NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Analysis: Power Studies Compilation Report

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List of Acronyms and Abbreviations

AEO	Annual Energy Outlook
AGR	Acid Gas Removal
CAP	Criteria Air Pollutant
CC	Capital Cost
CCS	Carbon Capture and Sequestration
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COE	Cost of Delivered Electricity
COS	Carbonyl Sulfide
CTG	Combustion Turbine Generator
DNG	Domestic Natural Gas
DOE	Department of Energy
ECF	Electric Conversion Facility
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
ESP	Electrostatic Precipitator
EXPC	Existing Pulverized Coal Plant
FE	Fossil Energy
FG	Flue Gas
FGD	Flue Gas Desulfurization
GHG	Greenhouse Gas
GWP	Global Warming Potential
Hg	Mercury

HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle Plant
IPCC	Intergovernmental Panel on Climate Change
kW	Kilo-Watt
kWh	Kilo-Watt Hour
LC	Life Cycle
LCA	Life Cycle Analysis
LCC	Life Cycle Costing
LCI	Life Cycle Inventory
LCOE	Levelized Cost of Delivered Electricity
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
MACRS	Modified Accelerated Cost Recovery System
MVA	Mega-Volt Amps
MW	Mega-Watt
MWH	Mega-Watt Hour
N_2O	Nitrous Oxide
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGCC	Natural Gas Combined Cycle Plant
NH_3	Ammonia
NOX	Nitrogen Oxides
O&M	Operation and Maintenance
OFA	Overfire Air
Pb	Lead
PM	Particulate Matter
psia	Pounds per square inch absolute
PT	Product Transport
PV	Present Value
RMA	Raw Material Acquisition
RMT	Raw Material Transport
RP	Replacement Power
SCPC	Super Critical Pulverized Coal Plant
SERC	Southeast Electric Reliability Council
SF_6	Sulfur Hexaflouride
SO_2	Sulfur Dioxide
SOI	Species of Interest
SOX	Sulfur Oxides
STG	Steam Turbine Generator
VOC	Volatile Organic Compounds
w-	With
wo-	Without

Executive Summary

Life Cycle Analysis (LCA) is a holistic method used to evaluate the environmental and economic consequences resulting from a process, product, or a particular activity over its entire life cycle (LC). The LCA, also known as a cradle-to-grave analysis, is studied within a boundary extending from the acquisition of raw materials, through productive use, and finally to either recycling or disposal. An LCA study can yield an environmental true-cost-of-ownership, which can be compared with results for other alternatives, enabling a better informed analysis.

This study is a compilation of results from four technology LCA reports (NETL 2010a,b,c,d). These reports evaluated the emissions footprint and LC costs of the technologies, including upstream and downstream emissions and costs. The analysis examines two energy conversion cases for each technology. One case assumes that the facility emits the full amount of carbon dioxide (CO_2) resulting from the utilization of the fuel. The second case builds upon the first by adding CO_2 capture technology to remove 90% of the CO_2 from the power generation facility. The case that captures 90% of the CO_2 includes the additional capture and compression equipment, pipeline and injection well materials, and energy requirements. The study time period (30 years) allows for the determination of long-term cost and environmental emissions associated with the production and delivery of electricity generated by the technologies.

The main take away from this study is that this is the first full LC inventory and costing for power systems. There have been some partial results for systems from previous studies, mainly dealing with the Energy Conversion Facility (ECF), but they were plant level results and not complete cradle-to-grave results. The concept of including the upstream and downstream emissions to the mix gives a new perception of the current systems, and provides insight into the value of CCS when added to a system.

The summary of the LCA study results can be seen in **Table 1** and **Table 2**. The results have been normalized in **Table 1** to the Natural Gas Combined Cycle fired on Foreign Liquefied Natural Gas (NGCC-LNG) without carbon capture and sequestration (CCS), showing percentage increase or decrease in the particular variable. The global warming potential (GWP) results showed that greenfield construction of power plants with-CCS resulted in lower emissions than the normalized case, and all CCS cases outperformed the GWP results from the Existing Pulverized Coal (EXPC) case with retrofit carbon capture in a brownfield application. Replacement power (RP) was found to have a major impact on the EXPC case. The SERC profile of the replacement power accounted for enough added emissions that the GWP for the EXPC with-CCS increased 28% points. The EXPC with-CCS and no replacement power would still have resulted in emissions higher than the with-CCS greenfield installations. This result could have a major implication upon build/retrofit decisions depending on emissions policies in the future.

Table 1: LCA Results Summary – Normalized Results

Case	Net Power (MW)	Capacity Factor	GWP (kg CO_2e/MWh)	CAP (kg / MWh)			Water (Liter/MWh)		CC ($/kW)	LCOE ($/kWh)
				NOX	**SOX**	**PM**	**Withdrawal**	**Consumption**		
IGCC	12%	-6%	78%	4%	5%	710%	83%	6%	209%	29%
IGCC w-CCS	-2%	-6%	-59%	-4%	23%	500%	155%	71%	337%	75%
NGCC-LNG	555.08	0.85	523.65	0.28	0.03	0.01	1098.61	832.15	881.70	0.09
NGCC -Dom.	0%	0%	-11%	30%	-51%	-37%	5%	9%	0%	0%
NGCC-LNG w-CCS	-15%	0%	-61%	17%	18%	17%	94%	90%	114%	42%
NGCC -Dom. w-CCS	-15%	0%	-74%	52%	-42%	-26%	100%	98%	114%	42%
SCPC	-1%	0%	80%	11%	1240%	668%	129%	55%	163%	2%
SCPC w-CCS	-1%	0%	-54%	54%	31%	965%	327%	216%	375%	76%
EXPC	-23%	0%	112%	625%	8218%	7306%	180%	141%	-78%	-70%
EXPC w-CCS w-RP	-23%	0%	-15%	63%	4473%	355%	450%	309%	129%	35%
EXPC w-CCS wo-RP	-45%	0%	-43%	-89%	0%	174%	386%	391%	129%	-4%

Table 2: LCA Results Summary - Full Results

Case	Net Power (MW)	Capacity Factor	GWP (kg CO_2e/MWh)	CAP (kg / MWh)			Water (Liter/MWh)		CC ($/kW)	LCOE ($/kWh)
				NOX	**SOX**	**PM**	**Withdrawal**	**Consumption**		
IGCC	622.05	0.80	930.95	0.30	0.03	0.08	2013.90	881.86	2727.57	0.12
IGCC w-CCS	543.25	0.80	217.12	0.27	0.04	0.06	2803.21	1422.79	3856.27	0.16
NGCC-LNG	555.08	0.85	523.65	0.28	0.03	0.01	1098.61	832.15	881.70	0.09
NGCC -Dom.	555.08	0.85	466.63	0.37	0.01	0.01	1155.11	909.57	881.70	0.09
NGCC-LNG w-CCS	473.57	0.85	203.84	0.33	0.03	0.01	2133.49	1582.16	1890.89	0.13
NGCC -Dom. w-CCS	473.57	0.85	137.00	0.43	0.02	0.01	2199.72	1651.14	1890.89	0.13
SCPC	549.99	0.85	943.49	0.32	0.38	0.07	2515.02	1291.72	2320.10	0.09
SCPC w-CCS	549.97	0.85	240.73	0.44	0.04	0.10	4687.91	2630.68	4190.97	0.16
EXPC	430.00	0.85	1108.87	2.06	2.38	0.70	3078.61	2003.26	196.45	0.03
EXPC w-CCS w-RP	430.00	0.85	444.15	0.46	1.31	0.04	6037.86	3406.58	2019.55	0.13
EXPC w-CCS wo-RP	303.00	0.85	296.03	0.03	0.03	0.03	5343.11	4086.21	2019.55	0.09

Land usage results showed that addition of CCS had a significant impact on overall footprint of the plants. CO_2 pipelines added significantly to land usage, in all land categories for all technologies. Forest areas were much more impacted in all but a few usage categories. Agriculture was typically less impacted than forest, except for the NGCC with-CCS case. Grasslands typically showed less usage than the other land use categories.

LCOE results showed that the NGCC without-CCS, both with imported LNG and Domestic NG, was the lowest cost to operate technology. When adding the CCS systems, an increase in both capital cost and LCOE was observed. Of the Greenfield sites NGCC shows the smallest increase in LCOE and CC.

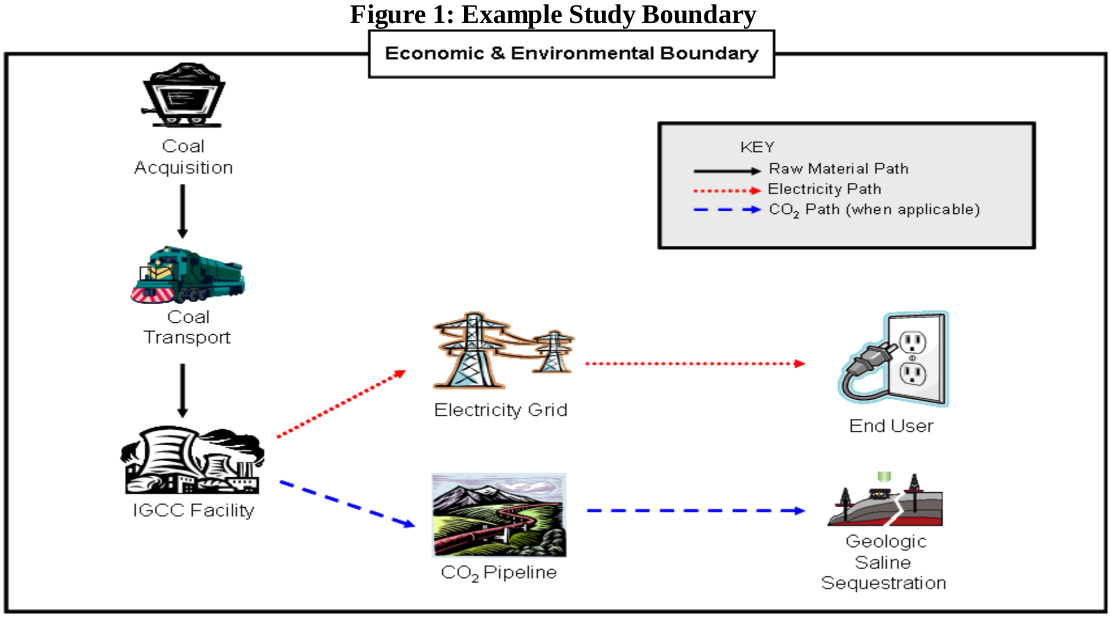
The EXPC with-CCS LCOE resulted in an incremental cost that appears to be in line with the other plant LCOE values. But since it is an incremental cost, the adder from the original plant's LCOE, which must be accounted for in the overall cost, pushes the LCOE even higher, higher than the other technologies with-CCS. When neglecting the replacement power, the EXPC with-CCS became more competitive from a market standpoint, but the LCOE would still be larger than in the Greenfield applications.

1.0 Introduction

Life Cycle Analysis (LCA) is a holistic method used to evaluate the environmental and economic consequences resulting from a process, product, or a particular activity over its entire life cycle (LC). The LCA, also known as a cradle-to-grave analysis, is studied within a boundary extending from the acquisition of raw materials, through productive use, and finally to either recycling or disposal. An LCA study can yield an environmental true-cost-of-ownership, which can be compared with results for other alternatives, enabling a better informed analysis. With the competitiveness of current power technologies, LCA is a perfect tool to provide an analysis of performance and cost to help discern differences in the types of plants.

This report is a compilation of results from four technology LCA studies (NETL 2010a,b,c,d). These studies evaluated the emissions and LC costs of the technologies (NETL 2010 and NETL 2007). The stages of the LC included are raw material acquisition (RMA), raw material transportation (RMT), electric conversion facility (ECF), and product transport (PT) to the customer. A typical study boundary can be seen in **Figure 1**, which is for a gasification system, but is similar to the other technology cases. The analyses examine two energy conversion cases for each technology. One case assumes that the facility emits all carbon dioxide (CO_2) resulting from the combustion of the fuel. The second case builds upon the first by adding CO_2 capture technology to remove 90% of the CO_2 from the power generation facility. The case that captures 90% of the CO_2 includes the additional capture and compression equipment, pipeline and injection well materials, and energy requirements. The study time period (30 years) allows for the determination of long-term cost and environmental emissions associated with the production and delivery of electricity generated by the technologies.

Figure 1: Example Study Boundary



1.1 System Configurations

This study summarizes four technologies for Life Cycle Inventories (LCI) and Life Cycle Costing (LCC). The technologies are: Integrated Gasification Combined Cycle (IGCC), Natural Gas Combined Cycle fired on imported Liquefied Natural Gas (NGCC-LNG), NGCC fired on Domestic Natural Gas (NGCC-DNG), Super Critical Pulverized Coal (SCPC), and Existing Sub-Critical Pulverized Coal with Retrofit (EXPC). Each case was modeled with and without carbon capture and sequestration (CCS) added to the system. In the case of EXPC, the CCS system was a retrofit to existing infrastructure as opposed to an element of the basic plant design. **Table 3** shows the stage-by-stage system modeling assumptions. **Table 4** shows other general operating assumptions that were utilized in the modeling.

Table 3: Power LCA Modeling Assumptions

Assumptions	IGCC	NGCC-LNG	NGCC-DNG	SCPC	EXPC
Temporal Boundary	30 Years				
Cost Boundary	Overnight				
LC Stage #1: Raw Material Acquisition					
Extraction Location	Southern Illinois	Trinidad & Tobago	Domestic US	Southern Illinois	
Feedstock	Illinois No. 6 Coal	NG	NG	Illinois No. 6 Coal	
Extraction Method	Underground	Offshore Drilling	Domestic Process	Underground	
C&O Costs	In Delivery Price				
LC Stage #2: Raw Material Transport					
Roundtrip transport Distance (Miles)	1,170	4,520	NA	410	400
Rail Spur Length (Miles)	25	NA	NA	25	Pre-Existing
Main Rail/Pipeline Length (Miles)	Pre-Existing	208	900	Pre-Existing	
Unit Train/LNG Infrastructure C&O Costs	In Delivery Price				
LC Stage #3: Energy Conversion Facility					
Location	Southern Mississippi			Southern Illinois	
Net Output (MW)	622	555	555	550	434
Net Output w/CCS (MW)	543	474	474	550	434
Power Trunk line Constructed Length (Miles)	50				Pre-Existing
CO_2 Pipeline Pressure (psia)	2,215				
CO_2 Pipeline Length (Miles)	100				
CO_2 Loss Rate	1% / 100 yrs				
LC Stage #4: Product Transport					
Transmission Line Loss	7%				
Transmission Grid Construction	Pre-Existing				

Table 4: General Assumptions

Parameter	Value	Units
Coal Mine Methane Emissions	360	Scf/Ton Coal
NG Liquefaction Energy Use	Zero, Process internal to plant	MJ/kg LNG
NG Regasification Energy Use	0.0212	MJ / kg LNG
	1.38E-5	kg Diesel / kg LNG
LNG Transport Fugitive Loss	0.15	% / Day
NG Pipeline Fugitive Loss	5.39E-6	kg NG Loss / kg-km
Replacement Power Cost	$0.0759	$ / kWh
Replacement Power GHG Emissions	236	kg CO_2e / MWh (434 MW Plant)
Cost of Transporting and Injecting CO2	59.68	$ / mtCO_2 - IGCC
	121.0	$ / mtCO_2 - NGCC
	97.75	$ / mtCO_2 – SCPC
	146.74	$ / mtCO_2 – EXPC

1.1.1 IGCC System Characteristics

The following outlines the operating characteristics of the IGCC cases:

- ICCC without-CCS: A 622-megawatt electric (MWe) (net power output) thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by water quench. Slurry of Illinois No. 6 coal and water is fed to two parallel, pressurized, entrained-flow gasifier trains. The cooled syngas from the gasifiers is cleaned in several steps utilizing carbonyl sulfide (COS) hydrolysis, mercury (Hg) capture, cyclone/candle filter particulate capture, and acid gas removal (AGR) before being fed to two advanced F-Class combustion turbine/generators (CTGs). The exhaust gas from each CTG is fed to an individual heat recovery steam generator (HRSG) where steam is generated. All of the net steam generated is fed to a single conventional steam turbine generator (STG). This case is configured without-CCS.

- IGCC with-CCS: A 543-MWe thermoelectric generation facility located, equipped, and operated as in the IGCC without-CCS. The cooled syngas from the gasifiers is converted in a series of shift reactors to a hydrogen-rich gas and cleaned to remove Hg, acid gas, particulate matter (PM), and CO_2 utilizing a two-stage Selexol® solvent process. COS control is not necessary since that reaction occurs in the shift reactors. The downstream processes are the same as in Case 1. This case is configured with 90% CO_2 CCS.

The upstream LC stages (underground coal mining and train transport of the coal) are the same for both IGCC cases; the case with-CCS includes the additional pipeline transport and storage of the captured CO_2. Illinois No. 6 coal is assumed to come from an underground mine, via longwall mining techniques. The coal is transported 1170 miles roundtrip via rail using a 100-car unit train. Power is transferred to the grid via a 50-mile trunkline (711 MVA transmission line). CO_2 is transported 100 miles at 2,215 psia to a sequestration location via a pipeline.

1.1.2 NGCC System Characteristics

There are four NGCC cases in this report; two fired with imported gas, and two fired with domestic gas. There are two NGCC-LNG case scenarios under consideration in this study:

- NGCC-LNG without-CCS: A 555-MWe thermoelectric generation facility, in southern Mississippi, utilizing two parallel, advanced F-Class natural gas-fired CTGs fired on imported LNG. Each CTG is followed by a HRSG. All net steam produced in the two HRSGs flows to a single steam turbine. This case is configured without-CCS.

- NGCC-LNG with-CCS: A 474-MWe thermoelectric generation facility, located, equipped and operated as in the NGCC-LNG without-CCS. This case is configured with a post-combustion Flour Econamine CCS system. Steam is extracted from the steam turbine to provide heat needed by the CCS system for solvent regeneration.

The upstream LC stages (foreign natural gas extraction and liquefaction, and ocean tanker transport) are the same for both NGCC-LNG cases and supplied by liquefied natural gas (LNG) imports. One source of natural gas was considered to isolate the upstream impacts associated with imported LNG. CO_2 is transported 100 miles at 2,215 psia to a sequestration location via a pipeline.

There are two NGCC-DNG case scenarios under consideration in this study:

- NGCC-DNG without-CCS: A 555-MWe thermoelectric generation facility, in southern Mississippi, utilizing two parallel, advanced F-Class natural gas-fired CTGs fired on Domestic NG. Each CTG is followed by a HRSG. All net steam produced in the two HRSGs flows to a single steam turbine. This case is configured without-CCS.

- NGCC-DNG with-CCS: A 474-MWe thermoelectric generation facility, located, equipped and operated as in the NGCC-DNG without-CCS. This case is configured with a post-combustion Flour Econamine CCS system. Steam is extracted from the steam turbine to provide heat needed by the CCS system for solvent regeneration.

The upstream LC stages (domestic natural gas extraction, and pipeline transport) are the same for both NGCC-DNG cases. CO_2 is transported 100 miles at 2,215 psia to a sequestration location via a pipeline.

1.1.3 SCPC System Characteristics

There are two SCPC case scenarios under consideration in this study:

- SCPC without-CCS: A 550-MWe thermoelectric generation facility located at a greenfield site in southeast Illinois (near Springfield, Illinois), utilizing a single-train supercritical steam generator (Benson-boiler). Illinois No. 6 pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional steam turbine generator (STG). Air emission control systems for the plant include a wet limestone scrubber that removes sulfur dioxide (SO_2), a combination of low-nitrogen oxides burners (LNBs) and overfire air (OFA), and a selective catalytic reduction (SCR) unit that removes nitrogen oxide (NO_X), a pulse jet fabric filter (baghouse) that removes particulates, and mercury (Hg) reductions via co-benefit capture. This case is configured without-CCS.

- SCPC with-CCS: A 550-MWe thermoelectric generation facility located, equipped and operated as in the SCPC without-CCS. This case is configured with additional sulfur polishing to reduce sulfur content below 10ppmv. CCS is utilized via a Fluor Econamine FG Plus process.

The upstream LC stages (underground coal mining and train transport of coal) are the same for both SCPC cases; the case with-CCS includes the additional transport and storage of the captured CO_2. Illinois No. 6 coal is assumed to come from an underground mine, via longwall mining techniques. The coal is transported 410 miles roundtrip via 100-car unit trains. Power is transferred to the grid via a 50-mile trunkline. CO_2 is transported 100 miles at 2,215 psia to a sequestration location via a pipeline.

1.1.4 EXPC System Characteristics

There are two EXPC case scenarios under consideration in this study:

- EXPC without-CCS: A 434-MWe plant with a subcritical boiler that fires Illinois No. 6 coal, which has been in commercial operation for more than 30 years, and is located in southern Illinois. After being routed through heat recovery equipment (including an economizer and regenerative air heater), the flue gas is sent to air emissions control equipment that includes an electrostatic precipitator (ESP) and a lime-based flue gas desulfurization (FGD) system that results in the removal of 94.9% of the sulfur found in the gas (NETL 2007).
- EXPC with-CCS: A 434-MWe plant with a subcritical boiler that is located, equipped, and operated as in the EXPC without-CCS. The EXPC plant in this case is retrofitted with a CCS system. This CCS system includes a state-of-the art advanced amine process that recovers 90% of CO_2 from the flue gas. After accounting for auxiliary power, CCS system energy requirements, and a 7% transmission loss, the net power delivered by the plant is 303 MWe. To establish a uniform basis of comparison, replacement power to the level of the EXPC without-CCS is generated within the Southeast Electric Reliability Council (SERC) electric grid. The fuel mix of the SERC grid is based on 2007 operating data for U.S. power plants (EPA 2008).

The upstream LC stages (underground coal mining and train transport of coal) are the same for both EXPC cases; the case with-CCS includes the additional transport and storage of the captured CO_2. Illinois No. 6 coal is assumed to come from an underground mine, via longwall mining techniques. The coal is transported 400 miles roundtrip via 100-car unit trains. Power is transferred to the grid via an existing trunkline. CO_2 is transported 100 miles at 2,215 psia to a sequestration location via a pipeline.

2.0 LCI Results

The following emissions, usage and consumptions were considered as inventory metrics within the study boundary:

- Greenhouse Gas (GHG) Emissions: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6)
- Criteria Air Pollutants (CAP): carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO_2), volatile organic compounds (VOCs), particulate matter (PM), and lead (Pb)
- Species of Interest Emissions: mercury (Hg), and ammonia (NH_3)
- Water (withdrawal and consumption)
- Transformed Land Area

The only impact characterized in this study is the global warming potential (GWP) of GHG emissions to the atmosphere. The most recent 100-year GWP values reported by the Intergovernmental Panel on Climate Change (IPCC) are listed in **Table 5** (IPCC 2007). The table shows the equivalent amount of CO_2 in kg that one kg of each GHG would represent, hence the kg CO_2e emission for each GHG emission.

Table 5: Global Warming Potential for Various Greenhouse Gases for 100-Yr Time Horizon

GHG	2007 IPCC GWP (kg CO_2e)
CO_2	1
CH_4	25
N_2O	298
SF_6	22,800

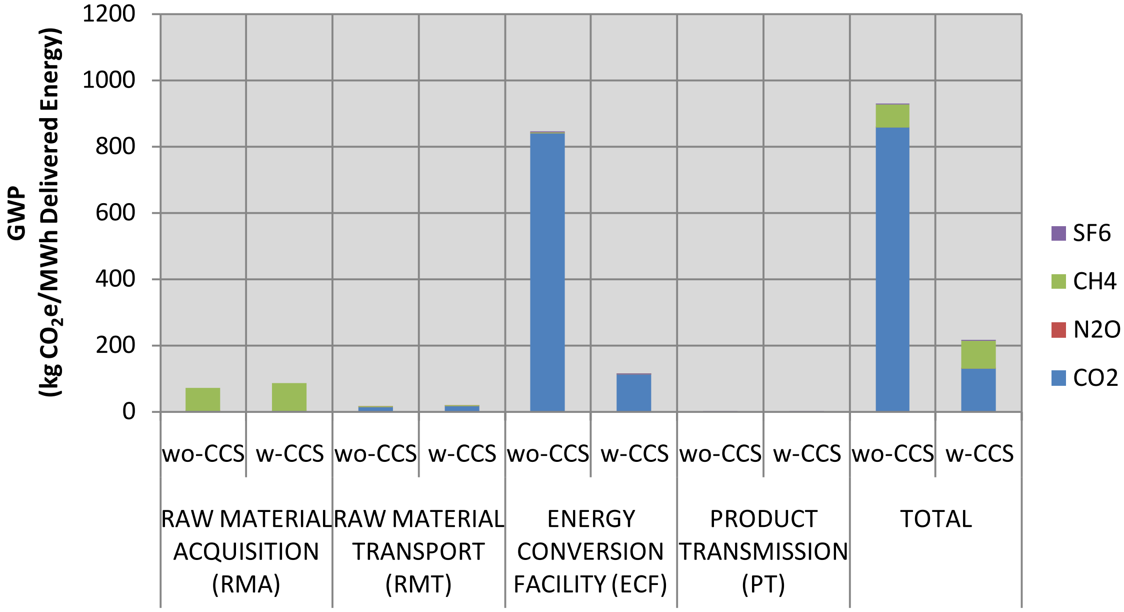
2.1 Greenhouse Gas Emissions

GHG emissions were calculated on both a mass kg and mass equivalent kg CO_2e basis. GHG results are reported on a kg CO_2e basis.

2.1.1 IGCC

The GHG emissions for the IGCC study can be seen in **Figure 2**. CH_4 is the dominant GHG emission during raw material acquisition (RMA), with most of the emission due to CH_4 off gassing from the coal during mining and coal preparation. During raw material transport (RMT), CO_2 is the primary GHG emission released to the atmosphere from the direct combustion of diesel fuel to power the trains' locomotives. CO_2 is also the largest emission from the energy conversion facility (ECF) for both with- and without-CCS cases. The CCS system is designed to remove 90% of the CO_2 in the system, but when total stage emissions are accounted for we see an 87% reduction in CO_2e emissions for the ECF operations. When looking at the total GHG emissions, CO_2 remains the dominant emission, primarily from the ECF, followed by coal bed methane from RMA. The addition of CCS leads to a CO_2e emission decrease of 77% for the entire LC.

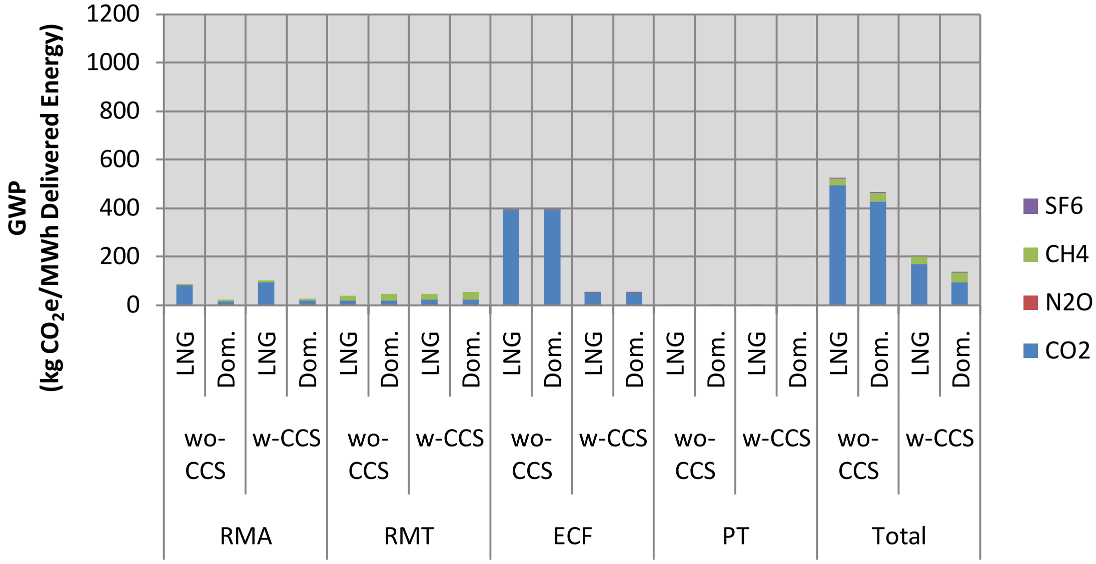
Figure 2: IGCC Study GHG Emission Results



2.1.2 NGCC

The results of the GHG emissions for the NGCC study can be seen in **Figure 3.** The chart shows that for both LNG and DNG CO_2 is the dominant GHG emission, primarily from the ECF. Acquisition and transport also show spikes of CO_2 emissions. RMT has a CH_4 spike during the transport phase, due to the losses seen from the regasification facility for the LNG cases and pipeline operation for both LNG and DNG. The addition of the 90% CCS system leads to a 61% reduction in CO_2e emissions for the LNG case, and 70% reduction for the DNG case for the LC of the plant. It is also interesting that in the CCS case with LNG the RMA accounts for approximately 50% of the overall LC emissions, whereas the RMA for the DNG with CCS accounts for only 20% of the overall LC emissions.

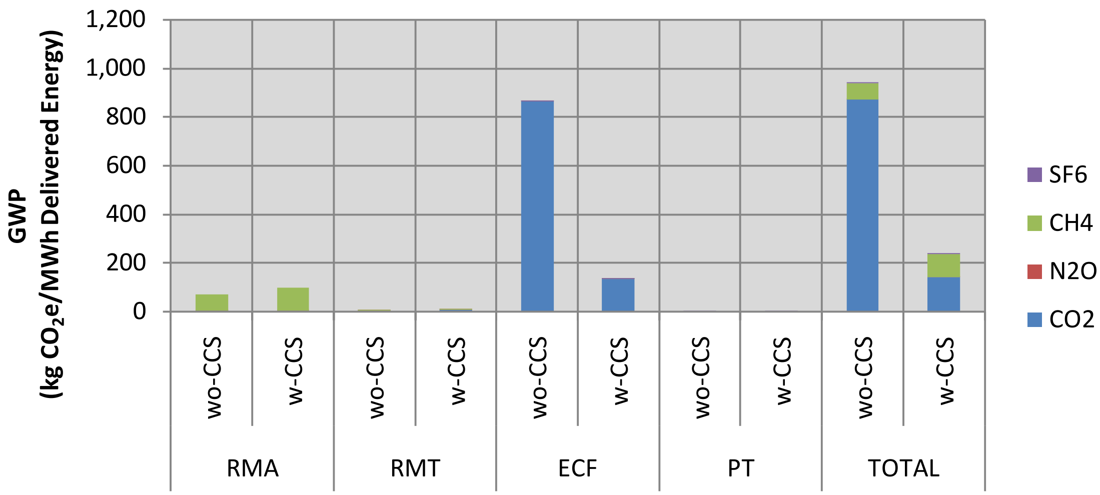
Figure 3: NGCC Study GHG Emission Results



2.1.3 SCPC

The results of the GHG emissions for the SCPC Study can be seen in **Figure 4**. The results show that CO_2 is the dominant emission, primarily from ECF operation. There is a CH_4 emission spike from RMA, due to coal bed methane emissions at the mine. The transport phase shows very small amounts of both CH_4 and CO_2. The addition of CCS leads to an overall 74% decrease in GHG emissions.

Figure 4: SCPC Study GHG Emission Results

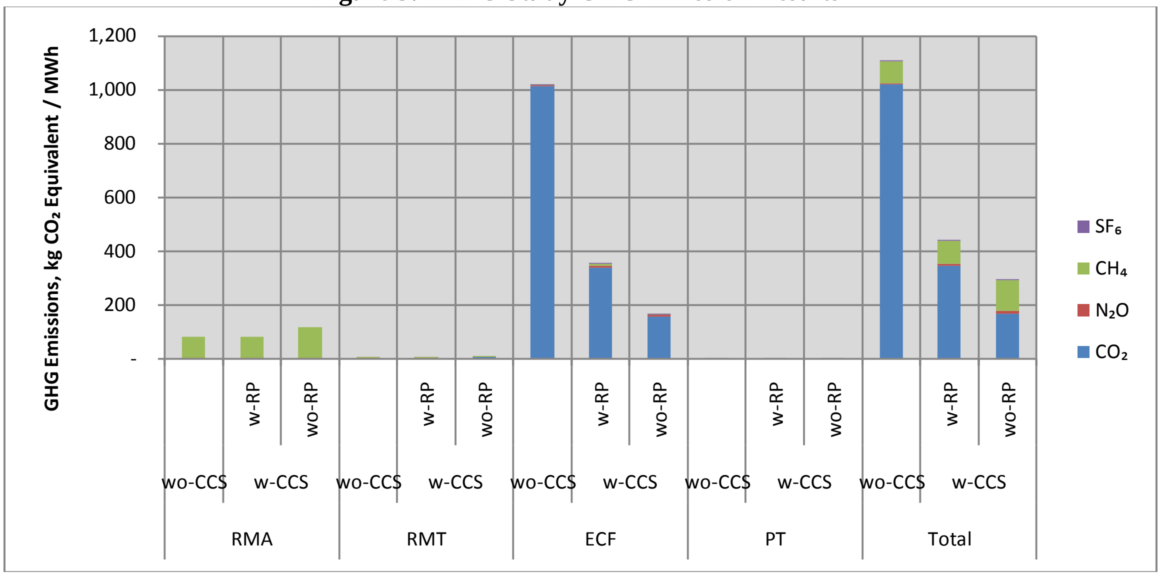


2.1.4 EXPC

The GHG Emissions for the EXPC Study can be seen in **Figure 5**. Starting with RMA, CH_4 is the dominant GHG emission, due to coal bed methane emissions. During RMT, CO_2 is the primary emission, due to fuel combustion in the train locomotives. In the ECF, CO_2 is the overwhelming emission for both with- and without-CCS, with small amounts of N_2O due to limitations in combustion equilibrium. For total GHG emissions,

CO_2 is the dominant emission, primarily from the ECF, followed by coal bed methane from the RMA. Addition of the CCS system leads to a 60% reduction in overall GHG emissions. When omitting the Replacement Power, CCS leads to a 73% reduction in overall GHG.

Figure 5: EXPC Study GHG Emission Results



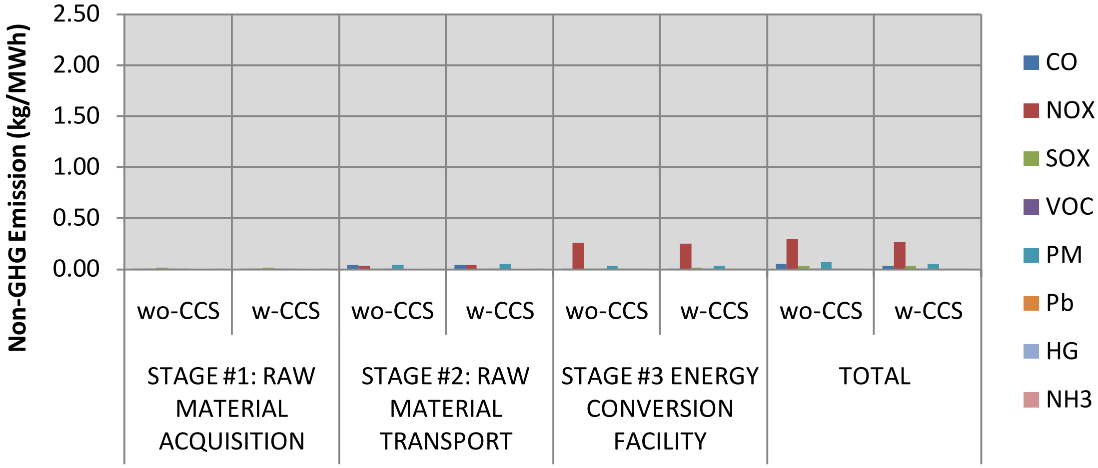
2.2 Criteria Air Pollutant and Other Emissions of Interest

Criteria air pollutants (CAP) are designated as such because permissible levels are regulated on the basis of human health and/or environmental criteria as set forth in the Clean Air Act (EPA 1990). Emissions designated as CAP are as follows: CO, NOX, SOX, VOC, PM, and Pb. Species of interest (SOI) are emissions not called out as CAP, but are identified as being important elements that impact emissions and performance of power systems. For this study they are as follows: Hg, and NH_3.

2.2.1 IGCC

The CAP and SOI emissions for the IGCC study can be seen in **Figure 6**. For the RMA, emissions are of a very low level, but SOX is the primary emission, mostly from the operation phase of the mine. RMT, also of a low level, shows spikes in CO and NOX and from rail transport. Also evident is a spike in PM emissions, due to fugitive dust emissions seen from the unit trains during transport. NOX is the primary effluent from the ECF, with smaller spikes in emissions seen for SO_2 and PM. For the full system, NOX is the dominant emission. CO and PM show smaller amounts of emissions, followed by SOX. Overall, the ECF is the primary emission phase, as was observed in the GHG results.

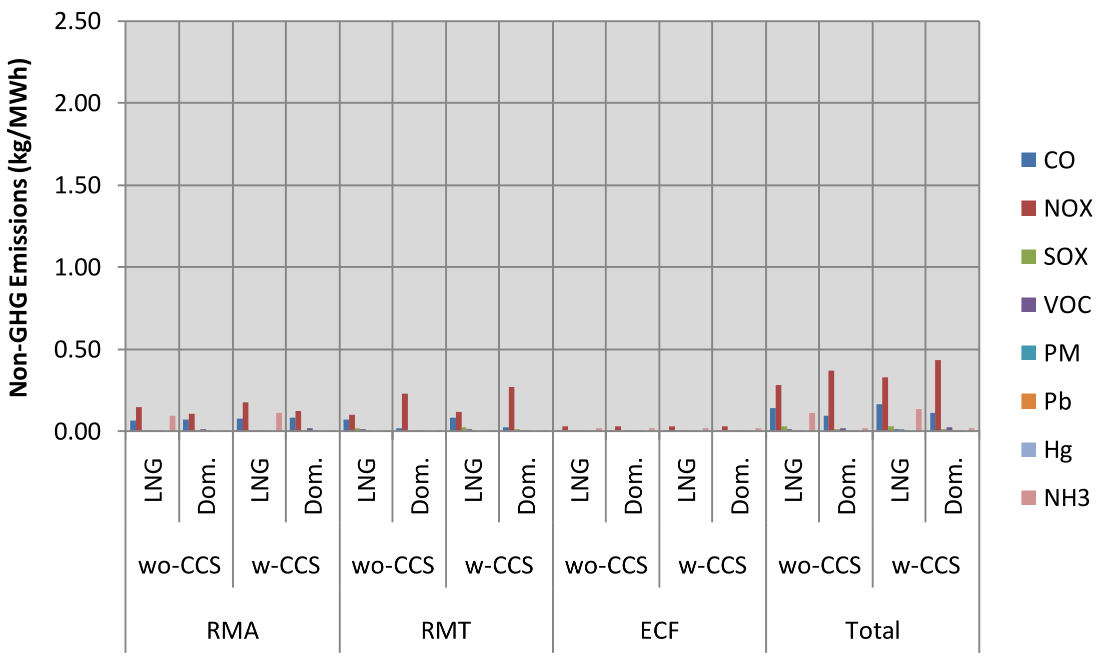
Figure 6: IGCC Study CAP and SOI Emissions



2.2.2 NGCC

The CAP and SOI emissions for the NGCC study can be seen in **Figure 7**. For the overall emissions, NOX is the primary effluent, followed by CO, VOCs and SOX for both LNG and DNG. NH_3 is also a significant emission stream for the LNG cases, due partially to the SCR ammonia slip at the ECF, but primarily due to the liquefaction plant in the acquisition phase. Most emissions show a decreasing trend when switching from LNG to DNG, except for NOX. NOX increases greatly for DNG in the RMT stage, leading to higher overall NOX emissions for the total LC when switching the fuel pathway.

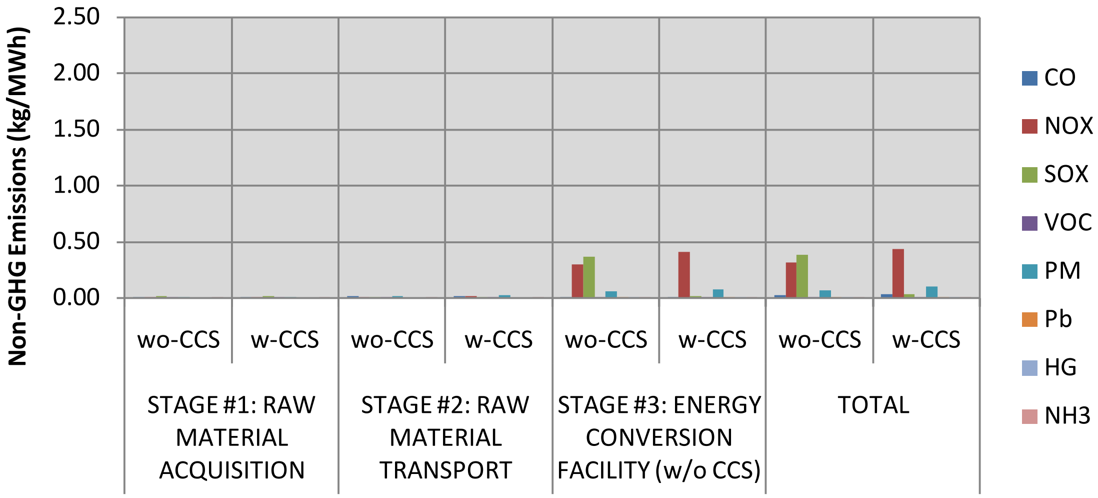
Figure 7: NGCC Study CAP and SOI Emissions



2.2.3 SCPC

The CAP and SOI emissions for the SCPC study can be seen in **Figure 8**. In the case without-CCS SOX is the main effluent, followed by NOX and PM. In the case with-CCS, SOX is reduced to a marginal level due to restrictions from the amine CCS system, leaving NOX as the primary effluent, followed by PM. NOX and PM show increases in emissions, due in small part to renormalizing to a lower net power output in the case with-CCS, but mostly due to larger throughput of coal into the system to allow equivalent power output from the SCPC with-CCS system.

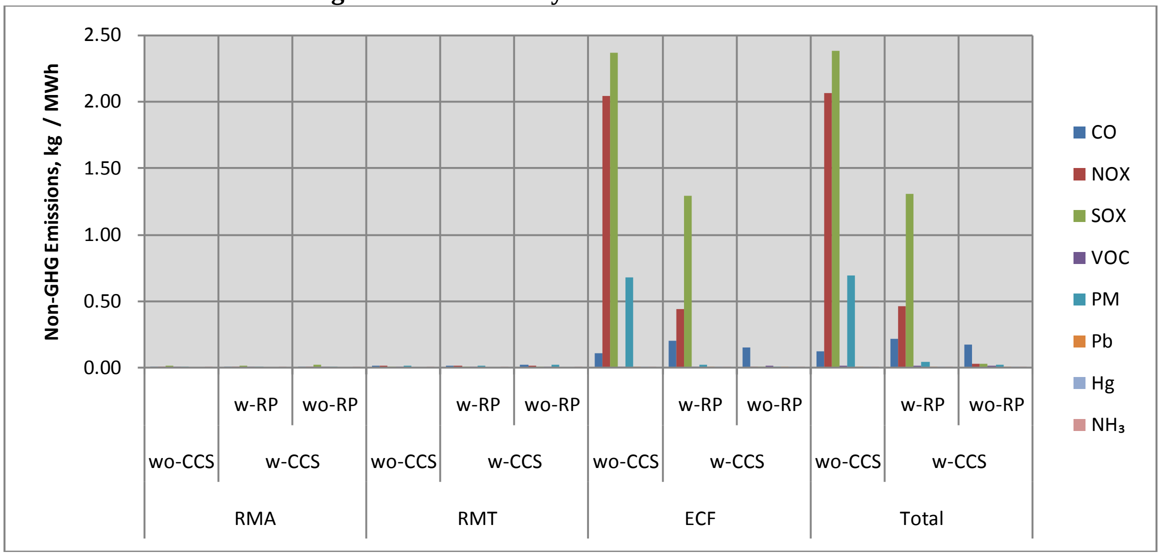
Figure 8: SCPC Study CAP and SOI Emissions



2.2.4 EXPC

The CAP and SOI emissions for the EXPC study can be seen in **Figure 9**. In the case without-CCS, SOX is the main effluent, followed by NOX and PM. In the w-CCS w-RP case, SOX is reduced to a marginal level in the ECF, as was seen with the SCPC results, but there is a spike in emissions related to the replacement power. This is verified by looking at the w-CCS wo-RP case, where SOX and NOX are minimized. PM is reduced to a small amount of emissions, and NOX and CO are the other primary emissions constituents.

Figure 9: EXPC Study CAP and SOI Emissions



2.3 Water Usage

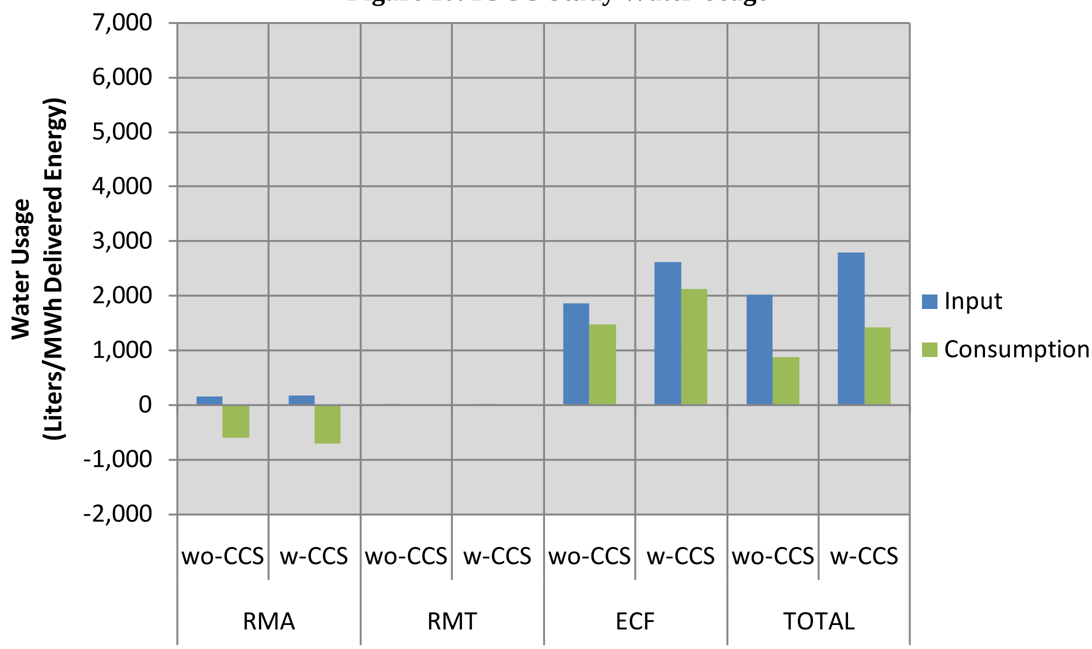
Within NETL LCA studies, water withdrawal is defined as the total amount of water that is drawn from an outside source in support of a process or facility. For instance, water withdrawal for an energy conversion facility would include all water that is supplied to the facility, via municipal supply, pumped groundwater, surface water uptake, or from another source. Water consumption is defined as water withdrawal minus water discharged from a process or facility.

2.3.1 IGCC

The Water Usage for the IGCC study can be seen in **Figure 10**. The RMA shows input of water to the mine, and water consumption is shown as negative, as the mine is a net producer of water. This takes into account water from the mine, storm runoff, and any recycled water, which counts as a credit against consumption. RMT registers some water usage, but notice that the scale of usage is so low as to not show up on this graph. Water usage at the ECF is the primary usage area. Addition of CCS forces an increase in specific water input and consumption, due to the increased water demand for cooling in the CCS equipment. The CCS system increases water input and consumption by 31% at the ECF. For the total system, water input increases 30% and consumption by 34% when adding CCS.

Note that the total system water inputs, both with- and without-CCS, are higher than the ECF input values. As well, note that with the offset from the raw material acquisition stage, water consumption for the entire plant is less than the consumption from the ECF.

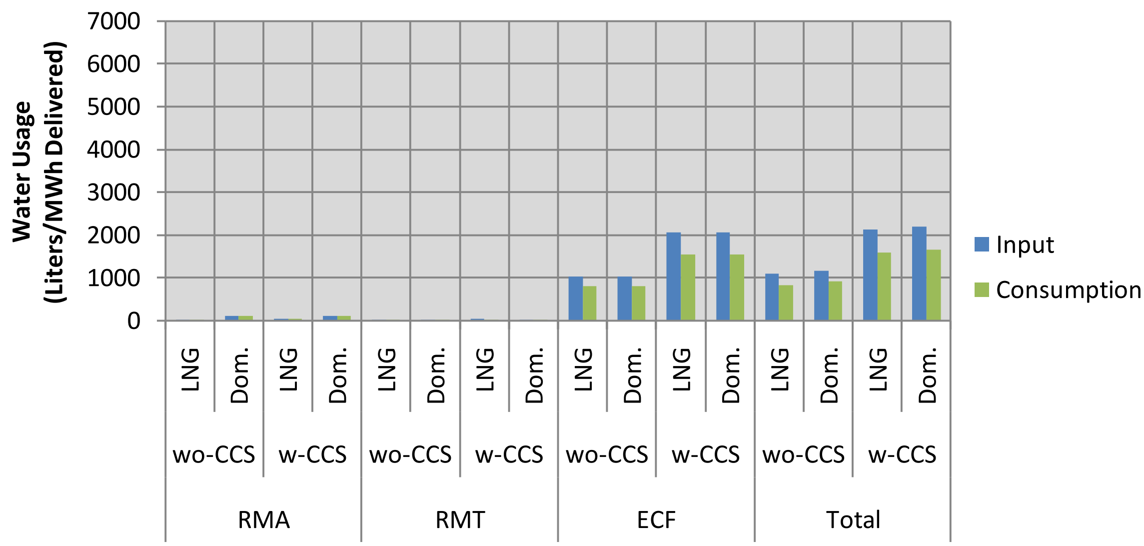
Figure 10: IGCC Study Water Usage



2.3.2 NGCC

The water usage for the NGCC Study can be seen in **Figure 11**. It is readily apparent that the ECF is the primary input and consumption vector of water usage. Small amounts of water input and consumption can be seen in the RMA and RMT stages, with DNG being slightly higher in water input and consumption. The addition of CCS almost doubles the amount of water input and consumption in the system. This is due to extra cooling requirements necessary in the plant with-CCS equipment installed. The CCS system for the LNG cases increases water input by 98% at the ECF and 94% for the total LC, whereas DNG increases ECF input by 98% and total input by 90%. As well, consumption for LNG increases by 91% at the ECF, and by 90% for the total LC, but 91% at the ECF and 81% for the total LC on DNG.

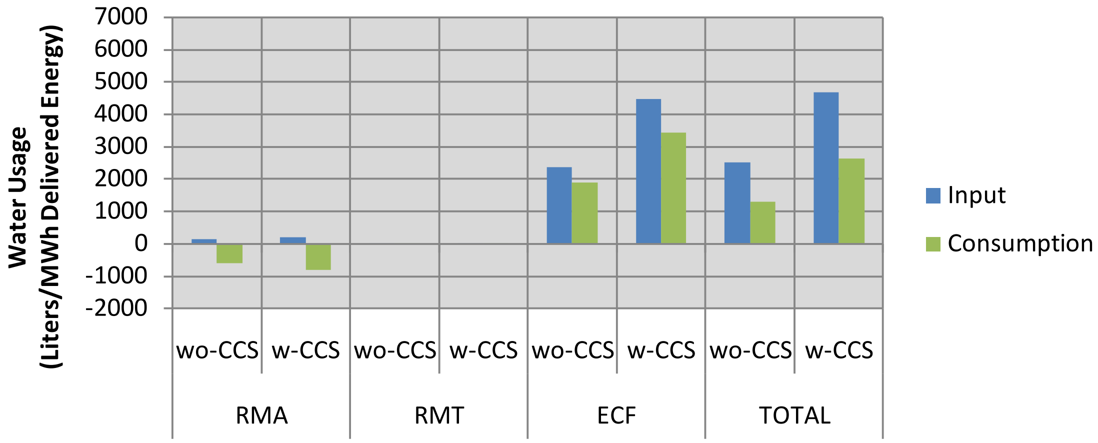
Figure 11: NGCC Study Water Usage



2.3.3 SCPC

The water usage for the SCPC Study can be seen in **Figure 12**. One can clearly see that the primary vector of water usage is the ECF. Addition of the CCS system almost doubles the amount of water input, as well as the amount consumed in the system. This is due primarily to the extra cooling demand necessary for the CCS system to cool the flue gas before contact with the MEA solvent. The CCS system increases water input and consumption by 89 and 83%, respectively, at the ECF, and water input by 86% and consumption by 103% for the total LC.

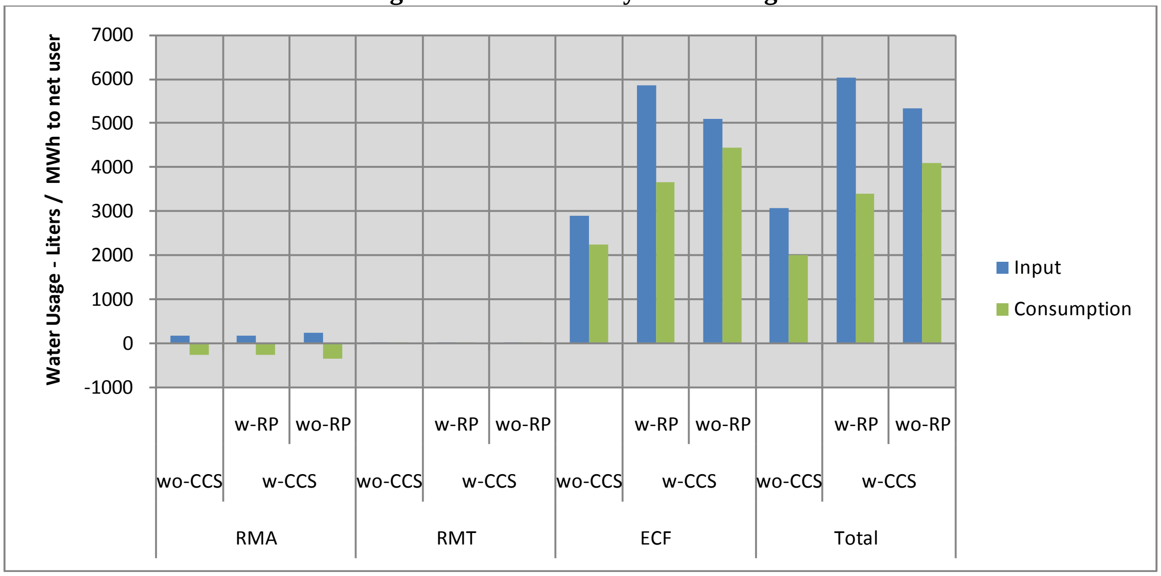
Figure 12: SCPC Study Water Usage



2.3.4 EXPC

The water usage for the EXPC study can be seen in **Figure 13**. The RMA shows input of water to the mine, in similar fashion to the IGCC cases. RMT registers some water usage, but notice that the scale of usage is too low to show up on this graph. The ECF is the primary usage area. Addition of CCS forces an increase in specific water input and consumption. This is mainly due to the increased water demand for cooling in the CCS equipment. The CCS system increases water input by 102% at the ECF and 96% for the total LC. Consumption increases by 62% at the ECF, and by 70% for the total LC. It is interesting to note that removing the Replacement Power from the w-CCS case causes a decrease in water input, but an increase in consumption. This is mostly because the Replacement Power affects input more than consumption due to once-through cooling in the SERC power profile.

Figure 13: EXPC Study Water Usage



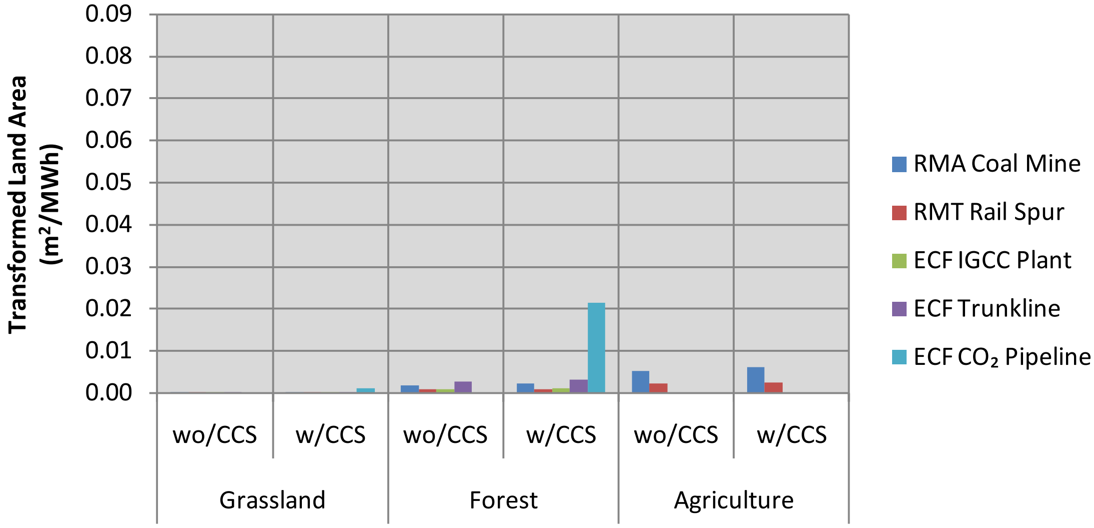
2.4 Transformed Land Area

For the purposes of this study, land use encompasses the changes in the type or nature of activity that occurs in the land area considered within the study boundary. The land use metrics used for this analysis quantify the land area that is transformed from its original state due to construction and operation of the operating technology plant and supporting facilities. Results from the analysis are presented as per the reference flow for each relevant LC stage, or per MWh when considering the additive results of all stages.

2.4.1 IGCC

The transformed land area for the IGCC technologies is shown in **Figure 14**. Grassland shows only minor changes, until the CCS system is added and the CO_2 pipeline has a not insignificant impact on the total grassland change. Forest usage shows changes for all aspects, but the largest impact is due to changes from the CO_2 pipeline, as was seen with grassland usage. Agriculture shows usage only for the coal mine and the rail spur. The increases in land usage for the tracked items when adding CCS (other than the CO_2 pipeline) is due primarily to the renormalization of the results with a decreased net electricity generation from the CCS auxiliary loads.

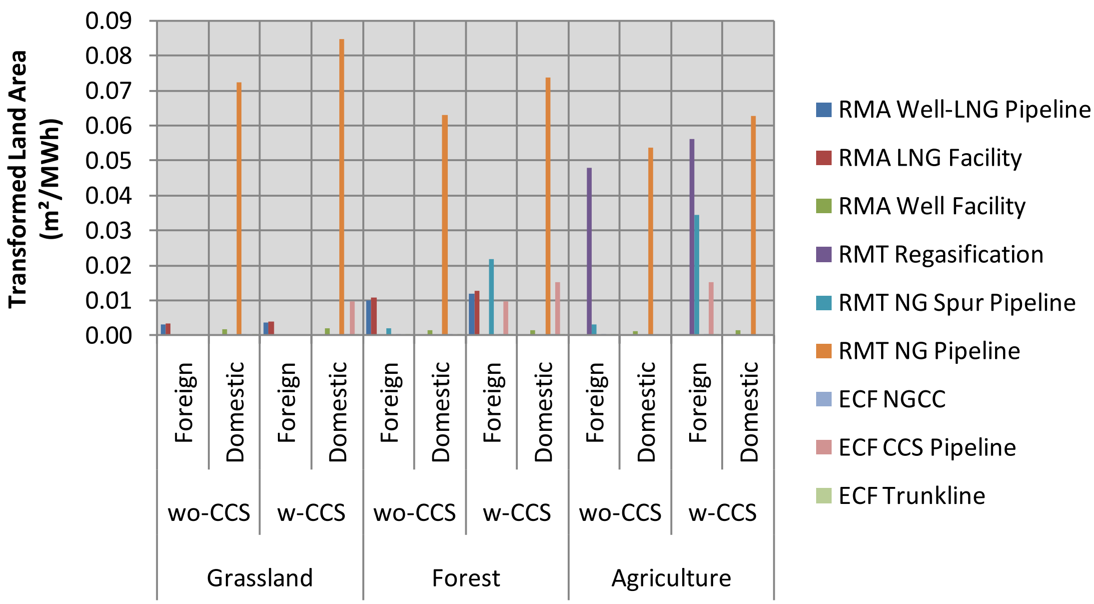
Figure 14: Transformed Land Area for the IGCC Systems



2.4.2 NGCC

The transformed land area for the NGCC technologies is shown in **Figure 15**. Both LNG and DNG impact the ECF items, but LNG affects the Well-LNG pipeline and LNG faciligy in the RMA and Regasification and NG Spur pipeline for RMT. The other items pertain to DNG RMA and RMT only. The largest land usage vector is the NG Pipeline in the DNG systems. The reason it is so large is that the distance from hub source to the ECF is 4.5 times larger in the DNG case than with the LNG case. The other land use categories for DNG amount to less than 20% of the NG pipeline values. For LNG, the

Figure 15: Transformed Land Area for the NGCC Systems

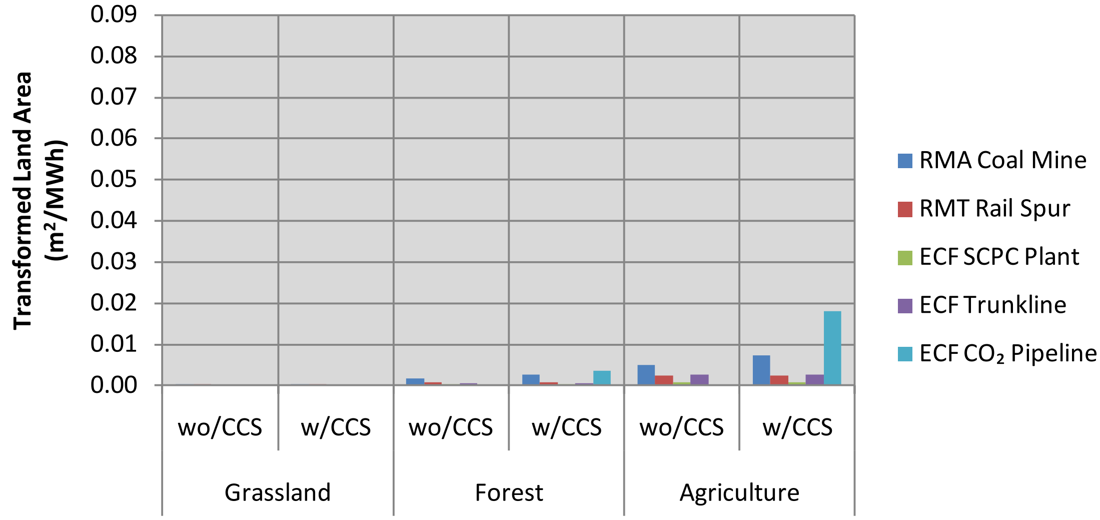


Regasification and NG Spur Pipeline account for the largest share of land usage, all impacting primarily agricultural land.

2.4.3 SCPC

The transformed land area for the SCPC technologies is shown in **Figure 16**. The figure shows that grassland plays only a small part in the overall land usage. The forest and agriculture numbers show the same type of trend, with the exception that the trunkline uses more area than the rail spur in the agriculture results. The CO_2 pipeline has larger land use than the other entities for the CCS cases. Renormalization of the results due to CCS auxiliary losses leads to larger overall land use values for the CCS case.

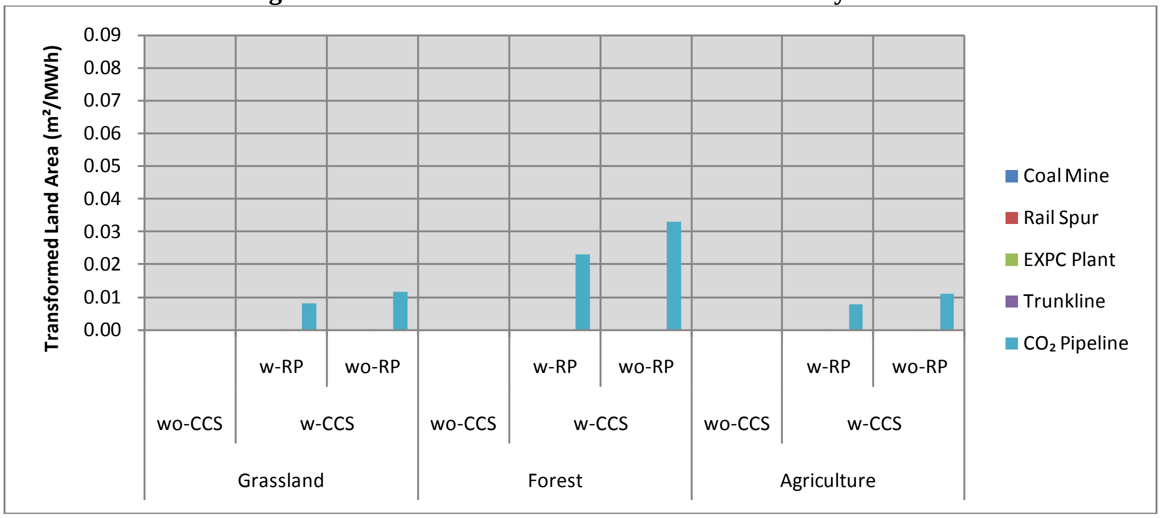
Figure 16: Transformed Land Area for the SCPC Systems



2.4.4 EXPC

The transformed land area for the EXPC technologies is shown in **Figure 17**. The values for the case without-CCS are all zero, due to the system being an existing facility, and land use already accounted for in the original construction. The CCS case w- and wo-RP shows small grassland usage, but the main item is the CO_2 pipeline land usage. Grassland and agriculture usage from the CO_2 pipeline is 1/3rd the amount of forest usage for the plant retrofit. The increase in land usage when removing Replacement Power is a result of renormalizing the values due to reduced power output.

Figure 17: Transformed Land Area for the EXPC Systems



3.0 LCC Results

The LCC analysis captures the significant capital and O&M expenses incurred by the cases with- and without-CCS for their 30-year life. The LCC provides the constant dollar levelized cost of electricity (LCOE) and the capital cost (CC) of the production and delivery of energy over the study period. It should be noted that the costs reported are for full CC and LCOE for each technology, except the EXPC, which is reported as incremental costs for both the CC and LCOE. The reason for this is that the EXPC is just that, an existing unit, and the sunk cost for the ECF capital has already been dealt with through the economics of operating the plant for the last 30 years.

Cash flow is affected by several factors, including cost (capital, O&M, replacement, and decommissioning or salvage), book life of equipment, Federal and State income taxes, tax and equipment depreciation, interest rates, and discount rates. For NETL LCC assessments, Modified Accelerated Cost Recovery System (MACRS) deflation rates are used. O&M costs are assumed to be consistent over the study period except for the cost of energy and feedstock materials as determined by EIA.

Capital investment costs are defined as per the Baseline Report (NETL 2010a, b, c, d) "equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project)." The following costs are excluded from the definition:

- Escalation to period-of-performance.
- All taxes, with the exception of payroll taxes.
- Site-specific considerations (including, but not limited to seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.).
- Labor incentives in excess of a five-day/10-hour workweek.
- Additional premiums associated with an engineer/procure/construct (EPC) contracting approach.

In accordance with the Baseline Report, all values are reported in January 2007 dollars; it is the assumption of this study that there is no difference between December 2006 dollars and January 2007 dollars. **Table 6** summarizes the LCC economic parameters that were applied to all pathways.

Table 6: Global LCC Analysis Parameters

Property	Value	Units
Reference Year Dollars	December 2006/January 2007	Year
Assumed Start-Up Year	2010	Year
Real After-Tax Discount Rate	10.0	Percent
After-Tax Nominal Discount Rate	12.09	Percent
Assumed Study Period	30	Years
MACRS Depreciation Schedule Length	Variable	Years
Inflation Rate	1.87	Percent
State Taxes	6.0	Percent
Federal Taxes	34.0	Percent
Total Tax Rate	38.0	Percent
Fixed Charge Rate Calculation Factors		
Capital Charge Factor	Variable Per Technology	--
Levelization Factor	Variable Per Technology	--
Start Up Year (2010) Feedstock & Utility Prices	*$2006*	
Natural Gas[1]	6.76	$/MMBtu
Coal[2]	1.51	$/MMBtu
Process Water[3]	0.00049 (0.0019)	$/L ($/gal)

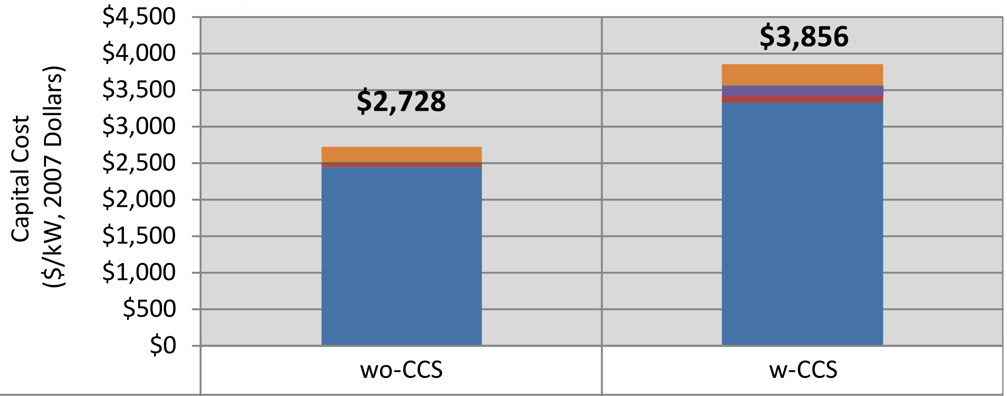
3.1 Capital Cost Results

Capital costs are reported as "overnight costs" (not incurring interest charges) and are expressed in 2007 dollars. Accordingly, all cost data from previous reports and forthcoming studies are normalized to January 2007 dollars. There is no difference between December 2006 dollars and January 2007 dollars.

3.1.1 IGCC

The capital costs for the IGCC study are shown in **Figure 18**. It can be seen that capital costs are the primary components of the estimates. The addition of the CCS system results in the addition of costs for CO_2 pipeline and the sequestration site, along with increases in the decommissioning costs. Capital costs are seen to increase by 41% when CCS is added.

Figure 18: IGCC Study Capital Cost Results

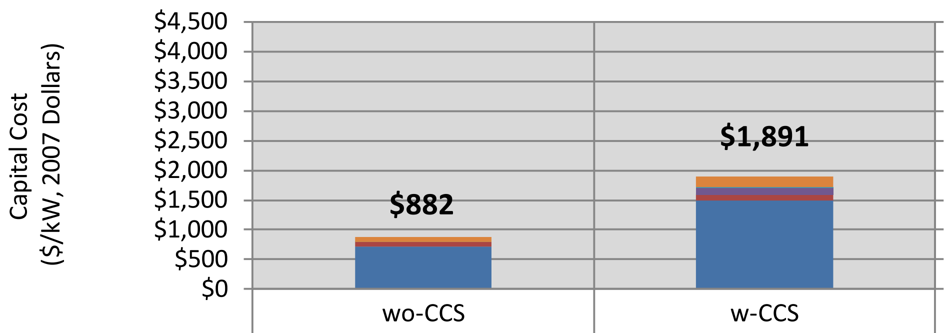


	wo-CCS	w-CCS
Decommissioning	$206	$295
Sequestration Site	$0	$14
CO2 Pipeline	$0	$127
Switchyard	$2	$2
Trunkline	$73	$84
Capital Costs	$2,446	$3,334
Total LC Plant Cost	$2,728	$3,856

3.1.2 NGCC

The capital costs for the NGCC Studies are shown in **Figure 19**. Again, the primary component of the capital costs is the equipment capital cost. The addition of CCS shows additional costs for CO_2 pipeline and the sequestration site, along with increased decommissioning costs. Capital costs are seen to increase by 114% when the CCS system is added, driven by doubling of the decommissioning and capital costs.

Figure 19: NGCC Study Capital Cost Results

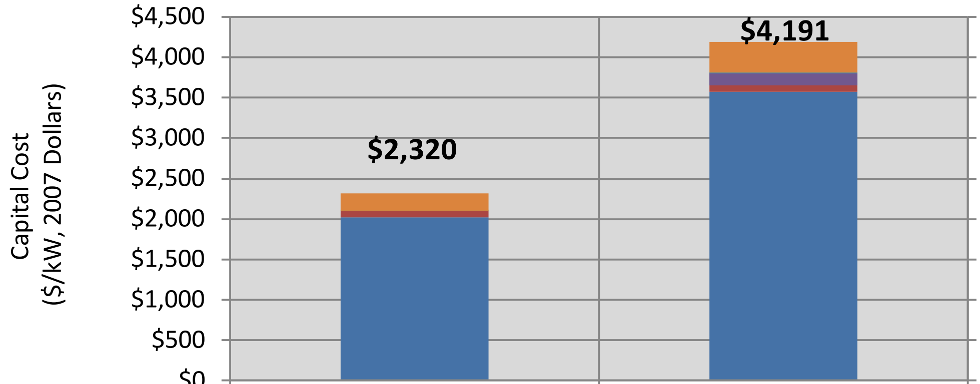


	wo-CCS	w-CCS
Decommissioning	$80	$173
Sequestration Site	$0	$13
CO2 Pipeline	$0	$110
Switchyard	$2	$2
Trunkline	$82	$96
Capital Costs	$718	$1,497
Total LC Plant Cost	$882	$1,891

3.1.3 SCPC

The capital costs for the SCPC Study are shown in **Figure 20**. Capital costs are the primary component of the estimate. The addition of CCS shows costs for the CO_2 pipeline and the sequestration site, and higher decommissioning value. Capital costs are seen to increase by 81% when the CCS system is added, driven by the near doubling of the decommissioning and capital costs, plus the addition of the CCS system costs.

Figure 20: SCPC Study Capital Cost Results

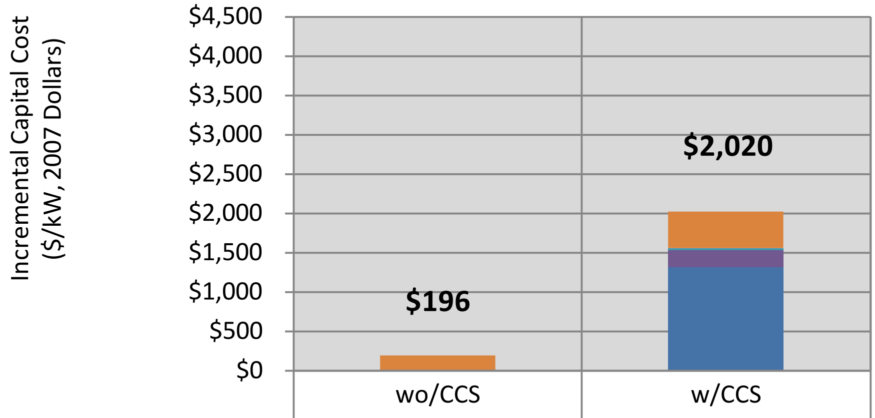


	wo-CCS	w-CCS
Decommissioning	$211	$382
Sequestration Site	$0	$14
CO2 Pipeline	$0	$140
Switchyard	$2	$2
Trunkline	$83	$83
Capital Costs	$2,024	$3,570
Total LC Plant Cost	$2,320	$4,191

3.1.4 EXPC

The capital costs for the EXPC Study are shown in **Figure 21**. The without-CCS case shows only decommissioning costs, and no capital and initial costs due to the brownfield application. The CCS case includes all capital items, except the switchyard and trunkline, which were assumed to be pre-existing. Equipment capital costs are the primary component of the capital costs for the with-CCS case. The addition of CCS shows the costs for the CO2 pipeline and the sequestration site, along with an increase in decommissioning costs. A case was run that did not include replacement power, but the capital costs are the same as the with replacement power case. The reason for this is that the capital cost is based on the plant retrofit, and the replacement power is a purchased utility, affecting the LCOE as will be seen in later graphs. The capital cost is shown to increase by 930% when adding the CCS system

Figure 21: EXPC Study Capital Cost Results



	wo/CCS	w/CCS
Decommissioning	$196	$463
Sequestration Site	$0	$20
CO_2 Pipeline	$0	$216
Switchyard	$0	$0
Trunkline	$0	$0
Capital + Initial Costs	$0	$1,320
Total Plant Cost	$196	$2,020

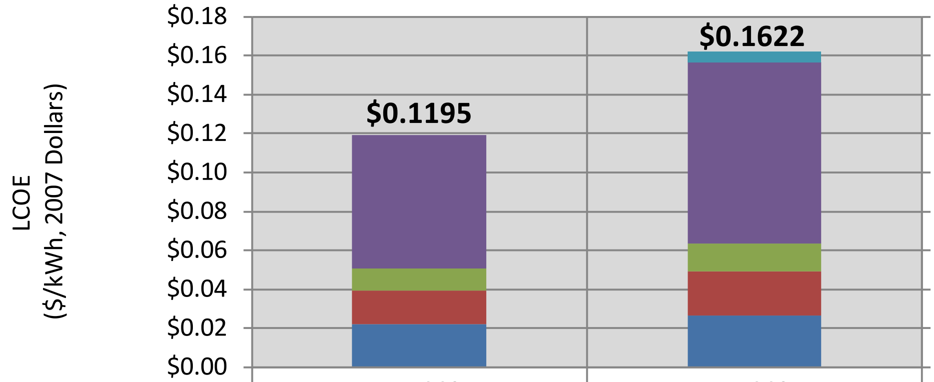
3.2 Levelized Cost of Electricity Results

The LCC analysis uses a revenue requirement approach, which is commonly used for financial analysis of power plants. This approach uses the cost of delivered electricity (COE) for a comparison basis, which works well when trying to evaluate different plant configurations. COE is levelized (LCOE) over a 20-year period, although the plant is modeled for a 30-year lifetime. The method for the 20-year LCOE is based on the NETL Power Systems Financial Model (NETL, 2008b). The LCOE is calculated using the present value (PV) costs. All PV were levelized using a capital charge factor (CCF) for capital costs and a levelization factor for O&M costs.

3.2.1 IGCC

The LCOE results for the IGCC Study are shown in **Figure 22**. Capital costs make up the largest component of the LCOE. Utility Costs are second order, followed by Variable O&M then Labor costs. Addition of the CCS system leads to an increase in LCOE of 36%, driven primarily by increases in the capital cost and the CCS system.

Figure 22: IGCC Study LCOE Results

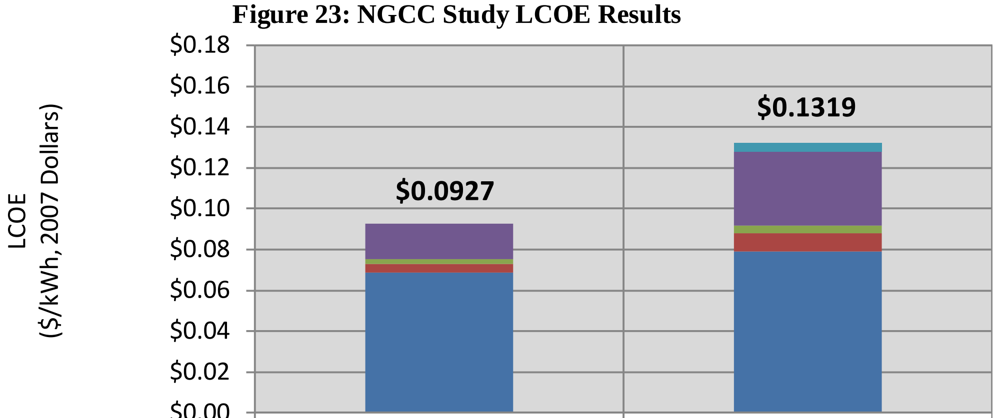


	wo-CCS	w-CCS
CO2 T, S & M	$0.0000	$0.0053
Capital Costs	$0.0690	$0.0936
Variable O&M Costs	$0.0112	$0.0143
Labor Costs	$0.0173	$0.0227
Utility + Feedstock Costs	$0.0220	$0.0263
Total LC LCOE	$0.1195	$0.1622

3.2.2 NGCC

The LCOE results for the NGCC Study are shown in **Figure 23**. Utility costs make up the largest component for the NGCC systems, followed by capital costs, then variable O&M and labor costs. Addition of the CCS systems leads to an increase in LCOE of 42%.

Figure 23: NGCC Study LCOE Results

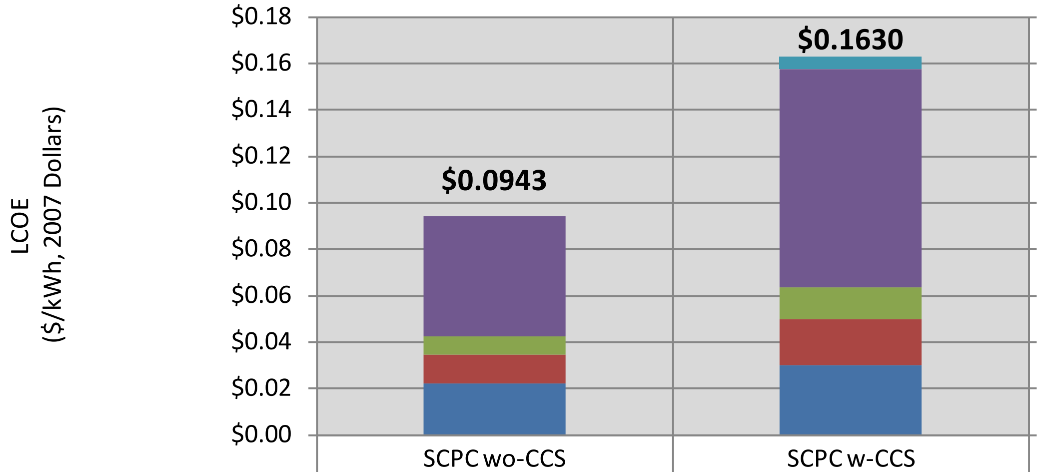


	wo-CCS	w-CCS
CO2 T, S & M	$0.0000	$0.0039
Capital Costs	$0.0175	$0.0363
Variable O&M Costs	$0.0020	$0.0039
Labor Costs	$0.0046	$0.0086
Utility + Feedstock Costs	$0.0686	$0.0792
Total LC LCOE	$0.0927	$0.1319

3.2.3 SCPC

The LCOE results for the SCPC Study are shown in **Figure 24**. Capital costs are the largest component of the LCOE, followed by utility, labor then variable O&M costs. Addition of the CCS system leads to an increase in LCOE of 73%.

Figure 24: SCPC Study LCOE Results

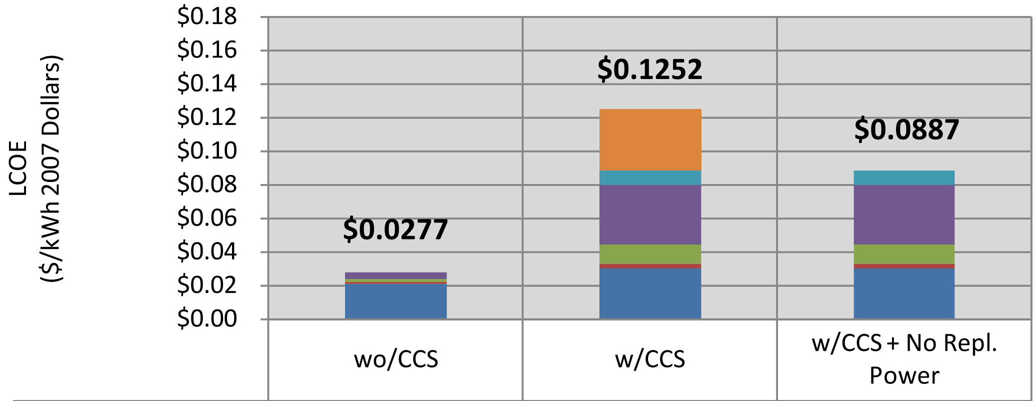


	SCPC wo-CCS	SCPC w-CCS
CO2 T, S & M	$0.0000	$0.0054
Capital Costs	$0.0518	$0.0941
Variable O&M Costs	$0.0079	$0.0134
Labor Costs	$0.0124	$0.0199
Utility + Feedstock Costs	$0.0222	$0.0302
Total LC LCOE	$0.0943	$0.1630

3.2.4 EXPC

The LCOE results for the EXPC Study are shown in **Figure 25**. The figure also includes a retrofit case without replacement power for comparison purposes. Utility costs are the largest component of the LCOE for the without-CCS case. The CCS case shows three primary components of the LCOE: utility, capital, and replacement power costs (variable O&M and labor costs are much lower). Note that when removing the replacement power the costs associated with the replacement power are merely subtracted out, because the LCOE is developed on the initial plant output, not the final output including the replacement power. In the overall, addition of CCS and replacement power increases the LCOE by 352%. When neglecting the replacement power, the LCOE increases by 220%.

Figure 25: EXPC Study LCOE Results



	wo/CCS	w/CCS	w/CCS + No Repl. Power
Replacement Power		$0.0365	
CO_2 TS&M Costs		$0.0086	$0.0086
Capital Costs	$0.0040	$0.0359	$0.0359
Variable O&M	$0.0013	$0.0109	$0.0109
Labor Costs	$0.0013	$0.0032	$0.0032
Utility Costs	$0.0211	$0.0301	$0.0301
Total	$0.0277	$0.1252	$0.0887

4.0 Results Interpretation

The GWP results for all four reports can be seen in **Figure 26**. The figure shows that the cases without-CCS have the highest GWP. For the without-CCS cases, NGCC-DNG shows the lowest GWP, and EXPC shows the highest GWP. A curious result is that the IGCC and SCPC cases show almost the same amount of GWP when CCS is not present.

When installing the CCS system, an immediate drop in GWP can be seen for all cases (**Table 7**). An interesting result is that the three greenfield installations (IGCC, NGCC-LNG, and SCPC) show almost the same total amount of GWP when adding CCS.

Figure 26: GWP of Full Power Studies

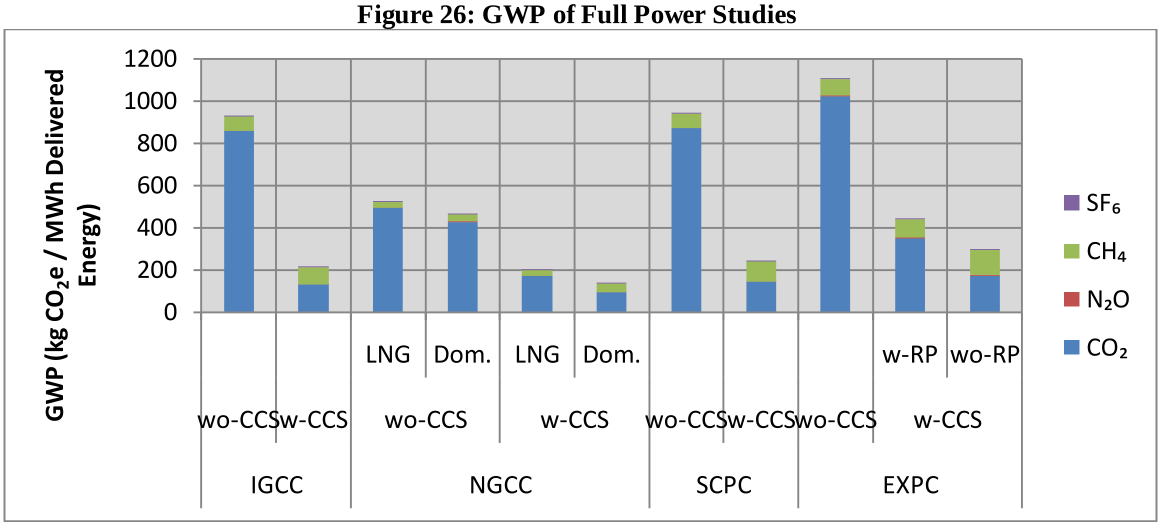


Table 7: Change in GWP Potential with Addition of CCS

Technology	Change in GWP
IGCC	-77%
NGCC-LNG	-61%
NGCC-DNG	-71%
SCPC	-74%
EXPC w-RP	-60%
EXPC wo-RP	-73%

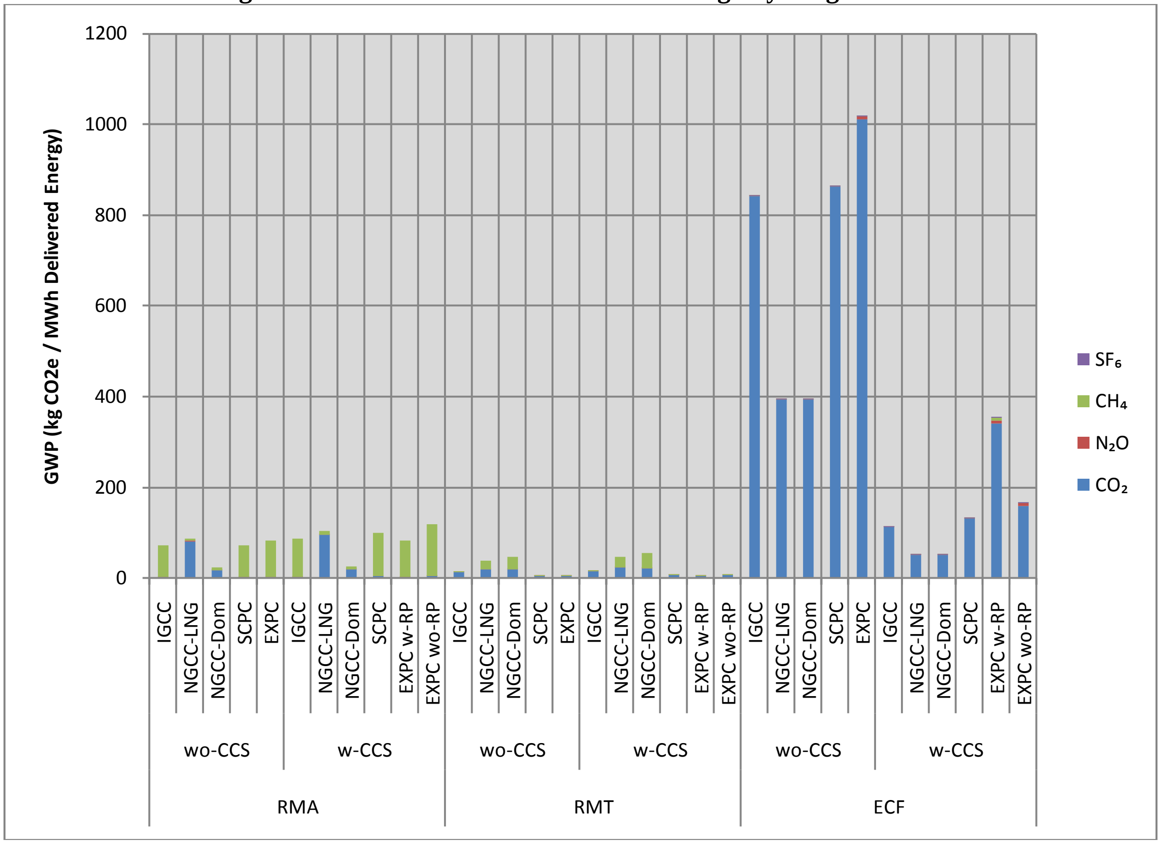
The EXPC case with-CCS has much higher GWP than the other technologies (average 100 percent larger GWP than the other CCS cases). As a comparison, the EXPC w-CCS and wo-RP shows a 50% larger GWP than the other CCS cases, so the difference between the retrofit and the base technology cases w-CCS can be attributed to the Replacement Power. The replacement power used in this study is generated within the Southeast Electric Reliability Council (SERC) electric grid. The fuel mix of the SERC grid is based on 2007 operating data for U.S. power plants (EPA 2008c). The fuel mix and generation percentage for the SERC grid is shown in **Table 8**.

Table 8: SERC Mix and Generation Profile

Fuel Source	Generation Percentage
Hard Coal	53%
Nuclear	24%
NG	12%
Lignite	5%
Hydropower	3%
Biomass	2%
Heavy Fuel Oil	1%
Wind	0%

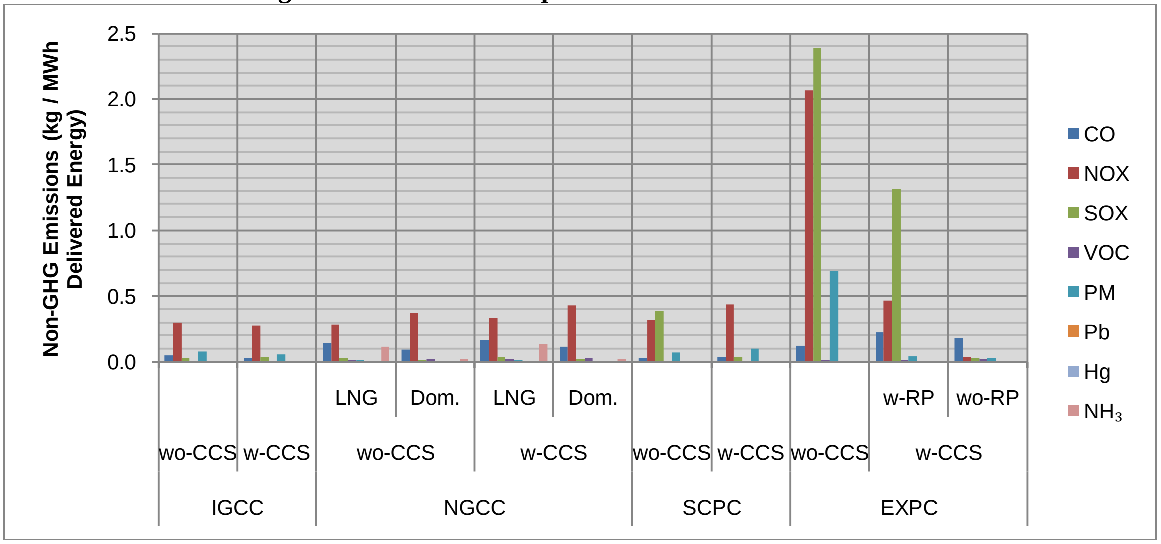
An expansion of the GWP results to include stage-by-stage results for all four studies can be seen in **Figure 27**. The ECF Stage is the primary GWP emitter for the cases without-CCS. This same trend is seen with-CCS, except for the NGCC-LNG with-CCS case. In that case the acquisition phase actually has a higher GWP than the ECF. This is due in part to the excessive emissions seen at the foreign drilling location, and the effect of the CCS system on the ECF emissions. All the coal studies show high CH_4 emissions from the RMA stage, due to coal bed methane emissions. The NGCC cases show higher CH_4 emissions in the RMT stage than the coal cases, due to venting losses seen from the tanker for LNG and pipeline losses for both LNG and DNG. With respect to the RMT stage, NGCC systems show higher total emissions than in the other studies. The PT stage takes into account losses from distribution equipment, seen primarily as SF_6 emissions, which are low for each case.

Figure 27: GWP of Full Power Studies – Stage-by-Stage Results



The CAP and SOI emissions study results can be seen in **Figure 28**. The primary item that stands out is the magnitude of the EXPC emissions compared to the other technologies. NOX is seen to vary between 0.25 and 0.4 kg/MWh for most technologies with- and without-CCS, but is almost an order of magnitude larger for the EXPC without-CCS. SOX is even higher in the EXPC without-CCS. There are two reasons for the disparity. First, the EXPC plant was already sited, with more than 30 years of operation, without the utilization of state-of-the-art (SOA) clean-up equipment. Second, even with the CCS retrofit to the EXPC, there are still issues with the emissions, primarily with SOX. These emissions are attributed to the Replacement Power, as one can see that with the EXPC w-CCS wo-RP there are minimal emissions, due to gas polishing steps for the amine capture process. The stage-by-stage analysis is not detailed here, due to the complexity of the figure.

Figure 28: Criteria and Species of Interest Air Emissions



The water usage for the entire study can be seen in **Figure 29**. For all technologies, the addition of CCS leads to an increase in water withdrawal and consumption (**Table 9**). NGCC-LNG shows the smallest water withdrawal and consumption for non-CCS cases. For CCS cases, NGCC-LNG shows the lowest withdrawal, and IGCC shows the smallest consumption. IGCC and NGCC-LNG, with- and without-CCS, show smaller amounts of withdrawal and consumption than both the SCPC and EXPC systems. It should be pointed out that the SCPC system without-CCS has a higher withdrawal rate than the IGCC with-CCS, and that rate nearly doubles when adding CCS.

Figure 29: Water Usage of Full Power Studies

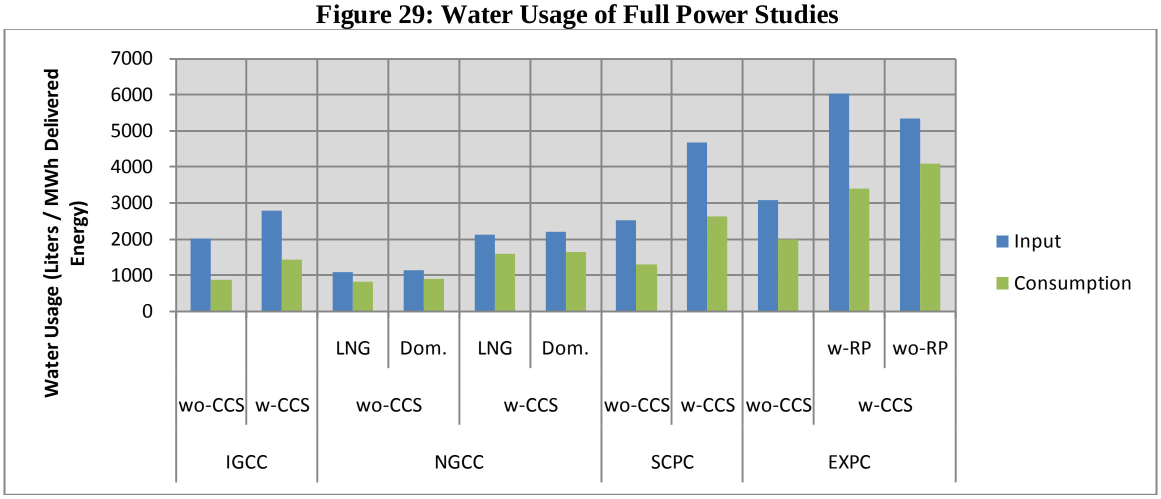
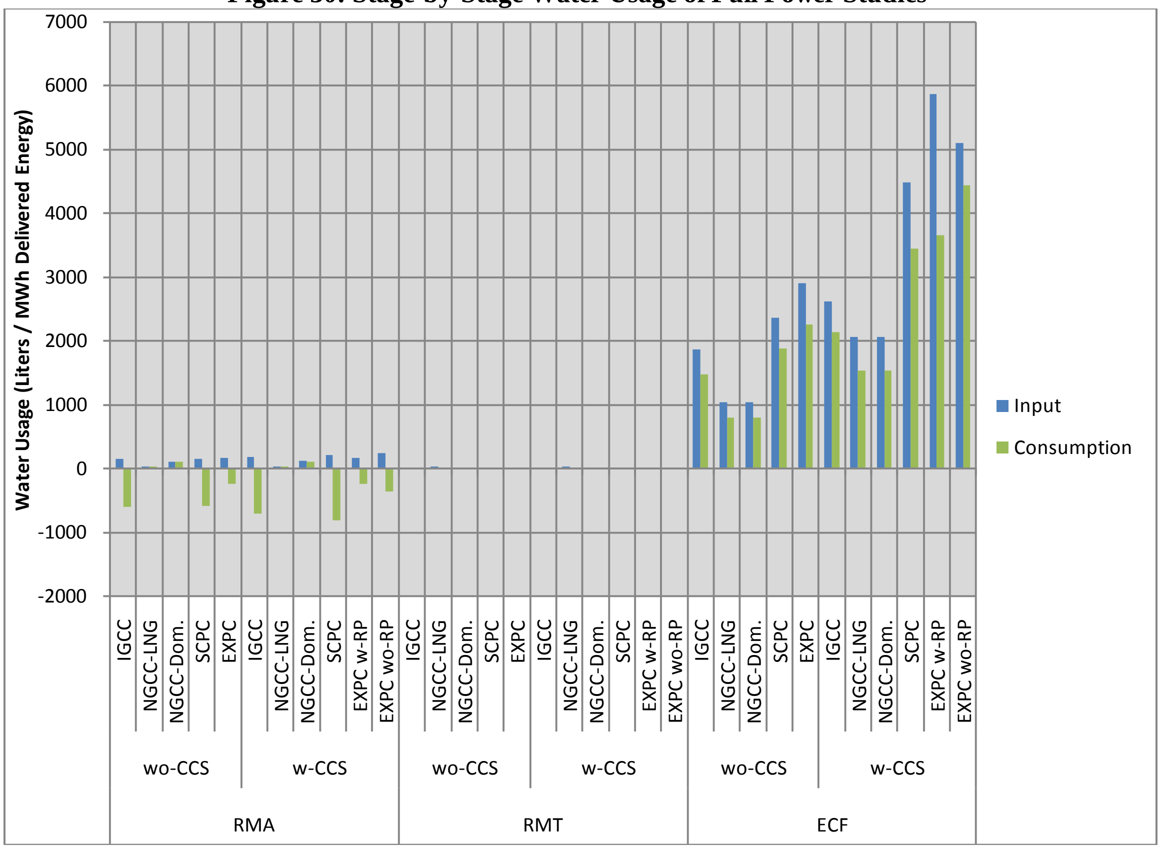


Table 9: Water Usage - Change in Withdrawal and Consumption with CCS

Technology	Withdrawal - %Increase with CCS	Consumption - %Increase with CCS
IGCC	+30%	+34%
NGCC-LNG	+79%	+76%
SCPC	+90%	+99%
EXPC	+96%	+70%

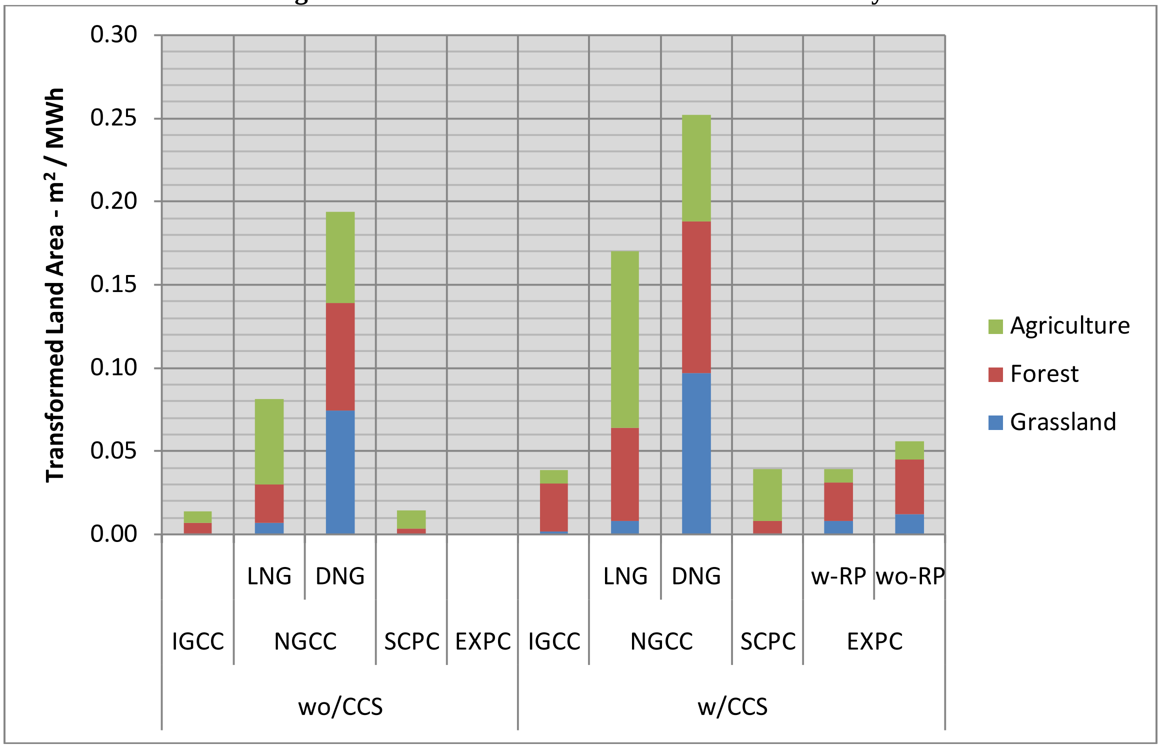
The stage-by-stage water usage for the entire study can be seen in **Figure 30**. Note that all the coal cases show negative consumption values in the RMA phase. ECF stages, with- and without-CCS, show the largest withdrawal and consumption. IGCC shows the lowest increase in water withdrawal and consumption at the ECF stage when adding CCS (33%), whereas the other technologies show near 100% increase in water withdrawal and consumption at the ECF stage when adding CCS. Of particular note is the near equal amount of water withdrawal and consumption for the ECF phase in the IGCC and NGCC-LNG with-CCS cases.

Figure 30: Stage-by-Stage Water Usage of Full Power Studies



The full study transformed land area can be seen in **Figure 31**. Each technology shows an increase in overall land usage when adding the CCS system. In general, grassland usage is small compared to forest and agriculture usage, except for the DNG cases. The CCS cases show increases in all land usage areas. It is interesting that the overall land usage for the IGCC w-CCS, SCPC w-CCS, and EXPC w-CCS w-RP are nearly identical, but note that the type of land usage is different among them. The IGCC and SCPC system share the same equipment footprint sizes, regardless of system type, and their net output is nearly equivalent, lending to nearly identical specific land usage values. However with respect to EXPC with-CCS, the system does have an overall lower total footprint than IGCC or SCPC, but due to lower net output the specific land usage is nearly identical to IGCC and SCPC. Recall as well that the EXPC value is an incremental amount that would be added to the footprint of the existing plant.

Figure 31: Transformed Land Area for the Full Study



To further understand where the land usage changes affect the results, the full study transformed land area, broken out by land category and contributing section can be seen in **Figure 32**. The figure clearly shows that the DNG pipeline contributes the largest part of the land usage for all technologies and land use categories. The reason is that the DNG pipeline is 900 miles instead of 210 as in the LNG case. The extra distance increases the specific land usage by a factor of 4.5. It is also interesting that regasification plant land usage, via agriculture land area, is the next largest transformed land area section, followed by the NG Spur Pipeline to the ECF for the LNG cases.

Figure 32: Transformed Land Area, Full Study, Sectional Breakout

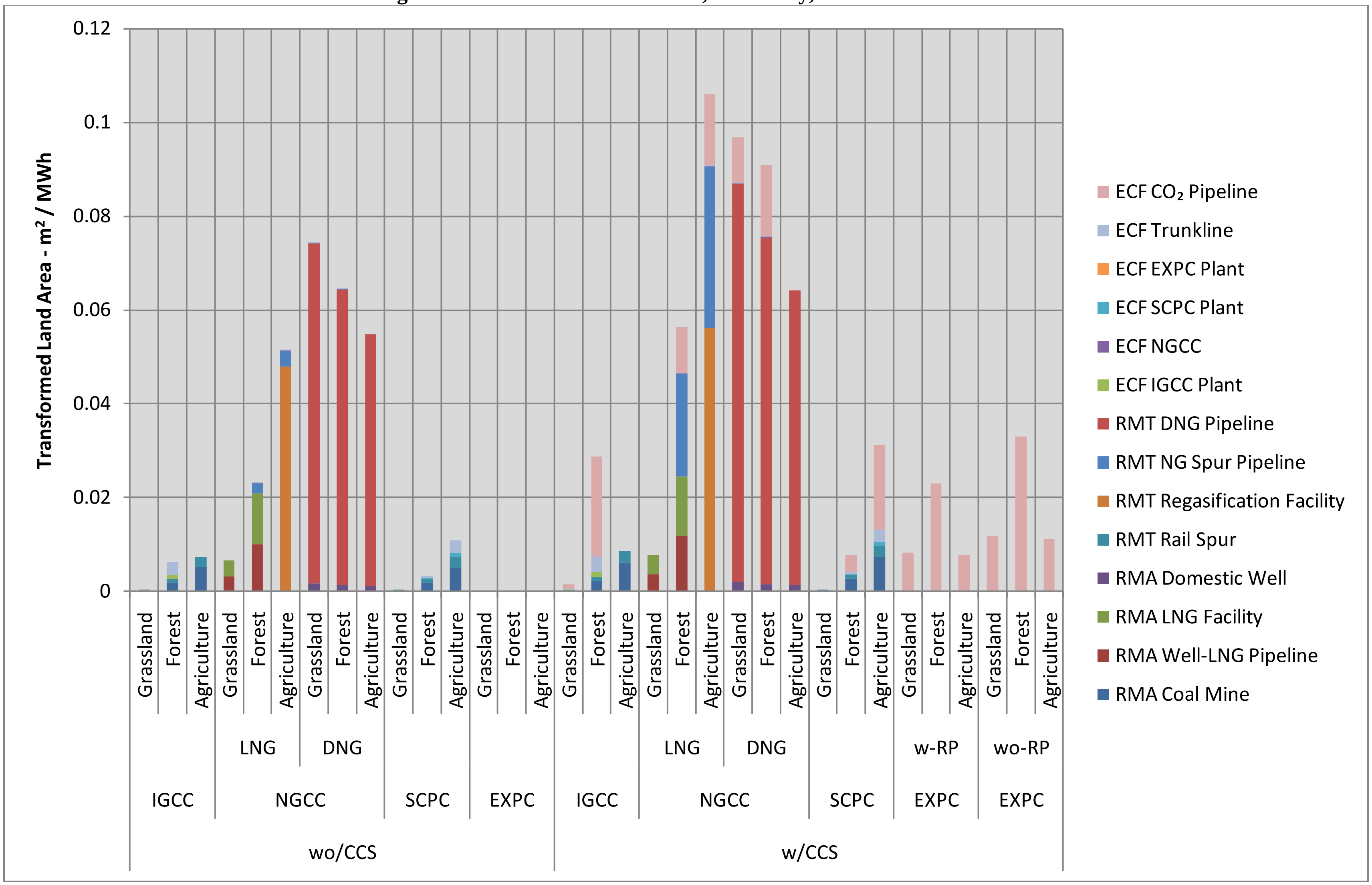


Figure 33 shows the Capital Costs for the full study. Note that the NGCC cases are combined now, since the NG price is at the plant gate, and is not reliant upon the acquisition or delivery method. Other than the EXPC case, the NGCC with- and without-CCS shows the lowest overall capital cost. SCPC with-CCS shows the highest overall capital cost. The EXPC system shows a modest capital cost for the without-CCS case, but the CCS case capital cost is larger than the NGCC cases.

Figure 33: Full Study Capital Costs

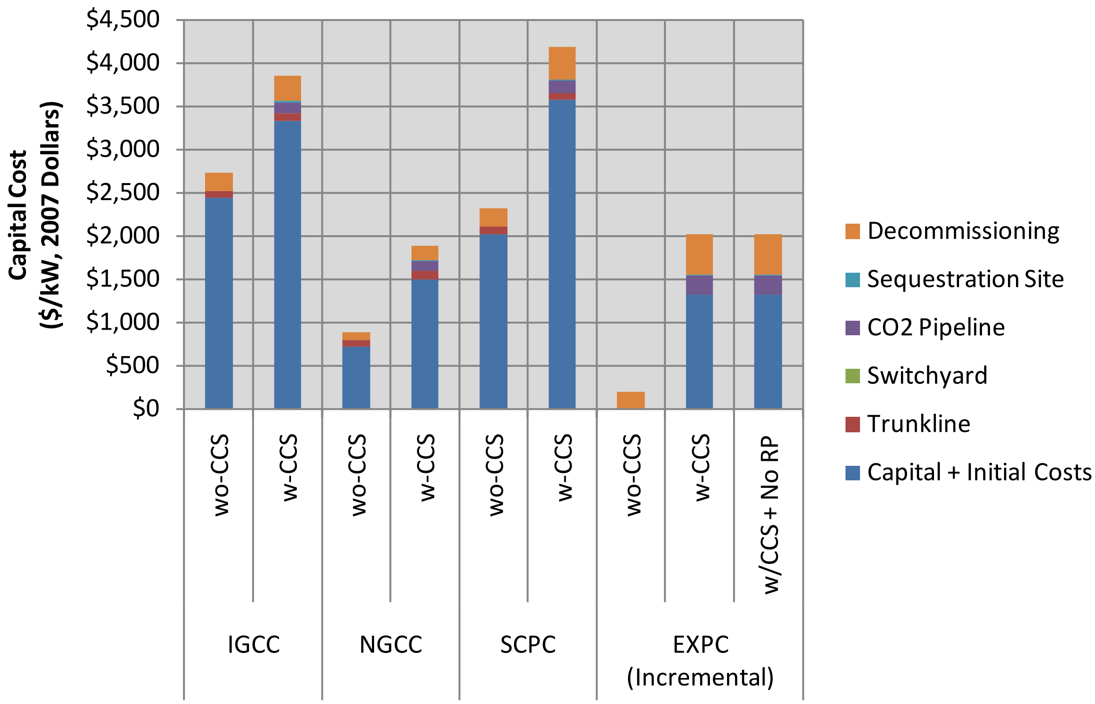
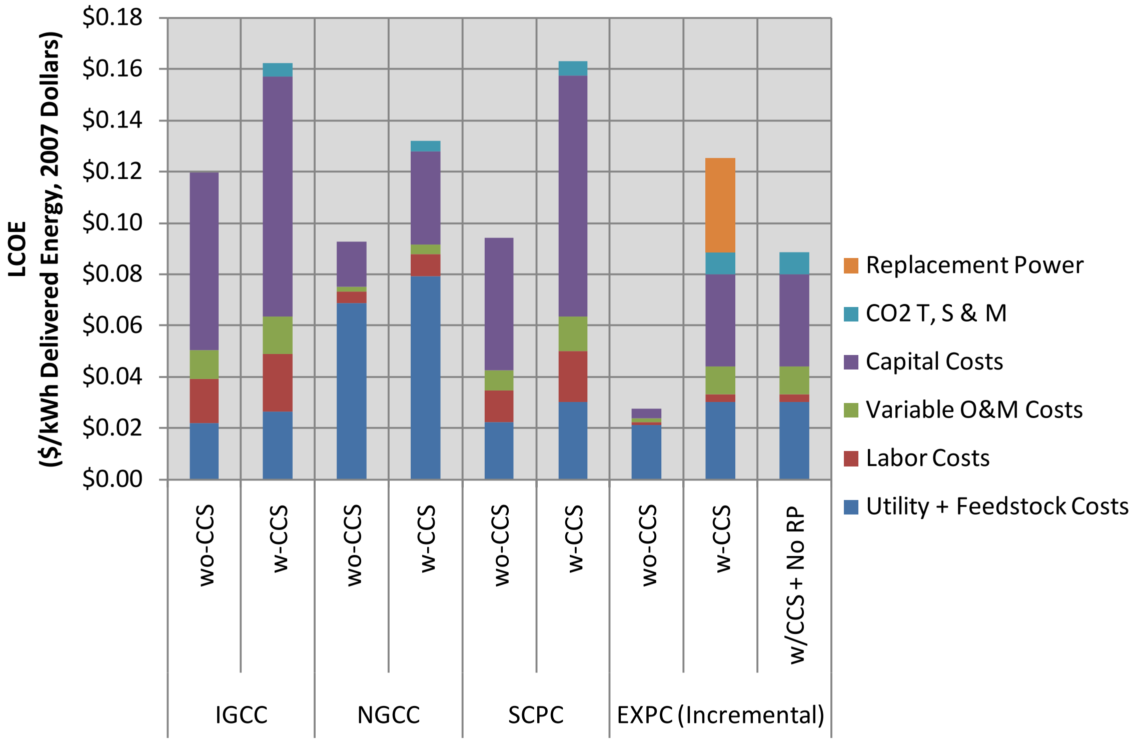


Figure 34 shows the full study LCOE. LCOE for the without-CCS cases for the IGCC, NGCC and SCPC range from $0.09/kWh up to $0.12/kWh. With-CCS cases for those same technologies vary between $0.13 and about $0.16/kWh. The EXPC wo-CCS value is quite low, mainly because of the assumption that it's a brownfield application, and the only expenditures are for utility costs, operating costs, labor, and the levelized decommissioning value. However, when adding the CCS system, the LCOE for the EXPC w-RP is considerably higher, yet still lower than the other technologies w-CCS. When the wo-RP case is factored in, a system which rivals even the NGCC systems wo-CCS begins to be unveiled.

Figure 34: Full Study Levelized Cost of Electricity



4.1 Sensitivity Analysis

Sensitivity analysis is a "what-if" analysis approach that identifies the impact of system parameters, including assumptions, on the final results. The outcome of a sensitivity analysis is the knowledge of the magnitude of the change of an output for a given variation of a system parameter. A final result is said to be sensitive to a parameter if a small change in the parameter gives the result of a larger change in a final result.

Another application for sensitivity analysis is when uncertainty exists about a parameter. Reasons for the uncertainty could be due to an absence of data regarding the construction estimates for an energy conversion facility or due to a questionable emissions profile for a specific piece of equipment to name a few. Knowing the effect that a parameter has on final results can therefore reduce the uncertainty about the parameter.

4.1.1 Sensitivity Analysis of LCI Assumptions

To test the sensitivity of the LCI cases, process parameters were varied in each case, as shown in **Table 10**. It should be noted that the EXPC case sensitivity only looked at the case w-CCS and w-RP. Two of the parameters of interest, materials of construction and tanker transport distance, are used to force increases in emissions to indicate the sensitivity of the parameter changes. The other parameters are used to force lower emissions to indicate the sensitivity of the original decision point. The tabular results of the sensitivity runs can be seen in **Table 11**, and the sensitivity range of the results in **Figure 35**.

The material parameter variable led to a maximum 1.5% change in GWP emissions, and is negligible in the figure. The LNG tanker distance led to the largest overall change in emissions. Methane recovery led to decreases in emissions of 3 to 16%. Rail changes led to decreases in emissions of 4 to 7.5%. Changes in DNG pipeline distance led to decreases in emissions of 5 to 20%. The primary result of the LCI sensitivity is that adding methane recovery to the mining operating offers a decrease in emissions, up to 16%, but a change in LNG port of call has a drastic affect, increasing the overall GWP by 36% for the CCS case.

Table 10: LCI Sensitivity Parameters

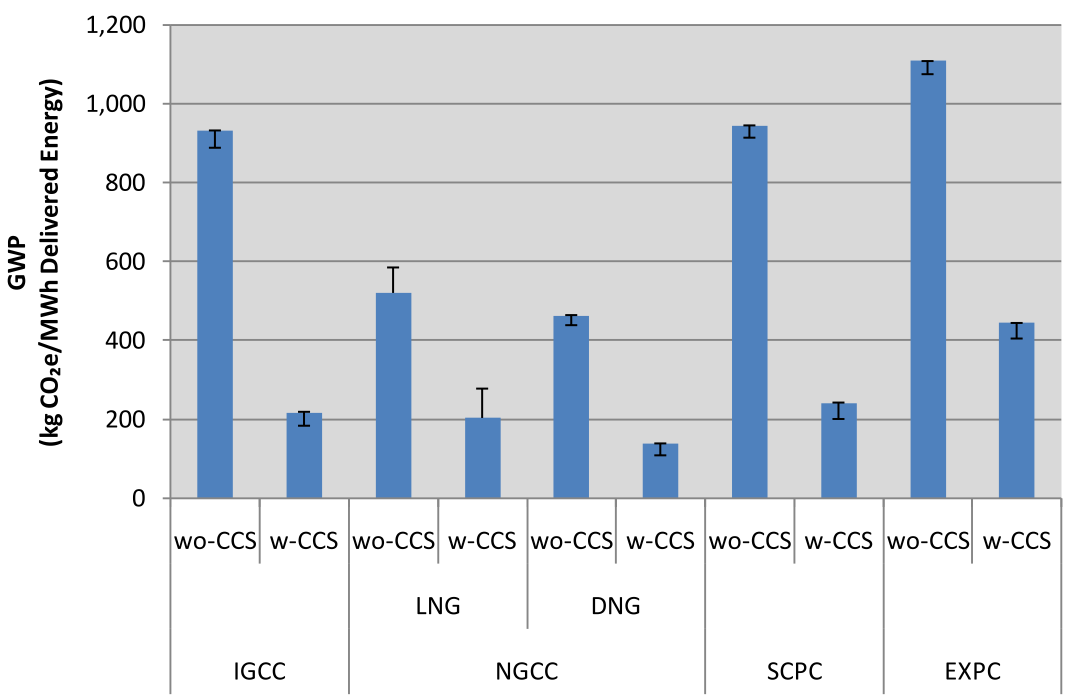
<table>
<tr><th>Parameter</th><th>IGCC</th><th>NGCC</th><th>SCPC</th><th>EXPC</th></tr>
<tr><th colspan="5">Materials</th></tr>
<tr><th>Stage Affected</th><td>RMA, ECF</td><td>RMA, RMT, ECF</td><td>RMA, ECF</td><td>ECF</td></tr>
<tr><th>Variable</th><td colspan="4">Total Materials for Construction: Steel, Concrete, etc.</td></tr>
<tr><th>Sensitivity Range</th><td colspan="4">+200% Material Input</td></tr>
<tr><th>Reason</th><td colspan="4">Arbitrary</td></tr>
<tr><th colspan="5">Methane Recovery</th></tr>
<tr><th>Stage Affected</th><td>RMA</td><td rowspan="4">NA</td><td colspan="2">RMA</td></tr>
<tr><th>Variable</th><td>Methane Recovery</td><td colspan="2">Methane Recovery</td></tr>
<tr><th>Sensitivity Range</th><td>0% - 40% CBM Recovery</td><td colspan="2">0% - 40% CBM Recovery</td></tr>
<tr><th>Reason</th><td>40% Coal Bed Methane recovery</td><td colspan="2">40% Coal Bed Methane recovery</td></tr>
<tr><th colspan="5">Rail Transport Distance</th></tr>
<tr><th>Stage Affected</th><td>RMT</td><td rowspan="4">NA</td><td colspan="2">RMT</td></tr>
<tr><th>Variable</th><td>One-Way Transport</td><td colspan="2">One-Way Transport</td></tr>
<tr><th>Sensitivity Range</th><td>1170 - 0 miles</td><td colspan="2">205 - 0 miles</td></tr>
<tr><th>Reason</th><td>Impact of Transport Distance</td><td colspan="2">Impact of Transport Distance</td></tr>
<tr><th colspan="5">LNG Tanker Transport Distance</th></tr>
<tr><th>Stage Affected</th><td rowspan="3">NA</td><td>RMT</td><td rowspan="3">NA</td><td rowspan="3">NA</td></tr>
<tr><th>Variable</th><td>One-Way Transport</td></tr>
<tr><th>Sensitivity Range</th><td>2,260 - 10,000</td></tr>
</table>

		miles		
Reason		Impact of Transport Distance		
Domestic NG Pipeline Distance				
Stage Affected	NA	RMT	NA	NA
Variable		Pipeline Length		
Sensitivity Range		900 - 450 miles		
Reason		Impact of Transport Distance		

Table 11: LCI Sensitivity Results – Change in GWP

	IGCC		NGCC				SCPC		EXPC	
			LNG		DNG					
	wo-CCS	w-CCS	wo-CCS	w-CCS	wo-CCS	w-CCS	wo-CCS	w-CCS	wo-CCS	w-CCS
Reported GWP	931	217	524	204	467	137	943	241	1109	444
Material Sensitivity	2.03	2.52	3.20	4.10	1.80	2.40	2.84	2.04	-	0.85
40% Methane Recovery	(27.87)	(32.78)					(28.29)	(39.67)	(33.27)	(38.64)
Rail Distance	(41.87)	(16.38)					(1.56)	(4.26)	(4.87)	(12.15)
LNG Tanker Distance			64.57	74.35						
DNG Pipeline Distance					(23.74)	(27.83)				

Figure 35: LCI GWP Results with Absolute Sensitivity Range Results



4.1.2 Sensitivity Analysis of Cost Assumptions

To test the sensitivity of LCOE for the study cases with- and without-CCS, capital and variable O&M costs for all components as well as fuel/feed costs from AEO 2008 were varied (**Table 12**).

Table 12: LCC Uncertainty Analysis Parameters

Parameter	Uncertainty Range
Capital Costs (CC)	+/-30%
Variable O&M Costs	+/-30%
AEO Values	Reference Case/High Case
Total Tax Rate	+/-10%
Capacity Factor	+/-5%

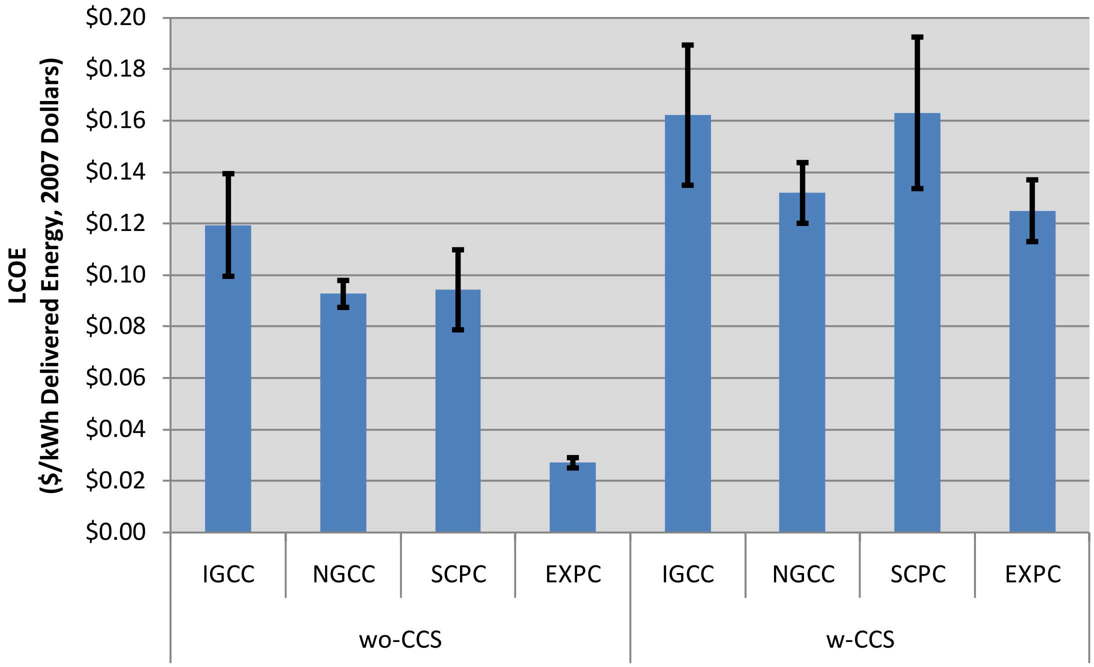
Table 13 and **Figure 36** show the LCOE sensitivity results for the case studies. The figure shows the reported LCOE for each technology case, with- and without-CCS, along with the maximum and minimum of variability from the sensitivity results. The table shows the tabulated results of the sensitivity study.

The main point to be taken from the sensitivity results is that each technology case with-CCS has a higher variability in LCOE than the same technology without-CCS case. Capital cost had the largest LCOE impact across all cases, followed closely by replacement power in the EXPC with-CCS case. Capacity factor and the AEO high price case were next in line with respect to impact on the LCOE, followed by the tax rate and O&M.

Table 13: LCC Sensitivity Results – Change in LCOE

	Plant	IGCC		NGCC		SCPC		EXPC	
	CCS	N	Y	N	Y	N	Y	N	Y
$ / kWh	Reported	$0.120	$0.162	$0.093	$0.132	$0.094	$0.163	$0.027	$0.125
Capital Cost	High	$0.020	$0.027	$0.005	$0.012	$0.016	$0.030	$0.001	$0.012
	Low	($0.020)	($0.027)	($0.005)	($0.012)	($0.016)	($0.029)	($0.001)	($0.012)
O&M	High	$0.003	$0.005	$0.001	$0.001	$0.002	$0.004	$0.000	$0.004
	Low	($0.003)	($0.005)	($0.001)	($0.002)	($0.002)	($0.004)	$0.000	($0.005)
AEO	High	$0.000	$0.000	$0.003	$0.004	$0.000	$0.001	$0.000	$0.000
	Low	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Tax Rate	High	$0.003	$0.004	$0.001	$0.002	$0.002	$0.004	$0.000	$0.002
	Low	($0.003)	($0.004)	($0.001)	($0.002)	($0.002)	($0.004)	$0.000	($0.002)
Capacity Factor	High	$0.006	$0.009	$0.002	$0.003	$0.005	$0.008	$0.002	$0.006
	Low	($0.006)	($0.008)	($0.001)	($0.003)	($0.004)	($0.007)	($0.002)	($0.005)
Replacement Power	High								$0.014
	Low								($0.010)

Figure 36: Sensitivity of LCOE to Cost Parameters



5.0 Summary

This study summarized the work that detailed the Life Cycle Inventory and Costing for four thermo-electric power plants. The systems were studied with- and without-CCS added to their operation. The inventory results seen in the study detailed the GHG emissions, the CAP and SOI emissions, as well as the water usage for all the technologies. Costing was performed, yielding information on capital costs and LCOE for each of the technologies.

The main take away from this study is that this is the first full LCA inventory and costing for power systems. There have been some partial results for systems from previous studies, mainly dealing with the ECF, but they were plant level results and not cradle-to-grave results. The concept of including the upstream and downstream emissions to the mix gives a new perception of the current systems, and provides insight into the value of CCS when added to a system.

A summary of the LCA study results can be seen in **Table 14**. The results have been normalized to the NGCC without-CCS, showing percentage increase or decrease in the particular variables. The GWP results showed that greenfield construction of power plants with-CCS resulted in lower emissions than a brownfield retrofit. Replacement power was found to have a major impact on the EXPC case. The SERC electric profile added enough GHG and CAP that the emissions for the EXPC with-CCS were increased.

Table 14: LCA Results Summary

Case	Net MW	Capacity Factor	GWP	CAP			Water		CC	LCOE
				NO_x	SO_x	PM	Withdrawal	Consumption		
IGCC	12%	-6%	78%	4%	5%	710%	83%	6%	209%	29%
IGCC w/CCS	-2%	-6%	-59%	-4%	23%	500%	155%	71%	337%	75%
NGCC-LNG	555.08	0.85	523.65	0.28	0.03	0.01	1098.61	832.15	881.70	0.09
NGCC -Dom.	0%	0%	-11%	30%	-51%	-37%	5%	9%	0%	0%
NGCC-LNG w-CCS	-15%	0%	-61%	17%	18%	17%	94%	90%	114%	42%
NGCC -Dom. w-CCS	-15%	0%	-74%	52%	-42%	-26%	100%	98%	114%	42%
SCPC	-1%	0%	80%	11%	1240%	668%	129%	55%	163%	2%
SCPC w/CCS	-1%	0%	-54%	54%	31%	965%	327%	216%	375%	76%
EXPC	-23%	0%	112%	625%	8218%	7306%	180%	141%	-78%	-70%
EXPC w/CCS + RP	-23%	0%	-15%	63%	4473%	355%	450%	309%	129%	35%
EXPC w/CCS	-45%	0%	-43%	-89%	0%	174%	386%	391%	129%	-4%

The EXPC with-CCS but without the replacement power would have shown emissions slightly higher than the greenfield installations, but the increase was even larger with the replacement power included. This result could have a major implication upon build/retrofit decisions, depending on emissions policies in the future.

Land usage results showed that addition of CCS had a significant impact on overall footprint of the plants. CO_2 pipelines added significantly to land usage, in all land categories and technologies. Forest areas were much more impacted in all but a few usage categories. Agriculture was typically less impacted than forest, except for the NGCC with-CCS case. Grasslands typically showed less usage than the other land use categories.

LCOE results showed that with respect to the Greenfield applications, the SCPC without-CCS was the lowest cost to operate technology, even lower than NGCC-LNG without-CCS. That result was unpredicted. It was thought that since the NGCC-LNG capital costs were the lowest among the plants, they would result in NGCC-LNG having the lowest LCOE. That trend changed when adding the CCS systems to the technologies. When adding the CCS system to the SCPC, a drastic increase in both capital cost and in LCOE was observed, even more than the NGCC-LNG with-CCS, giving a result that fits more in line with the typical trends.

The EXPC with-CCS LCOE resulted in a cost that appears to be in line with the other plant LCOE values. When neglecting the replacement power, the EXPC with-CCS became more competitive from a market standpoint. Even with the cost results, it seems unlikely to utilize the retrofit option due to the increased CAP emissions and water usage.

6.0 References

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