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Energy Procedia 37 (2013) 7512 – 7525
Energy Procedia

GHGT-11

Financial Assessment of CO_2 Capture and Storage with Electricity Trading in the U.S.: Role of Interim Storage and Enhanced Oil Recovery

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Abstract

This paper investigates the economic attractiveness of exporting coal-generated electricity from the State of Wyoming to the State of California while investing in large-scale CO_2 capture and sequestration to meet California's strict environmental regulations. The project involves partially capturing CO_2 from coal power plants, storing it temporarily underground using CO_2 Interim Storage, and ultimately using it for Enhanced Oil Recovery. A detailed financial assessment is performed in view of current electricity prices and federal and state regulations in the U.S., especially those related to CCS tax credits. The results show that the project is profitable under current regulations and technical assumptions, and it can be a good opportunity to drive large-scale deployment of CCS, along with the development of EOR activities and the deployment of the newly proposed CO_2 Interim Storage technology.

Selection and/or peer-review under responsibility of GHGT

Keywords: carbon capture and storage, enhanced oil recovery, interim storage, financial analysis, power trading, regulations

1. Introduction

As the United States continues to emit large volumes of CO_2 from power generation facilities, large-scale deployment of CO_2 Capture and Storage (CCS) continues to face serious economic challenges due to relatively high costs, and significant shortages in CO_2 supply continue to hinder further expansion of domestic oil production through Enhanced Oil Recovery (EOR). As proposed by Farhat, CO_2 Interim Storage, or CIS, involves storing CO_2 in subsurface reservoirs for a finite period of time to be

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1876-6102
Selection and/or peer-review under responsibility of GHGT
doi:10.1016/j.egypro.2013.06.695

subsequently withdrawn and utilized in CO_2-EOR and potentially other industrial processes. By bridging the gap between CO_2 supply and demand and buffering any short-term variations in both, CIS adds operational flexibility to CCS projects, which can expand CO_2 utilization in EOR, incentivize the development of CCS infrastructure, and improve CCS economics [1].

Motivated by recent studies investigating electricity importation from the state of Wyoming (WY) to meet the growing power demand in the state of California (CA) [2], this paper analyses the financial viability of an inter-state project that involves shifting coal-based electricity sales from WY to CA while capturing CO_2 from coal power plants, storing is temporarily underground through CIS, and ultimately using it for EOR. The difference in electricity retail price between both states, as well as the seasonal variation in electricity prices in CA, can offset the high cost of CCS and offer significant revenues.

This study presents a comprehensive financial assessment of the proposed project in 2010 monetary figures, based on applicable federal and state regulations in the U.S., and building on earlier technical feasibility case-study by Benson, Brandt, and Farhat [3]. The paper starts by highlighting the major technical aspects of the project. The second section explains the methodology and approach followed to conduct the financial assessment, and it details the relevant regulations considered in the assessment. The third section examines the results and assesses the sensitivity to key economic factors. The concluding section summarizes the key findings and provides insights and future recommendations.

2. Project Scope

2.1. Power Plants and Markets

Although the state of Wyoming has several coal-based power plants, only four are considered in this study; the plants' production capacities and CO_2 emissions profiles are detailed in Appendix A. The four plants (hereby referred to as CPPs) produced 31,000 gigawatt-hours (GWh) of electricity in 2010, equivalent to almost 40% of the total electricity imports to CA. This large market size, in addition to the 50,000 GWh projected growth in Californian power demand over the coming 10 years [4], incentivizes the proposed inter-state electricity trading project. Equally important, the CPPs' net generation is almost equal to WY's overall inter-state power exports, so shifting their electricity supply outside WY could be feasible without leaving a profound impact on the state's power market.

2.2. Power Prices

The major economic driver in this project is the difference in electricity retail price between both states. In 2010, the average retail price in CA was \$147.5/MWh, compared to \$87.7/MWh in Wyoming [5]. Another appealing aspect of the Californian power market is the seasonal variation in electricity prices. For instance, summer retail prices reported by Pacific Gas & Electric (PG&E) – a major Californian utility – in 2010 were, on average, 35% higher than winter prices [6]. This price arbitrage forms another potential revenue stream. Since CO_2 capture consumes a significant portion of the CPPs' energy output, the capture system operations can be manipulated to minimize the energy penalty and thus maximize power sales from the plant during high-price summer season, while still meeting the EPS. At the same time, CIS can be used to store excess CO_2 when the capture system is running, and then continue to sell the CO_2 to EOR fields when the capture system is off.

2.3. CO_2 Capture

An amine-based CO_2 capture system is assumed to be retrofitted to each of the power plants. The capital and operational costs of these systems are calculated using the Integrated Environmental Control Model (IECM) developed by Carnegie Mellon University [7]. In addition, exported electricity from Wyoming needs to meet the current Emissions Performance Standard (EPS) set by California which "establishes a standard for baseload generation owned by, or under long-term contract to, publicly owned utilities of 1,100 lbs CO_2 per megawatt-hour (MWh)" [8]. This necessitates the capture and permanent sequestration of at least 50% of the annual CO_2 emissions if electricity is to be generated from coal.

2.4. CO_2 Transportation

The integrated CO_2 network is optimized to minimize the overall capital and operational costs. In this study, the "network operator" is broadly defined as the single business entity responsible for developing and operating the CO_2 pipelines, the permanent storage site, and the CIS sites. For consistency, capital and operational costs of CO_2 transportation are also calculated using IECM.

2.5. Permanent Storage, CIS, and EOR Sites

Wyoming has a large number of saline aquifers and depleted gas reservoirs which can be used for CO_2 sequestration. In this study, two depleted gas fields are considered for CIS and one large saline aquifer for permanent sequestration. Before putting them in service, each CIS site is filled with a "cushion layer" of CO_2 necessary to ensure proper operations [1]; this is accounted for in this study. Additionally, all four CO_2-EOR fields that are currently operational in the State according to the Oil & Gas Journal [9] are considered in this study. A list of the CIS and CO_2-EOR sites, as well as their respective CO_2 storage capacities, is provided in Appendix A.

3. Methodology and Approach

3.1. Technical Analysis

The economic viability of the project is investigated by designing three basic scenarios:

- Scenario 1: CO_2 capture and permanent sequestration only; no EOR; no CIS
- Scenario 2: CO_2 capture and permanent sequestration; with EOR; no CIS
- Scenario 3: CO_2 capture and permanent sequestration; with EOR; with CIS

In each of the scenarios, three business segments are considered: the four power plants that independently capture the CO_2, the single network operator that builds and operates the integrated CO_2 pipelines and injection facilities (for permanent storage and CIS), and the four EOR sites that purchase CO_2 from the network operator. Two separate NPVs are calculated for each scenario: one for the network operator and one for the four power plants aggregated into one business entity. The NPV of the EOR operators is irrelevant to the economics of this project and thus is not considered in this study. Since the coal power plants' investment in CCS is driven by the imposed EPS regulations, the plants hold the full financial burden of reducing their CO_2 emissions. The network operator, on the other hand, needs to at least break-even for its business to be viable. Therefore, it is assumed that the coal power plants pay the operator a service fee for transporting and sequestering CO_2, enough for the operator to break-even.

3.1.1. Scenario 1: CCS

In this scenario, 50% of the CO_2 produced by the CPPs is continuously captured, compressed, and transported in pipelines to be safely and permanently stored in a saline aquifer; this is equivalent to 14.06 million tons of captured CO_2 per year ($MtCO_2/yr$). No CO_2 is sold for EOR or stored in CIS sites, and the total length of the CO_2 transportation network is about 870 km.

3.1.2. Scenario 2: CCS & EOR

In this scenario, 50% of the CO_2 produced by the CPPs is continuously captured, compressed, and transported in an integrated network of pipelines to be partly stored in the saline aquifer and partly sold to one of the EOR sites in WY; this adds up to 14.06 $MtCO_2/yr$, 2.21 $MtCO_2/yr$ of which are used for EOR. No CO_2 is stored in CIS sites, and the total length of the CO_2 transportation network is about 1150 km.

3.1.3. Scenario 3: CCS, EOR, & CIS

In this scenario, the coal power plants vary their capture rates to benefit from the variation in electricity prices; the CPPs' capture systems are turned off in May-September when electricity prices are high, and then they are turned on to capture 90% of the plants' emissions in October-April when electricity prices are low. This strategy is motivated by the fact that the cost of running the capture unit is high when electricity prices are high, and vice versa. Overall, the plants still comply with EPS; they capture about 53% of their emissions every year, equivalent to 15.21 $MtCO_2/yr$. To buffer the monthly variation in CO_2 supply from coal plants to EOR sites, two CIS sites are utilized. When the capture systems are operating, CO_2 is shipped directly into EOR, CIS for short-term storage, and the saline aquifer for permanent sequestration. When the capture systems are off, the stored CO_2 in CIS is shipped to the EOR fields to ensure their continuous operation, and no CO_2 is permanently sequestered in the aquifer. The total length of the CO_2 transportation network is about 1350 km.

3.2. Financial Analysis

3.2.1. Costs and Revenue Streams

For the network operator, major costs include the capital expenditure (CapEx) and operational expenditure (OpEx) on the CO_2 pipelines (all three scenarios), the CapEx and OpEx of CO_2 injection into the saline aquifer for permanent sequestration (all three scenarios), and the CapEx and OpEx of CIS (Scenario 3 only). The transportation costs are estimated using IECM, whereas the storage costs, both in the aquifer and in the CIS sites, are estimated based on a model developed by McCoy [10]. Revenues for the pipeline operator include payments by EOR companies for the purchased CO_2 and a service fee by the power plants necessary to ensure break-even.

For the CPPs, in all three scenarios, major costs include the CapEx and OpEx of the capture systems, the service fees to the network operator, and the energy penalty associated with running the capture unit. Unrelated to CCS infrastructure, another important cost is associated with the construction of new transmission lines to transport the power from WY to CA. The full cost of new transmission lines is assumed in this study, which is a conservative assumption that doesn't account for potential integration opportunities within the grid. On the other hand, the CPPs enjoy two revenue streams, both associated with the power price arbitrage. The first revenue stream, applicable in all three scenarios, is the difference in retail power price between WY and CA. The second revenue stream, applicable only in Scenario 3, is the savings due to the seasonal operation of the capture systems which avoids their energy penalty (and maximize the CPPs' power sales) when power prices are high.

3.2.2. Net Present Value Calculations

For each of the three scenarios, the Net Present Value (NPV) for the network operator and the CPPs are calculated according to the general assumptions listed below. Since the network operator is assumed to only break-even in this study, the NPV for the CPPs is the actual "overall project NPV".

- All calculations are carried in 2010 USD figures.
- The average electricity retail price in CA is \$147.5/MWh, compared to \$87.7/MWh in Wyoming [5].
- The average seasonal variation in electricity prices in California is 35% [6]
- The price paid by the EOR companies to purchase CO_2 is \$30/t CO_2 [11].
- The cost of power transmission is assumed to be \$1600/MW.mile [12].
- 150% declining balance is applied to all CCS-related capital investments [13].
- 10% discount rate is assumed for both the power plants and the network operator.
- 2% per year inflation factor is applied to all costs and revenues.
- A blended income tax rate of 35% is assumed for both the CPPs and the network operator.
- A useful project lifetime of 20 years is assumed for both the capture system and the integrated network infrastructure, including pipelines and injection equipment. Salvage value is not considered.
- All capital is installed in 2010, and operations are assumed to start in 2011.

3.2.3. Applicable Tax and Credits Regulations

CO_2 tax credit is accounted for in this financial analysis. In all three scenarios, the annual capture rate for each of the four CPPs is above the threshold of 0.5 million tons per year (Mt/yr) specified by §45Q Sequestration Credit of the federal tax code [14]. Thus, the CO_2 tax credit is applied to 14.06 Mt/yr of captured CO_2 in each of scenarios 1 and 2 (based on continuous 50% capture) and 15.21 Mt/yr in Scenario 3 (based on 90% seasonal capture). In addition, according to section 45Q, tax credits for the captured CO_2 "is attributable to the person that captures and physically or contractually ensures the disposal of or the use as a tertiary injectant of the qualified CO_2" [14]. As such, the credit in this case accrues to the CPP operators, who ensure proper disposal of CO_2 by contracting with the network operator. Furthermore, the tax code stipulates a 75 Mt limit on the overall amount of captured CO_2 at each facility that may be claimed for tax credits. This 75 Mt limit does not differentiate between CO_2 claimed for EOR and that claimed for CCS. In 2010, the tax credit allowed was \$20.24/tCO_2 for permanent storage and \$10.12/t CO_2 for EOR. These tax credits are annually adjusted for inflation.

Investment tax credits are applied to the capital expenditures by the coal power plants (on the capture units) but not by the network operator [15]. In accordance with §48A of the federal tax code, a 30% investment tax credit is applied to capital investments on units capable of capturing >65% of the CO_2 emissions, and a 15% investment tax credit is applied to capital investments on units capable of capturing <65% of the CO_2 emissions [16]. In this case, a 15% investment tax credit is applied to the capital expenditure on CO_2 capture units in scenarios 1 and 2, whereas a 30% investment tax credit is applied to the capital expenditure on CO_2 capture units in Scenario 3. The total amount of investment tax credits available for qualifying projects under §48A totals \$2.55 billion, with \$800 million earmarked for Integrated Gasification Combined Cycle (IGCC) projects. This effectively leaves \$1.75 billion available for other projects, including the one under consideration. As no evidence exists to indicate that payouts from this pool have occurred to date, full receipt of eligible investment tax credit is assumed in each of the three scenarios, as base-case. Instances where the full amount of the anticipated investment tax credit is not received are explored in the sensitivity analysis section.

3.3. Sensitivity Analysis

Sensitivity analysis is conducted to assess the dependence of the project economics on three key parameters: the price of CO_2 for EOR, the investment tax credit applicable to CO_2 capture, and the seasonal volatility of electricity retail prices in CA.

The revenues generated from selling CO_2 for EOR affect not only the gross profit of the network operator but also the net cost to the coal power plants through the service fees they pay to ensure the network operator breaks-even. While the amount of CO_2 used for EOR is relatively small compared to that permanently sequestered in the saline aquifer, the price of anthropogenic CO_2 is still highly uncertain, so it would be worthwhile to explore how it affects the overall project economics. The NPV for the three scenarios was calculated for CO_2 price that ranges between 10% and 200% of the assumed price in the base-case, equivalent to $3-60/t$CO_2$.

Also, while investment tax credits are potentially quite valuable, some uncertainty exists about whether the power plants would actually be able to receive the full amount for which they are eligible. Under section 48A of the federal tax code, $1.75 billion in investment tax credit is available for advanced coal projects excluding IGCC. Although no evidence indicates that this amount had already been paid out by 2010, the government does have discretion in choosing how to allocate the scarce tax credits if competing projects exist. Thus, the NPV for each of the three scenarios is calculated for an investment tax credit that ranges between 10% and 200% of the assumed amount in the base-case: 1.5-30% for Scenario 1 and Scenario 2, and 3-60% for Scenario 3.

Finally, the seasonal volatility of Californian retail electricity prices is an important yet very uncertain revenue stream in Scenario 3. On one hand, the technological developments of smart meters and electric storage can drive this price variation down. On the other hand, meeting the aggressive Californian RPS requires a rapid expansion of intermittent renewable power generation, which could increase this seasonal price variation significantly. To cover the wide range of possibilities, the NPV for this Scenario is calculated for a seasonal variation in electricity retail price that ranges between 10% and 200%; 20%, 100%, and 150% price arbitrages imply that the electricity price in the summer is 1.2, 2, and 2.5 times that in winter, respectively. In all scenarios, yearly average electricity retail price is maintained at $147.5/MWh.

4. Results and Discussion

The NPV calculations show that, under the given assumptions, investing in CCS for inter-state power trading between WY and CA is a profitable business where all scenarios show favorable economics. The cumulative depreciated cash flow for the three scenarios is plotted in Figure 1 below. An illustration of the NPV calculations for each of the three investigated scenarios is presented in Appendix B.

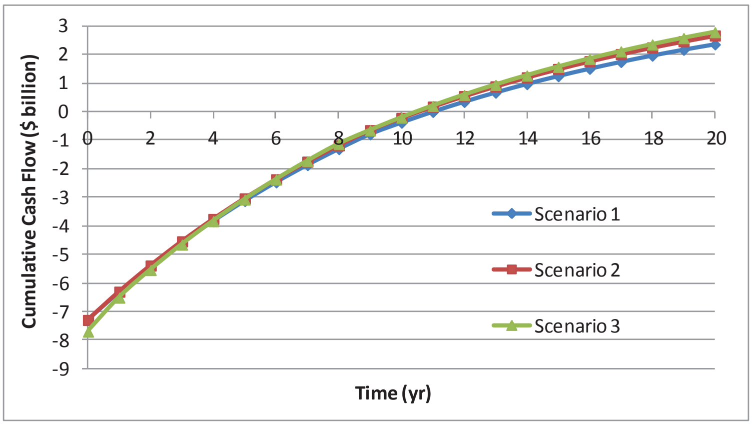

Fig. 1. Cumulative cash flow for the three investigated scenarios

4.1. Scenario 1: CCS

In this Scenario, the financial analysis shows a positive NPV of $2.358 billion with an Internal Rate of Return (IRR) of 14.17% and a payback period of 11 years. As expected, the major project expenses are associated with the high CapEx of the CO_2 capture units at $1.873 billion and with the power transmission infrastructure at $5.7 billion. This is accompanied by high OpEx, associated with the energy penalty of running the capture units, the operation and maintenance (O&M) cost of the capture units, and the service payments for the CO_2 pipeline operator, at $266 million, $130 million, and $102.7 million, respectively, in first year of operations (adjusted for inflation throughout the project lifetime). In the absence of any other source of revenue, the CO_2 network operator receives a payment of $7.16 per tCO_2 from the CPPs, necessary to break-even. These high expenses are compensated primarily by the annual revenue generated from the difference in the electricity retail price between both states, equivalent to $1.62 billion in the first year of operations. In addition, in line with section 48A of the federal tax code, the 15% investment tax credit applied in this scenario is approximately $281 million.

Assessing the economics of the CCS activities without accounting for inter-state electricity trading shows that in order for the CCS project to break-even, the government would need to raise the amount of the tax credit. Keeping current regulatory practices in place (75 Mt limit, and power plant emissions threshold), the CO_2 tax credit must be raised to approximately $39.9 per ton of captured and permanently sequestered CO_2; this is a 97% increase over the currently offered tax credit. Finally, it is worth mentioning that due to the large amount of CO_2 captured, the Jim Bridger plant reaches the 75 Mt ceiling on CO_2 credits in the 10th year of operation. As a result, total CO_2 eligible for CCS and EOR tax credits under section 45Q drops significantly from 14.06 Mt to 6.31 Mt beyond the 10^{th} year of operation.

4.2. Scenario 2: CCS & EOR

In this Scenario, the use of CO_2 for EOR seems to enhance the project economics. The financial analysis shows a positive NPV of $2.668 billion, which is about 13.15% higher than NPV in Scenario 1, with an IRR of 14.64% and a payback period of 10 years. Similar to Scenario 1, the major project expenses are associated with the high CapEx of the CO_2 capture units and the power transmission infrastructure, as well as the OpEx associated with the energy penalty and the O&M cost of running the capture units. In this case, however, the revenue stream from selling CO_2 for EOR reduces the service fees paid by the CPPs to allow the network operator to break-even; the network operator receives a payment of $2.6 per t CO_2 from the CPPs, which is about one-third the amount in Scenario 1. In addition, while the annual revenues from power trading and investment tax credit remain the same, the saved CO_2 tax credit decreases from $290 million in Scenario 1 to $267.4 million in Scenario 2; this drop is due to the lower tax credit rate for using CO_2 in EOR ($10.12/$tCO_2$) instead of permanent storage ($20.24/$tCO_2$). For example, of the total 14.06 Mt CO_2 eligible for tax credits in the first year, 11.84 Mt are allocated credits for permanent storage and 2.22 Mt are allocated credit for EOR.

Also similar to Scenario 1, assessing the economics of the CCS activities without accounting for inter-state electricity trading shows that in order for the project to break-even, the government would need to raise the amount of the tax credit. Keeping current regulatory practices in place (75Mt limit, and power plant emissions threshold), the CO_2 tax credit must be raised to approximately $39.5 per ton of captured and permanently sequestered CO_2; this is a 95.3% increase over the currently offered tax credit.

4.3. Scenario 3: CCC, EOR, & CIS

In this Scenario, the implementation of CIS, in addition to EOR, seems to achieve marginal economic gains. The financial analysis shows a positive NPV of $2.785 billion, which is about 18.1% higher than NPV in Scenario 1 but only 4.4% higher than NPV in Scenario 2. The project IRR is 14.55%, and the payback period is 10 years. The IRR in this case is lower than that in Scenario 2 due to the higher CapEx and OpEx of the CO_2 capture units at $2.85 billion and $173 million in the first year of operation, respectively. This higher expenditure is partially compensated by the additional savings from the seasonal variation in electricity prices, which maintains the project's IRR in this Scenario higher than that obtained in Scenario 1. Similarly, the service fee paid by the CPPs to the network operator in this Scenario is \$5.47/tCO_2; this is lower than the fee in Scenario 1 due to the additional revenue stream from selling CO_2 for EOR, but it is higher than the fee in Scenario 2 due to the additional expenditure on the CIS infrastructure. In addition, while the annual revenues from power trading remain the same, the investment tax credit set at 30% in this Scenario is higher than that in scenarios 1 and 2, equivalent to $856.6 million.

The economics of the CCS activities in the absence of inter-state power trading shows that a tax credit of \$41.5 per ton of captured and permanently sequestered CO_2 would be needed in order for the project to break-even; this is more than double the tax credit offered by the federal tax code. Despite the larger investment tax credit, the CO_2 tax credit necessary for break-even in this scenario is higher than that in the previous two scenarios due to three important factors: the higher CapEx and OpEx of the larger CO_2 capture units, the additional expenditure on the CIS infrastructure, and the inability to benefit from the potential additional savings due to the seasonal variation in electricity prices (only valid when inter-state power trading takes place).

4.4. Sensitivity Analysis

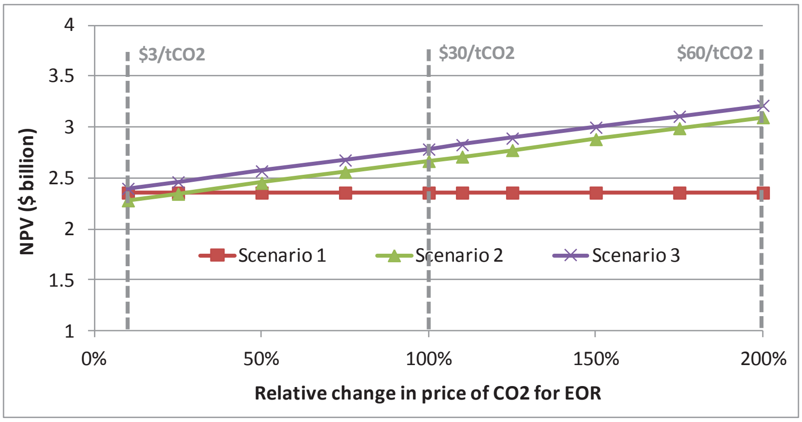

Fig. 2. Effect of price of CO_2 for EOR on project NPV

Figure 2 shows a direct linear relationship between the price of CO_2 for EOR and the Net Present Value of the investigated project across scenarios 2 and 3; Scenario 1 remained unchanged because enhanced oil recovery is not a revenue stream under this scenario. In both scenarios 1 and 2, decreasing the CO_2 price by 90% (down to 3\$/tCO_2) reduces the project NPV by 13.8%, whereas doubling the CO_2 price (up to 60\$/tCO_2) increases the project NPV by 15.4%. Alternatively, the relationship indicates that a \$1 increase in price paid by oil companies per tCO_2 equates to a \$14.3 million increase in the project

NPV, which is equivalent to about 0.51-0.53% of the overall NPV. As such, the price of CO_2 for EOR turns out to be a relatively weak factor in influencing the project economic attractiveness.

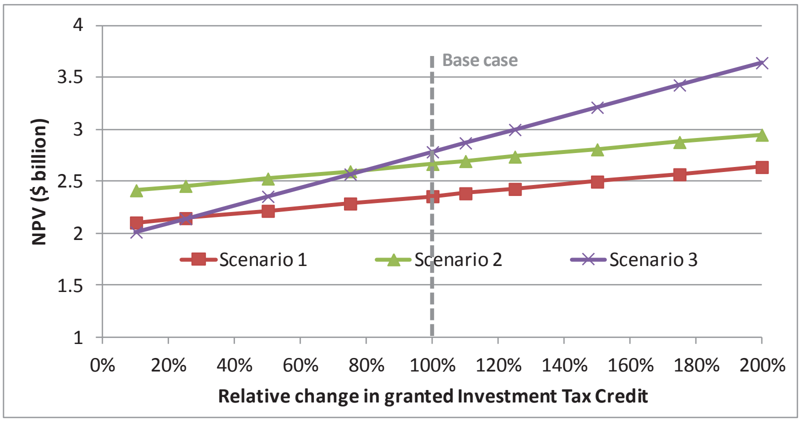

Fig. 3. Effect of investment tax credit on project NPV

Figure 3 shows that Scenario 3 is the most sensitive to investment tax credits because of the larger tax burden relief it receives as a function of increased investment. The results show that implementing CIS along with EOR and CCS is the most profitable scenario as long as the project receives at least 80% of the investment tax credit it's eligible for. If the project receives less than 80% of the investment tax it anticipates, investing in CIS loses its economic advantage, and CCS with EOR only becomes the most attractive option. Conversely, as scenarios 1 and 2 receive a smaller investment tax credit (15%) on a smaller capital expenditure, they are markedly less sensitive to changes in investment tax credit. This analysis indicates that should there exist an uncertainty around the receipt of investment tax credits, Scenarios 1 and 2 yield less risk than Scenario 3 even though higher savings can be achieved in the latter.

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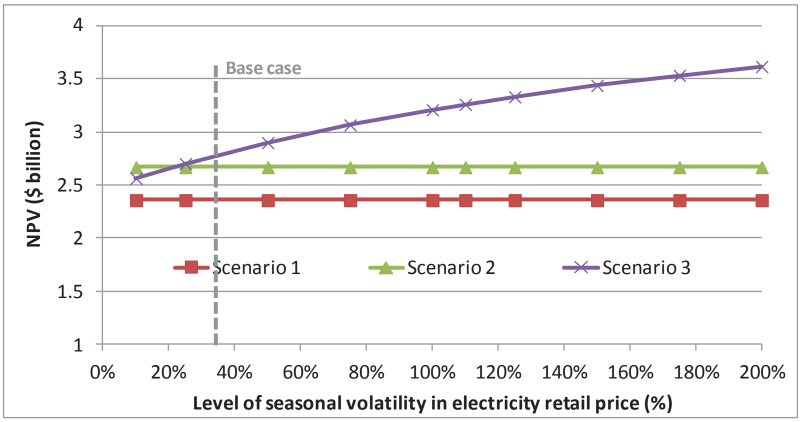

Fig. 4. Effect of seasonal volatility in CA electricity retail price on project NPV

Finally, taking advantage of the seasonal variation in electricity prices in California through the implementation of CIS seems to have a significant impact on the project economics, as depicted in Figure 4. Clearly, the economics of scenarios 1 and 2 are not affected by the extent of volatility in retail prices in the absence of the CIS technology to allow variable CO_2 capture rates. In Scenario 3, however, a seasonal price variation higher than 25% is sufficient to make CIS economically attractive and to incentivize its deployment with CCS and EOR. Interestingly, the effect of the price volatility on the project NPV seems to flatten progressively where it appears to be most significant at relatively low price variation rates; as the price variation increases, the incremental financial benefit decreases.

5. Conclusion

In conclusion, inter-state electricity trading in the U.S. seems to present a promising business opportunity that can drive large-scale deployment of CCS, along with the expansion of EOR activities and the deployment of the newly proposed CO_2 Interim Storage technology. Under current regulatory and financial assumptions, electricity importation from Wyoming to California is most profitable with the development of CCS, EOR, and CIS. While CCS allows meeting the required Californian Emissions Performance Standard through partial capture and permanent sequestration of CO_2 emissions, selling CO_2 for EOR generates additional revenue for the project. In addition, CO_2 Interim Storage allows flexible operation of the capture system to minimize energy penalty and maximize power sales when electricity retail prices are high. As such, the financial assessment carried in this study shows that implementing this project with CCS, EOR, and CIS is most profitable with a positive NPV of $2.784 billion; the NPV decreases to $2.668 billion without CIS, and even lower to $2.358 billion without EOR. In that regard, sensitivity analysis shows that CIS is an attractive investment, so long as the assumed seasonal volatility in the Californian retail electricity prices is above 25% and the project is guaranteed to receive at least 80% of the investment tax credits it qualifies for.

This project reflects the importance of finding a financially viable option to invest in large-scale CCS in the absence of a national price on CO_2. Alternatively, should the government wish to make CCS projects – similar to this one – financially viable, it has several different tools at hand. First, it could stick to the current regulatory methods while increasing the CO_2 injection tax credits. CCS credits on the order of $39.5-41.5/t$CO_2$ would be necessary for the project to break-even. Second, it could relax the yearly 0.5Mt CO_2 capture requirement threshold, which currently excludes CO_2 emissions coming from the small plants from receiving tax credits. Third, along similar lines, the government could relax the 75 Mt limit on the amount of CO_2 tax credits that may be claimed from a single facility. Fourth, a more aggressive depreciation schedule, such as the one used for solar projects, could be used. The fifth alternative, the introduction of a national carbon tax or cap-and-trade system, would perhaps be the most appealing; such approach results in avoided costs for the coal plants using carbon capture, and it has the benefit of letting the market decide the most efficient method of reducing carbon dioxide emissions.

Acknowledgement

The authors would like to thank Professor Sally M. Benson from the Department of Energy Resources Engineering at Stanford University, and Professors Stefan J Reichelstein and Dan Reicher from the Graduate School of Business at Stanford University, for their guidance and advice throughout this project. The authors would also like to thank the Department of Energy Resources Engineering and the Two Elk Energy Park: Integrated Clean Energy Solutions Fund at Stanford University for funding this work.

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Appendix A. Inventory of CPPs, CIS sites, and EOR sites

Table A1. List of power plants, their capacity, and annual CO_2 emissions

Power Plant	Capacity (MW)	CO_2 Emissions ($MtCO_2$/yr)
Wyodak	362	2.451
Dave Johnston	816	5.523
Jim Bridger	2311	15.641
Naughton	707	4.78

Table A2. List of EOR sites

Operator	Field	Location	CO_2 consumption for EOR (MtCO2/yr)
Anadarko	Patrick Draw Monell	Sweetwater	0.3285
Anadarko	Salt Creek	Natrona	0.657
Merit Energy	Lost Soldier	Sweetwater	0.7907
Merit Energy	Wertz	Carbon - Sweetwater	0.44008

Table A2. List of CO_2 Interim Storage sites

CIS site	Storage capacity (Mt CO_2)
Big Hand	8.21
Greive	5.79

Appendix B. CO_2 Pipeline Network Maps

B.1. Scenario 1: CCS

Assumptions	Amount	Unit
Tax Rate	35%	
Inflation factor 04-10	1.17	
Inflation factor 07-10	1.07	
Inflation factor, 02-10	1.21	
Discount rate	10%	
Inflation Rate	2%	
Useful Life	20	years
Yearly Depreciation	5%	
Service Fees (CPP to Pipeline)	7.166230921	$/tCO2
Investment Tax Credit	15%	
CO2 Tax Credit	20.24	$/tCO2 captured
Electricity Price Volatility	0.35	
Low Retail Price (Winter)	12.87	$cent/kWh
High Retail Price (Summer)	17.37818182	$cent/kWh
Yearly Average Price	14.75	$cent/kWh

150% Declining Balance		7.5%	6.9%	6.4%	5.9%	5.5%	5.1%	4.7%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
PIPELINE OPERATOR																					
	year 0	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20
Necessary Revenues (Cash Inflow)		102,776,006	104,831,526	106,928,156	109,066,719	111,248,054	113,473,015	115,742,475	118,057,325	120,418,471	122,826,841	125,283,377	127,789,045	130,344,826	132,951,722	135,610,757	138,322,972	141,089,431	143,911,220	146,789,444	149,725,233
Costs																					
Pipeline CapEx	(334,491,057)																				
Pipeline OpEx		(2,276,449)	(2,321,978)	(2,368,417)	(2,415,786)	(2,464,102)	(2,513,384)	(2,563,651)	(2,614,924)	(2,667,223)	(2,720,567)	(2,774,979)	(2,830,478)	(2,887,088)	(2,944,829)	(3,003,726)	(3,063,801)	(3,125,077)	(3,187,578)	(3,251,330)	(3,316,356)
Injection CapEx	(82,253,925)																				
Injection OpEx		(45,349,200)	(46,256,184)	(47,181,308)	(48,124,934)	(49,087,433)	(50,069,181)	(51,070,565)	(52,091,976)	(53,133,816)	(54,196,492)	(55,280,422)	(56,386,030)	(57,513,751)	(58,664,026)	(59,837,306)	(61,034,052)	(62,254,733)	(63,499,828)	(64,769,825)	(66,065,221)
Cash Inflow Before Tax	(416,744,982)	55,150,357	56,253,364	57,378,431	58,526,000	59,696,520	60,890,450	62,108,259	63,350,424	64,617,433	65,909,782	67,227,977	68,572,537	69,943,987	71,342,867	72,769,725	74,225,119	75,709,621	77,223,814	78,768,290	80,343,656
Tax	-	(19,302,625)	(19,688,677)	(20,082,451)	(20,484,100)	(20,893,782)	(21,311,658)	(21,737,891)	(22,172,649)	(22,616,101)	(23,068,424)	(23,529,792)	(24,000,388)	(24,480,396)	(24,970,004)	(25,469,404)	(25,978,792)	(26,498,367)	(27,028,335)	(27,568,902)	(28,120,280)
Depreciation Tax Shield		10,939,556	10,119,089	9,360,157	8,658,146	8,008,785	7,408,126	6,852,516	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105	6,501,105
Net Tax	-	(8,363,069)	(9,569,588)	(10,722,293)	(11,825,954)	(12,884,997)	(13,903,532)	(14,885,374)	(15,671,543)	(16,114,996)	(16,567,318)	(17,028,687)	(17,499,283)	(17,979,290)	(18,468,898)	(18,968,298)	(19,477,686)	(19,997,262)	(20,527,230)	(21,067,796)	(21,619,174)
Cash Flow	(416,744,982)	46,787,288	46,683,776	46,656,138	46,700,045	46,811,523	46,986,918	47,222,885	47,678,881	48,502,437	49,342,463	50,199,290	51,073,254	51,964,697	52,873,969	53,801,426	54,747,433	55,712,359	56,696,584	57,700,494	58,724,482
NPV (should be 0)	($0.00)																				

COAL POWER PLANTS																					
	-	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	year 0	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20
Costs																					
CCS Unit CapEx	(1,873,400,000)																				
Transmission Capex	(5,700,000,000)																				
CCS Unit O&M Fixed		(51,929,220)	(52,967,804)	(54,027,160)	(55,107,704)	(56,209,858)	(57,334,055)	(58,480,736)	(59,650,351)	(60,843,358)	(62,060,225)	(63,301,429)	(64,567,458)	(65,858,807)	(67,175,983)	(68,519,503)	(69,889,893)	(71,287,691)	(72,713,445)	(74,167,714)	(75,651,068)
CCS Unit O&M Variable		(78,067,740)	(79,629,095)	(81,221,677)	(82,846,110)	(84,503,032)	(86,193,093)	(87,916,955)	(89,675,294)	(91,468,800)	(93,298,176)	(95,164,139)	(97,067,422)	(99,008,771)	(100,988,946)	(103,008,725)	(105,068,900)	(107,170,278)	(109,313,683)	(111,499,957)	(113,729,956)
Payment to Pipeline		(102,776,006)	(104,831,526)	(106,928,156)	(109,066,719)	(111,248,054)	(113,473,015)	(115,742,475)	(118,057,325)	(120,418,471)	(122,826,841)	(125,283,377)	(127,789,045)	(130,344,826)	(132,951,722)	(135,610,757)	(138,322,972)	(141,089,431)	(143,911,220)	(146,789,444)	(149,725,233)
Energy pernalty		(266,140,024)	(271,462,824)	(276,892,081)	(282,429,922)	(288,078,521)	(293,840,091)	(299,716,893)	(305,711,231)	(311,825,456)	(318,061,965)	(324,423,204)	(330,911,668)	(337,529,901)	(344,280,499)	(351,166,109)	(358,189,432)	(365,353,220)	(372,660,285)	(380,113,490)	(387,715,760)
Revenue		1,619,076,409	1,651,457,937	1,684,487,096	1,718,176,838	1,752,540,374	1,787,591,182	1,823,343,005	1,859,809,866	1,897,006,063	1,934,946,184	1,973,645,108	2,013,118,010	2,053,380,370	2,094,447,978	2,136,336,937	2,179,063,676	2,222,644,949	2,267,097,848	2,312,439,805	2,358,688,601
Cash Flow Before Tax	(7,573,400,000)	1,120,163,419	1,142,566,688	1,165,418,021	1,188,726,382	1,212,500,910	1,236,750,928	1,261,485,946	1,286,715,665	1,312,449,978	1,338,698,978	1,365,472,958	1,392,782,417	1,420,638,065	1,449,050,826	1,478,031,843	1,507,592,480	1,537,744,329	1,568,499,216	1,599,869,200	1,631,866,584
Tax	-	(392,057,197)	(399,898,341)	(407,896,308)	(416,054,234)	(424,375,318)	(432,862,825)	(441,520,081)	(450,350,483)	(459,357,492)	(468,544,642)	(477,915,535)	(487,473,846)	(497,223,323)	(507,167,789)	(517,311,145)	(527,657,368)	(538,210,515)	(548,974,726)	(559,954,220)	(571,153,305)
Depreciation Tax Shield		49,176,750	45,488,494	42,076,857	38,921,092	36,002,011	33,301,860	30,804,220	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517
Investment Tax Credit	281,010,000																				
CO2 Injection Tax Credits		290,276,210	296,081,735	302,003,369	308,043,437	314,204,305	320,488,392	326,898,159	333,436,123	340,104,845	155,818,839	158,935,216	162,113,921	165,356,199	168,663,323	172,036,589	175,477,321	178,986,868	182,566,605	186,217,937	189,942,296
Net Tax	281,010,000	(52,604,236)	(58,328,112)	(63,816,081)	(69,089,705)	(74,169,002)	(79,072,573)	(83,817,702)	(87,689,844)	(90,028,131)	(283,501,286)	(289,755,802)	(296,135,409)	(302,642,607)	(309,279,950)	(316,050,039)	(322,955,530)	(329,999,131)	(337,183,604)	(344,511,766)	(351,986,492)
Cash Flow After Tax	(7,292,390,000)	1,067,559,183	1,084,238,575	1,101,601,940	1,119,636,677	1,138,331,907	1,157,678,354	1,177,668,245	1,199,025,822	1,222,421,848	1,055,197,692	1,075,717,155	1,096,647,008	1,117,995,458	1,139,770,877	1,161,981,804	1,184,636,950	1,207,745,198	1,231,315,612	1,255,357,434	1,279,880,092
Depreciated Cash Flow	(7,292,390,000)	970,508,348	896,064,938	827,649,842	764,726,916	706,814,554	653,479,250	604,330,020	559,354,395	518,426,194	406,824,389	377,032,301	349,425,533	323,843,461	300,137,295	278,169,205	257,811,516	238,945,949	221,462,936	205,260,972	190,246,020
Cumulative Depreciated Cash Flow	(7,292,390,000)	(6,321,881,652)	(5,425,816,714)	(4,598,166,871)	(3,833,439,956)	(3,126,625,402)	(2,473,146,151)	(1,868,816,131)	(1,309,461,736)	(791,035,542)	(384,211,153)	(7,178,852)	342,246,681	666,090,141	966,227,436	1,244,396,641	1,502,208,157	1,741,154,106	1,962,617,042	2,167,878,014	2,358,124,034
NPV	$2,358,124,034																				

	October	November	December	January	February	March	April	May	June	July	August	September
Electricity Price WY (cent/kWh)	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77
Elecricity Price CA (cent/kWh)	13	13	13	13	13	13	13	17	17	17	17	17
Energy Penalty (MW)	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30
Capacity Factor	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Days per month	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499
Lost-Revenue (MWh)	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057
Lost-Revenue (kWh)	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057
Lost-Revenue ($)	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466
Net Energy Generation (MW)	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563
Capacity Factor	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Days per month	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499
Added-Revenue (MWh)	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998
Added-Revenue (kWh)	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066
Added-Revenue ($)	90,752,247.95	90,752,247.95	90,752,247.95	90,752,247.95	90,752,247.95	90,752,247.95	90,752,247.95	190,412,815.38	190,412,815.38	190,412,815.38	190,412,815.38	190,412,815.38
TOTAL lost-revenue ($/yr)	$260,921,591.95											
TOTAL added-revenue ($/yr)	1,587,329,812.51											

B.2. Scenario 2: CCS & EOR

Assumptions	Amount	Unit
Combined Income Tax Rate	35%	
Inflation factor 04-10	1.17	
Inflation factor 07-10	1.07	
Inflation factor, 02-10	1.21	
Discount rate	10%	
Inflation Rate	2%	
Useful Life	20	years
Yearly Depreciation	5%	
Service Fees (CPP to Pipeline)	2.607315475	$/tCO2
Investment Tax Credit	15%	
CO2 Injection Tax Credit	20.24	$/tCO2 injected
CO2 EOR Injection Tax Credit	10.12	$/tCO2 injected for EOR
CO2 Price for EOR	30	
Electricity Price Volatility	0.35	
Low Retail Price (Winter)	12.87	$cent/kWh
High Retail Price (Summer)	17.37818182	$cent/kWh
Yearly Average Price	14.75	$cent/kWh

	year 0	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20
150% Declining Balance		7.5%	6.9%	6.4%	5.9%	5.5%	5.1%	4.7%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
PIPELINE OPERATOR																					
Necessary Revenues (Cash Inflow)																					
Payments from Power Plant		31,499,250	32,129,235	32,771,820	33,427,257	34,095,802	34,777,718	35,473,272	36,182,738	36,906,392	37,644,520	38,397,411	39,165,359	39,948,666	40,747,639	41,562,592	42,393,844	43,241,721	44,106,555	44,988,686	45,888,460
Revenues from Selling CO2		67,818,168	69,174,531	70,558,022	71,969,182	73,408,566	74,876,737	76,374,272	77,901,758	79,459,793	81,048,989	82,669,968	84,323,368	86,009,835	87,730,032	89,484,632	91,274,325	93,099,812	94,961,808	96,861,044	98,798,265
Total Revenues	-	99,317,418	101,303,767	103,329,842	105,396,439	107,504,368	109,654,455	111,847,544	114,084,495	116,366,185	118,693,509	121,067,379	123,488,726	125,958,501	128,477,671	131,047,224	133,668,169	136,341,532	139,068,363	141,849,730	144,686,725
Costs																					
Pipeline CapEx	(372,692,615)																				
Pipeline OpEx		(2,638,589)	(2,691,360)	(2,745,187)	(2,800,091)	(2,856,093)	(2,913,215)	(2,971,479)	(3,030,909)	(3,091,527)	(3,153,358)	(3,216,425)	(3,280,753)	(3,346,368)	(3,413,296)	(3,481,562)	(3,551,193)	(3,622,217)	(3,694,661)	(3,768,554)	(3,843,925)
Injection CapEx	(69,288,687)																				
Injection OpEx		(38,188,800)	(38,952,576)	(39,731,628)	(40,526,260)	(41,336,785)	(42,163,521)	(43,006,791)	(43,866,927)	(44,744,266)	(45,639,151)	(46,551,934)	(47,482,973)	(48,432,632)	(49,401,285)	(50,389,311)	(51,397,097)	(52,425,039)	(53,473,540)	(54,543,010)	(55,633,871)
Cash Inflow Before Tax	(441,981,302)	58,490,030	59,659,831	60,853,027	62,070,088	63,311,489	64,577,719	65,869,274	67,186,659	68,530,392	69,901,000	71,299,020	72,725,001	74,179,501	75,663,091	77,176,352	78,719,879	80,294,277	81,900,163	83,538,166	85,208,929
Tax	-	(20,471,510)	(20,880,941)	(21,298,560)	(21,724,531)	(22,159,021)	(22,602,202)	(23,054,246)	(23,515,331)	(23,985,637)	(24,465,350)	(24,954,657)	(25,453,750)	(25,962,825)	(26,482,082)	(27,011,723)	(27,551,958)	(28,102,997)	(28,665,057)	(29,238,358)	(29,823,125)
Depreciation Tax Shield		11,602,009	10,731,858	9,926,969	9,182,446	8,493,763	7,856,731	7,267,476	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785	6,894,785
Net Tax	-	(8,869,501)	(10,149,082)	(11,371,590)	(12,542,084)	(13,665,258)	(14,745,471)	(15,786,770)	(16,620,546)	(17,090,852)	(17,570,565)	(18,059,872)	(18,558,965)	(19,068,040)	(19,587,297)	(20,116,938)	(20,657,173)	(21,208,212)	(21,770,272)	(22,343,573)	(22,928,340)
Cash Flow After Tax	(441,981,302)	49,620,529	49,510,748	49,481,437	49,528,003	49,646,231	49,832,248	50,082,504	50,566,113	51,439,540	52,330,435	53,239,148	54,166,035	55,111,460	56,075,794	57,059,414	58,062,706	59,086,065	60,129,890	61,194,593	62,280,589
NPV (should be 0)	$0.00																				

COAL POWER PLANTS	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	year 0	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20
Costs																					
CCS Unit CapEx	(1,873,400,000)																				
Transmission CapEx	(5,700,000,000)																				
CCS Unit O&M Fixed		(51,929,220)	(52,967,804)	(54,027,160)	(55,107,704)	(56,209,858)	(57,334,055)	(58,480,736)	(59,650,351)	(60,843,358)	(62,060,225)	(63,301,429)	(64,567,458)	(65,858,807)	(67,175,983)	(68,519,503)	(69,889,893)	(71,287,691)	(72,713,445)	(74,167,714)	(75,651,068)
CCS Unit O&M Variable		(78,067,740)	(79,629,095)	(81,221,677)	(82,846,110)	(84,503,032)	(86,193,093)	(87,916,955)	(89,675,294)	(91,468,800)	(93,298,176)	(95,164,139)	(97,067,422)	(99,008,771)	(100,988,946)	(103,008,725)	(105,068,900)	(107,170,278)	(109,313,683)	(111,499,957)	(113,729,956)
Payment to Pipeline		(31,499,250)	(32,129,235)	(32,771,820)	(33,427,257)	(34,095,802)	(34,777,718)	(35,473,272)	(36,182,738)	(36,906,392)	(37,644,520)	(38,397,411)	(39,165,359)	(39,948,666)	(40,747,639)	(41,562,592)	(42,393,844)	(43,241,721)	(44,106,555)	(44,988,686)	(45,888,460)
Energy Penalty		(266,140,024)	(271,462,824)	(276,892,081)	(282,429,922)	(288,078,521)	(293,840,091)	(299,716,893)	(305,711,231)	(311,825,456)	(318,061,965)	(324,423,204)	(330,911,668)	(337,529,901)	(344,280,499)	(351,166,109)	(358,189,432)	(365,353,220)	(372,660,285)	(380,113,490)	(387,715,760)
Revenue		1,619,076,409	1,651,457,937	1,684,487,096	1,718,176,838	1,752,540,374	1,787,591,182	1,823,343,005	1,859,809,866	1,897,006,063	1,934,946,184	1,973,645,108	2,013,118,010	2,053,380,370	2,094,447,978	2,136,336,937	2,179,063,676	2,222,644,949	2,267,097,848	2,312,439,805	2,358,688,601
Cash Flow Before Tax	(7,573,400,000)	1,191,440,175	1,215,268,978	1,239,574,358	1,264,365,845	1,289,653,162	1,315,446,225	1,341,755,149	1,368,590,252	1,395,962,057	1,423,881,299	1,452,358,924	1,481,406,103	1,511,034,225	1,541,254,910	1,572,080,008	1,603,521,608	1,635,592,040	1,668,303,881	1,701,669,958	1,735,703,358
Tax	-	(417,004,061)	(425,344,142)	(433,851,025)	(442,528,046)	(451,378,607)	(460,406,179)	(469,614,302)	(479,006,588)	(488,586,720)	(498,358,454)	(508,325,624)	(518,492,136)	(528,861,979)	(539,439,218)	(550,228,003)	(561,232,563)	(572,457,214)	(583,906,358)	(595,584,485)	(607,496,175)
Depreciation Tax Shield		49,176,750	45,488,494	42,076,857	38,921,092	36,002,011	33,301,860	30,804,220	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517	29,224,517
Investment Tax Credit	281,010,000																				
CO2 Injection Tax Credits		244,521,553	249,411,984	254,400,224	259,488,228	264,677,993	269,971,553	275,370,984	280,878,403	286,495,971	155,818,839	158,935,216	162,113,921	165,356,199	168,663,323	172,036,589	175,477,321	178,986,868	182,566,605	186,217,937	189,942,296
CO2 EOR Tax Credits		22,877,329	23,334,875	23,801,573	24,277,604	24,763,156	25,258,419	25,763,588	26,278,860	26,804,437	-	-	-	-	-	-	-	-	-	-	-
Net Tax	281,010,000	(100,428,429)	(107,108,789)	(113,572,372)	(119,841,121)	(125,935,447)	(131,874,347)	(137,675,510)	(142,624,809)	(146,061,795)	(313,315,098)	(320,165,891)	(327,153,699)	(334,281,263)	(341,551,379)	(348,966,897)	(356,530,725)	(364,245,830)	(372,115,237)	(380,142,032)	(388,329,363)
Cash Flow After Tax	(7,292,390,000)	1,091,011,745	1,108,160,189	1,126,001,986	1,144,524,724	1,163,717,715	1,183,571,878	1,204,079,639	1,225,965,444	1,249,900,262	1,110,566,200	1,132,193,034	1,154,252,404	1,176,752,962	1,199,703,531	1,223,113,111	1,246,990,883	1,271,346,210	1,296,188,644	1,321,527,927	1,347,373,995
Depreciated Cash Flow	(7,292,390,000)	991,828,859	915,834,867	845,981,958	781,725,786	722,577,143	668,095,469	617,883,242	571,921,927	530,079,724	428,171,346	396,826,751	367,780,387	340,863,417	315,919,436	292,803,554	271,381,548	251,529,070	233,130,921	216,080,376	200,278,559
Cumulative Depreciated Cash Flow	(7,292,390,000)	(6,300,561,141)	(5,384,726,274)	(4,538,744,316)	(3,757,018,530)	(3,034,441,387)	(2,366,345,917)	(1,748,462,676)	(1,176,540,748)	(646,461,024)	(218,289,678)	178,537,074	546,317,461	887,180,878	1,203,100,313	1,495,903,867	1,767,285,416	2,018,814,486	2,251,945,407	2,468,025,783	2,668,304,342
NPV	$2,668,304,342																				

	October	November	December	January	February	March	April	May	June	July	August	September
Electricity Price WY (cent/kWh)	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77
Elecricity Price CA (cent/kWh)	13	13	13	13	13	13	13	17	17	17	17	17
Energy Penalty (MW)	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30	399.30
Capacity Factor	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Days per month	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499
Lost-Revenue (MWh)	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057	247930.057
Lost-Revenue (kWh)	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057	247930057
Lost-Revenue ($)	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466	21743466
Net Energy Generation (MW)	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563
Capacity Factor	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Days per month	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499
Added-Revenue (MWh)	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998	2,211,998
Added-Revenue (kWh)	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066	2,211,998,066
Added-Revenue ($)	90,752,247.95	90,752,247.95	90,752,247.95	90,752,247.95	90,752,247.95	90,752,247.95	90,752,247.95	190,412,815.38	190,412,815.38	190,412,815.38	190,412,815.38	190,412,815.38
TOTAL lost-revenue ($/yr)	$260,921,591.95											
TOTAL added-revenue ($/yr)	1,587,329,812.51											

B.3. Scenario 2: CCS, EOR & CIS

Assumptions	Amount	Unit
Tax Rate	35%	
Inflation factor 04-10	1.17	
Inflation factor 07-10	1.07	
Inflation factor, 02-10	1.21	
Discount rate	10%	
Inflation Rate	2%	
Useful Life	20	years
Yearly Depreciation	5%	
Service Fees (CPP to Pipeline)	5.473432896	$/tCO2
Investment Tax Credit	30%	
CO2 Injection Tax Credit	20.24	$/tCO2 injected
CO2 EOR Injection Tax Credit	10.12	$/tCO2 injected for EOR
CO2 Price for EOR	30	
Electricity Price Volatility	0.35	
Low Retail Price (Winter)	12.87	$cent/kWh
High Retail Price (Summer)	17.37818182	$cent/kWh
Yearly Average Price	14.75	$cent/kWh

150% Declining Balance		7.5%	6.9%	6.4%	5.9%	5.5%	5.1%	4.7%	4.5%	4.5%	4.5%
PIPELINE OPERATOR											
	year 0	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
Necessary Revenues (Cash Inflow)											
Payment from Power Plant		84,922,590	72,948,575	74,407,547	75,895,698	77,413,612	78,961,884	80,541,122	82,151,944	83,794,983	85,470,883
Revenues from Selling CO2		67,818,168	69,174,531	70,558,022	71,969,182	73,408,566	74,876,737	76,374,272	77,901,758	79,459,793	81,048,989
Total Revenues	-	152,740,758	142,123,107	144,965,569	147,864,880	150,822,178	153,838,621	156,915,394	160,053,702	163,254,776	166,519,871
Costs											
Pipeline CapEx	(609,447,018)										
Pipeline OpEx		(3,805,939)	(3,882,058)	(3,959,699)	(4,038,893)	(4,119,671)	(4,202,064)	(4,286,105)	(4,371,828)	(4,459,264)	(4,548,449)
CIS CapEx	(27,612,000)	(7,160,400)									
CIS OpEx		(954,720)	(973,814)	(993,291)	(1,013,157)	(1,033,420)	(1,054,088)	(1,075,170)	(1,096,673)	(1,118,607)	(1,140,979)
Injection CapEx	(74,939,802)										
Injection OpEx		(40,575,600)	(41,387,112)	(42,214,854)	(43,059,151)	(43,920,334)	(44,798,741)	(45,694,716)	(46,608,610)	(47,540,782)	(48,491,598)
Cash Flow Before Tax	(711,998,820)	100,244,099	95,880,123	97,797,725	99,753,680	101,748,753	103,783,728	105,859,403	107,976,591	110,136,123	112,338,845
Tax	-	(37,591,575)	(33,558,043)	(34,229,204)	(34,913,788)	(35,612,064)	(36,324,305)	(37,050,791)	(37,791,807)	(38,547,643)	(39,318,596)
Depreciation Tax Shield		18,689,969	17,288,221	15,991,605	14,792,234	13,682,817	12,656,606	11,707,360	11,106,983	11,106,983	11,106,983
Net Tax	-	(18,901,606)	(16,269,822)	(18,237,599)	(20,121,553)	(21,929,247)	(23,667,699)	(25,343,431)	(26,684,824)	(27,440,660)	(28,211,613)
Cash Flow After Tax	(711,998,820)	81,342,494	79,610,301	79,560,126	79,632,126	79,819,506	80,116,029	80,515,972	81,291,767	82,695,462	84,127,232
NPV (should be 0)	($0.00)										
COAL POWER PLANTS											
	-	1	2	3	4	5	6	7	8	9	10
	year 0	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
Costs											
CCS Unit CapEx	(2,855,500,000)										
Transmission CapEx	(5,700,000,000)										
CCS Unit O&M Fixed		(44,953,440)	(45,852,509)	(46,769,559)	(47,704,950)	(48,659,049)	(49,632,230)	(50,624,875)	(51,637,372)	(52,670,120)	(53,723,522)
CCS Unit O&M Variable		(88,120,095)	(89,882,497)	(91,680,147)	(93,513,750)	(95,384,025)	(97,291,705)	(99,237,539)	(101,222,290)	(103,246,736)	(105,311,671)
Payment to Pipeline		(84,922,590)	(72,948,575)	(74,407,547)	(75,895,698)	(77,413,612)	(78,961,884)	(80,541,122)	(82,151,944)	(83,794,983)	(85,470,883)
Energy Penalty		(262,557,498)	(267,808,648)	(273,164,821)	(278,628,117)	(284,200,679)	(289,884,693)	(295,682,387)	(301,596,035)	(307,627,955)	(313,780,514)
Revenue		1,895,239,943	1,711,275,707	1,745,501,221	1,780,411,246	1,816,019,471	1,852,339,860	1,889,386,657	1,927,174,391	1,965,717,878	2,005,032,236
Cash Flow Before Tax	(8,555,500,000)	1,414,686,320	1,234,783,479	1,259,479,148	1,284,668,731	1,310,362,106	1,336,569,348	1,363,300,735	1,390,566,749	1,418,378,084	1,446,745,646
Tax	-	(495,140,212)	(432,174,217)	(440,817,702)	(449,634,056)	(458,626,737)	(467,799,272)	(477,155,257)	(486,698,362)	(496,432,330)	(506,360,976)
Depreciation Tax Shield		74,956,875	69,335,109	64,134,976	59,324,853	54,875,489	50,759,827	46,952,840	44,545,002	44,545,002	44,545,002
Investment Tax Credit	856,650,000										
CO2 Injection Tax Credits		314,032,027	273,642,917	279,115,775	284,698,091	290,392,053	296,199,894	302,123,892	308,166,369	165,299,771	168,605,767
CO2 EOR Tax Credits			23,334,875	22,428,754	22,428,754	22,428,754	22,428,754	22,428,754	22,428,754	-	-
Net Tax	856,650,000	(106,151,310)	(65,861,316)	(75,138,197)	(83,182,358)	(90,930,442)	(98,410,797)	(105,649,772)	(111,558,237)	(286,587,556)	(293,210,207)
Cash Flow After Tax	(7,698,850,000)	1,308,535,010	1,168,922,163	1,184,340,951	1,201,486,373	1,219,431,664	1,238,158,551	1,257,650,963	1,279,008,512	1,131,790,529	1,153,535,439
Depreciated Cash Flow	(7,698,850,000)	1,189,577,282	966,051,374	889,812,886	820,631,359	757,171,122	698,908,223	645,373,802	596,666,910	479,989,668	444,737,848
Cumulative Depreciated Cash Flow	(7,698,850,000)	(6,509,272,718)	(5,543,221,344)	(4,653,408,458)	(3,832,777,099)	(3,075,605,977)	(2,376,697,754)	(1,731,323,952)	(1,134,657,042)	(654,667,374)	(209,929,526)
NPV	$2,784,995,593										

150% Declining Balance	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
PIPELINE OPERATOR										
	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20
Necessary Revenues (Cash Inflow)										
Payment from Power Plant	87,180,300	88,923,906	90,702,384	92,516,432	94,366,761	96,254,096	98,179,178	100,142,761	102,145,617	104,188,529
Revenues from Selling CO2	82,669,968	84,323,368	86,009,835	87,730,032	89,484,632	91,274,325	93,099,812	94,961,808	96,861,044	98,798,265
Total Revenues	169,850,269	173,247,274	176,712,219	180,246,464	183,851,393	187,528,421	191,278,989	195,104,569	199,006,661	202,986,794
Costs										
Pipeline CapEx										
Pipeline OpEx	(4,639,418)	(4,732,207)	(4,826,851)	(4,923,388)	(5,021,856)	(5,122,293)	(5,224,739)	(5,329,233)	(5,435,818)	(5,544,534)
CIS CapEx										
CIS OpEx	(1,163,798)	(1,187,074)	(1,210,816)	(1,235,032)	(1,259,733)	(1,284,927)	(1,310,626)	(1,336,838)	(1,363,575)	(1,390,847)
Injection CapEx										
Injection OpEx	(49,461,430)	(50,450,659)	(51,459,672)	(52,488,865)	(53,538,642)	(54,609,415)	(55,701,604)	(56,815,636)	(57,951,948)	(59,110,987)
Cash Flow Before Tax	114,585,622	116,877,334	119,214,881	121,599,179	124,031,162	126,511,786	129,042,021	131,622,862	134,255,319	136,940,425
Tax	(40,104,968)	(40,907,067)	(41,725,208)	(42,559,713)	(43,410,907)	(44,279,125)	(45,164,707)	(46,068,002)	(46,989,362)	(47,929,149)
Depreciation Tax Shield	11,106,983	11,106,983	11,106,983	11,106,983	11,106,983	11,106,983	11,106,983	11,106,983	11,106,983	11,106,983
Net Tax	(28,997,985)	(29,800,084)	(30,618,226)	(31,452,730)	(32,303,924)	(33,172,142)	(34,057,725)	(34,961,019)	(35,882,379)	(36,822,166)
Cash Flow After Tax	85,587,637	87,077,250	88,596,655	90,146,449	91,727,238	93,339,643	94,984,296	96,661,843	98,372,940	100,118,259
COAL POWER PLANTS										
	11	12	13	14	15	16	17	18	19	20
	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20
Costs										
CCS Unit O&M Fixed	(54,797,993)	(55,893,952)	(57,011,831)	(58,152,068)	(59,315,109)	(60,501,412)	(61,711,440)	(62,945,669)	(64,204,582)	(65,488,674)
CCS Unit O&M Variable	(107,417,904)	(109,566,262)	(111,757,587)	(113,992,739)	(116,272,594)	(118,598,046)	(120,970,007)	(123,389,407)	(125,857,195)	(128,374,339)
Payment to Pipeline	(87,180,300)	(88,923,906)	(90,702,384)	(92,516,432)	(94,366,761)	(96,254,096)	(98,179,178)	(100,142,761)	(102,145,617)	(104,188,529)
Energy Penalty	(320,056,125)	(326,457,247)	(332,986,392)	(339,646,120)	(346,439,042)	(353,367,823)	(360,435,180)	(367,643,883)	(374,996,761)	(382,496,696)
Revenue	2,045,132,881	2,086,035,538	2,127,756,249	2,170,311,374	2,213,717,601	2,257,991,954	2,303,151,793	2,349,214,828	2,396,199,125	2,444,123,108
Cash Flow Before Tax	1,475,680,559	1,505,194,170	1,535,298,054	1,566,004,015	1,597,324,095	1,629,270,577	1,661,855,988	1,695,093,108	1,728,994,970	1,763,574,870
Tax	(516,488,196)	(526,817,960)	(537,354,319)	(548,101,405)	(559,063,433)	(570,244,702)	(581,649,596)	(593,282,588)	(605,148,240)	(617,251,204)
Depreciation Tax Shield	44,545,002	44,545,002	44,545,002	44,545,002	44,545,002	44,545,002	44,545,002	44,545,002	44,545,002	44,545,002
CO2 Injection Tax Credits	171,977,882	175,417,440	178,925,789	182,504,304	186,154,391	189,877,478	193,675,028	197,548,528	201,499,499	205,529,489
CO2 EOR Tax Credits	-	-	-	-	-	-	-	-	-	-
Net Tax	(299,965,311)	(306,855,517)	(313,883,528)	(321,052,098)	(328,364,040)	(335,822,221)	(343,429,566)	(351,189,057)	(359,103,738)	(367,176,713)
Cash Flow After Tax	1,175,715,248	1,198,338,653	1,221,414,526	1,244,951,916	1,268,960,055	1,293,448,356	1,318,426,423	1,343,904,051	1,369,891,232	1,396,398,157
Depreciated Cash Flow	412,081,022	381,827,625	353,800,281	327,834,750	303,778,948	281,492,048	260,843,639	241,712,956	223,988,163	207,565,688
Cumulative Depreciated Cash Flow	202,151,495	583,979,120	937,779,401	1,265,614,151	1,569,393,099	1,850,885,147	2,111,728,786	2,353,441,742	2,577,429,905	2,784,995,593

	October	November	December	January	February	March	April	May	June	July	August	September
Electricity Price WY (cent/kWh)	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77
Elecricity Price CA (cent/kWh)	13	13	13	13	13	13	13	17	17	17	17	17
Energy Penalty (MW)	675.30	675.30	675.30	675.30	675.30	675.30	675.30	0.00	0.00	0.00	0.00	0.00
Capacity Factor	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Days per month	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499
Lost-Revenue (MWh)	419301.6966	419301.6966	419301.6966	419301.6966	419301.6966	419301.6966	419301.6966	0	0	0	0	0
Lost-Revenue (kWh)	419301696.6	419301696.6	419301696.6	419301696.6	419301696.6	419301696.6	419301696.6	0	0	0	0	0
Lost-Revenue ($)	36772758.8	36772758.8	36772758.8	36772758.8	36772758.8	36772758.8	36772758.8	0	0	0	0	0
Net Energy Generation (MW)	3,287	3,287	3,287	3,287	3,287	3,287	3,287	3,962	3,962	3,962	3,962	3,962
Capacity Factor	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Days per month	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499	30.4368499
Added-Revenue (MWh)	2,040,626	2,040,626	2,040,626	2,040,626	2,040,626	2,040,626	2,040,626	2,459,928	2,459,928	2,459,928	2,459,928	2,459,928
Added-Revenue (kWh)	2,040,626,427	2,040,626,427	2,040,626,427	2,040,626,427	2,040,626,427	2,040,626,427	2,040,626,427	2,459,928,123	2,459,928,123	2,459,928,123	2,459,928,123	2,459,928,123
Added-Revenue ($)	83,721,336.95	83,721,336.95	83,721,336.95	83,721,336.95	83,721,336.95	83,721,336.95	83,721,336.95	211,755,085.46	211,755,085.46	211,755,085.46	211,755,085.46	211,755,085.46
TOTAL lost-revenue ($/yr)	$257,409,311.57											
TOTAL added-revenue ($/yr)	1,644,824,785.95											