different factors affecting price changes can have short-term temporary effects, and/or long-term permanent effects to prices. Simple one-factor models like random walk model and the mean reversion model can only capture one of the effects of the price changes. There are more complex multi-factor models of price changes (Schwartz and Smith, 2000; Baker et al., 1998) that can increase the accuracy of forecasting price movements but it comes at the cost of increasing computational complexity.

For our analysis, we are interested in the how the long-term changes in spot prices impacts the project and influences the decision-making. In the long-term, the contribution of short-term price effects becomes small, and we see from the Schwartz and Smith (2000) that at long time horizons the solution from a two-factor model is indistinguishable from the one-factor model. So, in our study we use the random walk model, which is simple and yet reasonably accurate model to capture the long-term trend in spot prices.

Table 3 presents the initial price, the annual expected growth rate, and the annual volatility for the three market risk factors. The prices are in 2017 USD. The oil price and electricity price are from the 2013 Annual Energy Outlook reference case **(**US EIA AEO 2013); the initial price of oil at t = 0 of the project (year 2017) is \$105/bbl, and the initial price of electricity is 10.3 c/kWh. For the CO_2 emission penalty, we assume that the projected price in 2017 is \$5 per ton CO_2. We assume a zero expected growth rate in prices. The source for volatility in market risk factors is listed below the Table 3.

	Initial price	μ	σ
Oil price	\$105/bbl	0	21% [1]
Electricity price	10.3 c/kWh	0	10% [2]
CO_2 emission penalty	\$5/ton	0	47% [3]

References: [1] Pindyck, 1999; [2] Niemeyer, 2000; [3] Abadie and Chamorro, 2008

Table 3 Initial price, growth rate(μ), and volatility (σ) in the three market risk factors

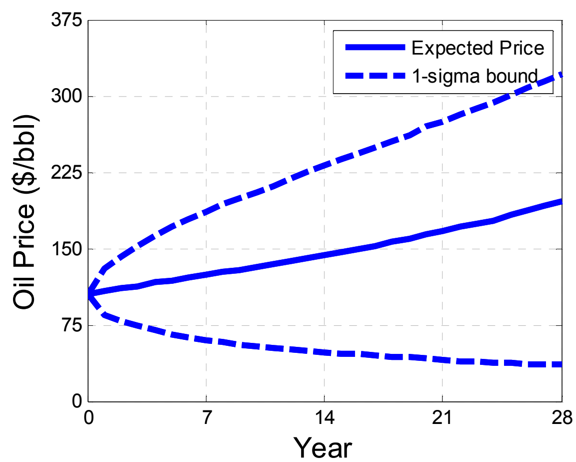


Figure 4 Oil price path from Monte Carlo simulations

We use the Monte Carlo method to model the movement of market risk factors through time. Looking forward from t = 0, the log value of the spot price at time t is given by:

$$\ln(P_t) = \ln(P_0) + \mu t + \sigma \sum_{j=1}^{t} \varepsilon_j$$

One Monte Carlo simulation involves T random draws of ε_i to generate a complete price path from $t = 0\ to\ t = T$. In this paper, we do not account for correlations between the three risk factors and thus price paths for each of the risk factors is generated independently. Figures 4 present the expected oil price and 1-sigma confidence bounds on the oil price generated from 5,000 Monte Carlo simulations where the initial price of oil is \$105/bbl. The prices paths are evaluated from t = 0 to t = 28 (end of project); the project construction period is from t = 1 to t = 3 years, and the project operations begin at t = 4 and continue for 25 years till t = 28.

We see that the expected price of oil increases from \$105/bbl at t = 0 to \$189/bbl at t = 28. The underlying random walk model of oil price reflects in the increasing confidence bounds on the expected price. Similarly, we simulate the price paths for the electricity price and the CO_2

emission penalty. The project operators will readjust the project operations in response to change in the market risk factors. As will be discussed in the next section, we focus on evaluating the optimal contingent decisions at t = 6 years. Table 4 presents the price distribution of the three risk factors at t = 6 and gives the expected value, 1-sigma and 2-sigma confidence bounds on the expected value.

		- 2 sigma	- 1 sigma	Mean	+ 1 sigma	+ 2 sigma
Oil price	($/bbl.)	38	63	**119**	173	289
Electricity price	(c/kWh)	6.3	8.1	**10.6**	13.1	16.7
CO_2 emission penalty	($/ton)	0.5	1.6	**9.6**	15.6	49.3

Table 4 Distribution of market risk factors at t = 6 years

In this section, we presented the modeling of evolution of market risk factors through the project life. Contingent decisions made in response to change in the market risk factors will change the project value. Next, we evaluate the optimal contingent decisions that would maximize the project value.

3.2 Optimal Contingent Decisions

The project operators will readjust the project operations in response to change in the market risk factors. In particular, we analyze the decision to adjust the CO_2 capture and injection rate contingent on change in the three market risk factors. In this section, we analyze how the optimal CO_2 capture rate changes in response to change in the market risk factors and evaluate the impact of this contingent decision on the project value.

We analyze the decision to adjust the CO_2 capture rate at a single point in time during the operational phase of the project: in year 2023 which is 6 years after the start of the project construction and 3 years after the start of project operations. In reality, the operational decisions might be revised regularly as the risk factors change. But, to model a regular revision in operational decisions would be computationally prohibitive. The amount of calculations needed exponentially increase with the modeling of each additional time step for the adjustment of operating choice because of the multiple risk factors involved. So, to keep it computationally tractable, we consider a single time slice of 6 years from the start of project. This choice of time is far along so as to embody a considerable change in the market risk factors to allow for a change in operational decisions, and is not too far along in the project life to not have a financial impact on the project net present value.

We evaluate a representative sample of the three market risk factors in year 2023 using stratified sampling technique such that each sample point is equally spaced on the probability scale (Hull, 2011: Chapter 20). We sample 15 points each from the probability distribution of oil price, wholesale price of electricity, and CO_2 emission penalty. Thus, we have 3,375 equal-probability triplets of the price of oil, wholesale price of electricity, and CO_2 emission penalty. For each of the 3,375 scenarios, we evaluate the optimal CO_2 capture rate that maximizes the project value in that scenario, and calculate the financial gains that are achieved by the contingent optimization of the CO_2 capture rate.

The results show that in 733 scenarios out of the 3,375 scenarios (implies 22% likelihood) it is financially attractive to reoptimize and lower the CO_2 capture rate from the initially planned 90% CO_2 capture rate. Figure 5 presents how the optimal CO_2 capture rate changes with the values of the three market risk factors in these 733 scenarios. Figure 6 presents the financial gains (in million 2010 USD) from reoptimizing CO_2 capture rate in the ex post scenarios. In both the figures, the x-axis shows the ex post price of oil (oil price in year 2023), the y-axis shows the ex post price of electricity, and the z-axis shows the ex post CO_2 emission penalty. The dots in Figure 5 represents the optimal CO_2 capture rate in each of the 733 ex post equal-probability scenarios where the optimal CO_2 capture rate is less than 90%. The color bar represents the range of ex post optimal CO_2 capture rates. In Figure 6, the dots represents the financial gains from adjusting CO_2 capture rate from 90% CO_2 capture rate to the optimal capture rate, and the color bar gives the range of financial gains.

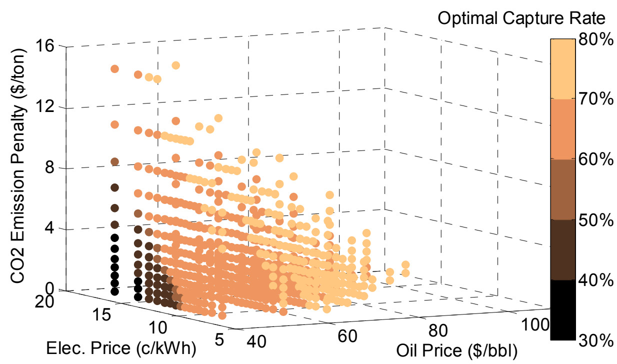


Figure 5 Optimal CO_2 capture rate as function of market risk factors

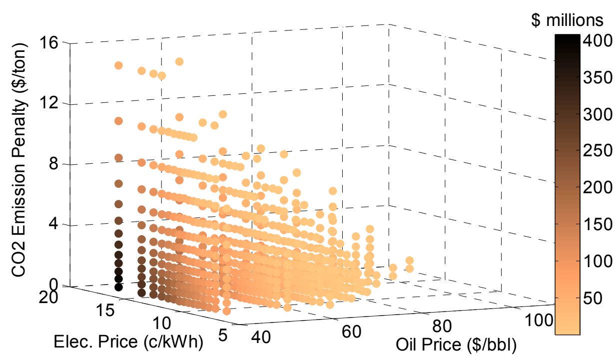


Figure 6 Financial gains ($million) from optimizing CO_2 capture rate

We see from Figure 5 and Figure 6 that as the oil price drops, electricity price increases, and the CO_2 emission penalty goes down, the optimal CO_2 capture rate decreases from 80% to 30%, and the financial gains from optimizing the CO_2 capture rate increase up to $400 million. This is because at low oil prices, high electricity prices and low CO_2 emission penalty, the marginal costs of CO_2 capture dominate and it becomes increasingly economical to lower the CO_2 capture rate. From these figures, we see that the contingent decision-making is economical when price of oil is less than $115/barrel (close to expected price, see Table 4), and the CO_2 emission penalty is less than $15/ton CO_2 (close to upper 1sigma confidence bound value). The price of electricity is not a constraint as it is economical to lower CO_2 capture rate even at a low electricity price of 6.6 c/kWh (close to upper 2sigma confidence bound value).

The project NPV is $1,319 million (in 2017 USD) assuming that the CO_2 capture rate is not optimized in response to change in market risk factors and continued at 90% CO_2 capture rate. Contingent decision-making increases the NPV by $14 million, which is a 1% increase in the project NPV. If we only consider the 22% of the ex post scenarios where it is economical to adjust the CO_2 capture rate, then the ex post adjustment of CO_2 capture rate leads to average financial gains of $63 million (2.2% increase in the project value). The maximum financial gain from contingent adjustment of CO_2 capture rate is $419 million, which is a 14% increase in project value compared to operating at 90% CO_2 capture rate. This scenario corresponds to a low oil price of $41/bbl., high electricity price of 16 c/kWh, and negligible CO_2 emission penalty (the values of three market risk factors is close to their 2sigma confidence bound values).

Overall, these results show that it is economical to reoptimize the CO_2 capture rate in response to change in the market risk factors. In this section, we have analyzed the market risk factors as purely exogenous risks and evaluate the optimal contingent decisions. But, these contingent decisions will be made by independent entities owning and operating the different parts of the CCS-EOR value chain. Thus, the final project value will depend both on the exogenous change in market risk factors and the endogenous response of the project operators to the change in the risk factors. In the next section, we will evaluate alternate contract structures for the CCS-EOR value chain in light of the contractual incentives to the involved entities to optimally adjust the CO_2 capture rate and maximize the overall project value.

4. Performance of Alternate CO_2 Delivery Contract Structures

The operation between the power plant company and the oil field company is integrated through a long-term contract for the delivery of CO_2.The CO_2 delivery contracts that link the two involved entities will define who bears the different risks, and the risk allocation determines the incentives each entity has to perform in the joint interest of the project. If the interests of the entities are not aligned with the overall project then it would lead to sub-optimal decisions that do not maximize the overall value of the project.

Two sets of economics literature that give useful insights for structuring CO_2 delivery contracts for the CCS-EOR projects is the literature on classical principal-agent theory and the applied contracting literature.

The principal-agent theory literature (Mirrlees, 1975; Holmstrom, 1979; Grossman and Hart, 1983) emphasizes the relationship between risk sharing and incentives in designing optimal contracts. This literature provides a theoretical framework to design optimal contracts in presence of exogenous uncertainty and asymmetric information related to hidden information (adverse selection) and hidden actions (moral hazard). The solution of the optimal contract in the principal agent model involves solving for two optimization problems: the principal's optimization problem of maximizing his total surplus, and embedded in the principal's optimization problem is the second optimization problem – the agent's optimization problem. The optimal contract is such that it incentivizes the agent to exert the optimal level of effort that maximizes the principal's value.

An important insight we get from the solution to this principal-agent problem is that the optimal contract involves sharing the project outcome (and risks) between the principal and the agent. Under this optimal contract, the agent's compensation depends on the project outcome and hence exposes him to the project risks. The resulting risk exposure incentivizes the agent to exert effort to reduce risks and increase the project value. In this paper, we are concerned about the similar issues as in the principal-agent problem, of maximizing total value and incentivizing optimal performance by the involved entities. But, we do not follow the theoretical framework as in these papers because of two key reasons. Firstly, in the CO_2 delivery contracts for CCS-EOR projects, the issue of information asymmetries is not a constraint unlike in the principal agent problem, and secondly our goal in this paper is to illustrate the inefficiencies that result from inappropriate risk sharing in standard contracts and not to solve for the optimal contract.

We want to evaluate how alternate standard contract structures for CO_2 delivery respond to changes in market risk factors and impact the value of CCS-EOR projects. The applied contracting literature studies the contractual provisions employed in actual transactions in projects involving large capital investments, and sheds light on how the contractual provisions have been used to allocate risks among the involved entities. For example, Canes and Norman (1983) describe how the take-or-pay provisions in the natural gas supply contracts distribute the risk of change in gas demand between the gas producer and the pipeline. Take-or-pay provisions contractually specify the minimum quantity of gas that the pipelines need to pay for even if the gas delivery is not taken. This way, the gas producers bear the risk of drop in demand till the take-or-pay level and the rest of the risk is borne by the pipeline. This risk sharing protects both the gas producer and the pipeline against sharp fluctuations in future cash flows, and thus protects against risk of inefficient contract breach.

We measure the contractual performance in the prototype CCS-EOR project by adopting the contract design objectives pointed out by Joskow (1985, 1988). Joskow studies contract provisions in long-term coal supply contracts between the coal mining companies and the electricity generating utilities, and points out that contract terms should 'facilitate efficient adaptation to changing market conditions'. This consideration in context of our paper implies that the contract terms linking the CCS-EOR value chain should be such that they incentivize the entities to optimize the CO_2 capture rate in response to change in the market risk factors. The other key objective of contract terms, Joskow points out, is that the contract terms should minimize inefficient breach of contractual obligations. One key reason for inefficient contractual breach would be if either of the involved entities finds it unprofitable to continue operations even though it might be profitable on aggregate terms. The CO_2 delivery contracts for the CCS-EOR value chain should be such that they minimize the risk of insolvency and thus prevent contractual breach when it is not efficient from the overall project perspective.

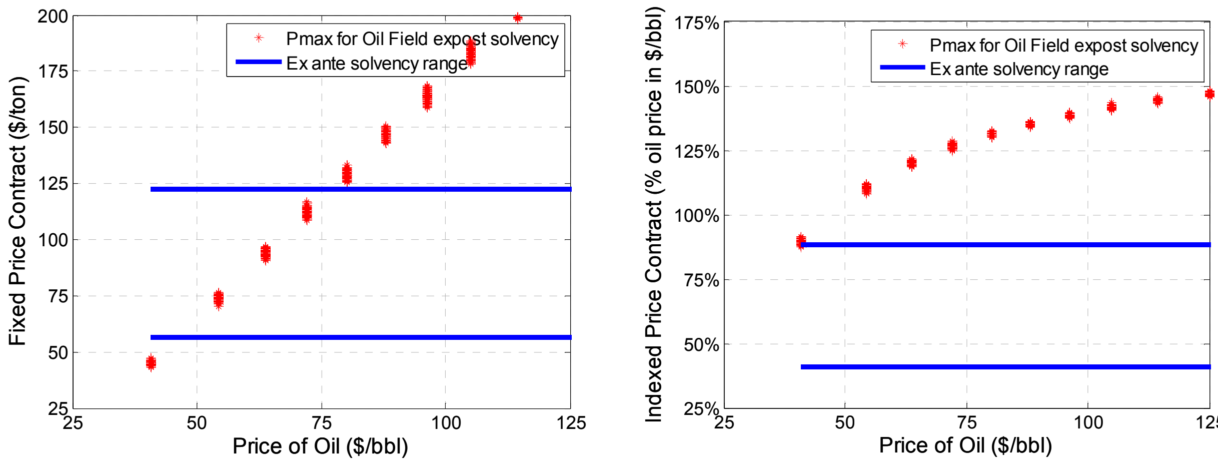
We consider two alternate contract structures for the CCS-EOR value chain: fixed price CO_2 contracts that specify a fixed price per ton CO_2 delivered, and oil-indexed price CO_2 contracts that index the price of CO_2 to the oil price: price of CO_2 (\$/ton) = x% of oil price (\$/bbl). In this section, we evaluate the performance of these two contract types in terms of the risk of ex post insolvency (Section 4.1), incentives provided for reoptimizing the CO_2 capture rate (Section 4.2), and the final project value achieved (Section 4.3). Next, we analyze the risk of insolvency under the fixed price contracts and the oil-indexed price contracts.

4.1 Insolvency Risk

The power plant company and the oil field company will go-ahead with the project only if it is financially attractive for both the entities. Furthermore, as the market risk factors evolve during the project, the financial value captured by both entities will also change. The entities will continue with the project ex post only if it is financially attractive to do so. Thus, the contract terms should be such that it is economical for both entities to go-ahead with the project at t=0, also the contract terms should still be financially attractive ex post as the risk factors evolve.

We analyze the two alternate contract types (fixed price and oil-indexed), and evaluate the contract terms that would be financially attractive to both entities at $t = 0$, and also ex post as risk factors evolve. For the ex post analysis, we consider the same set of ex post scenarios as evaluated in Section 3 for evaluating the optimal CO_2 capture rate. These are 3,375 equal-probability scenarios of changes in three market risk factors (oil price, electricity price, and CO_2 emission penalty) in year 2023 (6 years from the start of project).

Figure 7a presents the fixed price contract terms for which both the power plant company and the oil field company have a positive financial value, and Figure 7b presents the oil-indexed price contract terms to ensure solvency of the two entities.



(a) Fixed Price Contracts *(b) Oil-indexed Price Contracts*

Figure 7 Ex post insolvency risk under alternate contract structures

The solid lines in Figure 7a show the range of fixed price contracts that will result in positive financial value for both entities at t = 0 (ex ante). We see that the minimum fixed contract price that makes this project financially attractive to the power plant company is $57/ton, and the maximum contract price that the oil field company would be willing to pay is $123/ton. Similarly the solid lines in Figure 7b show that the range of oil-indexed contract prices that would be profitable to both entities ex ante is 41% of the oil price to 88% of the oil price.

The stars in Figure 7 (a & b) show the maximum contract price the oil field would be willing to pay ex post at different oil prices. The power plant company would always be solvent ex post as its ex post internal cash flows (not accounting for contractual payments) are always positive. We assume that project always operates at the 90% CO_2 capture rate (contingent CO_2 capture rate is considered in the next section). At a given ex post price of oil, if the contract price is more than shown by the stars in Figure 7, then the oil field company would have a negative ex post value and it would lead to breach in the contractual obligations by the oil field company. We see that as the ex post price of oil increases, the maximum contract price that the oil field company can pay and still be solvent also increases. For given oil price, there is a range of the maximum contract price, this reflects the sensitivity of the contract prices to the other risk factors: price of electricity and CO_2 emission penalty.

The key thing to note is that under fixed price contracts (Figure 7a) at ex post price of oil less than $50/bbl, the ex post maximum contract price for oil field solvency is less than the ex ante minimum contract price that would make power plant solvent. Thus, in fixed price contracts we don't find any price of CO_2 that would be financially attractive to both entities ex ante as well as ex post. Thus under all possible ex ante negotiable contract prices, there is a positive probability of ex post insolvency. If the minimum profitable contract price of $57/ton is negotiated, then there is a 6.7% probability that ex post the oil field company would have a negative project value and will discontinue project operations even though it is overall profitable to continue operations.

If the ex ante negotiated price is the maximum negotiable price of $123/ton, then the ex post insolvency risk increases to 26.7%.

Under oil-indexed price contracts, we see from Figure 7b that if the contract prices are in the range of 41%-87% of the oil price then there is zero risk of ex post insolvency. The risk of insolvency is 0.4% at the maximum negotiable contract price of 88% of the oil price.

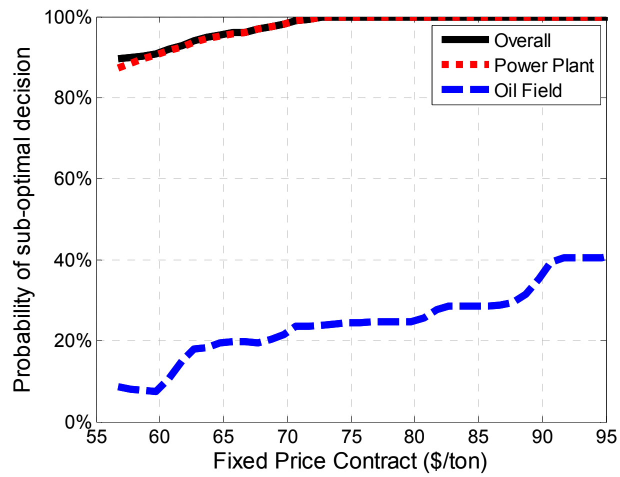
The results show that sharing the oil price risk between power plant company and the oil field company through oil-indexed contracts can eliminate the ex post insolvency risk. Under fixed price contracts the entire oil price risk is borne by the oil field company and thus at low oil prices (below $50/bbl) there is 100% probability of ex post insolvency. Overall, under fixed price contracts the risk of ex post insolvency is between 6.7% - 26.7%. Sharing the oil price risk as in oil-indexed contracts can eliminate the insolvency risk and thus prevent inefficient breach of contractual obligations.

In this section, we evaluated the risk of ex post insolvency under the two alternate contract structures. The other key consideration in design of contract terms is that contract should provide incentives for optimal contingent decision-making. Next, we evaluate the two contract structures in terms of incentives provided to the power plant company and the oil field company to optimize the CO_2 capture rate in response to change in the market risk factors.

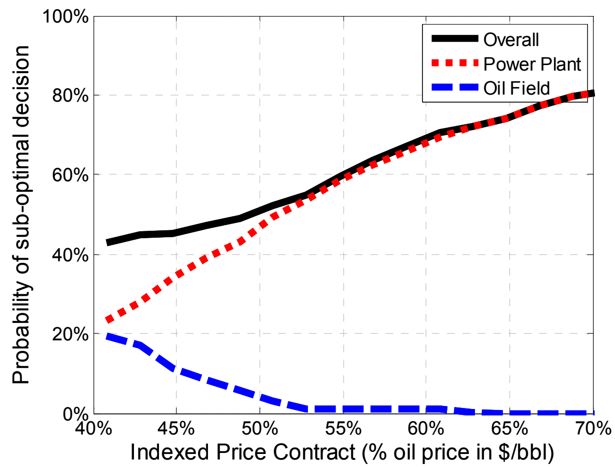
4.2 Incentives for Contingent Decision-making

In Section 3.2, we showed that significant financial gains are achieved by the contingent optimization of the CO_2 capture rate in response to change in the market risk factors. This contingent adjustment of the CO_2 capture rate will be made by independent entities owning and operating different parts of the value chain: the power plant company will decide on the CO_2 capture rate, and the oil field company will decide on the CO_2 injection rate. So, an important consideration in determining the contract terms between the involved entities is that the contractual risk allocation should provide incentives to the individual entities to make contingent decisions such that the overall project value is maximized. We calculated a 22% probability that ex post the optimal CO_2 capture rate will be less than the initially planned 90% capture rate, i.e. in 733 out of the 3,375 scenarios it is optimal to lower the CO_2 capture rate. We focus on these 733 scenarios where it is optimal to lower CO_2 capture rate, and evaluate the incentives provided under the two alternate contract types to the individual entities to optimize the CO_2 capture rate.

Figure 8 (a & b), present the probability of sub-optimal decision-making as a function of the contract price for the fixed price contracts and oil-indexed price contracts respectively. The probability of sub-optimal decision-making accounts for both the risk of operating at a sub-optimal CO_2 capture rate and the risk of ex post insolvency leading to contractual breach. The probability of sub-optimal decision-making is calculated only for the 22% of the ex post scenarios where it is economical to reoptimize the CO_2 capture rate.



(a) Fixed Price Contracts



(b) Oil-Indexed Price Contracts

Figure 8 Effect of choice of contract price on the probability of sub-optimal decision-making

From Figure 8a, we see that overall under fixed price contracts, there is at least a 89% probability of sub-optimal decision-making, and the contract price that minimizes the risk is the minimum ex ante negotiable contract price of $57/ton. At this 'optimal' fixed contract price there is a 87% probability that the power plant would not have incentives to reoptimize the CO_2 capture rate. The probability of sub-optimal decision-making by the power plant company increases with the contract price, and is 100% if the contract price is greater than $72/ton. The poor incentives for the power plant company arise from being paid a fixed price and not sharing any oil price risk. Furthermore, there is a 8% probability that the oil field company would make sub-optimal decisions under the optimal fixed price contract. This includes a 6% probability of ex post insolvency of the oil field company leading to a contractual breach, and an additional 2% probability that the oil field company would not have incentives to reoptimize the CO_2 capture rate even if it was solvent. The ex post insolvency risk for the oil field company would increase to 23%, if we also account for those scenarios where the power plant does not have incentives to reoptimize the CO_2 capture rate, and the project operations continued at 90% CO_2 capture rate. As the fixed contract price increases, the ex post insolvency risk increases, resulting in increased probability of sub-optimal decision-making by the oil field company. Even if the oil field company was solvent, there is a positive probability of 2% under the optimal contract price, that the oil field company would not have incentives to reoptimize the CO_2 capture rate. This points to scenarios where the oil price is high (greater than $95/bbl) and so the oil field company wants to operate at 90% CO_2 capture rate, even though it is overall optimal to lower the CO_2 capture rate as the electricity price is high (greater than 14 c/kWh) and the CO_2 emission penalty is low (less than $4/ton).

Figure 8b presents that the risk of sub-optimal decision-making under oil-indexed price contracts. We see that increasing the oil-indexed CO_2 contract price will reduce the risk of sub-optimal decision-making by the oil field company, but will increase the risk for the power plant company. The optimal oil-indexed contract price is 41% of oil price, which minimizes the overall project risk of sub-optimal decision-making to 43%. At the optimal oil-indexed contract price, there is a 23% probability that the power plant would not have incentives to reoptimize the CO_2 capture rate. We note that since the power plant company now shares the oil price risk with the oil field company, it has increased incentives to lower the CO_2 capture rate when the oil price goes down, compared to fixed price contracts. The risk sharing in indexed price contracts also eliminates the risk of ex post insolvency of the oil field company. From Figure 8b, we see that at the optimal oil-indexed contract price, there is a 20% probability that the oil field company would not have incentives to reoptimize the CO_2 capture rate. If the contract price is higher than 65% of oil price, then there is zero risk of sub-optimal contingent decision-making by the oil field company.

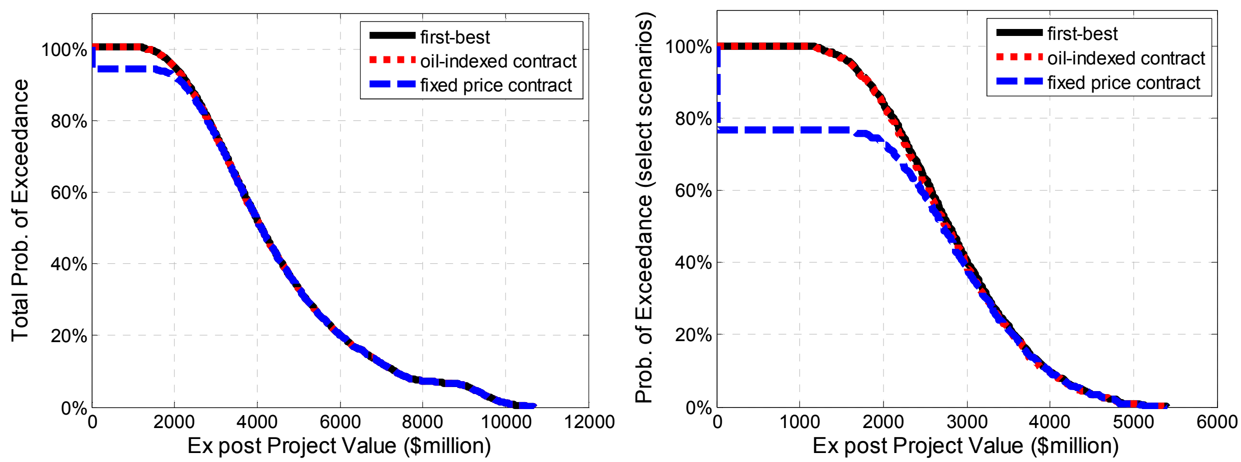
So far, in this section, we have evaluated two alternate contract types in terms of the risk of ex post insolvency and the risk of sub-optimal decision-making. We see that fixed price contracts have high risk of ex post insolvency and high probability of operating at a sub-optimal CO_2 capture rate. The optimal fixed contract price of $57/ton results in a 20.7% probability of sub-optimal decision-making, which includes contractual breach due to insolvencies and operating at a sub-optimal CO_2 capture rate. Indexed price contracts share the oil price risk between the power plant company and the oil field company, and thus reduce the risk of insolvency and sub-optimal decision-making. The optimal contract price under indexed price contract is 41% of the oil price, and under this contract price, there is no risk of ex post insolvency and a 9.3% probability of sub-optimal decision-making. To, further reduce the risk of operating at sub-optimal CO_2 capture, the CO_2 contract terms would need to reflect sharing of other risk factors such as electricity price and CO_2 emission penalty. Next, we quantify the impact of choice of contract structures on the financial value of the project.

4.3 Final Project Value

So far, we have evaluated the influence of contractual risk-sharing on the decision-making of the entities, and find that weak risk sharing in fixed price contracts results in high risk of sub-optimal decision-making. In this section, we evaluate the impact of the sub-optimal decisions on the final project value. We focus on the 'optimal' contract price that minimizes the risk of sub-optimal decision-making under the respective contract structures. For fixed price contracts we consider the ex ante minimum negotiable CO_2 contract price of $57/ton, and for indexed price contracts we consider the ex ante minimum negotiable CO_2 contract price of 41% of the oil price. For these two contract types, we evaluate the resulting project value. As we calculated earlier, the project NPV is $1,332 million in the 'first-best' case when there are no contractual inefficiencies.

We find that under the optimal fixed price contract due to high risk of sub-optimal decision-making the NPV decreases by $128 million to a value of $1,204 million (9.6% decrease). The NPV under the optimal oil-indexed price contract is $1,327 million, which is a $5 million or 0.4% decrease from the first-best.

Figure 9a presents the probability curve of the ex post project value in the first-best case, and under oil-indexed price and fixed price contracts. Figure 9b presents the probability curve of the ex post project value focusing only on 'select' 22% of the ex post scenarios where it is economical to reoptimize the CO_2 capture rate.



(a) Distribution of project value *(b) Distribution of project value in 'select' scenarios*

Figure 9 Impact of contract structure on the ex post project value

The maximum average ex post project value when there are no contractual inefficiencies (first-best) is $4,516 million. Figure 9a shows that the cumulative probability curve of the ex post project value for the indexed price contracts almost overlaps with the first-best. The average ex post under the optimal oil-indexed contract drops by $5 million (0.1% decrease) compared to the first-best value. The ex post value curve for the fixed price contract is shifted lower compared to the project first-best. This reflects the 6.7% probability of ex post insolvency and an overall 21% probability of sub-optimal decision-making under fixed price contracts. The optimal fixed price contract reduces the ex post value by $128 million to $4,388 million, which is a 2.8% decrease.

Figure 9b gives the cumulative probability curve for the ex post project value focusing only on the 22% of the ex post scenarios where it is economical to lower the CO_2 capture rate. The maximum ex post project value in absence of contractual inefficiencies is $2,864 million on average across the 22% of the scenarios. We see from Figure 9b that the ex post project value under the optimal oil-indexed price contract is almost the same as the first-best. Overall, under the optimal indexed price contract, the average ex post project value in the 22% of the scenarios is $2,839 million, which is $24 million or 0.8% less than the first-best project value. Fixed price contract leads to a larger financial loss and the average value across the 22% scenarios is $2,377 million, which is $487 million or 17% less than the first-best project value. We see from Figure 9b, that the probability of making positive financial gains in the optimal fixed price contract is only 77% compared to a 100% under the optimal oil-indexed price contract. This is a result of a 23% probability of ex post insolvency for the oil field company under the fixed price contract.

The results show that the fixed price CO_2 contracts result in much larger financial loss compared to the oil-indexed price contracts. Overall, the optimal fixed price contract leads to a 9.6% decrease in the project NPV and a high probability of ex post insolvencies. Indexed price contracts eliminate the risk of ex post insolvencies leading to 100% probability of positive ex post project value and result in a 0.4% loss in the project NPV.

5. Conclusions

In this paper, we evaluate the impact of contractual risk-sharing on decision-making by the involved entities and the final project value. We focus on a prototype CCS-EOR project, and evaluate two alternate CO_2 delivery contract structures (fixed price CO_2 contract and oil-indexed price CO_2 contract) in terms of the incentives provided to the power plant company and the oil field company to respond to changes in the market risk factors (volatility in the price of oil, the wholesale price of electricity, and the CO_2 emission penalty).

The results show that inappropriate contractual risk allocation, as in fixed price CO_2 contracts, leads to a significant loss in project value. This loss is due to high contracting risks associated with ex post insolvencies and weak incentives for contingent decision-making. At low oil prices, there is a 100% probability that the oil field company would be insolvent under fixed price contracts, which might lead to an inefficient breach of contractual obligations even though it is profitable to continue operations on an aggregate project basis. Furthermore, since the power plant company gets a fixed price for CO_2, it has very weak incentives to reoptimize the CO_2 capture rate in response to change in the market risk factors, resulting in sub-optimal outcomes.

We find that the risk sharing offered by oil-indexed price CO_2 contracts significantly lowers the contracting risks, including eliminating the risk of ex post insolvency and reducing the probability of sub-optimal decision-making. The project value achieved under an oil-indexed price CO_2 contract is very close to the first-best project value (maximum achievable project value), and is considerably higher compared to project value under a fixed price CO_2 contract.

These results emphasize the importance of strong contractual risk-sharing in optimizing project outcomes and maximizing the total project value. Analyzing the weaknesses of alternate CO_2 contract structures gives insights into the design of optimal contracts for the CCS-EOR value chain. We find that sharing the oil price risk through oil-indexed price CO_2 contracts lowers the risk of operating at a sub-optimal CO_2 capture rate; to further reduce the risk of sub-optimal project outcomes, the CO_2 contract terms would need to reflect sharing of other risk factors such as the electricity price and the CO_2 emission penalty.

References

Abadie, L.M., and Chamorro, J.M. 2008. "European CO_2 Prices and Carbon Capture Investments." Energy Economics, vol. 30(6), p. 2992-3015.

Al-Juaied, M.A., and Whitmore, A. 2009. "Realistic costs of carbon capture." Discussion Paper 2009-05, Harvard Belfer Center for Science and International Affairs, Cambridge, MA.

Baker, M.P., Mayfield, E.S., Parsons, J.E. 1998. "Alternative Models of Uncertain Commodity Prices for Use with Modern Asset Pricing Methods." The Energy Journal, vol. 19(1), p. 115-148.

Bloomberg. 2012. "Leading the Energy Transition: Bringing Carbon Capture & Storage to Market." Bloomberg energy finance whitepaper.

Brock, W.R., Bryan, L.A. 1989. "Summary Results of CO2 EOR Field Tests, 1972-1987." Paper presented at the Low Permeability Reservoirs Symposium, Denver, Colorado, March 1989.

Canes, M.E., and Norman, D.A. 1983. "Analytics of Take-or-pay Provisions in Natural Gas Contracts." American Petroleum Institute Discussion Paper no. 029.

Dewatripont, M., and Legros, P. 2005. "Public Private Partnerships: Contract Design and Risk Transfer." EIB Papers, vol. 10(1), p. 120–145.

Flyvbjerg, B., Bruzelius, N., and Rothengatter, W. 2003. "Megaprojects and Risk: an Anatomy of Ambition." Cambridge University Press.

GCCSI (Global CCS Institute). 2012. "The Global Status of CCS: 2012." Report by Global CCS Institute, Canberra, Australia.

GCCSI (Global CCS Institute). 2011. "Economic Assessment of Carbon Capture and Storage Technologies: 2011 Update." Report by WorleyParsons and Schlumberger, supported by Global CCS Institute, Canberra, Australia.

GCCSI (Global CCS Institute). 2010. "The Global Status of CCS: 2010." Report by Global CCS Institute, Canberra, Australia.

Grossman, S.J., and Hart, O.D. 1983. "An Analysis of the Principal-Agent Problem." Econometrica, vol. 51(1), p. 7-45.

Hildebrand, A.N. 2009. "Strategies for Demonstration and Early Deployment of Carbon Capture and Storage: A Technical and Economic Assessment of Capture Percentage." S.M. Thesis, Massachusetts Institute of Technology, Cambridge, MA.

Holmstrom, B. 1979. "Moral Hazard and Observability." The Bell Journal of Economics, vol. 10(1), p. 74-91.

Hovorka, S.D. 2010. "EOR as Sequestration—Geoscience Perspective." Paper presented at the Symposium on the role of EOR in accelerating the deployment of CCS, an MIT Energy Initiative and Bureau of Economic Geology at UT Austin Symposium, July 23, 2010.

Hull, J.C. 2011. "Options, Futures, And Other Derivatives." Eighth Edition, Prentice Hall.

Jakobsen, V.E., Hauge, F., Holm M. and Kristiansen, B. 2005. "CO2 for EOR on the Norwegian shelf – A case study." The Bellona Foundation.

Joskow, P.L. 1988. "Price Adjustment in Long Term Contracts: The Case of Coal." Journal of Law and Economics, vol. 31(1), p. 47–83.

Joskow, P.L. 1985. "Vertical Integration and Long-term Contracts: The Case of Coal-burning Electric Generating Plants." Journal of Law, Economics and Organization, vol. 1(1), p. 33-80.

Klein, B., Crawford, R.G., and Alchian, A.A. 1978. "Vertical Integration, Appropriable Rents, and the Competitive Contracting Process." Journal of Law and Economics, vol. 1(2), p. 297–326.

Martin, D.F., and Taber, J.J. 1992. "Carbon Dioxide Flooding." Journal of Petroleum Technology 44 (4): 396-400.

McCoy, S.T. 2008. "The Economics of CO_2 Transport by Pipeline and Storage in Saline Aquifers and Oil Reservoirs." PhD thesis, Carnegie Mellon University, Pittsburgh, PA.

Merrow, E.W. 2011. "Industrial Megaprojects: Concepts, Strategies, and Practices for Success." Wiley.

Miller, R. and Lessard, D.R. 2000. "The Strategic Management of Large Engineering Projects: Shaping Institutions, Risks, and Governance." MIT Press.

Mirrlees, J.A. 1975. "The Theory of Moral Hazard and Unobservable Behavior-Part I." Nuffield College, Oxford, Mimeo. (Reprinted in 1999 in Review of Economic Studies, vol. 66, p. 3-21.

MIT. 2007. “The Future of Coal: Options for a Carbon-constrained World.” Massachusetts Institute of Technology, Cambridge, MA.

NETL (National Energy Technology Laboratory). 2011. “Improving Domestic Energy Security and Lowering CO2 Emissions with Next Generation CO2-Enhanced Oil Recovery.” Report by National Energy Technology Laboratory DOE/NETL-2011/1504.

NETL (National Energy Technology Laboratory). 2008. “Storing CO_2 with Enhanced Oil Recovery.” Report by National Energy Technology Laboratory NETL/DOE -402/1312/02-07-08.

Niemeyer, V. 2000. “Forecasting Long-term Electric Price Volatility for Valuation of Real Power Options.” Paper presented at the 33rd Annual Hawaii International Conference on System Sciences.

Ostrom, E., Schroeder, L., Wynne, S. 1993. “Institutional Incentives and Sustainable Development: Infrastructure Policies in Perspective.” Westview Press.

Pindyck, R.S. 1999. “The Long-Run Evolution of Energy Prices.” The Energy Journal, vol. 20(2), p. 1-27.

Schwartz, E., and Smith, J.E. 2000. “Short-term Variations and Long-term Dynamics in Commodity Prices.” Management Science vol. 46(7): 893-911.

US EIA (Energy Information Administration). 2013. “Annual Energy Outlook 2013: With Projections to 2040.”

Williamson, O.E. 1971. “The Vertical Integration of Production: Market Failure Considerations.” American Economic Review, vol. 61(2), p: 112–23.

World Bank. 1994. “Infrastructure for Development.” World Bank Development Report, Oxford University Press for the World Bank, Washington, D.C.