Is Carbon Sequestration “Good” for the Environment?

An Evaluation Based on Current Technology and Methods

by

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ABSTRACT

Carbon capture and sequestration (CCS) is one of the important mitigation options for climate change. Numerous technologies to capture carbon dioxide (CO_2) are in development but currently, capture using amines is the predominant technology. When the flue gas reacts with amines (Monoethanaloamine) the CO_2 is absorbed into the solution and forms an intermediate product which then releases CO_2 at higher temperature. The high temperature necessary to strip CO_2 is provided by steam extracted from the powerplant thus reducing the net output of the powerplant by 25% to 35%. The reduction in electricity output for the same input of coal increases the emissions factor of Nitrogen Oxides, Mercury, Particulate matter, Ammonia, Volatile organic compounds for the same unit of electricity produced. The thesis questions if this tradeoff between CO_2 and other emissions is beneficial or not.

Three different methodologies, Life Cycle Assessment, Valuation models and cost benefit analysis are used to identify if there is a net benefit to the society on implementation of CCS to a Pulverized coal powerplant. These methodologies include the benefits due to reduction of CO_2 and the disbenefits due to the increase of other emissions. The life cycle assessment using ecoindicator'99 methodology shows the CCS is not beneficial under Hierarchical and Egalitarian perspective. The valuation model shows that the inclusion of the other emissions reduces the benefit associated with CCS. For a lower CO_2 price the valuation model shows that CCS is detrimental to the environment. The cost benefit analysis shows that a CO_2 price of at least \$80/tCO_2 is required for the cost benefit ratio to be 1. The methodology integrates Montecarlo simulation to characterize the uncertainties associated with the valuation models.

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INTRODUCTION

Carbon capture and sequestration (CCS) from powerplants is promoted as one of the mitigation technology to prevent climate change. CCS has the potential to contribute 15-55% cumulative mitigation effort for stabilization of atmospheric greenhouse gas emissions (GHG) concentrations below 450 ppmv(*1*). Current capture technologies can capture upto 90% (nominal value) of the Carbon dioxide CO_2 from a powerplant. A Pulverized coal powerplant with CO2 capture process would roughly need 24%-40% more energy than a plant without CCS(*1*).This high energy requirement decreases the net output of the powerplant. This high energy requirement would increase the net CO_2 emissions; therefore the net CO_2 captured is reduces approximately to 80% for the same kWh of electricity produced.

The high energy requirement not only increases the CO_2/kWh but all the criteria emissions like Sulfur dioxide SO_2, Nitrogen Oxides NO_X, Particulates less than 2.5μm $PM_{2.5}$, Volatile organic compounds (VOC), Ammonia (NH_3) also other pollutants like Mercury, lead and etc., Along with the capture process the transport and the sequestration also contributes to the increase in non-CO_2 emissions. Therefore it is important to identify if this tradeoff between CO_2 and other emission has any net benefit. The thesis aims to answer this question by quantifying the net benefit based on current technology and methods.

The following section provides a brief introduction to the current carbon capture and sequestration technologies and the methods to quantify the net benefit.

Carbon Capture and Sequestration

CCS consists of three steps, 1) CO_2 capture from powerplants 2) transportation of the captured CO_2 in ships or pipelines, 3) storing the CO_2 in underground sites or in the ocean.

Carbon capture. Based on where a CO_2 capture plant is located in a powerplant it is classified into Post combustion, precombustion and oxyfuel techniques. The three systems are explained in the Figure 1. In post combustion systems, the capture system is located after the boiler. The CO_2 is separated from flue gas produced when the fuel is burned in air. Pre-combustion system captures CO_2 before it enters the boiler. The process involves capturing the nitrogen from the air in an air supply unit thus increasing the concentration of oxygen which reacts with coal at a higher temperature producing syngas (CO_2+H_2). The CO_2 in syngas is captured and the H_2 is used for producing electricity. This process is also called integrated gasification combined cycle (IGCC). Oxyfuel systems are similar to a conventional system except that instead of air pure oxygen is used. The reaction product consist mainly CO_2 and water. The CO_2 can be easily captured and transported.

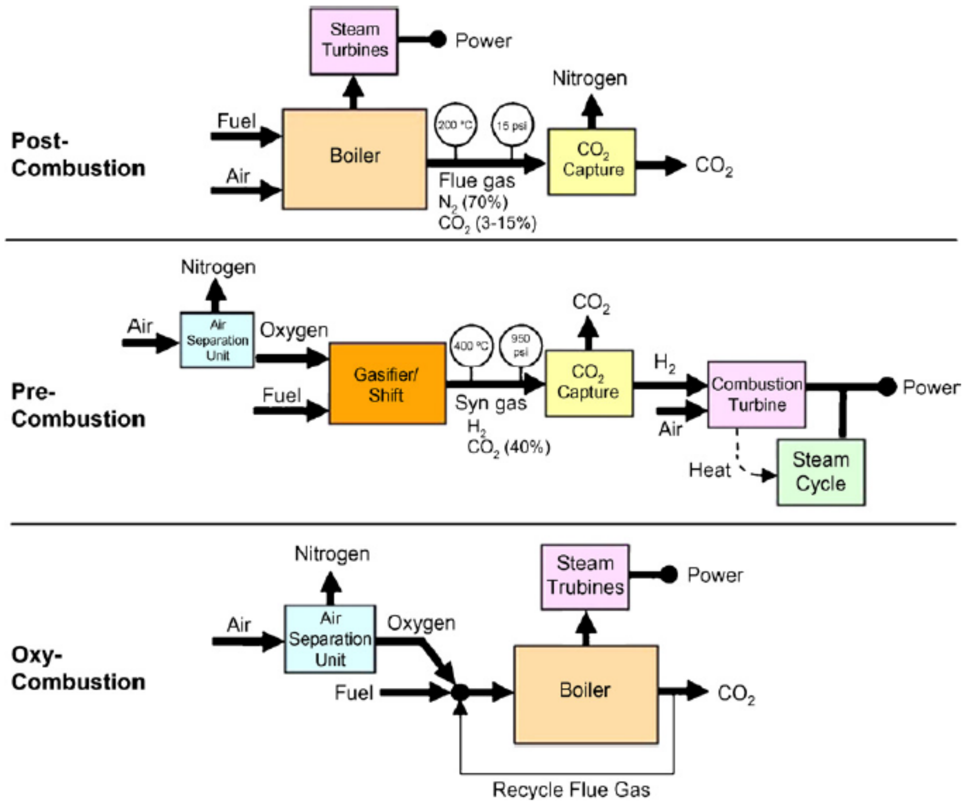


Figure1. - - Block diagrams illustrating post-combustion, pre-combustion and oxy-combustion systems (*2*)

All the three technologies have their advantages and disadvantages but Post combustion technology is currently important because it is compatible with – and can be retrofitted to – existing coal fired plants without requiring substantial changes in basic combustion technology. And also it offers the flexibility to temporarily shut down during period of peak power demand. It is also the leading candidate for gas fired powerplants (*3*). And most importantly there is a need to retrofit the nation's already existing powerplants while new powerplants can have the pre- and oxy- combustion technologies.

CO_2 capture technologies under post combustion are can be classified generally into Solvent, Solid sorbent and membranes. The solvent based CO_2 capture involves physical or chemical sorption of CO_2 into a liquid carrier. The

CO_2 is stripped from the solvent by a temperature swing process. Solid sorbents are similar to solvents except no water is present. Membranes use a permeable or semi permeable material that allows for selective transportation of chemicals between the membranes thus filtering out CO_2. Liquid solvents are the relevant technology which is close to commercialization (*4*). A short but more descriptive mechanism of the solvent systems is provided below.

Chemical liquid solvents involve one or more reverse reactions between CO_2 and an aqueous solution of the solvent. Common chemical solvents are Mono ethanol amine (MEA), hindered amine, aqueous ammonia or carbonate. A schematic Figure showing MEA carbon capture system for a powerplant is shown in Figure 2. The capture system consists of an absorber and a stripper. The absorber contains the sorbent (MEA) and when the flue gas pass through it the MEA reacts with CO_2 and forms a weakly bonded compound (carbamate). The remaining gases escape to the atmosphere while the carbamate is sent to the regenerator. In the regenerator a low pressure steam strips the carbamate into CO_2 and MEA. The MEA is recycled back while the CO_2 is compressed and transported. The main reactions taking place are shown in the equation below,

$$\boldsymbol{CO2\ Absorption}: 2R - NH_2 + CO_2 \rightarrow R - NH_3^+ + R - NH - COO^-$$

$$\boldsymbol{MEA\ Regeneration}: R - NH - COO^- + R - NH_3^+ + (Heat) \rightarrow CO_2 + 2R - NH_2$$

Where, R = HO-CH_2CH_2 (*5*).

Transport and sequestration. Transport occurs in pipeline or through ships. The most common mode of transportation is through pipeline because of the predominantly available geological sequestration sites in the US. For transportation through pipeline the captured CO_2 has to be compressed to around 13MPa. Geological sequestration in aquifers is the preferred method. The sequestered CO_2 is permanently stored underground. The confidence in this technology is supported by the knowledge that CO_2 produced through natural processes has been retained in geologic formations for hundreds of millions of years(*1*). The presence of multiple trapping mechanisms will reduce the mobility of CO2 underground over time, decreasing the risk of CO2 leaking to the surface(*1*).

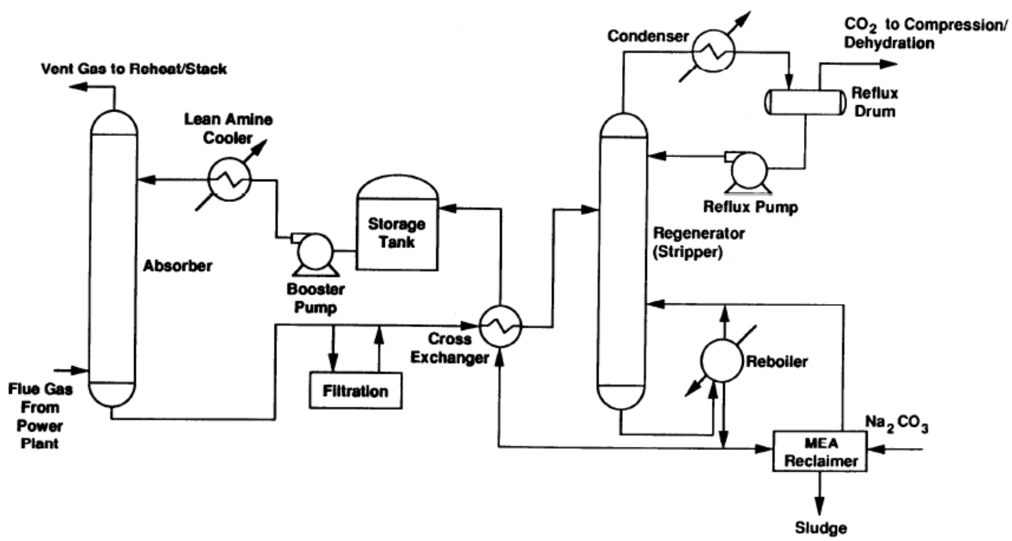


Figure 2. Process flow diagram for amine separation process (*3*)

In a summary, carbon capture using amines and transportation through pipeline and sequestration in aquifers could be the most common CCS system for a pulverized coal (PC) powerplant. This report uses this system to identify the net benefit of the technology. The net benefit is identified by comparing a PC plant with CCS and without CCS. The methods used to analyze are life cycle assessment and valuation model. A brief introduction to these methods follows.

Life cycle impact assessment

Life cycle impact assessment (LCIA) is an important tool available to measure the environmental performance of a technology. LCIA involves collecting the mass and energy balance of inputs and outputs of a system and evaluating the inputs and outputs by converting them into environmental categories. LCIA methodologies convert LCI data into environmental categories. Numerous methodologies are available in the literature like Eco Indicator99, IMPACT 2002+, EPS 2000, ReCiPe, CML. In general, all the impact assessment methods deal with three fields of scientific knowledge and reasoning, technosphere, ecosphere and valuesphere. The three fields are explained below (adapted from (*6*)),

- Technosphere is the analysis of the life cycle, the emission from processes, the allocation procedures as far as they are based on casual relations. The output of a technospehre is the life cycle inventory.
- Ecosphere is the modeling of changes (damages) that are inflicted on the “environment”. The impact of the life cycle inventory is characterized into different impact categories using characterization factors. The characterized impacts are then normalized into a dimensionless units using normalization factor which permit the characterizations (impact categories) to be compared. The normalized impacts are called midpoint categories.
- Valuespehre involves the modeling of the perceived seriousness of such changes (damages), as well as the management of modeling choices that are made on Techno- and Ecosphere. Weighting factors are used value different impact categories based on their perceived importance as set by social consensus.

The Figure - 3 below shows the process in life cycle impact assessments based on the eco-indicator’99 methodology. Following the flow of the Figure we can see that the modeling of the inventory is the right most which is followed by steps for characterizing the impacts of the inventory which is finally converted into an indicator based on normalization and weighting.

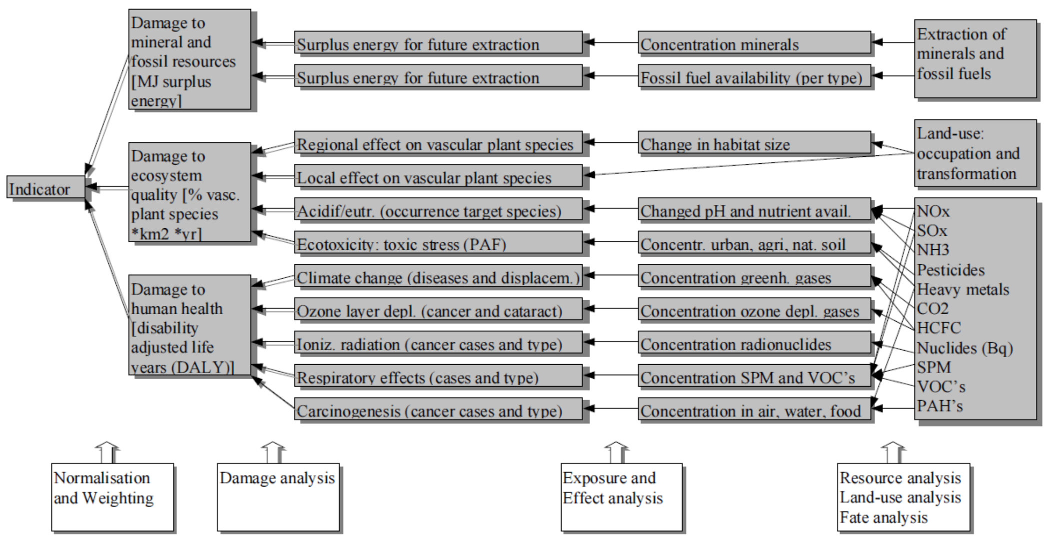


Figure 3. Life cycle impact assessment methodology of eco-indicator'99. Adapted from (7)

The concept of LCIA appeals to be the ideal way to assess the range of environmental impacts of a product. There are however many limitation to this practice. The important challenges are the following(*8*),

- LCIAs don't include temporal and locational information,
- they omit impacts for inventories that don't have an agreeable characterization factor,
- inventories are too general to perform an adequate LCIA
- LCIA excludes the nonlinear responses and thresholds that exist for many materials.
- The most daunting uncertainty is the normalization and weighting factors which depends on the societal structure and preferences.

Irrespective of the uncertainties LCIA can been used to understand the environmental burden of many technologies.

Valuation Models

Another environmental assessment tool is the valuation of the positive and negative externalities of a technology. Externality is a side effect or consequence of an industrial or commercial activity that affects other parties without this being reflected in the cost. Externalities are evaluated in monetary terms. CCS is a technology that aims to reduce the externalities associated with CO2 emissions, the benefit of CCS can be compared with the cost associated with construction of CCS plants.

Environmental economists have made notable progress in estimating the externality cost. Externality cost is the consequence of environmental discharges in monetary terms. The externality cost can be identified by damage cost models. In general, the damage cost model for air emissions from coal powerplants should incorporate all the impacts associated with the air emissions. The impacts that can be modeled are Health effects, visibility, material deterioration and damage to environment. Therefore the models should integrate knowledge from these multiple disciplines and this method is also called as Integrated Assessment Models (IAM). A general framework of IAM is shown in Figure 4.

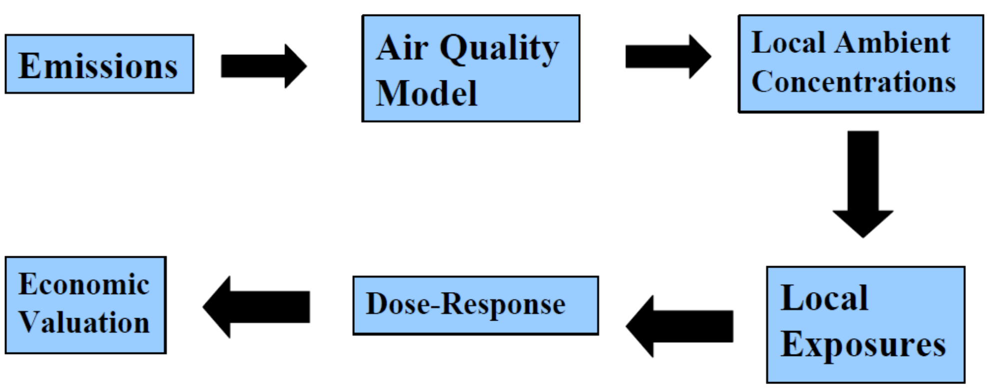


Figure4. Framework of Integrated assessment models.

The integrated assessment method involves the following steps in general. They damages mentioned are only few and they are reported for understanding the model.

- The quantity of a pollutant emitted by the coal power plant is estimated from national inventories.
- An air quality model, usually a Gaussian plume model, is used to identify the fate and transport of the emitted pollutant based on the metrology of the location. Based on which the local ambient concentrations of pollutants are obtained.
- The ambient concentration is translated into local exposure on Humans, Agricultural and material and visibility.
- The local exposure is translated into physical damage based on dose response functions. Dose response function is modeled based on epidemiological studies in case of Human health issues. While crop loss, material damage and visibility values are modeled based on historical response of these categories to the emissions.
- The physical effects are then translated into damage cost based on economic valuation models. Economic valuation models for human health use statistical value for life (VSL). The models for visibility is modeled based on the consumer surveys based on the avoided travel cost due to reduced visibility of landmarks or willingness to pay (WTP) for keeping the visibility below reduced levels. Material damage and crop losses generally have damage cost values associated with losses.

Damage cost models for criteria pollutants and CO_2 emissions already exists. Unfortunately the models are complex and have a wide uncertainty range for the modeled costs. However, these models are used by the USEPA to identify the benefits associated with the major regulations.

Organization of the Thesis

The following sections of the thesis consist of a literature review section which summarizes the technological and environmental assessment of CCS technology[1] (capture using amines and aquifer sequestration) already available in the literature. The literature review section is followed by the objective of the research which highlights the more clear research question of the thesis. The methodology section describes the methods and tools used to address the research question. Finally the result of the analysis using is presented with an uncertainty analysis.

[1] From here on the any mention of CCS represents carbon capture using amines and sequestration in aquifers unless otherwise mentioned.

OBJECTIVE & LITERATURE REVIEW

The objective of the thesis is to identify if carbon capture using MEA and sequestration using aquifer is a net environmental benefit or not by constructing a broader life cycle inventory for the system. A net environmental benefit means including the dis-benefits associated with the impact tradeoff associated with the implementation of CCS in the whole life cycle. The secondary objectives are to identify the significant contributors to the net benefit. The tools used for characterizing the tradeoff are life cycle impact assessment and valuation modeling.

The literature review is divided into three parts, 1.Life cycle assessment of CCS, 2.Cost of powerplant with CCS and 3.Valuation model.

Life Cycle Assessment of CCS

The key performance indicator of the amine technology is that a very high energy in the form of heat is needed to strip the carbamate into CO_2 and the MEA(*9*),(*10*). The heat is generally supplied by the steam extracted from the base plant. Extraction of steam from the boiler system leads to decrease of the net output of the plant. This is often expressed as plant derating or energy penalty. Energy penalty is either expressed as the increase in fuel input per unit of delivered electricity, or as the decrease in electricity output for a given fuel input(*1*). Typical values of energy penalty to capture 90% of CO_2 are between 23%-30%(*11*)-(*12*).

The objective of CCS systems is to reduce CO_2 emissions, whereas the energy penalty increases the emission of Non-CO_2 emissions due the additional fuel necessary to produce the same kWh of electricity. In other words, the reduction of CO_2 is traded off by increase in Non-CO_2 emissions due to the energy penalty. Several LCA studies of CCS systems have addressed the increase in non-CO_2 emission. A meta-analysis by Roger Sathre in the table 1 below (*13*) shows the increase in non-climate impact categories due to the energy penalty associated with CCS.

Table 1. Percentage change in non-climate environmental impacts between electricity production without and with CCS as reported in selected LCAs. Adapted from (*13*)

Reference[a]			Indicator[b]								
			ABD	ODP	FWAE	MAE	TEP	POP	EP	AP	HTP
Koornneef et al.											
Coal/USCPC/MEA			34	55	46	−27	57	27	80	46	181
Korre et al.											
Coal/PC/MEA			53	–	135	–	–	9	50	21	−29
Coal/PC/K + PZ			36	–	85	–	–	−4	0	−21	−39
Coal/PC/KS-1			30	–	67	–	–	−7	25	−8	−43
Pehnt & Henkel											
Coal/PC/MEA			–	–	–	–	–	156	100	−9	25
Coal/IGCC/Selexol			–	–	–	–	–	17	25	30	22
Viebahn et al.											
Coal/PC/MEA			–	–	–	–	–	96	44	39	–
Singh et al.											
Gas/NGCC/MEA			–	–	166	150	143	21	33	43	124
	Emission										
	NOx	SOx	PM	NH_3	CO	VOC	Pb	Hg			
Schreiber et al.											
Coal/PC/MEA	32	−91	–	–	–	–	–	–	111	57	265
Coal/SCPC/MEA	37	−91	–	–	–	–	–	–	113	54	250
Coal/USCPC/MEA	26	−92	–	–	–	–	–	–	61	21	123
Lignite/PC/MEA	47	−88	–	–	–	–	–	–	189	44	772
Lignite/SCPC/MEA	39	−89	–	–	–	–	–	–	156	50	718
Lignite/USCPC/MEA	28	−90	–	–	–	–	–	–	138	25	425
Odeh & Cockerill											
Coal/SCPC/MEA	44	−99	−48	9300	–	–	–	–			
Coal/IGCC/Selexol	−17	10	0	–	–	–	–	–			
NETL											
Coal/PC/MEA	−76	−46	−97	241	69	0	192	6			
NETL											
Coal/SC/MEA	38	−90	39	15	36	40	2	60			
NETL											
Coal/IGCC/Selexol	−10	17	−26	−54	−38	−50	31	17			
NETL											
Gas/NGCC/Amine	17	19	17	8	18	17	15	28			

For each reference, the results are listed for each combination of Fuel/Generation technology/Capture technology. (PC: Pulverized coal; IGCC: Integrated gasification combined cycle; NGCC: natural gas combined cycle; USCPC: Ultra-supercritical pulverized coal; SPC: Supercritical pulverized coal).
The Indicators: ABD - Abiotic resource depletion; ODP - Ozone layer depletion; FWAE - Fresh Water Aquatic Ecotoxicity; MAE - marine aquatic ecotoxicity; TEP - Terresrial ecotoxicity; POP - Photochemical oxidation; EP - Eutrophication; AP - Acidification; HTP - Human toxicity.
The table also includes other capture technologies like Selexol, Perprazine and KS-1 which are also amine based absorption systems.

The table 1 clearly shows the trade-off between CO_2 and Non-CO_2 emissions reported by various researchers. Schreiber (*14*), Odeh (*15*), NETL (*16*)-(*17*) have shown the increase in the Non-CO_2 emissions while Koorneef(*18*), Korre(*19*), Pehnt(*20*), Viebahn(*21*) and Singh(*22*) used the tradeoff and converted them into impact categories based on the life cycle impact assessment methods. The meta-analysis shows that the Abiotic resource depletion (ABD), Ozone depletion potential (ODP), Fresh water aquatic ecotoxicity (FWAE), Terrestrial ecotoxicity (TEP), Eutrophication (EP) are increasing across all the literature, while Marine aquatic ecotoxicity (MAE), Human toxicity potential (HTP), Photochemical oxidation (POP), Acidification (AP) show both an increase and decrease based on the cases analyzed.

For coal powerplants that uses amines the life cycle assessments show a wide range for the percentage change in the impacts. For example, the increase in Eutrophication potential (EP) is 80% for Koorneef, 44% for Singh and 100% for Viebahn. The wide range and conflicting results is the difference in the system boundary, temporal, geographical and methodological approaches between each system analyzed. Viebahn, Pehnt and Scherieber are LCIA for Germany and the scope of both the studies are different. Viebahn does not include the reaction of acid gases with the solvent. Pehnt provides the LCIA for powerplants with Carbon capture but doesn't include the transportation and sequestration phase.

Other literatures like IEA(*23*) and Scherieber(*24*) aren't included in the meta-analysis but both the analysis revolves around the LCIA for Germany and Europe respectively. Moreover all the report except IEA doesn't provide the life cycle inventory used for the analysis but IEA has a smaller system boundary that doesn't include the transport and sequestration phase. Wildboltz(*25*) and Koorneef(*18*) conducted the LCA including the transport and sequestration phase of the life cycle for the Europe. The LCA point out that the transport and sequestration options aren't significant contributor to impact when compared to the energy penalty. There hasn't been as many LCA for the US as that of Europe. The NETL (*16*) is the only US study that conducts a LCA to compare the environmental performance of a powerplant with CCS and powerplant without

CCS. The study also provides the Life cycle inventory used in the analysis. The life cycle inventory is limited to first order emissions from the powerplant. The second and third order emissions are excluded from the analysis. Example of a second order emission is the PM emissions associated with the production of Limestone which is used for Flue gas desulfurization. The inventory provided leads to an underestimation of the results.

An old study by NETL authored by Spath and Mann (*26*) has conducted a LCA for Super critical coal powerplant that includes the second order emissions of the feedstocks used to produce electricity. Spath's analysis includes a detailed modeling of the solid emissions from the life cycle of the powerplant. They also provide a publicly available inventory list for a pulverized coal powerplant. To construct a LCI for powerplant with CCS we use the inventory from Spath(*26*) and model the CCS system using the Koorneef(*18*) and Wildboltz(*25*).

Cost of powerplant with CCS

Another approach to identify the net benefits of the technology is the cost benefit analysis approach. The cost to construct the capture plant is compared with benefits associate with reducing CO_2. Most of the technologies necessary for CCS are already demonstrated. However, there are worldwide only four large CCS projects currently in operation, plus some smaller projects(*27*). Therefore the cost models that are available in the literature generally are models based on the performance of the CCS system modeled. Following are important studies that deal with the cost of a powerplant with CCS.

- Rubin models the cost of the plant based on Integrated Environmental Control Model (IECM) developed by Carnegie Mellon University. IECM is a computer modeling program that performs a systematic cost and performance analyses of emission control equipments. The IECM models four types of costs, capital cost, O&M cost, Cost of Electricity, Cost of CO_2 avoided. The CO_2 capture and sequestration system cost model is directly linked to the process performance modeled by Rubin et al. The full technical analysis of the system is presented here(*9*) and he models a subcritical powerplant that uses a sub-bituminous coal.

- Electric Power Research Institute (EPRI)(*28*) modeled and compared the economic cost for IGCC and a SCPC plant. SCPC using Powdered River Bed coal (PRB) with the CO_2 capture using Fluor's Econamine FG plant was modeled. The performance, emissions information and economic cost were provided by Flour
- National Energy Technology laboratory (NETL)(*29*) performed a similar economic analysis for a both a sub –critical and a super critical coal power plant that uses a bituminous coal.

All the three analysis are independent analysis therefore the capital cost, financial and operational assumptions added to the variability of the cost of electricity (COE). A MIT study (*30*) normalized these COE into a 2005 year cost basis. The table 2 below summarizes the values.

Table 2 - Summary of the COE for powerplant with CCS normalized to 2005 year cost basis. Adapted from (*30*)

Study		**NETL**		**EPRI**	**NCC**	**RUBIN**	**EPRI**	**SIMBECK**
Year		2002	2002	2002			2002	
Technology	SubC	SubC	SubC	SC Baseline	SC	USC	USC	CFB
TPC	\$/kWe	1192		1269	1355	1108	1289	1432
TCR	\$/kWe	1356		1422	1565	1241	1444	1604
Capital		2.42		2.57	2.75	2.25	2.61	2.9
O&M	¢/kWe-h	0.86		1.11	0.79	0.81	1.05	0.82
Fuel	¢/kWe-h	1.37		1.26	1.3	1.3	1.2	1.19
COE	¢/kWe-h	4.64		4.95	4.84	4.36	4.86	4.91
Capture		MEA	Oxy-fuel	MEA		MEA	MEA	MEA
TPC	\$/kWe	2232	2136	2199		1780	2157	2491
TCR	\$/kWe	2539	2417	2463		1994	2414	2790
Capital	¢/kWe-h	4.53	4.33	4.46		3.61	4.37	5.05
O&M	¢/kWe-h	1.79	1.32	1.9		1.65	1.79	1.42
Fuel	¢/kWe-h	1.92	1.75	1.77		1.71	1.65	1.51
COE	¢/kWe-h	8.24	7.39	8.13		6.97	7.81	7.99
Increase in COE	¢/kWe-h	3.6		3.18		2.61	2.95	3.08

SubC – Sub critical, SC – Super critical, USC – Ultra super critical.
TPC – Total plant cost, TCR – Total capital requirement, O&M – Operation and Maintenance, COE – Cost of electricity.
Note: SIMBECK is not publicly available.

Valuation Model

Valuation model are used to identify the net benefit from CCS. There isn't any literature that uses valuation models to identify the net benefit of CCS technology. This report is the first to apply the damage costs to identify the net benefit of CCS. Therefore the literature review of valuation model discusses the various emissions for which damage costs are available. From Table -1 the important non CO_2 emissions are Particulate Matter, Nitrogen oxides, Sulfur dioxide, Volatile organic compounds, Carbon Monoxide, Mercury and Lead. Damage cost for all the emissions except lead is available in the literature.

The damage for CO_2 has been modeled by numerous researchers. In fact, according to R.J. Tol (*31*) there were 47 reports with 211 estimates of the CO_2 damage cost that has been reported. Since then there are even more reports published and they are the recent and the current model available (*32*). A meta-analysis on all the recent values available in the literature was conducted by Tol(*32*). His research reaffirms the uncertainty on the CO_2 damage cost if very large with a mode of \$11.18/tCO_2; the mean of \$41/tCO_2 and the largest 99th percentile is \$460/tCO_2.

US government suggests its own estimate of the damage cost for CO_2. Under executive order 12866 agencies in the US are required "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." To fulfill this obligation a social cost for CO_2 has been reported by the Interagency working group on Social cost on Carbon of the US government(*33*).

The study revolves around three integrated assessment models DICE(*34*), FUND(*35*) and PAGE(*36*). The values reported are shown in the table-3 below,

Table 3. Summary of the CO2 price used by US Regulatory Impact analysis. Adapted from (*33*)

Year	5%	3%	2.50%	3%
	Avg	**Avg**	**Avg**	**95th**
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50	100
2035	11.2	36	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65	136.2

In addition to the above research a study conducted by the national academy of science reports a \$30/tCO_2 as the mean damage cost of CO_2(*37*).

The two notable IAM available for Non-CO_2 in the literature are the APEEP(*38*),(*39*) by Nick Muller, and another by Jonathan Levy(*40*). AP2 is the updated model of the APEEP. APEEP stands for The Air Pollution Emissions Experiments and Policy. Both AP2 and Levy models the damages across criteria emissions. The emissions modeled by Levy are $PM_{2.5}$, NO_X and SO_2. AP2 models include Volatile organic compounds (VOC) and ammonia (NH3) along with the pollutants modeled by Levy. The table 4 below shows the key differences of the two models.

Table 4 - Comparison of the APEEP and Levy's model

Parameters	AP2 (APEEP)	Levy
Goal and Scope	characterize the uncertainty associated with per ton damage estimates for 565 electric generating units (EGUs) in the contiguous United States (U.S)	Health effect damages associated with emission from coal powerplants.
Emissions	$PM_{2.5}$, SO_2, NO_X, VOC, NH_3, CO	$PM_{2.5}$, NO_X, SO_2
Availability	Damage costs in $/ton for each emission are not publicly available	Damage cost in $/ton for each emission are publicly available
Inventory source	Emissions are modeled for 565 power plants – 2005 data from Continuous Emission monitoring system (CEMS) are used	Emissions are modeled for 404 coal power plants – 1999 data from Continuous emission monitoring system (CEMS) are used.
Impacts Modeled	It includes the dose response for Mortality, morbidity, crop losses, visibility and materials. Due to a wider scope the dose response for the impacts follow a linear relationship.	Human health impacts related to $PM_{2.5}$, SO_2 and NO_X emission. SO_2 and NO_X are partial precursors of $PM_{2.5}$. The dose response model is a non-linear relationship.
Valuation	Value of Statistical Life (VSL) is USEPA value discounted to 2005 dollars	VSL is USEPA value discounted to 1999 dollars.
Uncertainty	Damage cost for each county is provided. The classification is only based on only two characteristics Rural and Urban.	Variability based on the type of fuel, combustion technologies, sulfur or ash content of the coal and population characteristics around the powerplant are included.

As an IAM both the models have huge uncertainties on the damage values. In this report we use the Levy's value due to three important reasons, the damage cost values for AP2 are not publicly available and the scope of Levy is specific to coal power plants and finally Levy model has a higher damage cost values when compared to AP2. Since damage costs for ammonia and volatile organic compounds are not modeled by Levy the report use the APEEP values. Mercury is another important emission of concern. The health benefit of reducing mercury emissions is studied by the Northeast states for coordinated air use management(*41*). The primary pathway of human exposure to mercury is the consumption of fish that is contaminated with methyl mercury. Mercury causes IQ deficiency, cardiovascular effects and premature mortality. Based on these impacts a benefit per ton of emission reduction is identified. The following table 5 summarizes the damage costs.

Table 5. The damage cost from the literature according to source of the values

Emissions	Min	Median	Max	Unit	Source
PM2.5	30,000	72,000	500,000	$/ton	Levy
Nox	500	4800	15,000	$/ton	Levy
SO2	6000	19000	50,000	$/ton	Levy
Hg	3.90E+06	1.10E+07	1.82E+08	$/ton	Glenn
NH_3	70	1,101	4,763	$/ton	APEEP
VOC	70	181	568	$/ton	APEEP

SCOPE OF THE ANALYSIS

The report aims to be a preliminary analysis of the methodology mentioned above. The methodology requires comprehensive life cycle inventory data and damage costs of the system analyzed. The life cycle of system analyzed is big and complex and equally complex are the valuation models and life cycle assessment methodologies. The report uses the already available knowledge on these venues to meet the objective. In other words the author doesn't collect or model the primary data required for the analysis instead data from literature sources are used to complete the model.

METHODOLOGY

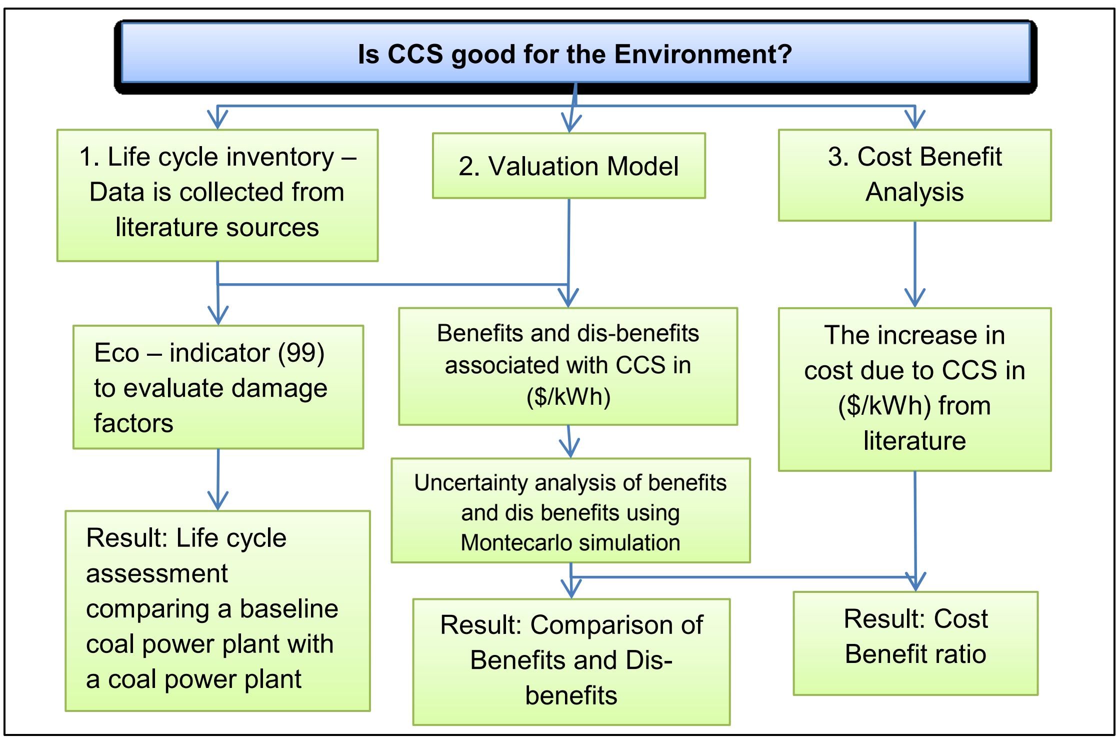


Figure 5. - A graphical representation of the methodology used

The literature review clearly shows that the decrease in carbon dioxide emission is traded off by the increase in other emissions per kWh of electricity produced in a coal powerplant. Therefore it is important to identify the net benefit in installing CCS. The methodology used in our study integrates Life cycle impact analysis, valuation model, cost-benefit analysis and Montecarlo simulations of uncertainty to evaluate the net benefit to the environment. A graphical representation of the methodology is show in in the Figure-5. The first step in the methodology is the identification of the life cycle inventory (LCI) for the emissions for both the powerplant with CCS and without CCS. The LCI is used to identify the life cycle impact assessment and the net benefits. The net benefits are inturn used in the cost benefit analysis. A detailed explanation of the methodology is provided in the section below.

Life cycle inventory (LCI)

The life cycle inventory for the emissions for CCS is quantified by constructing a model in SimaPro with data available from the literature. A detailed analysis of the procedure is provided in the section below starting with the system boundary of the model the followed by the data collection in each steps and finally the system model between the two cases (No CCS and CCS) are explained.

System Boundary

The system described in the report is a Pulverized coal powerplant with carbon capture using amines and geological sequestration in aquifers. Life cycle inventory is a complete list of the quantity of emissions, materials and energy in and out of the whole life cycle of the system. Theoretically, life cycle includes all the upstream and downstream process in the system. It is impossible to quantify the inventory for all the process and therefore a system boundary is required to scope the analysis. Due to the scope of the analysis the system boundary is also partially dictated by the data available in the literature. Nonetheless the system boundary covers the significant portion of the system.

The system boundary can be classified into two blocks as shown in the Figure Block 1 is the life cycle of a coal powerplant. A National renewable energy laboratory study (*26*) provides inventory data for block 1. Block 1 represents the life cycle of the production of electricity from coal. It includes material and energy flow of major processes like coal mining, transportation, construction of a power plant, equipment manufacturing and chemical production for all the operations.

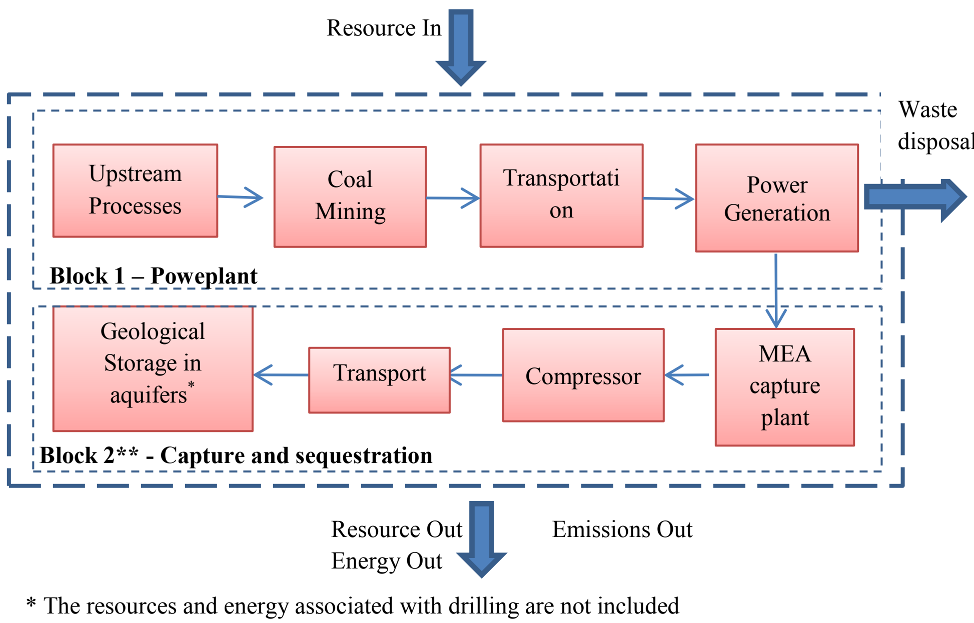


Figure 6. System boundary for the life cycle inventory modeled.

The end of life includes the waste generated in the plant and decommissioning of the mine and the power plant. The upstream process refers to major manufacturing steps needed to produce the intermediate feedstock. The mining includes both surface and underground mining.

A detailed system boundary of block 1 is shown in the Figures below. The solid line in these Figures represents the actual material and energy flows, while the dotted line indicates the logical connections between the process blocks. Block 2 consists of the carbon capture and the sequestration system. Due to the lack of comprehensive life cycle inventory for the system each part of block 2 is modeled individually.

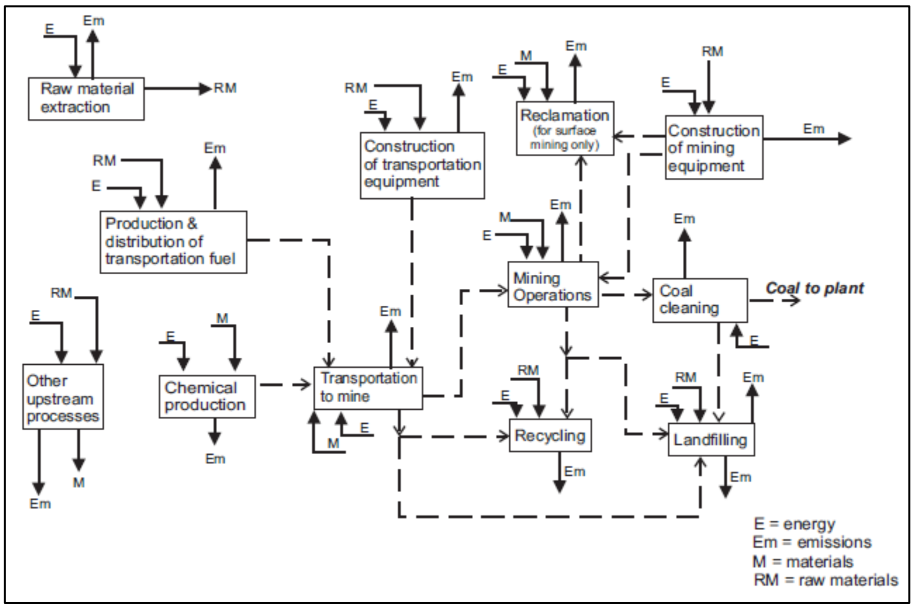


Figure 7 - Detailed system boundary of Coal mining and coal transportation (*26*)

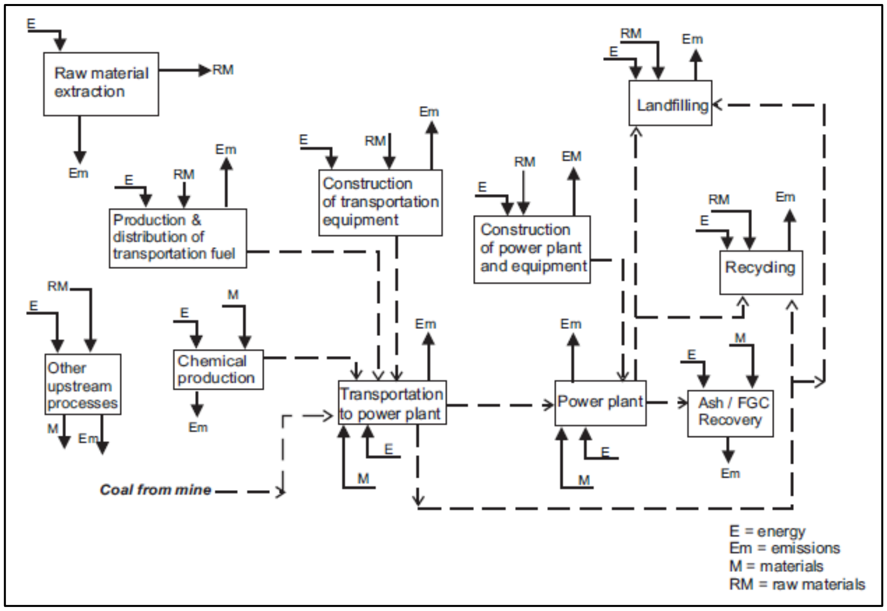


Figure 8 - Detailed system boundary of Powerplant (*26*)

Carbon dioxide capture plant

CO2 capture plant is a temperature swing process that uses MEA as the chemical sorbent to capture CO2. The CO2 capture plant is retrofitted to the powerplant. (*42*) models the energy, material and emissions associated with the technology. These values are modeled into the inventory using SimaPro(*18*) provides the infrastructure requirement and the transport required for the construction of the capture plant. MEA degenerates when it reacts with acid gases in the flue gas. Degeneration of MEA generates waste as reclaimer bottoms. The End-of-life disposal of reclaimer bottoms are not modeled in the system. The degradation of MEA produces ammonia which is included in the boundary. The infrastructure data of CO2 capture system does not include energy requirement for dismantling, material and energy requirement for maintenance of the infrastructure, and waste processing and recycling after dismantling.

Compressor

The captured CO2 should dehydrated and compressed for transport. The infrastructure and energy requirement of a compressor is provided by (*18*). The The LCI data for the infrastructure omits information on disposal and recycling of materials after dismantling. The leakage of CO2 over the life time is also taken into account.

Transport and Storage

The captured CO_2 is transported through a pipeline and stored in an aquifer. The aquifer holds the CO2 due to mechanisms like physical trapping, dissolution and mineralization. Based on the distance between the plant and the sequestration location booster compressors may be required. Aquifers are atleast 800m deep and the LCI of pipeline and aquifer storage is taken from (*25*). The LCI includes the materials and energy required to construct and dismantle the pipelines, the energy and material required for monitoring the pipeline. The LCI doesn't include the energy and material required for drilling. Eventhough (*25*) mentions a dataset for drilling which isn't available for the public. Moreover Caroline shows that drilling will not be a significant impact in relation to the powerplant.

Data Collection

Block 1 – Powerplant:

The R&D from Department of Energy (DOE) (*4*) expects first generation CCS technologies to be deployed in the year 2020. More advanced technologies are expected to be deployed in the year 2030. The air quality standards for powerplants are also becoming stringent with new thresholds for the New Source Performance Standards (NSPS) and new rules like Mercury and Air Toxic

Standards (MATS), National Emission Standard for Hazardous Air Pollutants Compliance Monitoring (NESHAPS). Due to these reasons the powerplant assumed in the report is a futuristic powerplant with a Low Emission boiler system (LEBS) modeled by (*26*). The power plant information is provided below. The objective of the LEBS system is lower NO_X and SO_2 emissions by one sixth of NSPS requirements and Particulate Emissions by one third of NSPS requirements. The system uses a Copper oxide flue gas sorbent that removes SO_2 and NO_X and produces Sulfuric acid and sulfur as a byproduct.

Bituminous coal represents 45% of the coal mined in the United States and the remaining 55% of the coal mined consists of 47% Sub-bituminous, 7% Lignite and 1% anthracite coal. The general difference between bituminous and sub-bituminous coal is that the bituminous coal has a higher energy content and lower volatile content but Sub-bituminous coal has lower sulfur content. The scope of the analysis limits the analysis to bituminous coal mined in the state of Illinois. The coal can be mined either through surface or underground mining. Surface mining is the major mining technique in the US accounting for 64% of the total coal mined (*43*). The primary difference between surface and underground mining is the higher emission of methane from coal beds in underground mining.

The inventory assumes that the methane emissions is vented into the atmosphere however some underground mines have begun to recover some methane for other uses such as power production, fuel use at the mine site or additional natural gas supply. The methane emissions and the rock dust from the mines cause coal dust explosions, it is prevented by applying limestone dust on the surface of the mines and this method is called rock dusting. Limestone use is important because of the high particulate emission associated with the quarrying. The analysis includes both the mining techniques and it accounts for the different mining equipment for operation and construction, materials, emissions and reclamation of the mines are included in the inventory.

Table 6 - Design parameters of the pulverized coal powerplant used in the analysis

Design Parameter	Unit	Data
Plant capacity	MW (100% capacity)	404
Operating capacity factor	%	60
Coal feed rate	kg/day (as-received)	3,229,556
Powerplant efficiency	%	42
Copper oxide for gas clean up	g/kWh	0.268
Ammonia for NO_X removal	g/kWh	0.136
Natural gas to regenerate the CuO sorbent	g/kWh	3.810
Emissions		
NOX	g/kWh	0.358
SOX	g/kWh	0.358
CO	g/kWh	0.100
CO2	g/kWh	719
Particulates	g/kWh	0.053
VOCs	g/kWh	0.012
Flue gas waste – dry	g/kWh	34.2
Total Ash	g/kWh	26.5

The coal transportation is assumed to be transported by barge and transferred to railcar. The transportation of other materials/chemicals is assumed to be 60% by rail and 40% by truck. The barge, train and truck material requirements are modeled in the inventory. The construction takes place over a period of two years and the life of the coal powerplant is assumed to be 30 years.

The complete inventory list of the Block 1 - power plant is provided in the appendix

Block 2 - Carbon dioxide (CO2) capture using amines and compressor

A full LCI for the amine technology is not available and therefore a streamline LCA approach is applied to identify the LCI. As discussed earlier Rubin (*10*, *42*) provides the energy and the chemicals needed for the model and Koorneef(*18*) provides the infrastructure requirement. A CO_2 reduction efficiency of 90% is observed. Other significant impact is the energy required to capture CO2. The energy is provided by the high pressure steam from the boiler. The use of powerplant steam derates the electricity produced by the powerplant and it is expressed as energy penalty. Energy penalty is defined as the increase in plant energy input per unit of product or output.

$$EP = \frac{\eta_{CCS}}{\eta_{ref}} - 1$$

Where, η_{CCS} and η_{ref} are the net efficiency of the powerplant with capture and powerplant without capture. The energy penalty is identified as 31.4% for the powerplant with capture. MEA is a base and degrades when it reacts with the acid gases in the flue gas. The important acid gases are SO_2, NO_2, HCl and HF. As MEA is regenerated and looped back to capture CO_2, degradation of MEA is expensive (*44*). The reactivity of the acid gases are of the same order but compared to other acid gases SO_2 is significant due to its higher mole fraction and therefore the flue gas should be further desulfurized to the order of 10ppm before CO2 capture. A summary of the data is presented in the table below.

Table 7. Physical parameters of the CO2 capture plant using MEA

Parameters	Unit	Value
Parameters used to model the Capture plant		
Energy Penalty	%	31.4
CO2 removal efficiency	%	90
SO2 removal efficiency	%	99.95
PM removal efficiency	%	50
NO2 removal efficiency	%	25
HCl and HI reduction efficiency	%	95
Ammonia emission	mol/mol of MEA oxidized	1
MEA oxidization	%	50
MEA concentration	wt%	30
Nominal MEA makeup	kg MEA/ tonneCO_2	1.5
Caustic consumption in MEA reclaimer	Kg NaOH/tonneCO_2	0.13
Activated carbon use	kgC/tonneCO_2	0.075
LCI data for CO_2 capture infrastructure from **(*18*)**		
Steel (absorber+stripper)	t	235
Steel (piping and small equipment)	t	82
Concrete	m^3	1
Transport	kt x km	9.5
Lifetime	Year	30
Total CO_2 captured over lifetime	Mt	94
Compressor Infrastructure also obtained from **(*18*)**		
Concrete	m^3	65
Diesel and Heavy fuel oil	Gj	1978
Electricity	MWh	61
Steel[a]	t	65
Copper	t	7
Polyethylene	t	20
Compressor capacity	MW	40
Lifetime	yr	20
Total CO2 compressed over life time	Mt	62
Total leakage of CO2 over lifetime	kt	18

The energy required for compression is already included in model by Rubin (*42*) as energy penalty. The infrastructure and energy required to manufacture the compressor is provided by Koorneef (*18*) and is presented in the table.

Block 2 - Transport and Sequestration

The transport of CO2 from the plant to the sequestration site is through pipeline. The distance between the aquifer and the powerplant is assumed to be 100mi (*42*) thus the requirement of additional compressors are not required. The material and energy requirement for construction and operation of the pipeline is provided by Wildboltz(*25*). Sequestration requires deep drilling of a hot dry rock reservoir. The parameters of the well are provided in the table below. The LCI dataset for the aquifer well without the inclusion of the dataset for drilling is provided by Wildboltz(*25*).

Table 8. Characteristics of the aquifer used. Adapter from (*25*)

	Aquifer [m]	depleted gas field [m]
Depth well	800	2500
Length borehole	1600	5000
Number of wells	2	2
Assumed monitoring well	400	1250
Total drilling length	3600	11 300

Based on the data collected as explained, the system was set up in Simapro as shown in the figure 9. The functional unit of the system is per kWh of electricity produced from the plant. The output of the CCS case is reduced based on the energy penalty assumed in the model.

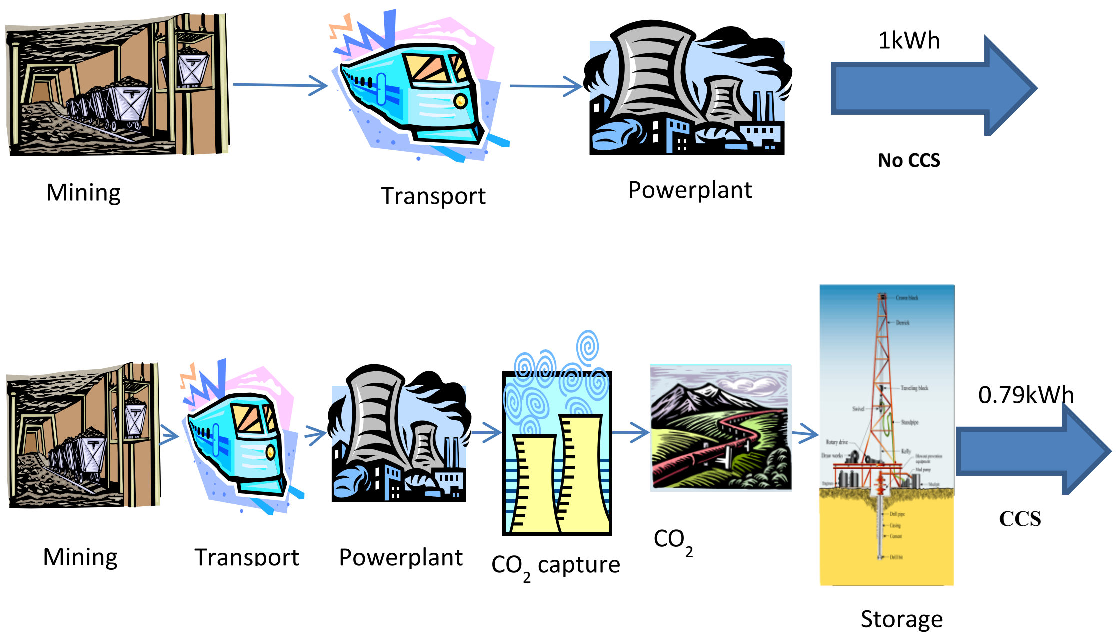


Figure 9. Schematic Figure of the systems included for the No CCS and CCS case

Life cycle impact analysis (LCIA)

The first step in LCIA is the collection of LCI for Powerplant with NO CCS and with CCS, which is already explained in the section above. The quantified inventory is translated to midpoint impact categories through characterization factors. The midpoint categories are further converted into end point categories through normalization factors. The end point categories are weighted and a single score measured in eco points represents the net environmental impact of the system under study. Here two final scores are developed one for No CCS and other for CCS case. The case with the biggest score has a high impact and therefore not beneficial. The characterization, normalization and the weighting factors are obtained from ecoindicator'99 methodology. All the three perspectives (hierarchical, egalitarian, and individualistic) in eco indicator methodology are used for the analysis to consider the model uncertainties.

Valuation Model

The valuation model is similar to that of the LCIA, here the total damage cost of No CCS and CCS case are compared. Instead of comparing the two cases based on eco points the valuation model quantifies the total damage based on the marginal damage cost of the quantity of emissions. The quantity of emissions is taken from the LCI. The marginal damage costs of emissions are taken from the literature. The emissions modeled in the literature are NOX, SO_2, $PM_{2.5}$, VOC, CO_{2eq}, NH_3 and Hg. Due to the wide range for the marginal damage costs for the emissions, Montecarlo simulation is used to characterize the uncertainty. Currently only uniform and triangular distribution of the marginal damage cost are simulated. MATLAB is used for the simulation and 10000 random variables for marginal damage cost for each emission are generated. The total damage cost for each case is the sum of the product of the quantity of emission and the marginal damage cost of the quantified emission. 10000 damage cost for both uniform and triangular distributions are generated. From these variables a min, median and max value is used to characterize the results. Net benefit is the difference between the damage cost of CCS case and No CCS case.

The following list of formula are the list of formula used to calculate the Net benefit.

$$Damage\ cost\ attributed\ to\ each\ pollutant, \qquad DC_i = Q_i \times MD_i$$

$$Benefit\ for\ each\ emission, \qquad B_i = (Q_{No\ CCS} - Q_{CCS})_i \times MD_i$$

$$Total\ damage\ cost\ for\ a\ No\ CCS\ plant, \qquad TD_{No\ CCS} = \sum_{No\ CCS,i} DC_i$$

$$Total\ damage\ cost\ for\ a\ No\ CCS\ plant, \qquad TD_{CCS} = \sum_{CCS,i} DC_i$$

$$Net\ benefit, \qquad NB = TD_{CCS} - TD_{No\ CCS}$$

Where,

i is the different emissions CO2, NO_X, $PM_{2.5}$, VOC, NH_3, SO_2 and Hg.

MD is the marginal damage cost associated to each emission. in $/tonnes of emission. The net benefit can be negative or positive and it depends on if the tradeoffs outweigh the CO_2 reduction benefits or not. The benefits are the CO_2 and SO_2 due to their reduction while $PM_{2.5}$, VOC, NH_3 and Hg are disbenefits.

Cost Benefit analysis

Cost benefit analysis is a prospective analysis to understand the benefit of reducing CO_2 by CCS by comparing it with the cost associated with building the equipment necessary to reduce CO_2. The benefits are identified using the valuation models as explained above. The net benefit with a min, median and max values from the valuation model is used here. Until now there hasn't been a commercial deployment of CCS plant in the US but numerous design studies have estimated the theoretical cost incurred to a powerplant. This makes it feasible to compare the cost to the benefits associated with the technology. The output of a cost benefit analysis is a cost benefit ratio. It is the ratio of benefit to cost. A cost benefit ratio of 1 means that the increase in the cost of electricity due to CCS equals the benefits associated with the technology. Typically the benefit of a technology should be greater than the cost associated with implementing it.

Of the emissions studied the CO2 could be the first externality cost that could be internalized. Numerous efforts have been taken to identify a single value for CO2 emissions. A cap and trade system is another solution to internalize. Therefore the net benefit and the cost benefit ratio are presented as a variable with the damage cost of CO_2.

RESULTS

Life Cycle Inventory

Based on the methodology a model was constructed for a pulverized coal powerplant with CCS. The model was constructed based on both surface mining and underground mining of coal. The table below shows the main list of inventory for the whole life cycle of the plant of the cases considered.

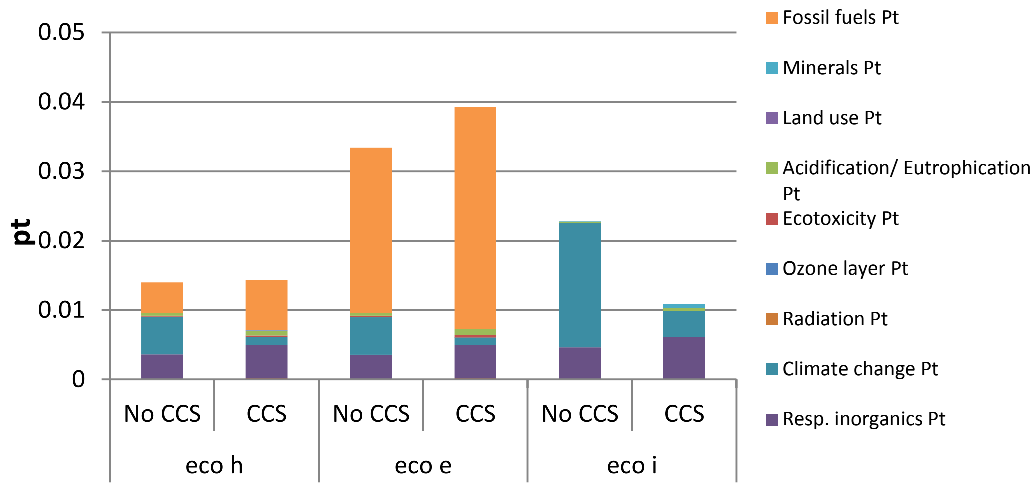
Table 9 - Life cycle inventory of emission from Powerplant without CCS (No CCS) and Powerplant with CCS (CCS) presented in quantity per kWh of electricity produced.

Emissions	Surface Mining		Underground Mining			Unit
	No CCS	CCS	Emissions	No CCS	CCS	
CO_{2eq}	758.8	159.48	CO_{2eq}	779	185.88	g/kWh
$PM_{2.5}$	0.0749	0.0962	$PM_{2.5}$	0.0758	0.0973	g/kWh
SO_2	0.648	0.4992	SO_2	0.648	0.4992	g/kWh
NO_X	0.544	0.7311	NO_X	0.536	0.7206	g/kWh
Hg	27.2	35.8	Hg	27.2	35.8	µg/kWh
NH_3	0.0734	0.3386	NH_3	9.5E-5	0.2425	g/kWh
VOC	0.191	0.258	VOC	0.18	0.244	g/kWh
Lead	22.3	35.16	Lead	22.3	35.16	µg/kWh

The emission inventory between Surface and underground mining between most of the emissions are of the same order except that of ammonia emissions. The difference in the ammonia emissions is because surface mining uses ammonium nitrate to blast the top layer of the soil during which a significant amount of ammonia is emitted. There are also small differences in the CO_{2eq} and $PM_{2.5}$ emissions which are primarily due to the excess amount of methane emitted in underground mines and the second order $PM_{2.5}$ emissions are due to the production of rockdust in underground mines. The minor differences in VOC and NO_X could not be clearly identified due to the data gaps in the literature. Due to the similarities the inventory results for surface mining are used in the analysis and the significance of the differences in these emissions will be discussed in the result section.

Life Cycle Impact Analysis

Once the inventories for both the CCS and No CCS case are assembled for the surface mining case, they are compared using the Ecoindicator'99 methodology. The result for all the three cases in ecopoints (pts) is presented in the Figure 10. The impact of each case is measured in ecopoints. Also comparing the total ecopoints across perspectives for the same case shows that Egalitarians perceive a larger impact for the system modeled than the other two perspectives. The reason for the difference in all the three perspectives is because each perspective values the impacts differently. The impacts measured by Eco indicator methodology are fossil fuels, minerals, land use, Climate change, Acidification, Ecotoxicity, Eutrophication, Ozone layer, Radiation, Respiratory Organics and Respiratory inorganics. The figure also shows the contribution of all these impacts for the total impact. The difference between value-systems of the different perspective can be noted, e.g., the impact category that has the largest contribution under each perspective for the No CCS case is Climate change (39%) for hierarchist, Fossil fuels (71%) for egalitarians and Climate change for individualists (79%).



Impact category	**Unit**	**Eco h**		**Eco e**		**Eco i**	
		No CCS	**CCS**	**No CCS**	**CCS**	**No CCS**	**CCS**
Carcinogens	%	1	1	0	0	0	0
Resp. organics	%	0	0	0	0	0	0
Resp. inorganics	%	25	33	10	12	20	56
Climate change	%	39	8	16	3	79	34
Radiation	%	0	0	0	0	0	0
Ozone layer	%	0	0	0	0	0	0
Ecotoxicity	%	1	2	1	1	0	0
Acidification/ Eutrophication	%	2	5	1	2	1	4
Land use	%	0	0	0	0	0	0
Minerals	%	0	0	0	0	0	5
Fossil fuels	%	32	50	71	81	0	0

Figure 10 - Result from Life cycle analysis for each perspective. Eco h – Hierarchical, Eco e – Egalitarian, Eco i – individualistic. No CCS is powerplant without CCS and CCS is powerplant with CCS case.

These differences in the modeling approach affect our main result, which shows that CCS is not beneficial for Hierarchist and Egalitarians while it is beneficial for individualists. Hierarchist and Egalitarian see a 2% and 18% increase in impacts due to CCS and an individualist see a 52% reduction in impact due to CCS. For the system modeled only three impact categories, climate change, respiratory inorganics and Fossil fuels are significant. As expected the climate change impact decrease while respiratory inorganics and Fossil fuel impact increase. For Hierarchist and the egalitarians the reduction of climate change impacts is completely traded-off by the increase of respiratory inorganics and depletion of fossil fuels. Since Individualists do not perceive depletion of fossil fuel as a threat, the reduction of climate change impacts are not completely traded-off by the increase in respiratory inorganics. In other words Ecoindicator methodology assumes zero as a weighting factor for fossil fuels under individualistic perspective.

The weighting is based on cultural theory(*45*), and according to it, Hierarchist and egalitarian view resources as scarce and depleting while individualist view them as abundant. Individualists are adaptive and believe that technology can solve/avoid many problems. They also have a short time perspective which makes them value benefits more than the risk. Therefore the increased depletion of fossil fuels is not included in an individualistic perspective. Detailed characteristics of the three approaches are provided in the table 10. These characteristics define the value system of three approaches.

The significance of LCIA is to identify the emissions that are significant contributors to the impact categories. It also identifies the source of the emission based on contribution from each life cycle stage. The following section discusses the important emissions and their source of these emissions at each life cycle stage.

Table 10. World views, attitudes, management styles and characteristics of the four perspectives. Adapted from (*45*)

Archetypes → ***Attribute categories ↓***	**Hierarchist**	**Egalitarian**	**Individualist**
Myth of nature	Nature is perverse/tolerant	Nature is fragile	Nature is benign
Perception of time	Balanced distinction between short and long term	Long term dominates short term	Short term dominates long term
Scope of knowledge	Almost complete and organised	Imperfect but holistic	Sufficient and timely
Benefit-risk dilemma	Benefits versus risks	Risks	Benefits
Spatial survival dilemma	Local versus global outcomes	Global	Local
Social survival dilemma	Individual versus collective outcomes	Collective	Individual
Procedures applied	Rules	Ethical standards	Skills
Criteria	Evidence	Argument	Experience
Temporal survival dilemma	Present versus future outcomes	Future	Present
Trust	Procedures	Participation	Successful individuals
View of resources	Scarce	Depleting	Abundant
Management style	Control	Preventive	Adaptive
Discounting	Technical standard	Zero/negative	Diverse/high
Search and change behaviour	High on search; low in (internal) change	High on search: high on (external) change	'Satisficing'; enough search for enough change
Method for applying model of consent	Natural (or other ideal) standards	Expressed preferences	Revealed preferences
Attitude towards risk	Risk-accepting	Risk-aversive	Risk-seeking

Climate change, respiratory inorganics and Fossil fuels are the three categories that contribute atleast 95% to the total score. The increase of impact categories like eutrophication, acidification and ecotoxicity are not relatively significant. Climate change impacts are caused by the CO_2 and methane emissions. Respiratory inorganics are Sulfur dioxide, Particulate Matter, Nitrogen oxides and Ammonia. Fossil fuel impacts are from Coal and Natural gas used. The percentage contribution of these emissions to their corresponding characterized impact category for the both No CCS and CCS case are shown in the table 11. The impact category Fossil fuel is dominated by depletion of coal, natural gas and crude oil. The biggest contributor is Coal followed by natural gas and crude oil. For the Hierarchical and the Egalitarian perspective the percentage contribution of Coal to the total impact decreases in the CCS case when compared to No CCS case. The decrease in the contribution doesn't signify a reduction of the depletion of fossil fuel but it means the percentage contribution of Natural gas and Crude oil has a greater marginal increase than fossil fuel according to the Ecoindicator methodology. For climate change impacts the emission of CO_2 and CH_4 are major contributors with CO_2 contributing atleast 85% of the impact in all the perspectives.

Table 11. Contribution of the resources and emissions to the total characterized impact categories. Fossil fuel is measured in MJ surplus. Climate change and Respiratory inorganics are measured in DALY – Disability adjusted light year

Impact Category	Emissions	Eco I		Eco H		Eco E	
		No CCS	CCS	No CCS	CCS	No CCS	CCS
Fossil Fuel	Coal	0%	0%	72%	58%	97%	95%
	Natural Gas	0%	0%	28%	32%	0%	4%
	Crude Oil	0%	0%	0%	10%	3%	1%
	Total (MJ Surplus)	0	0	0.112	0.181	0.664	0.893
Climate change	CO_2	98%	86%	98%	87%	98%	87%
	CH_4	2%	14%	2%	13%	2%	13%
	Total ($X10^{-7}$DALY)	1.51	0.314	1.58	0.328	1.59	0.328
Respiratory. Inorganics	Particulates	23%	26%	12%	13%	12%	13%
	SO_2	65%	38%	35%	20%	35%	19%
	NO_X	2%	2%	47%	47%	47%	47%
	NH_3	10%	34%	6%	21%	6%	21%
	Total ($X10^{-7}$DALY)	0.387	0.511	1.02	1.39	1.03	1.4

For respiratory inorganics all the emissions Particulates, SO2, NOX and Ammonia are significant. The total DALY for respiratory inorganics increases due to CCS in each perspective. SO2 is the only other emission except CO2 that decreases due to CCS. The reduction of SO2 is significant because it keeps the increase in the impact due to respiratory inorganics to a minimum. The figure shows the contribution of the reduction of SO2 to the total DALY. Scenarios where SO2 aren't reduced before sending the flue gas to capture plant increases the total environmental impact of CCS case.

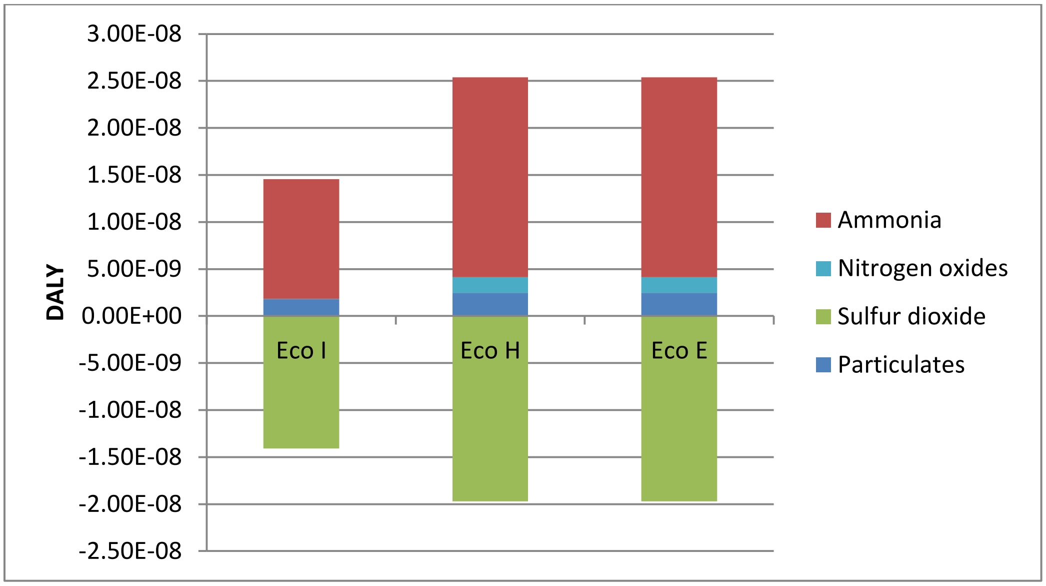


Figure 11 - Contribution of emissions to the increase of respiratory inorganics under each perspective.

Reporting the emissions based on the different stages and its life cycle phases is necessary to identify the opportunities for the reduction of these emissions. The different stages in the analysis are the Powerplant with Capture, transport and sequestration. The table 13 below shows the contribution of the emissions from each stage to the total score. The emission from the powerplant is the biggest contributor. In other words the fossil fuel use, climate change contributors and emission of respiratory inorganics are primarily from the powerplant. The only other stage that has a notable contribution is the transportation of CO2 for an individualist. It contributes to 6.87% of the total impact. The use of nickel in the pipelines is the cause of the impact. The powerplant with CCS is an integrated system therefore it is difficult to separate the contribution of a powerplant and a carbon capture system. One of the notable contributions of the carbon capture plant is the increase in the emission of ammonia during the reaction of MEA with the flue gas. The other significant contribution of the capture plant is the reduction of SO_2 which is a prerequisite for the capture plant.

Table 12. Contribution of each stage to the single score

Impact Category	Powerplant +carbon capture	Transport	Sequestration
Eco I	93.13%	6.87%	0.00%
Eco H	98.30%	1.69%	0.00%
Eco E	99.39%	0.61%	0.00%

The table below shows the life cycle contribution of the powerplant emissions assumed in the model. The majority of the emissions come from the electricity generation phase except for NOx and Methane. Methane is emitted during coal mining but it contributes to about 14% of the total impact on climate change. A significant portion of NOx is from the transportation and mining of coal. A significant portion of the total emission of SOX and PM are also emitted in the transportation phase. The transportation of coal assumed in the analysis is through barges (railcar = 48 km plus barge = 434 km). If transportation through rail is assumed for an average distance of 483km the quantity of emissions change only by a factor of ±1%(*26*). The raw materials coal and natural gas used are atleast 99% for the electricity production.

Table 13. Contribution of emissions according to their life cycle stages

Emission	Mining	Transportation	Electricity Generation
Nox	6.53%	25.24%	68.23%
Sox	7.41%	9.86%	82.72%
PM	8.66%	12.24%	79.11%
CO_2	0.96%	1.76%	97.28%
Methane	94.07%	0.10%	5.84%

Sensitivity Analysis. The results show that the majority of the impact comes from the operation of the powerplant. Therefore the biggest opportunity lies in reducing the energy needed to capture the CO_2. The analysis assumes that the energy needed to capture is provided by the powerplant itself. An alternative could be to use energy from a cleaner energy source if it economically feasible.

Based on a literature review it is identified that the energy penalty varied between 25% to 35%(*11*). Assuming the values as the minimum and maximum energy penalty a sensitivity analysis is done to identify the total benefit of CCS. At 35% energy penalty the individualists continue to see CCS as a beneficial technology. At 25% energy penalty egalitarian approach continue to show that CCS is not beneficial. But the hierarchical approach shows that CCS is beneficial at 25% energy penalty. While individualistic approach remains the same. The energy penalty target necessary to make CCS beneficial even according to egalitarian approach is identified to be atmost 13%. The energy penalty is identified by trial and error basis for the current scope of the analysis. Due to lack of micro level LCI data the scope of the uncertainty analysis is limited to sensitivity analysis.

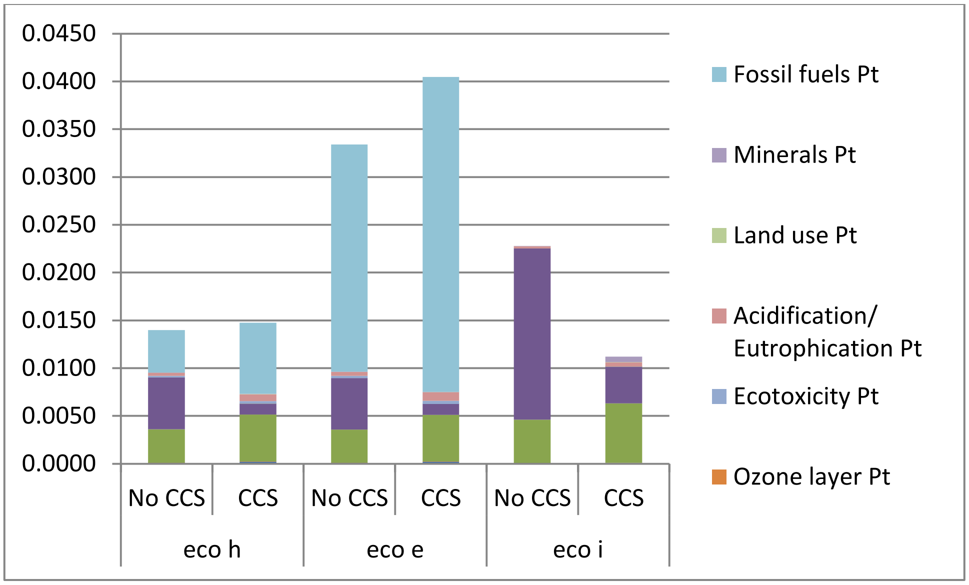


Figure12. Total score of the two cases when energy penalty is 35%

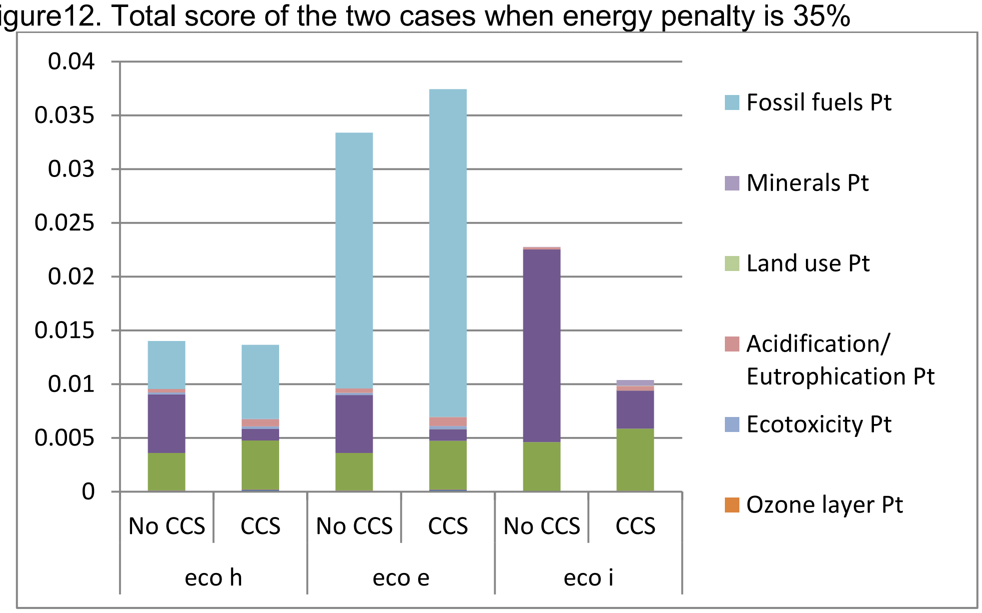


Figure13. Total score of the two cases when energy penalty is 25%

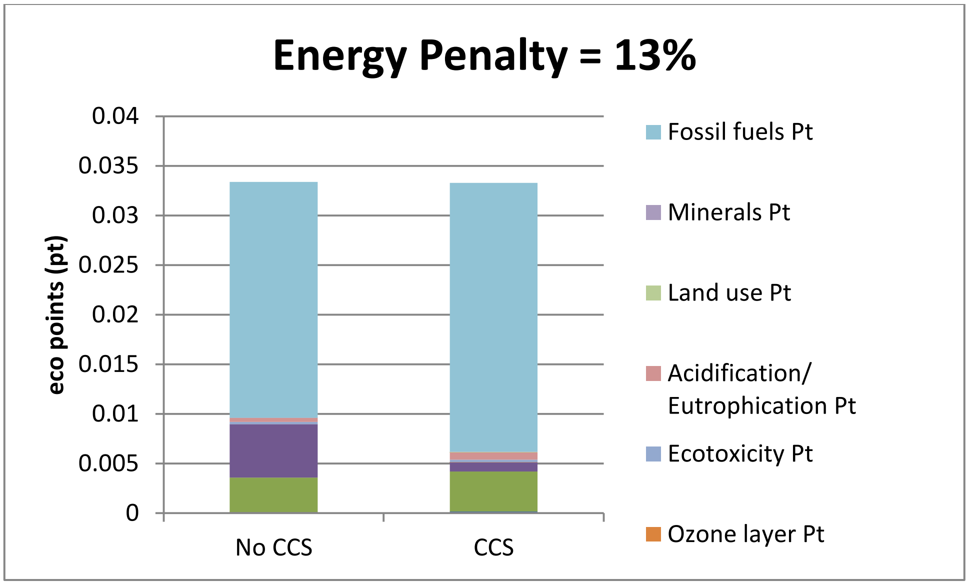


Figure 14 - Total score of the two cases when energy penalty is 13%

Summary. The life cycle impact assessment is one of the advanced and further evolving scientific tools to assess sustainability of a product/technology. LCIA has been used to quantify the tradeoff that would otherwise be left unquantifed. The important tradeoff impacts are the increased fossil fuels and respiratory inorganics. The increases are based on per unit (kWh) of electricity generated. The LCIA is attributed to the electricity produced from a single powerplant with CCS therefore the results conclude that there is an increase in the emission factor of all emissions and resources except CO_2 and SO_2 per kWh of electricity produced. The increase in the emission factor doesn't mean an increase in the total emissions at the national level because the net emission depends on the number of new powerplants, how many plants implement CCS. A consequential or a scenario analysis is required to identify if there will be a net increase of impacts at a national level. Overall the model is underestimated due to many reasons including, 1.assuming a linear relationship between the energy penalty and the resources in an out of the model; 2. No characterization and fate of waste from capture plant; 3. Non-inclusion of land use change impacts from mining and powerplant. 4. Exclusion of energy and material required to drill the sequestration site. Underestimated model has shown that the net benefit from installing CCS may not be beneficial based on different approaches.

Valuation Model

The valuation model calculates the total benefit of CCS from the following emissions, CO_2, $PM_{2.5}$, NO_X, VOC, SO_2, NH_3 and Hg. Of the 7 emissions CO_2 and SO_2 emissions decrease while $PM_{2.5}$, VOC, NH_3, NO_X and Hg emissions increase in CCS case. Therefore CO_2 and SO_2 are benefits while the remaining gases are not benefits also called as 'disbenefits' in the rest of the report. As defined in the methodology, the net benefit and contribution of each of the seven emissions to the net benefit are calculated for damage cost of CO2 between $10 - $100 per ton. The reason to characterize the results based on CO_2 price is because CO_2 could be the first external cost to be internalized in the form of carbon tax or carbon cap and trade. The values also have a min, median and max based on Montecarlo simulation of the marginal damage cost.

The Figure 15 below shows the net benefit in c/kWh associated with the implementation of CCS. The values are characterized with the marginal damage cost of CO_2 according to two uniform and triangle distribution scenarios. Under uniform distribution scenario the net benefit varies from 0.14 to 5.53 cents/kWh and the range under triangular distribution scenario is slightly higher varying between 0.33 to 5.72 cents/kWh. It is higher because the median values of the marginal damage costs are skewed to the left in other words the median of the marginal damage costs are less than the mean values. The increase in the net benefit with the increase in the price of CO2 can be noted and the reason for the increase is intuitive reducing CO2 is a benefit and higher the value of the benefit in Cents the higher the net benefit. At CO_2 price \$10 and \$20 per ton there could be no benefit from CCS. The low CO2 scenarios are when the damage cost of benefits (CO2, SO2) are valued lesser and the damage cost of the disbenefits (PM2.5, NOX, Hg, VOC, NH3) are valued higher. In the current model when CO2 is valued less than \$30/ton CCS might not be beneficial.

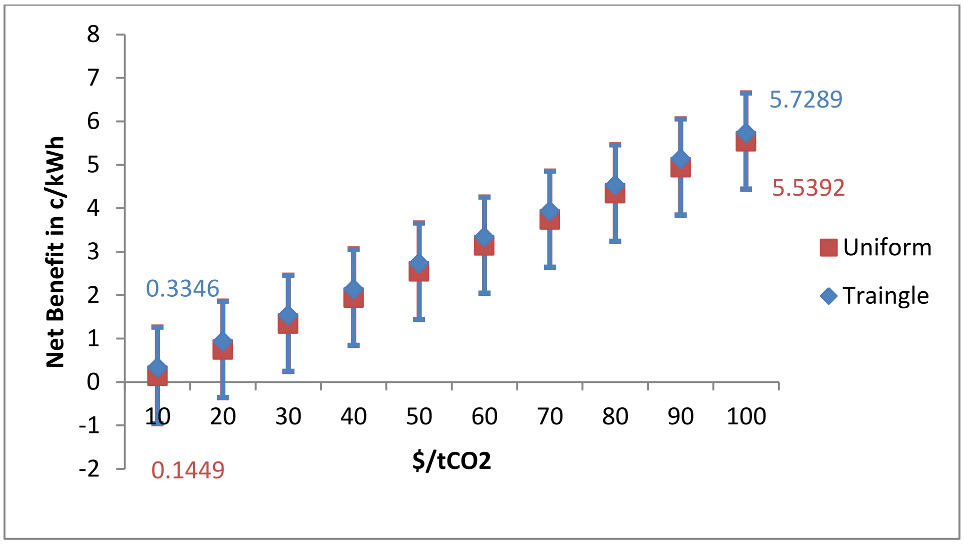


Figure15. Net benefit of implementing CCS characterized to marginal damage cost of CO_2

The table14 shows the contribution of each emission to the net benefit based on the two distribution scenarios at CO_2 price of \$30/tCO_2. \$30/tCO_2 is assumed to be the mean value according to the National academic of sciences (*37*). The total damage cost of each emission is classified into Min, median (uniform), median (triangle) and max based on the Montecarlo simulation. The min and max for both triangle and uniform distributions are the same therefore they are not mentioned. The benefits (CO_2 and SO_2) are positive while the disbenefits are negative. The 'Net Benefit without CO_2' is the sum of the benefits of all the emissions except CO_2. The 'Total disbenefit' column is the sum of all the emission that is disbenefits. The median values of the total disbenefit under triangle distribution are lesser when compared to the median of the uniform distribution due to the rightly skewed marginal damage cost function of all the emissions. The triangular distributed values show a more characteristic result therefore the results based on triangle distribution are provided in the following sections. Results characterized using uniform distributions are reported in the appendix. The contribution of SO_2 to the net benefit is significant because at the max range the benefits from SO2 are greater than the total disbenefits from all the disbenefits.

Valuation models generally don't consider the life cycle emissions. Also in all through the literature the benefit of CCS is valued based on the benefit value of CO_2. The inclusion of SO2 as a benefit and disbenefits will reduce the benefits calculated and the inclusion of these life cycle emissions are significant. The Figure-16 shows the contribution of the each emission to the net benefit at \$10, \$20 and \$30 per ton of CO_2. The three cases consistently show that at Min and the median scenario the disbenefits significantly reduce the net benefit. Disbenefits from the emission of $PM_{2.5}$ are the major contributor to the disbenefits.

Table 14- The total benefits and disbenefits from uniform and triangular distribution scenario at a constant \$30/tCO2

Range (c/kWh)	CO2	Net Benefit without CO_2	Total Disbenefit	Net Benefit
Min	1.80	-1.56	-1.65	0.24
Median (Uniform)	1.80	-0.45	-0.87	1.34
Median (Triangle)	1.80	-0.26	-0.62	1.53
Max	1.80	0.66	-0.08	2.46

Note: Min is the combination of maximum marginal damage costs for disbenefits and minimum marginal cost for the benefits. Max is the combination of the minimum marginal damage cost values for the disbenefits and the maximum values for the benefits.

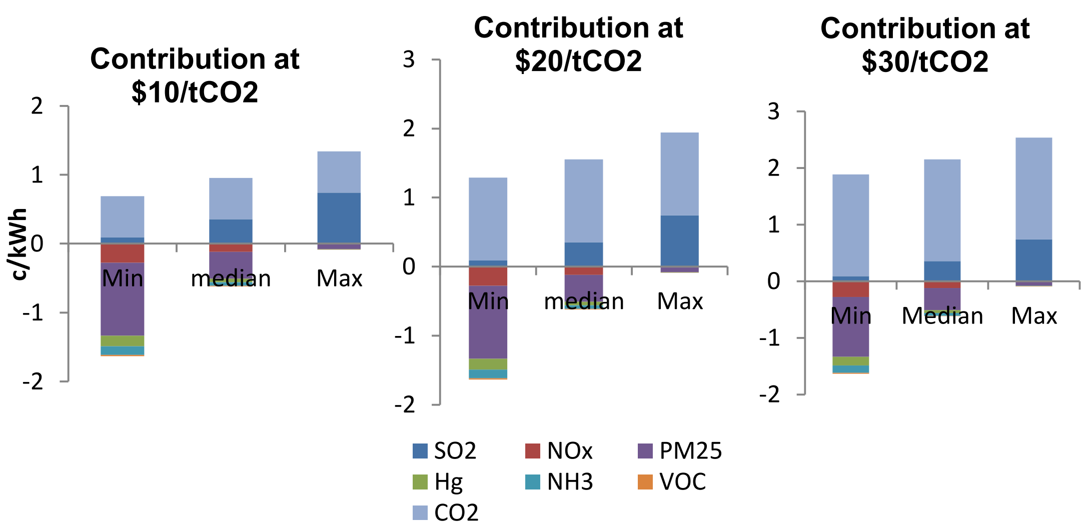


Figure 16 . Contribution of each emission to the total benefit at \$10, \$20 and \$30 per tCO2

Cost Benefit Analysis

Cost benefit is the ratio of net benefit of CCS to the cost involved with construction, operation and maintenance of CCS. In our valuation model we have used two scenarios for benefit.

1. Net Benefit associated with CO_2 and other life cycle emission. [B1]
2. Benefits associated only with the reduction of CO_2 only [B2]

The cost associated with constructing, operating and maintaining a powerplant are taken from the other literature studies and a summary of the literature available are already discussed in the literature review. Table 2 shows the Levelized cost of a powerplant without carbon capture and with carbon capture using amines in c/kWh. Levelized cost of electricity (COE) is the constant dollar electricity price that would be required over the life of the plant to cover all the operating expenses, payment of debt and accrued interest on intial project expenses, and the payment of acceptable return to investors. The COE doesn't include the cost for sequestration. Many other reports have calculated the cost for transportation and sequestration and it is identified to be between -1 to 1 c/kWh(*46*). The negative costs associated with the offsetting revenues generated from CO_2 storage in enhanced oil recovery (EOR) or enhanced coal bed methane emissions (ECBM) projects. The geographical setting of a coal powerplant determines whether it can receive the revenue from EOR and ECBM therefore two scenarios for cost are developed

1. Levelized cost of electricity that includes revenue from EOR and ECBM. (in c/kWh) [C1]
2. Levelized cost of electricity that doesn't include revenue from EOR and ECBM. (in c/kWh) [C2]

Table 15 - The increase in the cost of electricity (COE) with and without sequestration revenue

Range	With sequestration revenue	Without sequestration revenue	Unit
Min	3.61	1.61	c/kWh
Median	4.08	2.08	c/kWh
Max	4.6	2.6	c/kWh

The table 15 above shows the increase in COE due to CCS with and without the sequestration revenues. Based on the two scenarios for both cost and benefit four combination of cost benefit ratio are obtained as shown below,

- Cost benefit ration without sequestration credit for all life cycle emission R1= C2/B1
- Cost benefit ratio without sequestration credit for only CO2 emissions R2= C2/B2
- Cost benefit ratio with sequestration credit for all life cycle emission R3= C1/B1
- Cost benefit ratio with sequestration credit for only CO2 emissions R4= C1/B2

The Figure 17 plots the cost benefit ratio (R1 and R2) with varying CO_2 prices when there is no revenue from sequestration. Similarly the Figure 18 shows the cost benefit ratio with the sequestration revenue (R3 and R4). The error bars for the cost benefit ratio are characterized based on the min, median and max for both the benefit and cost. The benefits are based on the triangular distribution of the marginal damage cost. The cost benefit ratio based on uniform distribution of the marginal damage costs are presented in the appendix. It is expected that the cost benefit from uniform distribution will be lesser than the triangle distributed values shown below.

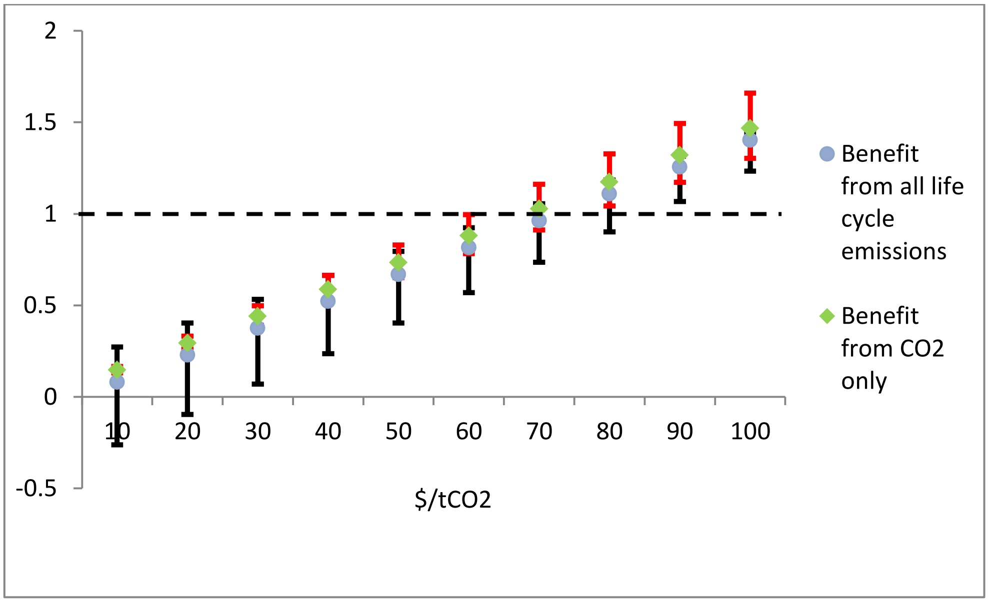


Figure17. Cost benefit analysis for the powerplant with CCS without sequestration credits.

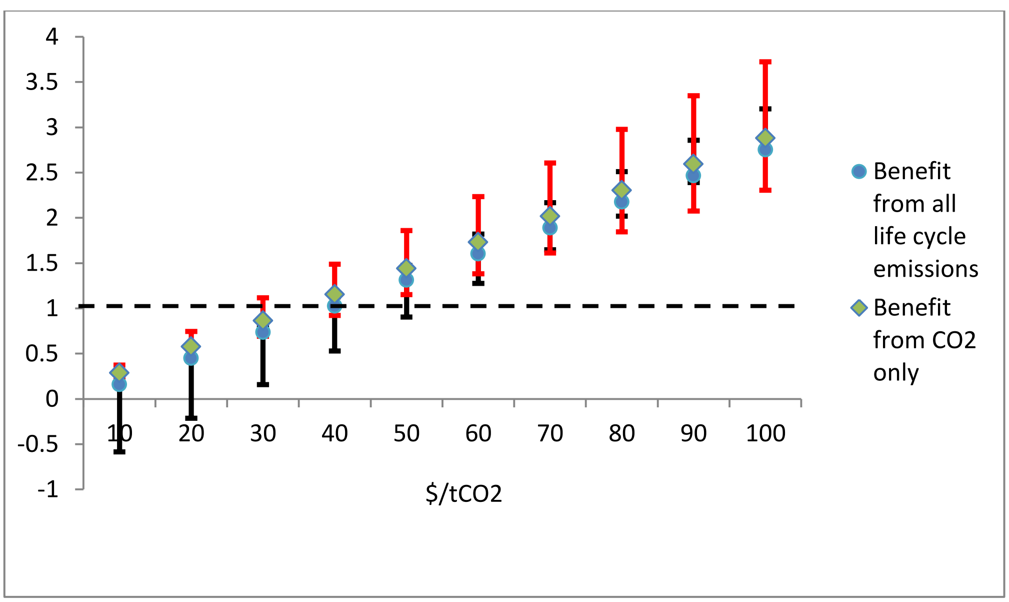


Figure18. Cost benefit analysis for the powerplant with CCS with sequestration credits.

Table 16. Percentage reduction of cost benefit ratio due to the addition of life cycle emissions

	$10/tCO2	$20/tCO2	$30/tCO2
With Credit	76%	38%	25%
Without Credit	76%	38%	25%

Inorder for CCS to be beneficial (cost benefit ratio ≥ 1) the cost of CO_2 should be atleast greater than $80/tCO2 when there is no sequestration credit and greater than $50/t$CO_2$ when there is sequestration credit. Valuing the cost benefit ratio with only CO_2 emissions results in underestimating the cost of CO_2 required to tradeoff the cost and benefit. The table 16 shows the percentage reduction of cost benefit ratio due to the addition of life cycle emissions at differenct cost of CO_2. At lesser CO_2 cost the percentage reduction is higher and it decreases as the cost of CO2 increases but never overlaps each other until $100t/$CO_2$.

INTERPRETATION OF THE RESULTS

Coal powerplants that capture CO_2 using CCS has a reduced electricity output. The reduced electricity output translates into more resources for the same unit of electricity produced. More resource/coal means more emissions per unit of electricity produced. Though the CO2 is captured all the other emissions aren't. Is to beneficial to let other emissions increase while to reduce CO2? To identify the net benefit of CCS three methodologies, LCA, valuation models and cost benefit are used. All the three methodologies showed that CCS might not be beneficial under certain conditions. Life cycle assessment was used to compare the impact of a powerplant to the same powerplant with a CCS. The LCA showed that under Hierarchical and Egalitarian approaches in the EcoIndicator'99 methodology CCS might not beneficial while CCS is beneficial under individualistic methodology. The difference between these methodologies is the value system based on which the impacts are weighted. For CCS to be beneficial under all the three approaches, atleast 60% reduction of the current energy penalty (31%) is needed.

The valuation model identifies the net benefit of the two cases based on the externality cost for the emissions. The results are generated using Montecarlo simulation. The lower quartile of the net benefits at $10/t$CO_2$, shows that CCS is not beneficial. The disbenefit from the emission of PM2.5 is greater than the benefit of reducing CO_2 at lower CO_2 prices. This is a very important result because valuation models have been used by regulators to identify the benefit of environmental regulations. Numerous research papers report only benefits associated with the reduction of CO_2 in the case of CCS. The contribution of emissions other than CO_2 to the net benefit is important because it provides the actual benefits associated with CCS by including the tradeoffs.

Cost benefit analysis is the most traditional method to identify the benefit of a technology. Factoring the disbenefits due to other life cycle emissions into the cost benefit analysis makes this methodology unique. The cost benefit ratio is less than one for CO_2 price lesser than and equal to \$60/tCO_2 and \$90/tCO_2 when there is sequestration credit and no credit respectively. The traditional cost benefit analysis which don't include other LCE have CO_2 price reduced by \$10/tCO_2 value when the cost benefit ratio equals one. With the current CO_2 prices in the European exchange market, around \$15/tCO2, CCS is not beneficial.

UNCERTAINTY AND FUTURE RESEARCH

To understand the limitation of the results variability and uncertainty of the data has to be understood. The prime difference between variability and uncertainty is, variability can be measured using statistical methods while uncertainty cannot be measured.

Variability: The result of the analysis is valid for an ultra-critical pulverized coal powerplant that uses Illinois type bituminous coal mined either in surface or underground mines. The CO_2 capture is using amines and transportation through pipeline and sequestered in aquifers. This combination of life cycle phases is considered to be the typical case for new CCS systems. However depending on geographic, political and economic factors there will be variations. These variations have already been discussed for the inventory. The other important variability is the geographical variation of the damage cost. The range for the damage cost includes the geographical variability for the US.

Uncertainty: Uncertainty is classified into parametric, model and scenario. The CO_2 capture system analyzed hasn't been commercialized yet; therefore the inventory derived from such a system has data uncertainty. It is difficult to address this uncertainty until amine capture system is commercialized.

Model Uncertainty: In general LCA assumes a linear relationship for the emissions per kWh. Also the model for identifying the inventory is a theoretical model which doesn't consider how different actors involved with the supply chain behave. The model assumes the supply chain behaves as it is set up in the model. These over simplification are model uncertainty for the inventories. Also limited damage cost models are available. The damage cost models is combination of statistical value of life, dose response functions, age cohorts, atmospheric chemistry and wind patterns around powerplant. Each component is calculated based on models and therefore there are inherent model uncertainties at each step due to aggregation. Some models have a higher VSL than the other while some include a limited atmospheric reactions compared to other models. Due to these differences the thesis uses the model that has the highest uncertainty range for the emissions considered. Even though there is a huge uncertainty range used it doesn't cover all the impacts associated to the emission due to the limited scientific knowledge. The valuation model doesn't include pollutants like lead, carbon monoxide. The non-inclusion increases the net benefit of CCS although how much increase couldn't be quantified.

Scenario uncertainty has a broader context to uncertainty than the model and parametric uncertainty. Our results points out that according to cost benefit analysis the cost due to CCS is higher than the environmental benefit at mean cost of CO2. It is improper to predict that CCS is not beneficial from this result but scenario analysis has to be conducted to identify cases for eg., when CO2 cost can be higher than \$100/ton? Will mandatory implementation of CCS increase the cost of electricity and favor other fuel sources in long term? Understanding scenario uncertainty helps in policy decisions.

The thesis has all the three types of uncertainties and the future research would primarily based on addressing the uncertainties. First, the geographic variation of the damage cost can help in providing a county wise net benefit of CCS. This information is helpful in identifying new sites for coal powerplants. Secondly, for policy decisions, scenarios needs to be developed to address variability in the electricity mix in the future and the different scenarios discussed above. Finally the thesis continues to mention the importance of life cycle inventory and assessment methods that needs to be perfected to reduce uncertainty.

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APPENDIX A

Data Used To Construct The Life Cycle Inventory

Table A 1. Average resource consumption per kWh of Net electricity produced – Surface mining

	% of Total in this Table	Total (g/kWh)	% of Total from Surface Coal Mining	% of Total from Transportation	% of Total from Electricity Generation
(r) Bauxite (Al2O3, ore)	0.00%	2.50E-03	0.00%	3.69%	96.30%
(r) Clay (in ground)	0.00%	2.07E-08	19.99%	2.20%	77.81%
(r) Coal (in ground)	97.34%	3.53E+02	0.75%	0.01%	99.24%
(r) Iron (Fe, ore)	0.03%	9.54E-02	23.29%	1.96%	74.75%
(r) Limestone (CaCO3, in ground)	0.01%	3.96E-02	81.38%	0.48%	18.14%
(r) Natural Gas (in ground)	1.25%	4.53E+00	7.91%	0.35%	91.74%
(r) Oil (in ground)	1.34%	4.88E+00	4.94%	84.18%	10.88%
(r) Sand (in ground)	0.00%	2.24E-08	0.00%	3.69%	96.30%
(r) Sodium Chloride (NaCl, in ground or in sea)	0.00%	7.17E-05	1.56%	3.58%	94.86%
(r) Uranium (U, ore)	0.00%	3.23E-05	100.89%	0.09%	-0.98%
Aluminum Scrap	0.00%	6.13E-04	0.00%	3.69%	96.30%
Iron Scrap	0.03%	1.02E-01	23.65%	1.93%	74.42%
Lubricant	0.00%	1.73E-03	23.28%	1.94%	74.78%
Trinitrotoluene (C6H3(NO2)3)	0.00%	4.47E-06	0.00%	3.69%	96.30%

Table A 2. Average air emissions per kWh of Net electricity produced – Surface mining

	% of Total in this Table	% of Total in this Table except CO2	Total (g/kWh)	% of Total from Surface Coal Mining	% of Total from Transportation	% of Total from Electricity Generation
(a) Aldehydes	0.00%	0.01%	1.97E-04	16.50%	76.96%	6.54%
(a) Ammonia (NH3)	0.01%	2.87%	7.34E-02	99.88%	0.10%	0.01%
(a) antimony	0.00%	0.00%	3.06E-06	0.00%	0.00%	100.00%
(a) arsenic	0.00%	0.00%	3.68E-05	0.00%	0.00%	100.00%
(a) barium	0.00%	0.00%	9.50E-06	0.00%	0.00%	100.00%
(a) beryllium	0.00%	0.00%	1.19E-06	0.00%	0.00%	100.00%
(a) boron	0.00%	0.49%	1.26E-02	0.00%	0.00%	100.00%
(a) cadmium	0.00%	0.00%	3.02E-06	0.00%	0.00%	100.00%
(a) total Carbon Dioxide (CO2)	99.66%		7.41E+02	0.96%	1.76%	97.28%
(a) Carbon Monoxide (CO)	0.03%	7.47%	1.91E-01	3.58%	39.52%	56.89%
(a) Chlorides (Cl-)	0.00%	0.00%	5.64E-07	0.00%	2.61%	97.39%
(a) chromium	0.00%	0.00%	4.40E-05	0.00%	0.00%	100.00%
(a) cobalt	0.00%	0.00%	5.11E-06	0.00%	0.00%	100.00%
(a) copper	0.00%	0.00%	1.74E-05	0.00%	0.00%	100.00%
(a) Fluorides (F-)	0.00%	0.00%	2.57E-07	19.72%	2.61%	77.66%
(a) non-methane Hydrocarbons (including VOCs)	0.03%	7.48%	1.91E-01	31.53%	22.85%	45.62%
(a) Hydrogen Chloride (HCl)	0.00%	0.00%	1.81E-06	0.23%	2.40%	97.38%
(a) Hydrogen Fluoride (HF)	0.00%	0.00%	1.63E-07	4.44%	3.36%	92.19%
(a) Hydrogen Sulfide (H2S)	0.00%	0.00%	1.03E-08	19.99%	2.20%	77.81%
(a) lead	0.00%	0.00%	2.23E-05	0.00%	0.00%	100.00%
(a) manganese	0.00%	0.00%	3.19E-05	0.00%	0.00%	100.00%
(a) mercury	0.00%	0.00%	2.72E-05	0.00%	0.00%	100.00%
(a) Metals (unspecified)	0.00%	0.00%	1.26E-09	16.43%	2.47%	81.10%
(a) Methane (CH4)	0.10%	27.91%	7.14E-01	94.07%	0.10%	5.84%
(a) molybdenum	0.00%	0.00%	2.83E-05	0.00%	0.00%	100.00%
(a) nickel	0.00%	0.00%	4.30E-05	0.00%	0.00%	100.00%
(a) Nitrogen Oxides (NOx as NO2)	0.07%	21.27%	5.44E-01	6.53%	25.24%	68.23%
(a) Nitrous Oxide (N2O)	0.00%	0.05%	1.19E-03	62.34%	15.29%	22.38%
(a) Organic Matter (unspecified)	0.00%	0.07%	1.86E-03	85.13%	12.21%	2.65%
(a) total Particulates (unspecified)	0.02%	4.39%	1.12E-01	8.66%	12.24%	79.11%
(a) selenium	0.00%	0.01%	3.01E-04	0.00%	0.00%	100.00%
(a) Sulfur Oxides (SOx as SO2)	0.10%	27.97%	7.15E-01	7.41%	9.86%	82.72%
(a) Tars (unspecified)	0.00%	0.00%	3.63E-07	19.57%	2.23%	78.19%
(a) vanadium	0.00%	0.00%	6.54E-05	0.00%	0.00%	100.00%

Table A 3. Average water emission per kWh of Net electricity produced – Surface Mining

	% of Total in this Table	Total (g/kWh)	% of Total from Surface Coal Mining	% of Total from Transportation	% of Total from Electricity Generation
(w) Acids (H+)	0.03%	2.31E-05	82.11%	0.01%	17.88%
(w) Ammonia (NH4+)	22.72%	1.74E-02	100.00%	0.00%	0.00%
(w) Ammonia (NH4+, NH3, as N)	0.01%	5.51E-06	43.53%	0.21%	56.26%
(w) TOTAL BOD5 (Biological Oxygen Demand)	0.66%	5.07E-04	78.36%	4.49%	17.15%
(w) Chlorides (Cl-)	0.00%	3.36E-06	2.17%	3.61%	94.23%
(w) COD (Chemical Oxygen Demand)	1.98%	1.52E-03	78.41%	4.48%	17.11%
(w) Cyanides (CN-)	0.00%	7.22E-09	23.29%	1.96%	74.75%
(w) Dissolved Matter (unspecified)	71.46%	5.48E-02	3.87%	87.68%	8.45%
(w) Fluorides (F-)	0.01%	5.87E-06	87.81%	0.41%	11.78%
(w) Inorganic Dissolved Matter (unspecified)	0.00%	5.22E-07	19.78%	2.22%	78.01%
(w) Iron (Fe++, Fe3+)	0.00%	9.43E-09	100.89%	0.09%	-0.98%
(w) Metals (unspecified)	0.00%	3.18E-07	19.50%	2.24%	78.26%
(w) Nitrates (NO3-)	0.00%	1.15E-06	100.89%	0.09%	-0.98%
(w) Nitric acid	1.26%	9.68E-04	100.00%	0.00%	0.00%
(w) Nitrogenous Matter (unspecified, as N)	0.00%	1.03E-08	19.99%	2.20%	77.81%
(w) Oils	1.26%	9.63E-04	6.63%	64.29%	29.07%
(w) Oils (unspecified)	0.00%	0.00E+00	0.00%	0.00%	0.00%
(w) Organic Dissolved Matter (unspecified)	0.00%	2.07E-08	19.99%	2.20%	77.81%
(w) Phenol (C6H6O)	0.00%	2.27E-08	23.14%	1.97%	74.89%
(w) Sodium (Na+)	0.00%	1.26E-06	64.10%	1.41%	34.50%
(w) Sulfates (SO4--)	0.00%	1.47E-06	70.85%	1.17%	27.98%
(w) Sulfides (S--)	0.00%	1.44E-08	23.29%	1.96%	74.75%
(w) Suspended Matter (unspecified)	0.56%	4.33E-04	9.47%	5.56%	84.98%
(w) Tars (unspecified)	0.00%	5.18E-09	19.57%	2.23%	78.19%
(w) Water: Chemically Polluted	0.04%	3.07E-05	0.00%	2.85%	97.15%

Table A 4. Average solid emission per kWh of Net electricity produced – Surface mining

	% of Total in this Table	Total (g/kWh)	% of Total from Surface Coal Mining	% of Total from Transportation	% of Total from Electricity Generation
(s) antimony	0.00%	1.11E-05	0.00%	0.00%	100.00%
(s) arsenic	0.00%	9.68E-05	0.00%	0.00%	100.00%
(s) barium	0.00%	3.25E-04	0.00%	0.00%	100.00%
(s) beryllium	0.00%	1.05E-05	0.00%	0.00%	100.00%
(s) boron	0.00%	5.34E-04	0.00%	0.00%	100.00%
(s) cadmium	0.00%	7.31E-06	0.00%	0.00%	100.00%
(s) chromium	0.00%	1.65E-04	0.00%	0.00%	100.00%
(s) cobalt	0.00%	3.46E-05	0.00%	0.00%	100.00%
(s) copper	0.00%	8.50E-05	0.00%	0.00%	100.00%
(s) lead	0.00%	7.43E-05	0.00%	0.00%	100.00%
(s) manganese	0.00%	2.03E-04	0.00%	0.00%	100.00%
(s) mercury	0.00%	1.23E-07	0.00%	0.00%	100.00%
(s) molybdenum	0.00%	2.89E-05	0.00%	0.00%	100.00%
(s) nickel	0.00%	1.16E-04	0.00%	0.00%	100.00%
(s) selenium	0.00%	7.64E-06	0.00%	0.00%	100.00%
(s) vanadium	0.00%	2.36E-04	0.00%	0.00%	100.00%
ash - landfilled (dry)	92.57%	1.91E+01	0.00%	0.00%	100.00%
FGC waste (dry) - landfilled	0.00%	0.00E+00	0.00%	0.00%	0.00%
Waste (hazardous)	0.00%	3.27E-09	6.31%	3.22%	90.47%
Waste (municipal and industrial)	0.56%	1.16E-01	23.50%	1.95%	74.55%
Waste (unspecified)	6.86%	1.42E+00	96.48%	0.58%	2.94%

Table A 5. Average resource consumption per kWh of Net electricity produced – Underground Mining

	% of Total in this Table	Total (g/kWh)	% of Total from Underground Coal Mining	% of Total from Transportation	% of Total from Electricity Generation
(r) Bauxite (Al2O3, ore)	0.00%	2.50E-03	0.01%	3.69%	96.30%
(r) Clay (in ground)	0.00%	1.84E-08	9.95%	2.48%	87.57%
(r) Coal (in ground)	95.36%	3.53E+02	0.67%	0.01%	99.33%
(r) Iron (Fe, ore)	0.02%	8.30E-02	11.86%	2.25%	85.89%
(r) Limestone (CaCO3, in ground)	2.07%	7.67E+00	99.90%	0.00%	0.09%
(r) Natural Gas (in ground)	1.14%	4.24E+00	1.47%	0.38%	98.16%
(r) Oil (in ground)	1.38%	5.11E+00	9.38%	80.25%	10.37%
(r) Sand (in ground)	0.00%	2.24E-08	0.01%	3.69%	96.30%
(r) Sodium Chloride (NaCl, in ground or in sea)	0.00%	7.10E-05	0.70%	3.61%	95.69%
(r) Uranium (U, ore)	0.00%	2.85E-05	101.01%	0.11%	-1.11%
Aluminum Scrap	0.00%	6.13E-04	0.01%	3.69%	96.30%
Iron Scrap	0.02%	8.83E-02	12.04%	2.22%	85.73%
Lubricant	0.00%	1.51E-03	11.83%	2.23%	85.94%
Trinitrotoluene (C6H3(NO2)3)	0.00%	4.47E-06	0.01%	3.69%	96.30%

Table A 6. Average air emissions per kWh of Net electricity produced – Underground mining

	% of Total in this Table	% of Total in this Table except CO2	Total (g/kWh)	% of Total from Underground Coal Mining	% of Total from Transportation	% of Total from Electricity Generation
(a) Aldehydes	0.00%	0.01%	2.03E-04	19.15%	74.52%	6.33%
(a) Ammonia (NH3)	0.00%	0.00%	9.52E-05	9.06%	79.68%	11.27%
(a) antimony	0.00%	0.00%	3.06E-06	0.00%	0.00%	100.00%
(a) arsenic	0.00%	0.00%	3.68E-05	0.00%	0.00%	100.00%
(a) barium	0.00%	0.00%	9.50E-06	0.00%	0.00%	100.00%
(a) beryllium	0.00%	0.00%	1.19E-06	0.00%	0.00%	100.00%
(a) boron	0.00%	0.32%	1.26E-02	0.00%	0.00%	100.00%
(a) cadmium	0.00%	0.00%	3.02E-06	0.00%	0.00%	100.00%
(a) total Carbon Dioxide (CO2)	99.47%		7.41E+02	0.87%	1.76%	97.37%
(a) Carbon Monoxide (CO)	0.02%	4.71%	1.86E-01	1.07%	40.55%	58.38%
(a) Chlorides (Cl-)	0.00%	0.00%	5.64E-07	0.01%	2.61%	97.38%
(a) chromium	0.00%	0.00%	4.40E-05	0.00%	0.00%	100.00%
(a) cobalt	0.00%	0.00%	5.11E-06	0.00%	0.00%	100.00%
(a) copper	0.00%	0.00%	1.74E-05	0.00%	0.00%	100.00%
(a) Fluorides (F-)	0.00%	0.00%	2.40E-07	14.08%	2.80%	83.12%
(a) non-methane Hydrocarbons (including VOCs)	0.02%	4.57%	1.80E-01	27.45%	24.21%	48.34%
(a) Hydrogen Chloride (HCl)	0.00%	0.00%	1.81E-06	0.11%	2.40%	97.50%
(a) Hydrogen Fluoride (HF)	0.00%	0.00%	1.59E-07	2.02%	3.45%	94.53%
(a) Hydrogen Sulfide (H2S)	0.00%	0.00%	9.18E-09	9.95%	2.48%	87.57%
(a) lead	0.00%	0.00%	2.23E-05	0.00%	0.00%	100.00%
(a) manganese	0.00%	0.00%	3.19E-05	0.00%	0.00%	100.00%
(a) mercury	0.00%	0.00%	2.72E-05	0.00%	0.00%	100.00%
(a) Metals (unspecified)	0.00%	0.00%	1.14E-09	8.00%	2.72%	89.28%
(a) Methane (CH4)	0.20%	38.47%	1.52E+00	97.21%	0.05%	2.74%
(a) molybdenum	0.00%	0.00%	2.83E-05	0.00%	0.00%	100.00%
(a) nickel	0.00%	0.00%	4.30E-05	0.00%	0.00%	100.00%
(a) Nitrogen Oxides (NOx as NO2)	0.07%	13.56%	5.36E-01	5.12%	25.62%	69.26%
(a) Nitrous Oxide (N2O)	0.00%	0.03%	1.10E-03	59.12%	16.59%	24.29%
(a) Organic Matter (unspecified)	0.00%	0.01%	3.46E-04	20.16%	65.59%	14.25%
(a) total Particulates (unspecified)	0.11%	20.16%	7.97E-01	87.12%	1.73%	11.16%
(a) selenium	0.00%	0.01%	3.01E-04	0.00%	0.00%	100.00%
(a) Sulfur Oxides (SOx as SO2)	0.10%	18.17%	7.18E-01	7.79%	9.82%	82.38%
(a) Tars (unspecified)	0.00%	0.00%	3.23E-07	9.71%	2.51%	87.78%
(a) vanadium	0.00%	0.00%	6.54E-05	0.00%	0.00%	100.00%

Table A 7. Average water emission per kWh of Net electricity produced – Underground mining

	% of Total in this Table	Total (g/kWh)	% of Total from Underground Coal Mining	% of Total from Transportation	% of Total from Electricity Generation
(w) Acids (H+)	0.01%	4.15E-06	0.13%	0.06%	99.81%
(w) Ammonia (NH4+)	0.00%	0.00E+00	0.00%	0.00%	0.00%
(w) Ammonia (NH4+, NH3, as N)	0.01%	5.18E-06	39.93%	0.23%	59.84%
(w) TOTAL BOD5 (Biological Oxygen Demand)	0.18%	1.12E-04	2.19%	20.28%	77.54%
(w) Chlorides (Cl-)	0.01%	3.35E-06	1.79%	3.62%	94.59%
(w) COD (Chemical Oxygen Demand)	0.55%	3.36E-04	2.15%	20.29%	77.56%
(w) Cyanides (CN-)	0.00%	6.29E-09	11.86%	2.25%	85.89%
(w) Dissolved Matter (unspecified)	96.93%	5.93E-02	11.11%	81.07%	7.81%
(w) Fluorides (F-)	0.01%	5.16E-06	86.15%	0.46%	13.39%
(w) Inorganic Dissolved Matter (unspecified)	0.00%	4.65E-07	9.83%	2.49%	87.68%
(w) Iron (Fe++, Fe3+)	0.00%	8.32E-09	101.01%	0.11%	-1.11%
(w) Metals (unspecified)	0.00%	2.83E-07	9.67%	2.51%	87.81%
(w) Nitrates (NO3-)	0.00%	1.02E-06	101.01%	0.11%	-1.11%
(w) Nitric acid	0.00%	0.00E+00	0.00%	0.00%	0.00%
(w) Nitrogenous Matter (unspecified, as N)	0.00%	9.18E-09	9.95%	2.48%	87.57%
(w) Oils	1.60%	9.77E-04	7.96%	63.38%	28.66%
(w) Oils (unspecified)	0.00%	0.00E+00	0.00%	0.00%	0.00%
(w) Organic Dissolved Matter (unspecified)	0.00%	1.84E-08	9.95%	2.48%	87.57%
(w) Phenol (C6H6O)	0.00%	1.98E-08	11.77%	2.26%	85.97%
(w) Sodium (Na+)	0.00%	1.17E-06	61.20%	1.52%	37.28%
(w) Sulfates (SO4--)	0.00%	1.35E-06	68.23%	1.27%	30.50%
(w) Sulfides (S--)	0.00%	1.26E-08	11.86%	2.25%	85.89%
(w) Suspended Matter (unspecified)	0.66%	4.03E-04	2.79%	5.97%	91.24%
(w) Tars (unspecified)	0.00%	4.62E-09	9.71%	2.51%	87.78%
(w) Water: Chemically Polluted	0.05%	3.07E-05	0.01%	2.85%	97.15%

Table A 8. Average water emission per kWh of Net electricity produced – Underground mining

	% of Total in this Table	Total (g/kWh)	% of Total from Underground Coal Mining	% of Total from Transportation	% of Total from Electricity Generation
(s) antimony	0.00%	1.11E-05	0.00%	0.00%	100.00%
(s) arsenic	0.00%	9.68E-05	0.00%	0.00%	100.00%
(s) barium	0.00%	3.25E-04	0.00%	0.00%	100.00%
(s) beryllium	0.00%	1.05E-05	0.00%	0.00%	100.00%
(s) boron	0.00%	5.34E-04	0.00%	0.00%	100.00%
(s) cadmium	0.00%	7.31E-06	0.00%	0.00%	100.00%
(s) chromium	0.00%	1.65E-04	0.00%	0.00%	100.00%
(s) cobalt	0.00%	3.46E-05	0.00%	0.00%	100.00%
(s) copper	0.00%	8.50E-05	0.00%	0.00%	100.00%
(s) lead	0.00%	7.43E-05	0.00%	0.00%	100.00%
(s) manganese	0.00%	2.03E-04	0.00%	0.00%	100.00%
(s) mercury	0.00%	1.23E-07	0.00%	0.00%	100.00%
(s) molybdenum	0.00%	2.89E-05	0.00%	0.00%	100.00%
(s) nickel	0.00%	1.16E-04	0.00%	0.00%	100.00%
(s) selenium	0.00%	7.64E-06	0.00%	0.00%	100.00%
(s) vanadium	0.00%	2.36E-04	0.00%	0.00%	100.00%
ash - landfilled (dry)	87.39%	1.91E+01	0.00%	0.00%	100.00%
FGC waste (dry) - landfilled	0.00%	0.00E+00	0.00%	0.00%	0.00%
Waste (hazardous)	0.00%	3.16E-09	2.90%	3.34%	93.76%
Waste (municipal and industrial)	0.46%	1.01E-01	12.47%	2.23%	85.31%
Waste (unspecified)	12.13%	2.66E+00	98.12%	0.31%	1.57%

Table A 9. The Unit processes used to set up the LCI model

No.	Process	Unit Conversions to kWh	Conversion factor
1	US Coal LEBS S. Mining	kWh	0.76
2	MEA emission modeled from Rubin	kWh	1
3	MEA infra from Koorneef	Mtn_{CO2}/kWh	8.5E-10
4	Compressor	Mtn_{CO2}/kWh	8.5E-10
5	CO2 transport, Pipeline, No Recompression	km_{CO2}/kWh	1.25E-9
6	CO2 storage, well double, aquifer	Mtn_{CO2}/kWh	4.52E-11

There are 6 unit process used to set up the model. US Coal LEBS S.mining represents the inventory for a coal powerplant whose coal is surface mined. To integrate the CO2 capture two unit process are used, 1. MEA emissions are modeled based on Rubin(*9*) and is provided in the table A10 below. Both the increase in emissions and the decrease in emissions are modeled here. CO_2, SO_2, HCl, NO_2 and particulates decrease. So2, HCl, No2 decrease due to reaction with the amine. While Particualtes are removed during the cooling of the flue gas using water spray.

Table A 10. The parameters used to model the Unit process - MEA emission (*9*, *10*, *42*)

Parameters	Values
CO2	90%
So2	99.95%
No2	25%
HCL	95%
Particulates	50%
Ammonia	1 mol/mol of MEA oxidized. 50% of MEA is oxidized
Coal Ash	6.7g/kWh
FGD residues	12.2
Spent CCS sorbent	4.05

The infrastructure for the capture plant is modeled based on data from Koorneef(*18*). The values in the table A11 are modeled for a capture plant life of 30 years with total CO2 captured equaling 94Mt of CO2. The compressor needed for transport is modeled separately and the resource required can be found in the table A11

Table A 11. LCI data for infrastructure of capture plant and compressor

Materials/fuels	Value	Unit
Steel, converter, chromium steel 18/8, at plant/RER WITH US ELECTRICITY U	4.68	ton
Concrete, exacting, at plant/CH WITH US ELECTRICITY U	0.0148	m3
Transport, single unit truck, diesel powered NREL /US	140	tkm
Concrete, normal, at plant/CH WITH US ELECTRICITY U	1.048387	m3
Diesel, at refinery/l NREL /US	8764.622	L
Electricity mix/US WITH US ELECTRICITY U	0.983871	MWh
Steel, converter, low-alloyed, at plant/RER WITH US ELECTRICITY U	1.048387	ton
Copper, primary, at refinery/GLO WITH US ELECTRICITY U	0.112903	ton
Polyethylene, HDPE, granulate, at plant/RER WITH US ELECTRICITY U	0.322581	ton

The Life cycle inventory for transport and sequestration are based on work done be Wildbolz(*25*). The table A12 shows the resource used for transport through pipelines and for sequestration in geological aquifers. From the information in the table below the materials for transport are modeled based on 100mi of pipeline. The sequestration site is modeled based on its storage capacity.

Table A 12. LCI data per tkm transportation of CO2 in pipeline without recompression and LCI data for construction of double well for geological storage in deep saline aquifers.

Pipeline, supercritical CO2		**Unit/km**
Resources		
Occupation, construction site	3330	m2a
Transformation, from forest	2000	m2
Transformation, to heterogeneous, agricultural	2000	m2
Water, unspecified natural origin/m3	187	m3
Materials/fuels		
Sand, at mine/CH U	4.40E+06	kg
Diesel, burned in building machine/GLO U	3.31E+06	MJ
Steel, low-alloyed, at plant/RER U	2.70E+05	kg
Drawing of pipes, steel/RER U	2.70E+05	kg
Rock wool, packed, at plant/CH U	5119	kg
Transport, helicopter/GLO U	26	hr
Transport, helicopter, LTO cycle/GLO U	10.4	p
Transport, lorry 32t/RER U	3.15.E+05	tkm
Transport, freight, rail/RER U	5.51.E+04	tkm
Waste to treatment		
Disposal, inert waste, 5% water, to inert material landfill/CH U	4.40E+06	kg
Disposal, steel, 0% water, to inert material landfill/CH U	1.35E+05	kg
Disposal, mineral wool, to final disposal/CH U	5.12E+03	kg

well double, aquifer		**per unit**
Resources		
Occupation, industrial area	900	m2a
Occupation, industrial area, vegetation	8100	m2a
Transformation, from pasture and meadow	600	m2
Transformation, to industrial area	60	m2
Transformation, to industrial area, vegetation	540	m2
Materials/fuels		
drilling, deep borehole for HDR	3.60E+03	m
Cement, unspecified, at plant/CH U	1.26E+05	kg
Gravel, unspecified, at mine/CH U	1.32E+06	kg
Transport, lorry 28t/CH U	2.89E+04	tkm
Transport, freight, rail/CH U	1.26E+04	tkm

APPENDIX B

Underground Mining and Uniform Distribution Results

Table B 1 - . The total benefits and disbenefits from uniform distribution scenario at a constant \$30/tCO2 – Underground mining

Range in (c/kWh)	CO2	Total Disbenefit	Benefit without CO_2	Net Benefit
Min	1.80	-1.66	-1.56	0.24
Median	1.80	-0.86	-0.40	1.39
Max	1.80	-0.08	0.73	2.53

Table B 2 - The total benefits and disbenefits from triangle distribution scenario at a constant \$30/tCO2 – Underground mining

Range in (c/kWh)	CO2	Total Disbenefit	Benefit without CO_2	Net Benefit
Min	1.80	-1.63	-1.53	0.26
Median	1.80	-0.62	-0.23	1.57
Max	1.80	-0.09	0.72	2.52

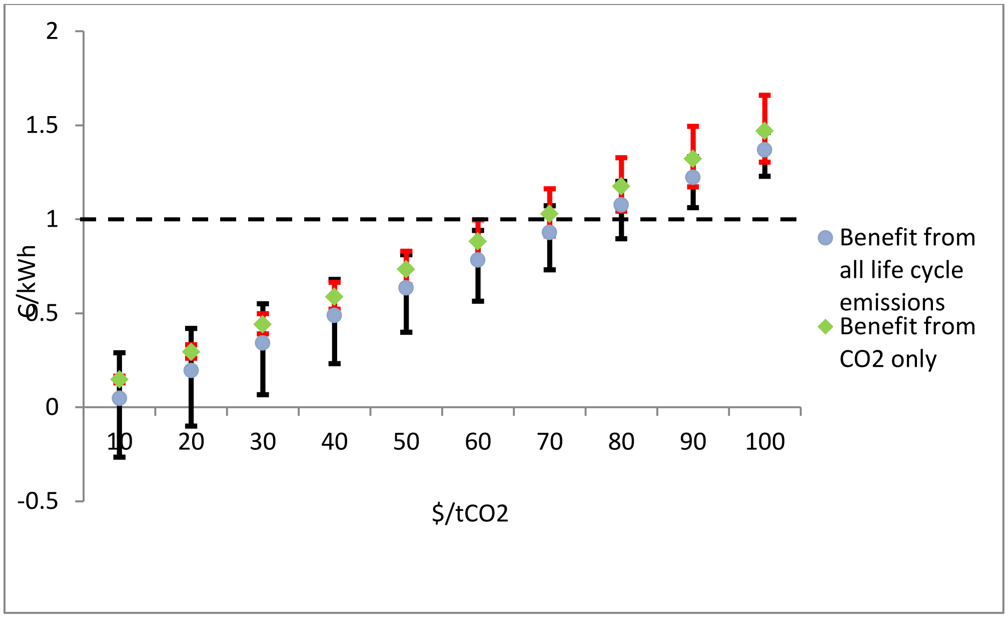

Figure B 1. Cost benefit analysis for the powerplant without CCS without sequestration credits.- Surface Mining and Uniform Distribution.

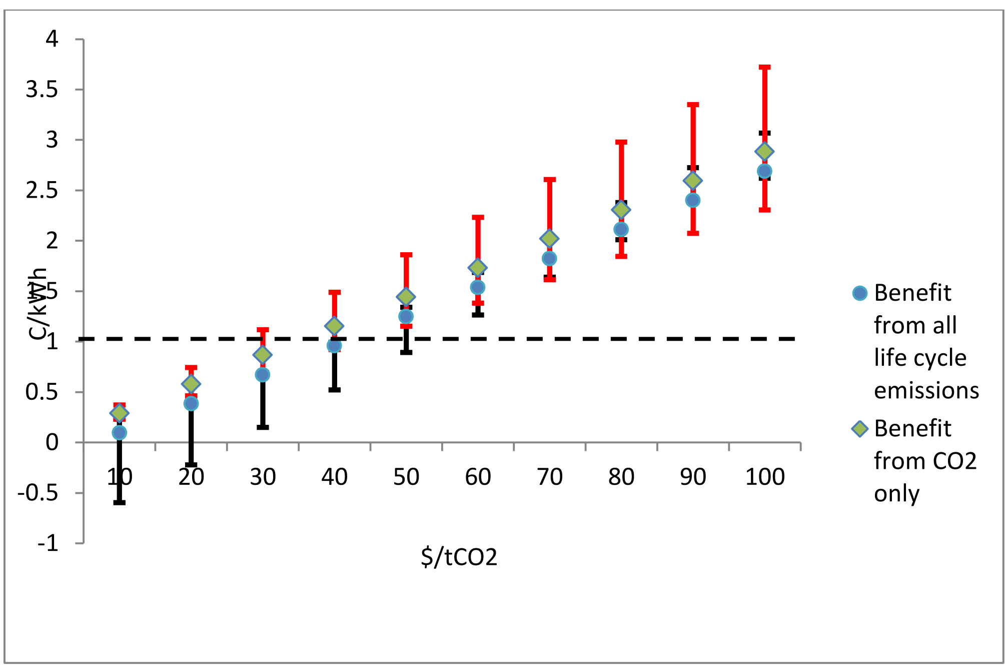

Figure B 2. Cost benefit analysis for the powerplant with CCS without sequestration credits.- Surface Mining and Uniform Distribution

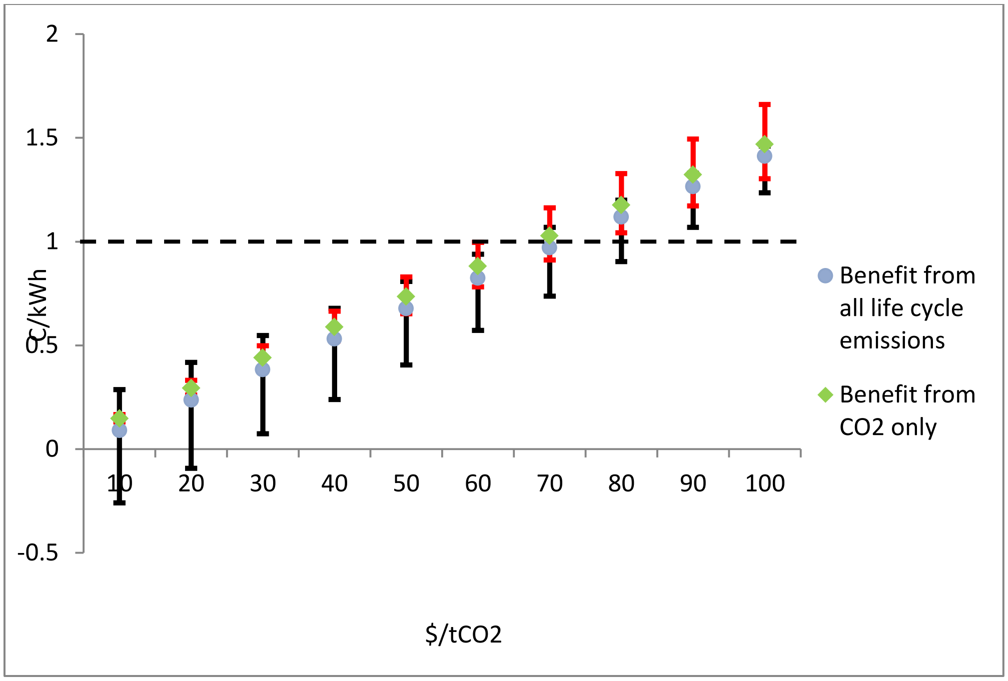

Figure B 3. Cost benefit analysis for the powerplant with CCS without sequestration credits.- Underground Mining and Triangle Distribution

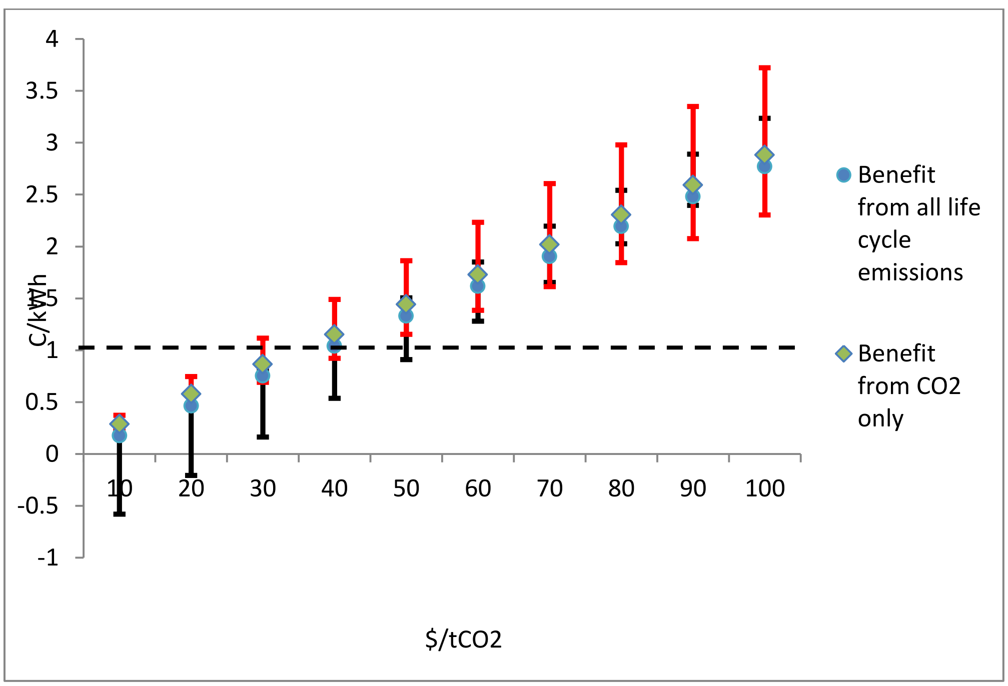

Figure B 4. Cost benefit analysis for the powerplant with CCS with sequestration credits.- Underground Mining and Triangle Distribution

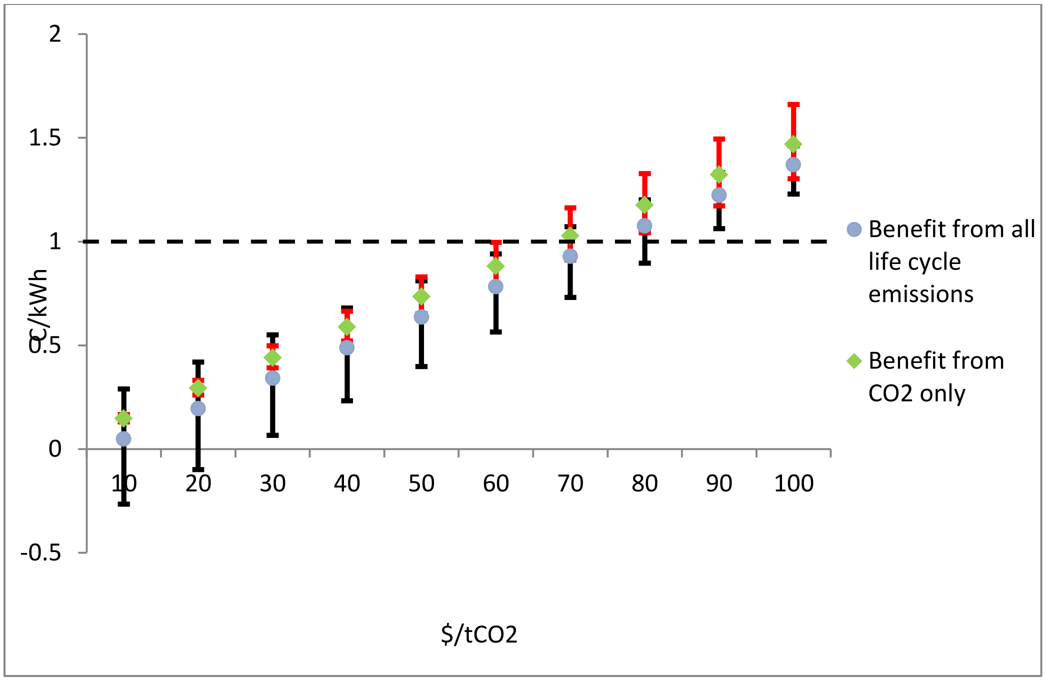

Figure B 5. Cost benefit analysis for the powerplant with CCS without sequestration credits- Underground Mining and Uniform Distribution

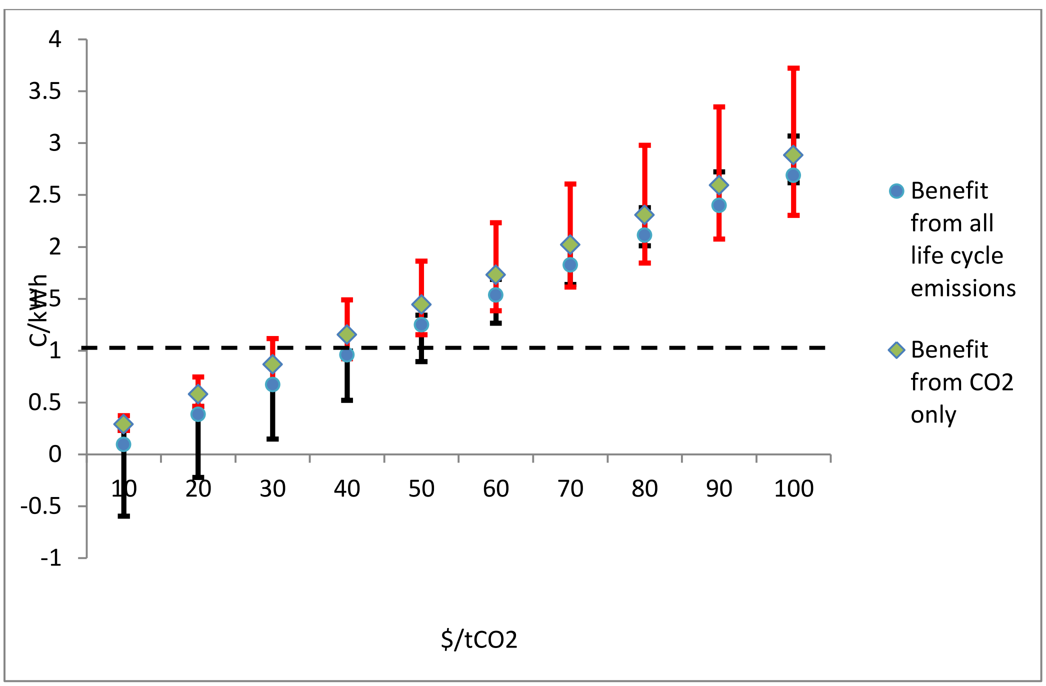

Figure B 6. Cost benefit analysis for the powerplant with CCS with sequestration credits.- Underground Mining and Uniform Distribution