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Commercial Structures for Integrated CCS-EOR Projects

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Abstract

In this paper, we evaluate alternate commercial structures for an integrated CCS-EOR project where the source of CO_2 is a coal-fired power plant, and the CO_2 is transported via a dedicated pipeline to an oil field where the CO_2 is injected for EOR. We evaluate alternative contract types that link the involved entities in light of exogenous market risks, such as the fluctuating price of oil recovered. The choice of the contract type determines who would bear the risks along the value chain, and the incentives that the risk allocation produces fixes the total project value. We see that the fixed price contracts have weaknesses in terms of ex-post insolvencies and poor incentive structures that result in a sub-optimal decision-making by the involved entities. The risk-sharing offered by the indexed price contracts reduces the likelihood of ex-post insolvency and provides incentives to each entity to optimize the total project value.

Keywords: CCS; value chain; contract; risk sharing; incentives

1. Introduction

In 2008, leaders of the Group of Eight (G8) committed to launch 20 large-scale carbon capture and storage (CCS) demonstration projects by 2010 with the goal of beginning broad deployment of CCS by 2020 [4]. Among other things, the criteria developed for the launch of these large-scale CCS projects specify that they should be integrated projects, i.e. the project should include the entire CCS value chain of capture, transport and storage of CO_2 [4]. We evaluate an integrated CCS project where the source of CO_2 is a coal-fired power plant, and the CO_2 is transported via a dedicated pipeline to an oil field where it is injected for enhanced oil recovery (EOR) and subsequently stored. In integrated CCS projects, the different parts of the value chain are linked through a commercial structure that determines the ownership, financial and operating structure for the involved entities. For example, the entire value chain could be owned by a single company, or, alternatively, each component of the chain could be owned by a separate company with the relations between them specified in a contract for delivery of the CO_2. We evaluate alternative contract terms that link the involved entities in light of exogenous market risks, such as the fluctuating price of oil recovered.

The specific ownership structure we study is where the power plant and the oil field are owned by separate companies and the pipeline is jointly owned by the two companies. In this ownership structure we find that even though the overall integrated project has a positive net present value (NPV), the power plant company would have a negative NPV without any internal revenue transfer. We evaluate two contract types where the oil field company pays the power plant company for the CO_2 delivery as per a fixed CO_2 contract price, or, alternatively, a CO_2 contract price that is indexed to the oil price. Section 3 of this paper identifies the contracts that have the following key features:

a) Contracts should distribute the aggregate project value between the involved entities so that it is profitable for each entity to go-ahead with the project.
b) Contracts should offer risk allocation among the entities to reduce the uncertainty on the ex-post desirability of the ex-ante negotiated contract terms.

In the fixed price CO_2 contracts the oil field company bears all the oil price risk and hence there is a high likelihood that ex-post if the price of oil changes then it would not be profitable for the oil field company to continue on the ex-

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ante negotiated contract terms. Indexed price contracts distribute the oil price risk between both companies and thus reduce the likelihood of ex-post dissatisfaction with the contract terms.

In Section 4, we show that if the project operations are optimized in response to the change in risk factors such as the oil price then the overall project value will be maximized. We see that lowering the CO_2 capture rate in a low oil price environment can save up to \$156 million. This is because at a low oil price, the marginal costs of CO_2 capture are higher than the benefits from incremental oil recovery and so it is more economical to lower the capture rate. As these contingent decisions will made by different entities owning and operating the different parts of the CCS-EOR value chain, the contract terms should provide incentives to each entity such that they adjust their operations to optimize the overall project value. Evaluating alternate contract types, we find that the risk-sharing offered by the indexed price contracts give incentives to each entity to optimize the CO_2 capture rate in response to the change in the oil price. On the other hand, the fixed price contracts would result in a sub-optimal project value as the power plant company does not bear any oil price risk and thus has no incentive to reduce the CO_2 capture rate.

This paper is organized as follows: Section 2 describes the integrated CCS-EOR project we study in this paper and calculates the cash-flows generated by each component of the integrated project. In Section 3, we describe the key features of the commercial structures that link the individual entities in the value chain, and evaluate alternate commercial structures for the CCS-EOR project. In Section 4, we illustrate the importance of contingent decision-making in optimizing the total project value , and evaluate alternate contract types in terms of the incentives they provide to individual entities to optimize their operations. Finally, some conclusions are presented in Section 5.

2. The CCS-EOR Project

The CCS-EOR project analyzed in this paper 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. The specifications of each of the components of this project are described next.

2.1. Project Description

The power plant is a coal-fired integrated coal gasification combined cycle (IGCC) plant designed to capture 90% of the CO_2 generated. This is a baseload plant with a capacity factor of 80% and the heat rate is 10,000 Btu/kWh. The CO_2 will be transported via a 20-inch, 50-mile dedicated pipeline to the oil field that has estimated 190 million barrels of oil reserves recoverable through EOR. It is estimated that it would take 25 years to recover the total oil recoverable. The project construction is planned to begin in 2017, the operations will start in 2020 and continue for 25 years till 2044.

Every year the 3.2 million tons of CO_2 that will be captured at the power plant is planned to be injected in the oil field. Some of this injected CO_2 will come to the surface with the oil and will be recycled and injected back into the oil field. The rate of CO_2 recycling (expressed as a % of the total CO_2 injected in the previous year that comes to the surface and is injected back in the current year) is 0.05% in year 2021 and will increase to 60% by 2039 and then stay constant. The total CO_2 injected in a year (Table 2: row b5) is the sum of the 'new' CO_2 (from the power plant) and the recycled CO_2 (Table 2: row b4). At the end of the project, the oil field will be closed and all of the CO_2 injected will be permanently stored.

The average EOR efficiency (oil recovered per ton of CO_2 injected) in the oil field is estimated to increase from 1 bbl/ton in year 2021 to 2 bbl/ton by 2031 and then fall again to 1bbl/ton by 2044. The annual oil production (Table 2: row b6) will increase till 2031 due to the increasing CO_2 injection and EOR efficiency. From 2031 to 2039, the decrease in EOR efficiency offsets the increase in CO_2 injection, and thus the annual oil production will be almost constant; the annual oil production will decrease after 2039. Next, we describe the cash-flows involved in this CCS-EOR project.

2.2. Project Cash-Flows

Table 2 presents the project cash-flows (due to space constraints we just show an extract of the entire table). The parameters used to calculate these cash-flows are given in Table 1. All values in Table 1 remain constant in real terms through the project life and grow at an inflation rate of 3%. We use a nominal discount rate of 10% and tax rate of 35%.

The first investment begins in 2017 with the start of power plant construction. The construction schedule and the investment cash-flows for the power plant are given in Table 2: rows a1, a2. This investment will get depreciated using a 20-year Modified Accelerated Cost Recovery System (MACRS). The pipeline construction schedule is: 40% in 2018 and 60% in 2019, this investment is depreciated using a 15-year MACRS. Unlike the power plant and the pipeline, only part (60%) of the capital investment for EOR will be done upfront before the start of operations. This upfront investment involves the oil field upgrades such as constructing a CO_2 spur-line from the main CO_2 pipeline to the oil field, investment in the surface equipment such as a CO_2 recycle plant. This investment (row b2) is depreciated as per a 15-year MACRS. The remaining 40% capital investment involves drilling of the CO_2 injection wells and the oil production wells, and will be done gradually (10% every 5 years starting in 2024) reflecting the temporal increase in the amount of CO_2 injected and the oil produced. This investment (row b9) has no salvage value and is expensed. Other costs incurred during the project involve the O&M costs (power plant: row a4; oil field: b7), the fuel cost (row a5), the

CO_2 emission penalty (row a6), and the cost of CO_2 recycling (row b8). There are two sources of revenue for this project: revenue from the electricity generation (row a8), and revenue from the oil production (row b11).

Power Plant		
Overnight Cost [1]	$/kW	6,900
Fixed O&M Cost [5]	$/kW/year	50
Variable O&M Cost [5]	mills/kWh	9
Price of Coal	$/MMBtu	2
Penalty for CO_2 Emissions	$/ton	10
Wholesale Electricity Price	cents/kWh	10
Oil Field		
Capital Investment [11]	$/bbl	5
O&M Cost [11]	$/bbl	10
CO_2 Recycle Cost [11]	$/ton	30
Price of Oil Recovered	$/bbl	70
Royalty Payment (% of oil production value)		12.5%
Pipeline		
Capital Investment [1]	$million/mile	1.7
O&M Costs [1]	$/ton	2.5

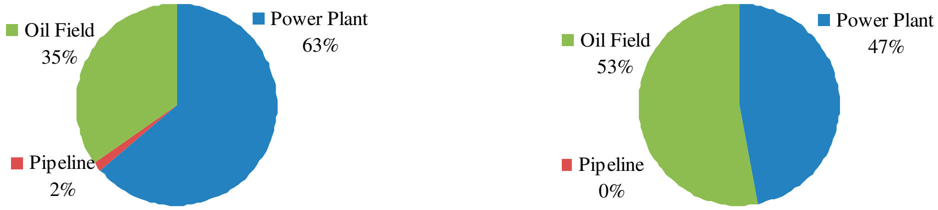
Table 1 Unit costs and prices used to calculate cash-flows (real values in 2010 dollars)

		Year									
Row #		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**...2031**	**...2044**
	Discount Factor	1.9	2.1	2.4	2.6	2.9	3.1	3.5	3.8	7.4	25.5
	POWER PLANT										
a1	Construction Schedule	20%	50%	30%							
a2	Overnight Costs	849	2,185	1,350							
a3	Depreciation	-	-	-	164	316	293	271	250	196	0
a4	O&M Costs	-	-	-	76	78	81	83	86	105	155
a5	Fuel (Coal) Costs	-	-	-	94	97	100	103	106	130	192
a6	CO_2 Emission Penalty	-	-	-	4.7	4.9	5.0	5.1	5.3	6.5	9.6
a7	Total Expenses	-	-	-	339	497	478	462	447	438	356
a8	Electricity Gen. Revenue	-	-	-	471	485	500	515	530	652	958
a9	Total Income	-	-	-	132	-11	22	53	83	215	602
a10	Tax	-	-	-	46	-4	8	19	29	75	211
a11	Net Cash Flows	-849	-2,185	-1,350	250	309	307	305	304	335	392
	Total Power Plant NPV = -$798 million										
	OIL FIELD										
b1	Investment Schedule	-	30%	30%							
b2	Capital Investment	-	361	372							
b3	Depreciation	-	-	-	37	70	63	56	51	43	0
b4	CO_2 Recycled (m ton)	-	-	-	-	0.002	0.1	0.2	0.3	1.5	4.7
b5	Total CO_2 Injected (m ton)	-	-	-	3.2	3.2	3.3	3.4	3.5	4.6	7.8
b6	Amt. Oil Recovered (m bbl)	-	-	-	-	3.2	3.6	4.1	4.6	9.9	7.8
b7	O&M Costs	-	-	-	-	44	52	60	69	185	214
b8	CO_2 Recycle Costs	-	-	-	-	0.1	5	10	15	82	384
b9	Drilling Costs	-	-	-	-	-	-	-	144	-	-
b10	Total Expenses	-	-	-	37	113	119	126	279	311	598
b11	Oil Prod. Revenue	-	-	-	-	306	361	420	485	1,296	1,499
b12	Royalty	-	-	-	-	38	45	53	61	162	187
b13	Total Revenue	-	-	-	-	268	316	368	424	1,134	1,311
b14	Total Income	-	-	-	-37	154	197	242	145	823	714
b15	Tax	-	-	-	-13	54	69	85	51	288	250
b16	Net Cash Flows	-	-361	-372	13	170	191	213	145	578	464
	Total Oil Field NPV = $907 million										
	PIPELINE										
	Total Pipeline NPV = -$74 million										

Table 2 Project Cash-Flows (in $million unless specified)

Considering these project cash-flows, we see that the overall project has a net positive NPV of $35 million, but the power plant and the pipeline have a net negative NPV of -$798 million and -$74 million respectively. In the entire value chain, only the oil field generates a net positive NPV of $907 million. This is because as seen from Figure 1, the power plant bears the largest share of the project costs (64%), while the oil field captures the largest revenue share (53%).

Note that these NPV calculations do not account for any cash-flow transfers between the involved entities. If separate companies were to own the individual components of the value chain then the aggregate project value would need to be distributed through internal cash-flow transfers so that it is profitable for each company to go-ahead with the project. Commercial structures that link the different entities along the value chain would determine the value-sharing structure of the value chain; this will be discussed in detail in Section 3.



Total Costs (NPV) = $484 million **Total Revenue (NPV) = $491 million**

Figure 1 NPV of total costs and total revenue of the different components of the CCS-EOR value chain

The cash-flows calculated in this section are based on the expected value of the economic variables as given in Table 1. Next, we discuss how the project value might change in light of change in the exogenous market risk factors.

2.3. Exogenous Market Risks and Ex-post Scenarios

In this paper we analyze the impact of the exogenous market risks that might be realized after a major investment has been made specifically in the operational phase of the project from 2020 to 2044. These risk factors include the wholesale price of electricity, the price of coal, the price of oil recovered and the CO_2 emission penalties. For illustration, we will analyze the impact of the change in the expected price of oil one year after the start of project operations (in 2021). Table 3 gives the ex-post NPV of the power plant, the oil field, the pipeline and the overall integrated project for different ex-post oil prices.

	Price of Oil ($/bbl)				
	35	**50**	**70**	**90**	**105**
Power Plant	1,133	1,133	1,133	1,133	1,133
Oil Field	382	745	1,229	1,712	2,075
Pipeline	-23	-23	-23	-23	-23
Integrated Project	1,491	1,854	2,338	2,822	3,184

Table 3 Ex-post NPV($million) of the indiviual components of the CCS-EOR chain for a range of ex-post oil prices

We see that if the oil price dropped from $70/bbl to $35/bbl then there will be a loss of $847 million, but if the oil price increased to $105/bbl then the ex-post NPV will increase by $846 million. A change in the oil price would have a direct impact only on the EOR revenue and thus only the value of the oil field is affected; the NPV of the power plant and the pipeline do not change with the oil price. The commercial structure linking the involved entities would determine how the risks are shared among the involved entities and the resulting project value captured by each entity. This will be discussed further in the next section.

3. Commercial Structures for the CCS-EOR Value Chain

In an integrated CCS project the different parts of the CCS value chain – CO_2 capture, transport and storage, would be linked through a commercial structure. Commercial structures determine the ownership, financial and operating structure for the involved entities in the value chain. This paper focuses on an ownership structure such that the power plant and the oil field are owned by separate companies and the pipeline is jointly owned by the power plant company and the oil field company. If we only account for the externally generated cash-flows, based on the cash-flows calculated in Section 2.2, in this ownership structure the power plant company would have a negative NPV of -$835 million and the oil field company would have a positive NPV of $870 million. Since this project is profitable on an aggregate basis, the commercial structure should specify a transfer of value from the oil field company to the power plant company such that it is profitable for each company to go-ahead with the project.

Let us assume that both companies negotiate a price for the delivery of CO_2. What is the guarantee that after the power plant company has built the power plant, the oil field company will not want to renegotiate and offer a lower price for the CO_2 than agreed on earlier. Klein et al [9] and Williamson [13] talk about the risk of opportunistic behavior in transactions involving large upfront investments that are dedicated to a single buyer. The likelihood of ex-post opportunism might make it unattractive to invest in this CCS-EOR project. Long-term contracts have been used by the electric utility industry for the coal supply [8] and the natural gas industry [3, 10] to provide protection from such opportunistic behavior. So, before any major investment is made, the companies involved in this CCS-EOR project would enter a long-term CO_2 contract for the estimated project life.

The long-term contracts linking the individual entities in the value chain should have two key features:

1. Distribute the Project Value

The contracts should distribute the aggregate project value between the individual entities such that it is profitable for each entity to go-ahead with the project.

2. Distribute the Project Risk

If the oil field company were to bear all the risk of the change in the oil price, then there might be a scenario wherein the oil price drops so low that it is no more profitable for the oil field company to operate as per the ex-ante negotiated contract terms. This uncertainty on the ex-post profitability of the contract terms is likely to reduce the overall attractiveness of this project and the project might not take-off at all or might be abandoned ex-post, even though it is overall profitable both ex-ante and ex-post [2]. Blitzer et al [2] through their study of contracts of oil exploration and development motivate that risk-sharing between the entities can help reduce the ex-post contracting risks and is mutually beneficial. Hence the contract terms should offer risk allocation among the involved entities such that it is profitable for each entity to continue with the operations even when the risk factors change ex-post.

In this paper we evaluate the following two types of long-term contract structures:

1. Fixed Price CO_2 Contracts

We evaluate alternate fixed price contracts where the CO_2 contract price is pre-determined and remains fixed for the contract term.

2. Indexed Price CO_2 Contracts

EPRI's EOR scoping study [6] reports that often CO_2 supply contracts between the Shell CO_2 Co. (now Kinder Morgan) and the EOR operators index the CO_2 supply costs to the oil price to reduce the EOR operator's risk of low oil price. In this paper we evaluate alternate indexed price contracts which index the CO_2 contract price to the oil price such that the *contract price of CO_2 (\$/ton) = x% of the price of oil (\$/bbl).*

Next, we evaluate these two contract types in light of value-sharing and risk-sharing between the involved entities.

3.1. Value-Sharing Offered by Contracts

Figure 2 shows the value-sharing between the power plant company and the oil field company at different contract prices of CO_2. The x-axis gives the contract price per ton CO_2 for the two contract types: a) fixed price contracts (\$), and b) indexed price contracts (% expected price of oil (=\$70/bbl)).

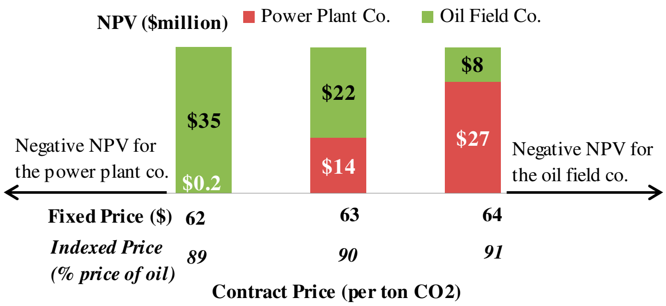


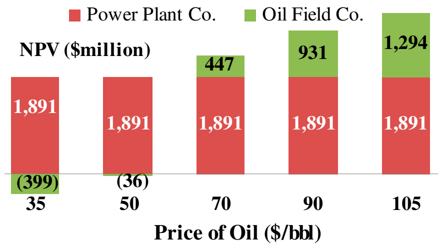
Figure 2 NPV(\$million) of the involved companies under alternate contract terms

The total project value is \$35 million and dependent on the contract price of CO_2, each individual entity's share of the total project value changes. The NPV of the power plant company will be negative for a contract price less than \$62 (or 89% of the price of oil) per ton CO_2, and as the contract price of CO_2 increases the power plant company's share of total project value increases. At a contract price of \$64 (or 96% of the price of oil) per ton CO_2, the power plant company captures 77% of the total project value. The oil field company would not pay more than \$64 (or 91% of the oil price) per ton CO_2, as a higher price would result in a negative NPV for the oil field company. Hence we find that for both companies to go-ahead with this project, the contract price per ton CO_2 should be between \$62 - \$64 for the fixed price contracts, and 89%-91% of the oil price for the indexed price contracts.

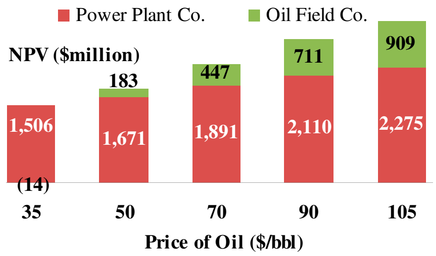
These contract terms are calculated based on the expected value of the oil price. But, ex-post if the price of oil changes, the project value captured by each company would depend on how the risk is shared among the involved companies. In the next section we analyze the risk allocation offered by these two alternate contract types and identify the contract terms that would be desirable to both companies ex-post.

3.2. Risk-Sharing Offered by Contracts

To find out if the ex-ante negotiated contract terms would also be profitable to both companies when the oil price changes, we analyze the same ex-post scenario as in Section 2.3 – the oil price changes in 2021. Figure 3 gives the ex-post NPV of the two companies at the minimum contract price of CO_2 that both companies would agree to ex-ante i.e. \$62 for the fixed price contracts (Figure 3a) and 89% of the oil price for the indexed price contracts (Figure 3b).



a. Fixed price contract @ $62/ton



b. Indexed price contract @89% of oil price/ton

Figure 3 Ex-post NPV($million) of the involved companies under alternate contract terms

We see that for either of the contract types, if ex-post the expected price of oil did not change ($70/bbl) or increased, then both companies would continue to have a net positive NPV. But, if the price of oil dropped ex-post, then we see from Figure 3a that under the fixed price contracts the oil field company would have a negative NPV and thus would not be able to afford even the minimum price of CO_2 it offered to pay ex-ante to the power plant company. This is because the oil field company bears all the oil price risk as the power plant company is always guaranteed a fixed price for the CO_2.This uncertainty on the ex-post profitability of the contract terms is likely to discourage investment in this project even though it is profitable on an aggregate level both ex-ante and ex-post [2].

Using the indexed price contracts can reduce the likelihood of the ex-post dissatisfaction with the contract terms– we see from Figure 3b that if the price of oil fell to $50/bbl then this indexed price contract would still be profitable to both companies. Thus the indexed price contracts reduce the risk of ex-post insolvency by distributing the oil price risk between the two companies – we see from Figure 3b that unlike in the case of the fixed price contracts, in the indexed price contracts the NPV of the power plant company is sensitive to the oil price. But, if the oil price dropped very low to $35/bbl, then the oil field company would have a net negative NPV even under this contract.

An important consideration we have not accounted for so far is the contingent decisions made by the project operators in response to the change in the risk factors. As risk factors such as the oil price change, the operators might re-optimize their operating decisions. In the next section we analyze the impact of contingent decision-making on the NPV of the overall project and identify the contract terms that will incentivize optimal contingent decisions.

4. Contingent Decision-Making

The project operators will make contingent decisions to adjust the project operations in response to the change in risk factors. The optimal contingent decisions are such that the overall project value is maximized. To illustrate the significance of contingent decision-making, we analyze the decision to adjust the rate of CO_2 capture and injection contingent on the price of oil. The optimal capture rate depends on the marginal costs and benefits of CO_2 capture and injection. These include the O&M costs, the incremental oil recovery and the avoided CO_2 emission penalty - modeled earlier in Section 2. Another 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 [12] 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, this translates into approximately 25% decrease in the power output – we assume that 10% comes from the CO_2 compression and the rest 15% is the energy penalty of the water-gas shift reaction and the CO_2 separation.

The IGCC power plant in this project is designed to have dynamically adjustable CO_2 capture rate that can be changed in response to the fluctuating risk factors. We recognize that there is uncertainty on the technically recoverable energy penalty as the capture rate is dynamically reduced from 90% to 0%, and the subsequent increase in the net power output can be between 10% (compression penalty) and 25% (theoretical maximum). Figure 4 presents the net power output as a function of the CO_2 capture rate for alternate levels of increase in the net power output. The curve for the 10% gain is linear reflecting only the change in the CO_2 compression rate; other curves have a kink at the 60% capture rate. This is because we assume that larger energy gains occur as the capture rate is reduced from 90% to 60% and thereafter lowering the capture rate does not yield as much energy gains. For analysis purpose, in this paper we use the 20% curve i.e. there is a 20% increase in the net power output by reducing CO_2 capture rate from 90% to 0%.

4.1. Optimization of the Overall Integrated Project Value

We analyze the same ex-post scenario as in Section 2.3 and Section 3.2 – price of oil changes in 2021, and calculate the ex-post NPV of the overall integrated project at different levels of CO_2 capture. Figure 5 gives the ex-post NPV of the overall integrated project at different capture rates for ex-post price of oil ranging from $20-$45/bbl. The black dots indicate the optimal capture rate at which the NPV is the maximum for a given ex-post oil price.

We see that if the price of oil is lower than $45/bbl, it is economical to lower the CO_2 capture rate from the design 90%. The optimal CO_2 capture rate is 30% at the oil price of $20/bbl, and by adjusting the capture rate from 90% to

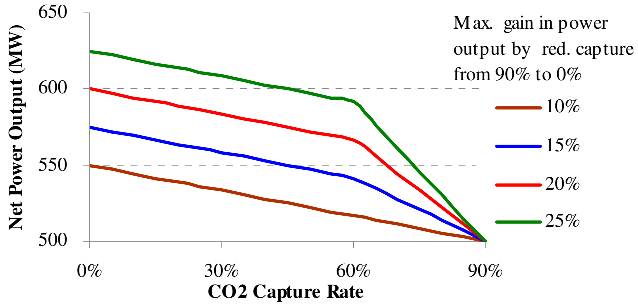


Figure 4 Net power output at different levels of the CO_2 capture rate

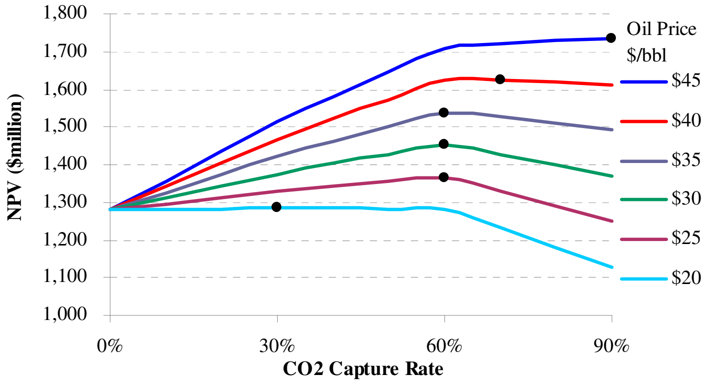


Figure 5 Ex-post NPV($million) of the integrated project at different CO_2 capture rates and different oil prices

30%, the overall project NPV increases by $156 million. This is because at a low oil price, the marginal costs of CO_2 capture are higher than the benefits from the incremental oil recovery and so it is more economical to do partial capture.

This scenario illustrates the importance of contingent decision-making in maximizing the overall project value. As these contingent decisions will often be made by independent entities owning and operating different parts of the value chain, the contract terms linking the individual entities should be such that each entity has incentives to optimize the integrated project value. This is discussed in detail next.

4.2. Incentives Offered by Contracts

In Section 3, we had discussed that contract terms should be structured such that they offer profitable value-sharing and risk-sharing between the individual entities. A third important consideration in determining the contract terms between the involved entities is to provide incentives for optimal contingent decision-making such that the overall project value is maximized. Blitzer et al [2] and Hall et al [7] talk about the importance of structuring the contracts such that the contracts provide incentives to the individual entities' to perform in the common interest. We evaluate the two contract types as analyzed in Section 3.3 to see whether they provide incentives to the power plant company and the oil field company to adjust the CO_2 capture rate when ex-post the oil price drops to $35/bbl. Figure 6 gives the ex-post NPV of both companies for two alternate contract types at two different levels of CO_2 capture: 90% capture (as designed) and 60% capture (optimal CO_2 capture rate at $35/bbl: from Figure 5).

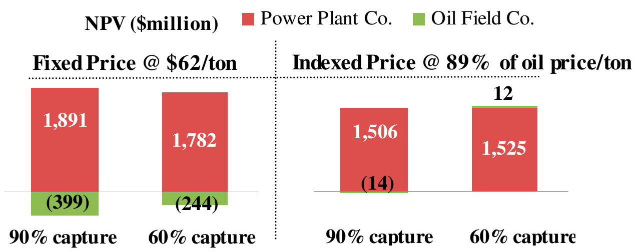


Figure 6 Ex-post NPV($million) of the involved companies at different CO_2 capture rates under alternate contract terms

We see that under the fixed price CO_2 contract, it would be economical for the oil field company to operate at the optimal 60% capture rate, but there is a conflict of interest with the power plant company for which it is more economical to continue at 90% CO_2 capture. This is because the power plant company gets paid a fixed price for the CO_2 and thus has no incentive to lower the capture rate. On the other hand, under the indexed price contract we see that it would be economical for both companies to lower the capture rate to the optimal 60%. This is because in the indexed price contracts, both companies share the oil price risk and have incentives to lower the rate of CO_2 capture and injection at a low oil price. By lowering the CO_2 capture rate to the optimal 60% rate, the power plant company and the oil field company gain $19 million and $27 million respectively and the overall project value is also maximized.

Thus, in a low oil price environment the indexed price contract optimizes the value of the overall integrated project and the fixed price contract would result in a sub-optimal integrated project value. Another thing to note from Figure 6 is that under the indexed price contract terms both companies now have a net positive NPV even at $35/bbl. Thus, the indexed price contracts along with contingent decision-making not only provide incentives to the individual entities to maximize the overall project value, but also minimize the risk of ex-post insolvency and dissatisfaction with the ex-ante negotiated contract terms.

5. Conclusions

In this paper, we evaluate alternate commercial structures for an integrated CCS-EOR project where the source of CO_2 is a coal-fired power plant, and the CO_2 is transported via a dedicated pipeline to an oil field where the CO_2 is injected for EOR. We evaluate alternative contract types that link the involved entities in light of exogenous market risks, such as the fluctuating price of oil recovered. The choice of the contract type determines who would bear the risks along the value chain, and the incentives that the risk allocation produces fixes the total project value. We see that the fixed price contracts have weaknesses in terms of ex-post insolvencies and poor incentive structures that result in a sub-optimal decision-making by the involved entities. The risk-sharing offered by the indexed price contracts reduces the likelihood of ex-post insolvency and provides incentives to each entity to optimize the total project value.

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