Demonstration of Advanced CO2 Capture Process Improvements for Coal-Fired Flue Gas

Final Report

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EXECUTIVE SUMMARY

This document summarizes the activities of Cooperative Agreement DE-FE0026590, "Demonstration of Advanced CO_2 Capture Process Improvements for Coal-Fired Flue Gas" during the performance period of October 1, 2015 through May 31, 2017. This project was funded by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL). Southern Company Services, Inc. (SCS) was the prime contractor and co-funder of the project. Mitsubishi Heavy Industries America (MHIA) and AECOM were project team members.

The overall project objective was to improve costs, energy requirements, and performance of an existing amine-based CO_2 capture process. This will occur via improvements in three areas:

1. Reboiler design – The first objective of the program was to demonstrate performance of an integrated stripper/reboiler (termed Built-in Reboiler, or BIR) to reduce footprint, capital costs, and integration issues of the current technology.

2. Particulate management – The second objective was to carry out a Particulate Matter Management (PMM) test. This has the potential to reduce operating costs and capital costs due to the reduced or eliminated need for mechanical filtration.

3. Solvent – The third objective was to carry out a new solvent test plan (referred to as NSL) to demonstrate a new solvent (termed New Solvent A), which is expected to reduce regeneration steam. The bulk price is also expected to be lower than KS-1, which is the current solvent used in this process. NSL testing would include baseline testing, optimization, long term testing, solvent reclamation testing, and final inspection.

These combine to form the Advanced Carbon Capture (ACC) technology. Much of this work will be applicable to generic solvent processes, especially in regards to improved reboiler design, and focused to meet or exceed the DOE's overall carbon capture performance goals of 90% CO_2 capture rate with 95% CO_2 purity at a cost of $40/tonne of CO_2 by 2025 and at a cost of electricity (COE) 30% less than baseline CO_2 capture approaches by 2030.

This project was divided into two phases. Phase 1 is the planning phase, and Phase 2 is the construction, operations, testing, and analysis phase. A down select occurred after Phase 1. Phase 1 activities were carried out during this reporting period, and therefore, Phase 1 activities are solely considered in this report. The project was not selected for Phase 2 funding. Phase 1 milestones included:

1. Updating the project management plan (PMP).

2. Holding a project kickoff meeting with DOE-NETL.

3. Producing a Techno-Economic Analysis (TEA) and report.

4. Producing a Target Cost Estimate and Employee Health & Safety (EH&S) Analysis.

5. Executing Financial and Host Site Agreements, and Updated Representations and Certifications.

All project milestones were completed on time during the period of performance. The project team accomplished the timely completion of milestones through four main tasks:

Task 1: Project Management and Reporting
Task 2: Techno-Economic Analysis
Task 3: EH&S Analysis
Task 4: Front End Design and Target Cost Estimate

Project management and reporting was handled by SCS. SCS developed the project scope and provided coordination and planning with DOE-NETL and the other project participants. This task included all project management functions, administration of the grant, finance and accounting work, audit and compliance support, preparation and submission of reports as required, sub award management and communications. Meetings were held with DOE-NETL at the project's inception and conclusion and results were presented at the annual NETL CO_2 Capture Technology Meeting. Technical reports and deliverables were provided in accordance with the Statement of Project Objectives (SOPO) Section D, and the Federal Assistance Reporting Checklist requirements.

A preliminary TEA was submitted to DOE-NETL on March 31, 2016. It included: (1) general process flow diagram, (2) material and energy balances, (3) stream tables, (4) economic analysis per the NETL Quality Guideline for Energy System Studies (QGESS), "*Cost Estimation Methodology for NETL Assessments of Power Plant Performance*," and (5) cost estimates for equipment and consumables. The process design for this analysis was based on a nominal 550 MW (net), Greenfield Pulverized coal plant. The TEA evaluated three plant configurations against the DOE-NETL Case 12 baseline study: (12a) MHI's Kansai Mitsubishi-Carbon Dioxide Recovery (KM CDR) amine-based CCS process with heat integration, (12b) ACC CCS plant with heat integration, and (12c) ACC CCS plant with heat integration and auxiliary turbine. Case 12c featured the lowest Total Overnight Cost (TOC) at $2,090MM and the largest reduction in COE from Case 12 COE at 12.7%.

An EH&S assessment was submitted to DOE-NETL on March 31, 2016. Five streams from the KM CDR were analyzed for their potential environmental and health impacts: (1) treated flue gas, (2) solvent reclaiming waste, (3) flue gas pre-treatment wastewater, (4) cooling tower wastewater, and (5) solvent manufacturing. Since KS-1 and New Solvent A are proprietary chemicals, monoethanolamine (MEA) was used a surrogate. Selenium accumulation in solvent reclaiming waste is expected to classify as hazardous waste and result in a full-scale plant requiring Large Quantity Generator (LQG) status. No other impacts are expected.

Front End Design and Target Cost Estimate information was submitted to DOE-NETL on March 31, 2016. This work drew on the information required to complete Task 2. Budgets for each project participant were completed and justified to develop the overall project budget within the agreed scope.

1.0 INTRODUCTION

This project received Phase 1 funding through Cooperative Agreement DE-FE0026590, "Demonstration of Advanced CO_2 Capture Process Improvements for Coal-Fired Flue Gas". The project was funded by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL). Southern Company Services (SCS) was the prime contractor and co-funder of the project. Mitsubishi Heavy Industries America (MHIA) and AECOM were project team members. The overall objective of the project is to evaluate the effects of improvements in solvent design, particulate management, and reboiler design on the cost, energy savings and performance of an existing amine-based CO_2 capture process operating at a pulverized coal-fired power plant.

Solvent-based systems for capturing and purifying CO_2 are closest to maturity and implementation for CO_2 removal from fossil fuel-fired power stations. MHIA and Southern Company have demonstrated one such system, the Kansai Mitsubishi Carbon Dioxide Recovery (KM CDR) Process, at Southern Company Alabama Power's Plant Barry Power Station. The demonstration used KS-1 solvent and showed several benefits relative to monoethanolamine (MEA)-based processes. These include significant reductions in energy requirements for CO_2 regeneration, lower corrosivity, and better stability against flue gas constituents such as oxygen. The technology was developed by Mitsubishi Heavy Industries, Ltd. (MHI). Southern Company, MHI, and the Electric Power Research Institute (EPRI) joined together to install the coal-based 500 ton-per-day (tpd), 25 MW equivalent, CO_2 capture demonstration plant at Plant Barry. The system began operation on June 2, 2011 and demonstrated 90% CO_2 capture and a production rate of 500 metric tons per day. SCS, MHI, and EPRI also tested a heat integration system, MHI's High Efficiency System (HES), in 2015 under Cooperative Agreement DE-FE0007525.

This project proposed a demonstration of the 25-MW KM CDR pilot unit at Plant Barry with various system improvements collectively termed the Advanced Carbon Capture (ACC) demonstration. These modifications are:

1. Reboiler design – The first objective of this project is to demonstrate performance of an integrated stripper/reboiler (termed Built-in Reboiler, or BIR) to reduce footprint, capital costs, and integration issues of the current technology.

2. Particulate Management – The second objective is to carry out a Particulate Matter Management (PMM) test. This has the potential to reduce operating costs and capital costs due to the reduced or eliminated need for mechanical filtration.

3. Solvent – The third objective is to carry out a new solvent test plan (referred to as NSL) to demonstrate a new solvent (termed New Solvent A), which is expected to reduce regeneration steam. The bulk price is also expected to be lower than KS-1, the current solvent. NSL testing will include baseline testing, optimization, long-term testing, solvent reclamation testing, and final inspection.

The project is divided into two phases. Phase 1 is the planning phase. Phase 2 is the construction, operations, testing, and analysis phase.

2.0 PROJECT OBJECTIVES

2.1 Major Goals of Project

The overall objective of this project is to improve costs, energy requirements, and performance of an existing amine-based CO_2 capture process. Much of this work will be applicable to generic solvent processes, especially in regards to improved reboiler design, and focused to meet or exceed the DOE's overall carbon capture performance goals of 90% CO_2 capture rate with 95% CO_2 purity at a cost of $40/tonne of CO_2 captured by 2025 and at a cost of electricity (COE) 30% less than baseline CO_2 capture approaches by 2030.

2.2 Milestones

Table 1 provides the program's milestone schedule and the project's status with respect to completion of milestones.

Table 1. Program Milestone Schedule

Milestone	Budget Period	Task	Milestone Description	Planned Completion Date	Actual Completion Date	Verification Method
1	1	1	PMP Updated	10/31/2015	10/31/2015	PMP Submitted
2	1	1	Kickoff Meeting with DOE-NETL	12/01/2015	12/01/2015	Presentation File
3	1	1, 2	Final Draft Techno-Economic Analysis Submitted	03/31/2016	03/31/2016	Draft Techno-Economic Analysis File
4	1	4	Target Cost Estimate and EH&S Analysis Finalized	03/31/2016	03/31/2016	Budget and EH&S Report Files
5	1	1	Executed Financial and Host Site Agreements, and Updated Representations and Certifications	06/30/2016	06/30/2016	Agreements and Certifications Files

3.0 PROJECT ACTIVITIES AND RESULTS

The project objectives and milestones were completed through four major tasks:
Task 1: Project Management and Reporting
Task 2: Techno-Economic Analysis
Task 3: EH&S Analysis
Task 4: Front End Design and Target Cost Estimate

3.1 Task 1: Project Management and Reporting

SCS took responsibility for project coordination and planning between all project participants and DOE-NETL. A kickoff meeting and final project review meeting were held with DOE-NETL. All technical reports and deliverables were produced on time and in accordance with SOPO Section D and the Federal Assistance Reporting Checklist requirements. SCS personnel presented project progress annually at the NETL CO_2 Capture Technology Conference. Other project management tasks were also included, such as grant administration, finance and accounting functions, audit and compliance support, sub award management, and communications. These efforts occurred throughout the project's period of performance.

3.2 Task 2: Techno-Economic Analysis

A preliminary Techno-Economic Analysis (TEA) was to be submitted to DOE-NETL within six months of the project award. The final draft of the TEA was submitted on March 31, 2016. The TEA compared three cases of MHI's KM CDR process to the DOE-NETL Case 12 baseline supercritical pulverized coal plant with CCS, which features the Fluor Econamine FG Plus MEA-based CCS process. Case 12a is the KM CDR process with heat integration. The KM CDR offers economic advantages over MEA-based systems and is the technology installed at the host site, Plant Barry. KS-1 solvent replaces MEA and heat integration is provided through MHI's HES which uses boiler condensate in a flue gas cooler and CO_2 cooler. Case 12b is the ACC CCS plant with heat integration. The ACC process adds the BIR, eliminates the solvent purification unit, and replaces KS-1 solvent with New Solvent A. Case 12c is the ACC plant with heat integration and an auxiliary turbine, which captures surplus work from the stripper reboiler steam.

3.2.1 Methodology

Each case was evaluated using the same conditions as Case 12 in the DOE baseline study. These aspects include:

1. Feed Coal (Illinois #6 bituminous)
2. Site characteristics and ambient conditions
3. Boiler design (load does vary by case)
4. Capacity Factor (85%)
5. Environmental controls (excluding CCS-specific systems and the Flue Gas Cooler)

Environmental controls include an SCR for 85% NO_x control, fabric filter for 99.8% particulate removal, and a wet limestone forced oxidation scrubber for 98% SO_2 removal. The assumed flue gas composition at the exit of the flue gas desulfurization unit (FGD) is shown in the table below:

Table 2: Flue Gas Composition

Property	Value	Composition - Mole %					
Temperature	58°C (136°F)	N_2	O_2	CO_2	H_2O	Ar	SO_2
Pressure	100 kPa (14.5 psia)	67.93	2.38	13.5	15.37	0.81	0.000042

All four cases add a CO_2 removal system to achieve >90% CO_2 capture. Flue gas from the outlet of the FGD is sent to a polishing scrubber that uses sodium hydroxide solution to reduce the flue gas SO_2 concentration from 42 ppm to <10 ppm.

The four scenarios were evaluated on a common 550 MW_e net basis for consistency with DOE-NETL's approach for making side-by-side comparisons. The heat input was calculated for Cases 12a-c such that the plants maintained the 550 MW_e net output. An Aspen model was developed to simulate each case and the data generated for Case 12 and was verified against the NETL data. CO_2 capture rate for cases 12a-c were calculated per the below equation, with y representing a-c:

> **CO_2 capture rate for Case 12y** = (Capture rate for Case 12) x (Heat input for Case 12y / Heat input for Case 12)

The heat inputs were also used as the basis for calculating the plant capacities and capital cost. The steam consumption for Case 12a was calculated based on previous KM CDR Process experience, and has been reported as 0.98 ton-steam/ton-CO_2 (Holton, 2011) (Wu, 2012). The steam consumption of New Solvent A for Cases 12b and 12c given as 0.90 ton-steam/ton-CO_2 was measured in previous laboratory and pilot testing. The change in steam consumption could affect the pressure of crossover steam but this study assumed that the steam pressure profiles for each case to be identical. Case 12 does feature feedwater heaters whereas Cases 12a-c replace those feedwater heaters with the HES system.

Capital costs for each case were estimated based on using Case 12 as a starting point. Most components remain the same from case to case. The differences include the modified CCS process, the HES system, and the auxiliary turbine. The common plant equipment total overnight cost (TOC) was calculated first and then combined with estimations of capital cost for non-common equipment to produce a final TOC for each case. Complete details on the formulas used to calculate capital costs can be found in Appendix A.

Operating and maintenance (O&M) cost estimates were derived from fixed O&M (OCFIX) and variable O&M (OCVAR). OCFIX is proportional to power generation and is the sum of operating labor, maintenance labor, administration and support labor, and property taxes and insurance. Operating labor, maintenance labor, and administration and support labor were all assumed to be equal for all four cases. Property taxes and insurance for Cases 12a-c were calculated as proportional to the ratio of the Case 12y TOC to the Case 12 TOC.

OCVAR for Case 12 was calculated according the process used in the DOE-NETL report as the sum of maintenance material, water, chemicals, SCR catalyst, and ash disposal. The costs for Cases 12a-c were calculated as proportional to the ratio of the Heat Input for Case 12y to the Heat Input for Case 12. The same process was applied for fuel costs.

COE was calculated using the methodology in the DOE-NETL Report. CO2 Transportation, Storage, and Monitoring (TS&M) costs for Cases 12a-c were adjusted from Case 12 based on CO2 capture rate and net output. The cost of CO2 captured and avoided were calculated based on equations from the DOE-NETL report where Case 11 is the reference. These equations can be found in Appendix B.

3.2.2 Results

3.2.2.1 Plant Efficiency Assessment

Case 11, the supercritical PC plant without CCS, has a net plant efficiency of 39.3%. Case 12, which adds the Econamine CCS process, decreased the plant efficiency to 28.4%. Case 12a swaps the Econamine process for the KM CDR process and yields a plant efficiency of 31.6%. Case 12b applies the ACC process and increases plant efficiency to 32.0%. The addition of an auxiliary turbine for Case 12c increases the plant efficiency to 32.7%.

3.2.2.2 Water Use

Applying the MHI HES system to the carbon capture process reduces makeup water consumption through reduced FGD water makeup and reduced cooling water usage in the CO_2 product cooler. Case 12a achieves a reduction of 18.6%, Case 12b achieves a reduction of 19.4%, and Case 12c achieves a reduction of 21.2%. A full water balance is available in Appendix C.

3.2.2.3 Environmental Assessment

Case 12 reduces CO_2 emissions per MWh net by 86.2% from the Case 11 base plant. Case 12a achieves a reduction of 87.8%, Case 12b of 88.0%, and Case 12c of 88.2%. The Flue Gas Cooler in the HES system also provides other benefits for Cases 12a-c that are not accounted for in the cost model. These include:

- Reducing the particulate concentration at the ESP outlet (from 0.03 lb/MMBtu to 0.004 lb/MMBtu)
- Reducing the emissions of volatile toxics (mercury, selenium) by improving adsorption to fly ash
- Reducing potential for limestone blinding in the FGD or polishing scrubbers due to lower particulate loading in the inlet flue gas
- Reducing the waste water treatment cost by lowering the toxics loading in scrubber waste water
- Reducing the contaminant loading of particulate matter and toxics to the amine solvent, thereby reducing solvent reclaiming and loss

A summary of all plant emissions can be found in Table 3.

Table 3: Total Plant Emissions

Case		11	12	12a	12b	12c
Plant Configuration		Supercritical PC w/out CCS	Supercritical PC w MEA CCS	Supercritical PC w KM CDR CCS w heat integration	Supercritical PC w ACC CCS w heat integration (HES)	Supercritical PC w ACC CCS w heat integration (HES) w Aux. turbine
CO_2	lb/MMBtu	203.5	20	20	20	20
CO_2	lb/Mwhnet	1,768	244	215	213	208
SO_2	lb/MMBtu	0.086	0.002	0.002	0.002	0.002
NO_x	lb/MMBtu	0.07	0.07	0.07	0.07	0.07
PM (filterable)	lb/MMBtu	0.013	0.013	0.003	0.003	0.003
Hg	% capture	>90%	>90%	>90%	>90%	>90%

3.2.2.4 COE Assessment

Cases 12a-c achieve successive cost reductions in O&M costs, fuel costs, CO_2 TS&M costs, capital cost, and subsequently COE. Cases 12a-c achieved COE reductions from Case 12 of 9.2%, 11.3%, and 12.7%, respectively. A summary of costs for Cases 11, 12, and 12a-c can be found in the table below:

Table 4: Cost of Electricity Results

Case		11	12	12a	12b	12c
Plant Configuration		Supercritical PC w/out CCS	Supercritical PC w MEA CCS	Supercritical PC w KM CDR CCS w heat integration	Supercritical PC w ACC CCS w heat integration (HES)	Supercritical PC w ACC CCS w heat integration (HES) w Aux. turbine
OCFIX	Mil$/y	38.83	64.14	60.53	59.35	58.89
OCVAR x CF	Mil$/y	31.69	54.09	48.64	48.06	47.09
Fuel Cost x CF	Mil$/y	104.59	144.5	129.95	128.41	125.8
CO_2 TS&M x CF	Mil$/y	-	40.91	36.79	36.35	35.61
Capacity Factor		85%	85%	85%	85%	85%
Capital Charge Factor		0.116	0.124	0.124	0.124	0.124
Fixed O&M Cost	mils/kWh	9.48	15.66	14.8	14.5	14.4
Variable O&M Cost	mils/kWh	7.74	13.21	11.9	11.7	11.5
Fuel Cost	mils/kWh	25.54	35.29	31.7	31.4	30.7
CO_2 TS&M Cost	mils/kWh	-	9.99	9	8.9	8.7
Capital Cost	mils/kWh	38.2	73.12	66.4	64.2	63.3
COE	mils/kWh	80.95	147.27	133.7	130.6	128.6
Cost Reduction from Case 12		-	-	9.2%	11.3%	12.7%

3.2.2.5 Cost of CO_2 Avoided Assessment

The CO_2 avoided cost for Case 12 was $95.9/ton on a net output basis. By replacing Econamine with the heat integrated KM CDR Process (Case 12a) this was reduced to $75.0/ton at net output basis. The ACC Process (Case 12b) reduced this cost to $70.5/ton and applying the auxiliary turbine (Case12c) reduced the CO_2 avoided cost to $67.5/ton. Full results can be found in Table 5 below:

Table 5: Cost of CO_2 Avoided (Net output basis)

Case		12	12a	12b	12c
Plant Configuration		Supercritical PC w MEA CCS	Supercritical PC w KM CDR CCS w heat integration	Supercritical PC w ACC CCS w heat integration (HES)	Supercritical PC w ACC CCS w heat integration (HES) w Aux. turbine
COE with removal	$/MWh	147.3	133.7	130.6	128.6
COE reference	$/MWh	80.95	80.95	80.95	80.95
CO_2 emissions reference	mtpd	10,593	10,593	10,593	10,593
CO_2 emissions with removal	mtpd	1,464	1,316	1,301	1,274
CO_2 emissions reference	tons/MWh	0.80	0.80	0.80	0.80
CO_2 emissions w CCS	tons/MWh	0.11	0.10	0.10	0.10
Avoided Cost	$/ton	95.9	75	70.5	67.5

3.2.2.6 Cost of CO2 Capture Assessment

The CO_2 captured cost for Case 12 was $66.4/ton on a net output basis. Replacing the Econamine process with the heat-integrated KM CDR process for Case 12a reduced that cost to $58.8/ton. Applying the ACC process for Case 12b reduced the cost to $56.0/ton and the auxiliary turbine reduced the cost for Case 12c to $54.8/ton. See Table 6 below for a summary.

Table 6: Cost of CO_2 Captured

Case		12	12a	12b	12c
Plant Configuration		Supercritical PC w MEA CCS	Supercritical PC w KM CDR CCS w heat integration	Supercritical PC w ACC CCS w heat integration (HES)	Supercritical PC w ACC CCS w heat integration (HES) w Aux. turbine
COE retrofit	$/MWh	147.3	133.7	130.6	128.5
COE base	$/MWh	80.95	80.95	80.95	80.95
CO_2 production	mtph	14,636	13,163	13,006	12,742
CO_2 production	ton/MWh	1.11	1.00	0.99	0.97
Capture Cost	$/ton	66.4	58.8	56.0	54.8

3.3 Task 3: EH&S Analysis

An Environmental, Health, and Safety Analysis was conducted and the report was submitted to DOE-NETL on March 31, 2016.

3.3.1 Methodology

The EH&S was conducted for the ACC Process, which includes the original KM CDR Process, and the manufacture of the amine based solvents. EH&S professionals from AECOM conducted the analysis and MHIA provided the required process information. The following aspects were considered for the analysis:

- Emissions, Wastes, and Environmental Transport and Fate Characteristics
- Human Health and Ecotoxicity
- Physical and Chemical Characteristics
- Exposure Guidelines and Regulatory Implications
- Engineering Controls and Minimization of hazards
- Safe Handling and Waste Disposal

3.3.1.1 Identification of Streams for EH&S Analysis

The reference plant for this project was the 550-MW coal-fired power plant with the ACC Process. The plant configuration is similar to the Case 11 supercritical PC boiler without CO_2 capture as found in the NETL report *"Cost and Performance Baseline for Fossil Energy Plants – Volume 1: Bituminous Coal and Natural Gas to Electricity (Rev2a, November 2010)"* with the exception that the ACC process was added for carbon capture. The nominal plant output was maintained at 550-MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the ACC process. The bottom ash, fly ash, and gypsum streams associated with the Case 11 coal-fired power plant were not addressed in this analysis. The chemical composition of these streams will not change with the addition of a carbon capture and sequestration process; however, the flow rate of these streams will increase with the higher coal firing rate required to maintain 550-MW net output.

There are four streams associated with the ACC process and considered for the EH&S analysis:

- Treated flue gas
- Solvent reclaiming waste
- Wastewater from flue gas pre-treatment (caustic scrubber and quencher) and from Cooling Water Tower
- Reactants and Products of Solvent Manufacture

Only the components of the flue gas that were contributed by the ACC process were subjected to the EH&S analysis; the flue gas constituents from the Case 11 coal-fired power plant were not included in the analysis. The reclaiming waste includes solvent, solvent degradation products, and heavy metals from the flue gas stream.

The wastewater from the flue gas pre-treatment is similar to flue gas desulfurization (FGD) wastewater. The Case 11 plant does not include wastewater treatment for the FGD wastewater; for the purpose of this study, it was assumed that a wastewater treatment plant will be added to the Case 11 plant to treat the FGD wastewater in order to comply with U.S. Steam Electric Power Generating Effluent Guidelines and Standards. It was also assumed that the flue gas pre-treatment wastewater will be treated by this same wastewater treatment process. Additional environmental impact associated with this wastewater stream is not expected to be significantly different from the Case 11 FGD treated wastewater stream and the assessment of this stream remained cursory.

Cooling tower water is used by the CO_2 absorber, deep FGD, and regenerator; this cooling tower water is then purged as wastewater without direct contact with the ACC solvent or flue gas. The cooling tower water for the ACC plant is essentially the same as cooling tower wastewater from the Case 11 plant and does not contain any hazardous constituents. Only a cursory environmental assessment was conducted for this stream.

3.3.1.2 Effect of Proposed Process Modifications on EH&S Analysis

The project will investigate improvements in the ACC process from the original KM CDR Process:

1. Built-In-Reboiler (BIR): The use of the BIR in the solvent regenerator is an equipment modification that should not have any impact on the environmental and health aspects of the ACC Process; therefore, no further EH&S analyses were performed on the BIR.

2. Particulate Matter Management (PMM): Bypassing the mechanical filters in the system may increase particulate accumulation in the solvent; however, it is expected that the solvent life will not be shortened. The frequency of solvent reclaiming and the flow rate of reclaimed solvent waste will not be affected. The concentration of metals in the reclaimed solvent waste has been addressed in the EH&S assessment.

3. New Solvent (NSL): Both KS-1 and New Solvent A were subjected to the EH&S analysis.

The removal of the mechanical filters and the use of New Solvent A were considered in the EH&S assessment.

3.3.1.3 Solvent Assumptions for EH&S Analysis

KS-1 and New Solvent A are proprietary blends of solvents that are trade secrets belonging to MHI. Revealing solvent composition, specific aspects of solvent physical property data, and/or the solvent degradation products would reveal critical information about the identity of the solvent. Therefore, for the purposes of the EH&S assessment, MEA solvent was used as a surrogate for KS-1 and New Solvent A.

KS-1 and New Solvent A have lower solvent emissions than MEA and lower solvent degradation rates than MEA; in addition, a lower solvent circulation rate is required for these solvents. Therefore, the use of MEA in the EH&S Assessment provides a conservative estimate of the quantity of emissions and waste produced by the ACC Process. Table 7 illustrates the relative solvent volatilities and circulation rates of MEA versus KS-1 and New Solvent A, with updated values for New Solvent A from the Technology Gap Analysis:

Table 7: Comparison of Solvent Volatility and Degradation Rates for MEA, KS-1 and New Solvent A (with updated values as described in Tech Gap Analysis)

	MEA	KS-1	New Solvent A	
			Previous	Updated
Steam Consumption	1	0.68	0.65	0.63
Solvent Circulation	1	0.6	0.83	0.75
Solvent Degradation	1	0.1	0.1	0.05
Corrosion Inhibitor Required?	Yes	No	No	No
Solvent Emissions	1	0.1	0.1	0.05

Comparing the Safety Data Sheet (SDS) of each solvent shows MEA to be a good choice to represent the toxic effects of KS-1 and New Solvent A. The acute toxicity of MEA is similar to that seen in KS-1 and New Solvent A, both for mammals and aquatic receptors. SDS data is inadequate to compare chronic exposures and for potential carcinogenic, mutagenic, teratogenic, or developmental effects; however, there are no reasons to believe MEA would produce substantially different effects from KS-1 or New Solvent A.

The IEA Environmental Projects Ltd report "Evaluation of Reclaimer Sludge Disposal from Post-Combustion CO2 Products" (IEA, 2014) outlined the concentrations of chemical components in reclaimed solvent waste from a coal-fired power plant equipped with an MEA-based CO_2 capture process. These concentrations were assumed for the solvent reclaiming waste stream for this EH&S analysis. The stream is composed primarily of the solvent, thermal degradation products of the solvent, and metals. The two primary thermal degradation products of MEA, hydroxyethylimidazolidinone (HEIA) and Trihydroxyethyl-imidazolidinone (triHEIA) were used as surrogates for the primary thermal degradation products of KS-1 and New Solvent A. The IEA report found mercury to be a trigger for hazardous waste classification solvent reclaiming waste while experience with the 25-MW KM CDR Process at Plant Barry indicates that selenium may trigger hazardous classification. The metals in the solvent reclaiming waste were taken from analysis done on the KM CDR Process during previous operation. The hazard classification of the waste will be specific to each coal-fired power plant due to variability in coal composition and performance of air pollution control devices.

3.3.1.4 Solvent Manufacturing Assumptions for EH&S Analysis

Similar to MEA, the manufacturing of KS-1 and New Solvent A generate very little wastewater and are not expected to generate any significant ancillary or incidental air emissions or solid wastes. Therefore, the EH&S analysis for the solvent manufacturing process was limited to the primary reactants and products of the MEA manufacturing process: ammonia, ethylene oxide, DEA, and TEA.

3.3.2 Results

3.3.2.1 Treated Flue Gas

The first consideration for the treated flue gas stream is increased ammonia emissions. Ammonia is readily degradable and does not bioaccumulate. While ammonia can be toxic and is volatile, flammable, and explosive, this only occurs in concentrations that vastly exceed that present in the flue gas stream. The emissions of ammonia would be reported under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and the Emergency Planning and Community Right-to-Know Act (EPCRA), also known as Title III of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Ammonia emissions are not expected to have a significant impact on human health or the environment.

MEA is the second consideration. The analysis was conducted assuming the maximum possible stack concentration of MEA (1 ppm). It should be noted that this is a conservative estimate. Initial data on New Solvent A shows emission rates only 4% of MEA rates. This would drive a large increase in VOC emissions and could require a major modification application for the facility air permit. This would initiate a Prevention of Significant Deterioration (PSD) review and would require evaluation of VOC and ozone parameters. This evaluation would include analysis of the Best Available Control Technology (BACT), source impact analysis, air quality analysis, and other impact analyses. Aerosolized solvent and degradation product emissions would be minimized by MHI's wash water section that achieves greater than 90% reduction in emissions under high SO_3 conditions.

3.3.2.2 Solvent Reclaiming Waste

The reclaiming waste is made up of solvent, solvent degradation products, and water with low concentrations of heavy metals, such as selenium or mercury, from the flue gas. The solvent has high potential for soil mobility but the biodegradation rate is also high with a low risk of bioaccumulation. Solvent and degradation products are expected to be moderately toxic to aquatic organisms although these degrade quickly. Human toxicity is low but exposure to the solvent can cause irritations or burns. The metals in the solvent reclaiming waste are bioaccumulative, mobile, and stable and could be present in concentrations sufficient to make the waste characteristically hazardous. These metals have high ecotoxicity and human toxicity in large quantities but are present in only small quantities.

The reclaiming waste is not expected to be ignitable, corrosive or reactive. Exposure to the general public or animal species is unlikely. Worker exposure will be minimized through engineering and administrative controls and worker PPE. Engineering controls include loading reclaiming waste into trucks for transport and disposal via pumps and hoses. PPE for workers will include face shields, goggles, chemical resistant gloves and clothing to prevent dermal exposure.

A full scale facility will be a Large Quantity Generator (LQG) of hazardous waste during the months where reclaiming waste is generated. It is possible that air pollution controls installed to comply with the Mercury and Air Toxics Standards (MATS) will reduce flue gas mercury and selenium concentrations to the point that reclaimed solvent waste would no longer characterize has hazardous.

3.3.2.3 Wastewater from Flue Gas Pre-Treatment and Cooling Water Tower

Facilities in compliance with their water permit are presumed to be protective of human health and the environment. Well-designed and well-operated wastewater treatment facilities minimize operational risk and exposure through the use of automatic tanks and pumps. There are no physical or chemical hazards associated with this stream. Permitting is covered under the Clean Water Act and National Pollution Discharge Elimination System (NPDES) and can vary by state.

3.3.2.4 Reactants and Products of Solvent Manufacture

Ammonia and ethylene oxide are the reagents in the manufacture of MEA. Diethanolamine (DEA) and triethanolamine (TEA) are other products of the process and can be sold. Reactants and products are not emitted. The solvent manufacturer will be responsible for all personnel protection and waste disposal considerations.

3.4 Task 4: Front End Design and Target Cost Estimate

Task 4 featured two subtasks, Basic Engineering and the Target Cost Estimation. MHIA coordinated with AECOM to perform a Front End Design to a level of detail necessary to complete a Target Cost Estimate, sometimes called a Definitive Estimate, to confirm the project could be completed within budget. This was submitted on March 31, 2016.

3.4.1 Subtask 4.1: Basic Engineering

MHIA developed the basic engineering package from December 2015 to March 2016. This included the following components:

- Final Process Flow Diagram, General Arrangement Sketch, and Elevation Sketch with written process description
- Pilot plant electricity, heat, and water consumption; waste generation and management/tie-ins to existing host facility
- BIR feed conditions (pressure, temperature, flowrate, and composition)
- Startup, steady-state operation, and shut-down procedures
- Protocols, reference methods, measurements, and quality assurance for baseline and performance testing

Much of this information could be based on previous experience with the existing KM CDR process at Plant Barry.

3.4.2 Subtask 4.2: Target Cost Estimation

The Basic Engineering package was used to develop a cost estimate covering all engineering, construction, commissioning, operating, decommissioning, and miscellaneous project tasks. Southern Company worked with MHIA and AECOM to compile all costs and refine them into a final project estimate. The total estimated cost of the project was $19,740,536 over the five budget periods. The cost share for this project would total $3,948,107. Supporting documents for these figures were provided.

4.0 PARTICIPANTS AND COLLABORATING ORGANIZATIONS

4.1 Individuals Who Have Worked on the Project

The following individuals from SCS have worked on the project for at least one person-month during the reporting period.

Name	Jerrad Thomas
Organization	Southern Company Services, Inc.
Project Role	Principal Investigator
Nearest Person-Month Worked	N/A
Contribution to Project	Coordinated and led progress meetings with partner organizations, provided input to technical discussions and planning, and developed and presented kick-off presentation.
Funding Support	N/A
Collaborated with Individual in Foreign Country?	No
Countries of Foreign Collaborators	N/A
Traveled to Foreign Country?	No
Duration of Stay in Foreign Country	N/A

Name	John Carroll
Organization	Southern Company Services, Inc.
Project Role	Principal Investigator
Nearest Person-Month Worked	N/A
Contribution to Project	Compiled project reporting and close-out information after Mr. Thomas left Southern Company.
Funding Support	N/A
Collaborated with Individual in Foreign Country?	No
Countries of Foreign Collaborators	N/A
Traveled to Foreign Country?	No
Duration of Stay in Foreign Country	N/A

4.2 Organizations Who Have Been Involved as Partners

The following organizations are partners for the project.

Organization Name	Mitsubishi Heavy Industries America, Inc.
Location of Organization	20 Greenway Plaza, Suite 600, Houston, TX 77046
Partner's Contribution to the Project	Led engineering & design, and planning for the TEA and EH&S.
Financial Support	None
In-Kind Support	None
Facilities	None
Collaborative Research	None
Personnel exchangers	None

Organization Name	AECOM
Location of Organization	9400 Amberglen Boulevard, Austin, TX 78729
Partner's Contribution to the Project	Record keeping and assistance with project documentation.
Financial Support	None
In-Kind Support	None
Facilities	None
Collaborative Research	None
Personnel exchangers	None

4.3 Other Collaborators or Contacts Involved

The project team had the following collaborators during this reporting period:

Name	John Carroll
Organization	Southern Company Services, Inc.
Project Role	Project Coordinator
Nearest Person-Month Worked	N/A
Contribution to Project	Compiled information for submission of report upon Jerrad Thomas' departure.
Funding Support	N/A
Collaborated with Individual in Foreign Country?	No
Countries of Foreign Collaborators	N/A
Traveled to Foreign Country?	No
Duration of Stay in Foreign Country	N/A

The project team made the following contacts during the reporting period:

- None.

5.0 IMPACT

This project will impact the design and efficiency of solvent-based post-combustion carbon capture facilities.

- **Impact on Principal Discipline of the Project**: Increase in knowledge base of team executing the project.
- **Impact on Other Disciplines:** None during the reporting period.
- **Impact on Development of Human Resources:** None during the reporting period.
- **Impact on Physical, Institutional, and Information Infrastructure**: None during the reporting period.
- **Impact on Technology Transfer:** None during the reporting period.
- **Impact on Society Beyond Science and Technology**: None during the reporting period.

The total amount of award budget spent in a foreign country during this budget period was $0.

Appendix A – Capital Cost Calculations

The capital costs for Case 12 were used as the starting point to estimate the capital costs of Cases 12a–c. The bulk of the equipment remains the same from case to case. Differences include an altered CCS process, heat integration equipment for Cases 12a–c, and the auxiliary turbine for Case 12c. LP Heaters 1-4 were removed for Cases 12a–c. To calculate the capital cost for each case, the common plant equipment total overnight cost (TOC) was first calculated, then the capital costs for the non-common equipment were estimated, and finally the costs for the common and non-common equipment were added together. The Total Overnight Costs (TOC) for Case 12 was first adjusted by subtracting out the capital costs associated with LP Heaters 1 through 4 (generically referred to as LP Heater Z) and the CCS system.

The following equations were used:

- **Common Equipment TOC for Case 12** = (TOC for Case 12) – Σ(Capital Costs of LP Heaters 1, 2, 3, 4 for Case 12) – (Total Plant Cost of CCS for Case 12)
- **Capital Costs of LP Heater Z for Case 12** = ($10,000/(MMBtu/h)) x (Heat Duty for LP Heater Z in MMBtu/h, for Case 12); Capital cost of LP Heaters based on MHI data for shell and tube exchanger
- **Total Plant Cost of CCS for Case 12** = $593,497,000 per the updated DOE/NETL report

The Common Equipment TOC for Case 12y was calculated as follows:

- **Common Equipment TOC for Case 12y** = (Common Equipment TOC Case 12) x (Heat Input for Case 12y / Heat Input for Case 12)

Next, the total plant costs for the non-common equipment (i.e., ACC, heat integration equipment) were calculated. The Econamine process was used as a baseline for the analysis of the ACC process. For the purposes of this study, proprietary solvent calculation model was used to determine the differences between the Econamine process and the ACC process.

The following equations were also used to determine the ACC costs:

- **CCS Capital Cost for Case 12y** = (Total Plant Cost of CCS for Case 12 – Capital Cost Reduction by adaption of Built-in Reboiler (BIR) system for Case 12y – Capital Cost of the Solvent Purification unit for Case 12y) x (CO_2 capture rate for Case 12y / CO_2 Capture rate for Case 12)
  The unit capital costs were assumed to be the same for the Econamine process in Case 12 and KM CDR Process® in Cases 12a–c; the CCS processes require less heat input to the coal-fired power plant to achieve 550 MW net, so the KM CDR® and ACC have lower total capital costs; the capital cost reduction by adaption of BIR system that was calculated at $10M for Case 12 plant was incorporated only in Cases 12b and 12c; the capital cost reduction of the solvent purification unit that was calculated at $17M for Case 12 plant was incorporated only in Case 12b and 12c; the capital cost reduction due to reducing the height of the absorber tower washing section was calculated at $25.6M for Case 12b and 12c because of the lower amine emission of New Solvent A compared with KS-1, however, assuming same level of amine emission as Case 12a.
- **LP Heater Z Capital Cost for Case 12y** = ($10,000/(MMBtu/h)) x (Heat Duty for LP Heater Z in MMBtu/h, for Case 12y)
  Capital cost of LP Heaters based on MHI data for shell and tube

exchangers; Case 12 included LP Heaters 1,2,3,4, while Cases 12a–c eliminated LP Heater 1-4.
• **Flue Gas Cooler Capital Cost for Case 12y** = ($33/kw for Cases 12a-c) x (Gross Output of Case 12y);
Capital cost of Flue Gas Cooler was based on MHIA commercial experience for a greenfield plant; the capital costs includes the soot blowers and other auxiliary equipment.
• **CO_2 Cooler Capital Cost for Case 12y** = ($2500/(MMBtu/h) x (CO2 Cooler Heat Duty in MMBtu/h);
Capital cost of CO_2 Cooler based on MHIA data for plate type exchangers.
• **Auxiliary Turbine Capital Cost for Case 12c** = ($850/kw) x (Auxiliary Turbine Output in kW);
Capital cost of auxiliary turbine based on MHIA commercial experience for small turbine and generator

Finally, the TOC costs for each case were calculated as follows:
• **Case 12a TOC** = (Common Equipment TOC Case 12a) + (CCS Capital Cost for Case 12a) + (Flue Gas Cooler Capital Cost for Case 12a) + (CO_2 Cooler Capital Cost for Case 12a)
• **Case 12b TOC** = (Common Equipment TOC Case 12b) + (CCS Capital Cost for Case 12b) + (Flue Gas Cooler Capital Cost for Case 12b) + (CO_2 Cooler Capital Cost for Case 12b)
• **Case 12c TOC** = (Common Equipment TOC Case 12c) + (CCS Capital Cost for Case 12c) +(Flue Gas Cooler Capital Cost for Case 12c) + (CO_2 Cooler Capital Cost for Case 12c) + (Auxiliary Turbine Capital Cost)

Appendix B – COE Calculations

COE was calculated based on the methodology in DOE/NETL Report:

$$COE = \frac{\begin{matrix}\textit{first year} \\ \textit{capital charge}\end{matrix} + \begin{matrix}\textit{first year} \\ \textit{fixed operating} \\ \textit{costs}\end{matrix} + \begin{matrix}\textit{first year} \\ \textit{variable operating} \\ \textit{costs}\end{matrix}}{\begin{matrix}\textit{annual net megawatt hours} \\ \textit{of power generated}\end{matrix}}$$

$$COE = \frac{(CCF)(TOC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)}$$

where:

COE =	revenue received by the generator ($/MWh, equivalent to mills/kWh) during the power plant's first year of operation (*but expressed in base-year dollars*), assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant.
CCF =	capital charge factor taken from Exhibit 2-22 that matches the applicable finance structure and capital expenditure period
TOC =	total overnight capital, expressed in *base-year dollars*
OC_{FIX} =	the sum of all fixed annual operating costs, *expressed in base-year dollars*
OC_{VAR} =	the sum of all variable annual operating costs, including fuel at 100 percent capacity factor, *expressed in base-year dollars*
CF =	plant capacity factor, assumed to be constant over the operational period
MWH =	annual net megawatt-hours of power generated at 100 percent capacity factor

MHI used the same assumptions as the DOE/NETL Report for the capacity factor and capital charge factor:

Items	Conditions
Capacity Factor (CF)	85%
Capital Charge Factor (CCF) (Cases 12, 12a, 12b, 12c)	0.124*

* Assumed as High Risk IOU, Five years in Exhibit 2-22 of DOE/NETL Report[1].

Appendix C – Water Balance

Exhibit 4-51 Case 12 Water Balance

Water Use	Water Demand		Internal Recycle		Raw Water Withdrawal		Process Water Discharge		Raw Water Consumption	
	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)
Econamine	0.1	36	0	0	0.1	36	0	0	0.1	36
FGD Makeup	5.1	1,340	0	0	5.1	1,340	0	0	5.1	1,340
BFW Makeup	0	0	0	0	0	0	0	0	0	0
Cooling Tower	39.4	10,399	6.5	1,703	32.9	8,696	8.9	2,339	24.1	6,357
Total	44.6	11,774	6.5	1,703	38.1	10,071	8.9	2,339	29.3	7,733

Exhibit 4-51a Case 12a Water Balance

Water Use	Water Demand		Internal Recycle		Raw Water Withdrawal		Process Water Discharge		Raw Water Consumption	
	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)
Econamine	0.1	32	0	0	0.1	32	0	0	0.1	32
FGD Makeup	2.1	543	0	0	2.1	543	0	0	2.1	543
BFW Makeup	0	0	0	0	0	0	0	0	0	0
Cooling Tower	35.4	9,352	5.8	1,532	29.6	7,820	8.0	2,103	21.7	5,717
Total	37.6	9,927	5.8	1,532	31.7	8,396	8.0	2,103	23.8	6,292

Exhibit 4-51b Case 12b Water Balance

Water Use	Water Demand		Internal Recycle		Raw Water Withdrawal		Process Water Discharge		Raw Water Consumption	
	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)
Econamine	0.1	32	0	0	0.1	32	0	0	0.1	32
FGD Makeup	2.1	551	0	0	2.1	551	0	0	2.1	551
BFW Makeup	0	0	0	0	0	0	0	0	0	0
Cooling Tower	35.0	9,241	5.8	1,513	29.2	7,727	7.9	2,078	21.4	5,649
Total	37.2	9,824	5.8	1,513	31.4	8,310	7.9	2,078	23.6	6,232

Exhibit 4-51c Case 12c Water Balance

Water Use	Water Demand		Internal Recycle		Raw Water Withdrawal		Process Water Discharge		Raw Water Consumption	
	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)	m3/min	(gpm)
Econamine	0.1	31	0	0	0.1	31	0	0	0.1	31
FGD Makeup	2.0	526	0	0	2.0	526	0	0	2.0	526
BFW Makeup	0	0	0	0	0	0	0	0	0	0
Cooling Tower	34.3	9,053	5.7	1,483	28.6	7,570	7.7	2,036	21.0	5,534
Total	36.4	9,610	5.7	1,483	30.7	8,127	7.7	2,036	23.1	6,091