

Ionic Liquid Catalyzed MEA solvent for Post-combustion CO₂ Capture Testing Using the PSTU at NCCC

Technical Report

Report Issued: December 2022

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Abbreviations

NCCC	National Carbon Capture Center
NGCC	Natural Gas Combined Cycle
SRD	Specific Reboiler Duty (GJ/tonne _{CO2})
PSTU	Pilot Solvent Test Unit
NG	Natural Gas
U5	Unit 5 from Gaston
MEA	Monoethanolamine
PPM	Parts Per Million
CCSI™	Carbon Capture Simulation Initiative
SSM	Steady State Model
IECM	Integrated Environmental Control Model
TIC	Total Inorganic Carbon
GC	Gas chromatography
KOH	Potassium Hydroxide
ELECNRTL	Electrolyte Non-random Two Liquid model

Executive Summary

Susteon has developed ionic liquid (IL) based homogeneous catalysts that are active in catalyzing CO₂ absorption and desorption reactions and are stable at higher temperatures. Such catalysts are aimed to substantially increase CO₂ absorption and desorption rate for amine solvents by orders of magnitude. The increase in absorption rate can reduce the absorption column height, while the increase in desorption at temperatures below the boiling point of water can significantly reduce the overall energy required for solvent regeneration and solvent loss due to degradation and emissions. The major advantages of the homogeneous catalysts are that they can be added to solvents used in already constructed plants to effectively reduce energy consumption and solvent losses.

Small pilot testing at University of Kentucky (UKy) using an absorber (4-inch diameter and 11 feet height) and 2.7 kW Stripper system using aqueous monoethanolamine (MEA) solvent (30 wt.%) catalyzed by the ionic liquid catalyst (3,000 ppm) has shown that there was about a 18% increase in absorption amount under the same test conditions with about 13% reduction in the energy of solvent regeneration for coal derived flue gases. For natural gas combined cycle (NGCC) flue gases, the benefit drops to about 9%. Susteon has completed 4 weeks testing campaign to confirm those findings using the Pilot Solvent Test Unit (PSTU) at the National Carbon Capture Center (NCCC) (Absorber 26-inch diameter and 60 feet packed height) and 0.5 MW regenerator system using 30 wt.% MEA solvent. Thus, the NCCC testing is expected to produce the data necessary to confirm and validate the small pilot test results and ready the catalyst for commercialization. If validated, this catalyst could impact the CO₂ capture process by transforming the conventional amine scrubbing technology to much higher efficiencies and at lower costs for widespread global adoption. Summary of the full campaign with the tested flue gas conditions are given **Table 1** below:

Table 1. Summary of run dates, and duration, and flue gas conditions

Start and End Dates of Runs				Flue Gas from Boiler (NG)		Flue Gas from Gaston U5 (Coal/ NG)	
Start	End	Catalyst	Total Hrs.	NG4 (diluted, ~4% CO ₂)	NG10 (undiluted, ~10% CO ₂)	U5-12 (Coal, ~12% CO ₂)	U5-4 (diluted, ~4% CO ₂)
8/10/2022	8/16/2022	No	134	134	-	-	-
8/16/2022	8/29/2022	No	311	-	311	-	-
8/29/2022	9/2/2022	Yes	96	-	96	-	-
9/4/2022	9/9/2022	Yes	133	-	-	-	133
	Sub-total w/o Catalyst	No	445	134	311	-	0
	Sub-total w/ Catalyst	Yes	228	0	96	-	133
	Total Op Hours		673	134	407	-	133

PSTU was operated for about 600 hrs. under steady-state conditions with different CO₂ capture rates in absorption side and different steam flow rates for regeneration side. 280 hrs. of simulated coal flue gas (~9.21% vol.CO₂ undiluted NG10 flue gas) were used to obtain CO₂ capture performance using uncatalyzed aqueous MEA and 90 hrs. using catalyzed aqueous MEA. 135 hrs. of simulated natural gas flue gas (~4.41% vol.CO₂, diluted NG-4 and U5-4 coal flue gas) were used to obtain CO₂ capture performance using uncatalyzed aqueous MEA and 91 hrs. using catalyzed aqueous MEA.

For NGCC flue gas which uses 2 beds in PSTU absorber, the baseline runs were with 30wt.% monoethanolamine (MEA) by adjusting the steam flow rate in stripper to attain lean loading for 80% CO₂ capture in the absorber at different L/G (liquid to gas flow rates) mass ratios (0.8, 1, 1.25), and at constant L/G (1.25) but varying steam flow rates in the stripper to get higher capture rates of 90%, 95% and 98% to determine the energy required for the process. For Coal flue gas which uses 3 beds in PSTU absorber, the

baseline experiments were run with 30wt.% monoethanolamine (MEA) by adjusting the steam flow rate in stripper to attain lean loading for 80% CO₂ capture in absorber at different L/G mass ratios (2.5, 3, 3.5), and at constant L/G (3.5) but varying steam flow rate to get higher capture rates of 90%, 95% and 98% to determine the energy required for the process.

The catalyst was then added to the 30 wt.% MEA already in the PSTU and the solvent circulated for 24 hours prior to repeating the same process conditions as those runs without the catalyst.

Concentration of aqueous MEA dropped from 31 wt.% initially to 23wt.% (unloaded with CO₂) during the campaign due to higher water content variability (~6-15 vol.%) of the incoming flue gas and absorber water imbalance. Due to large MEA concentration changes for NGCC flue gas conditions, we cannot directly compare the results from the PSTU runs. For coal flue gas, the MEA concentration changes were relatively small and test results for solvent with and without catalyst can be compared directly. Nonetheless, there was clear evidence of the CO₂ reaction rate enhancement with catalyzed MEA solvent as indicated by the larger temperature bulge in the absorber column. To do an apple-to-apple comparison for NGCC case, the concentrations of catalyzed and uncatalyzed MEA were normalized using the Aspen Plus™ model developed by CCSI™ to match the temperature profiles of absorber and stripper. Based on the observation as shown below in , under same amine concentration, we observed 5-12% reduction in specific reboiler duty (GJ/tonne_{CO2}) for both Coal and NGCC flue gases.

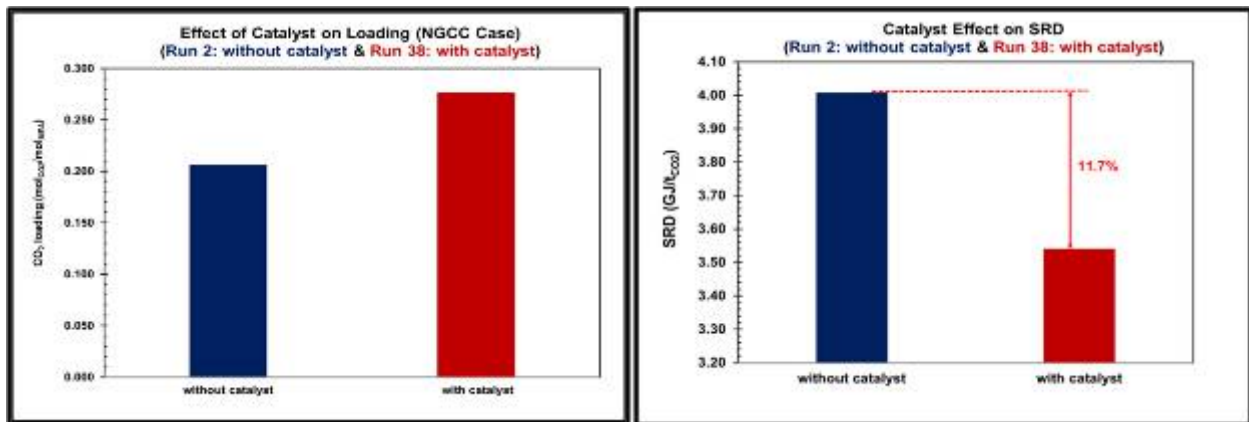


Figure 1. Noticed shift in working capacity due to the addition of catalyst (3000 ppm) and corresponding SRD reduction during NCCC campaign in NGCC Case (~4% CO₂) after normalizing amine concentration

For Coal flue gas, observations made during catalyst addition to the solvent in campaign are as follows: (a) Increase in CO₂ reaction rates in solvent were evidence by the increase in temperature bulge in the absorber (as shown in **Figure 3**). (b) There is a 20% upward shift in measured lean CO₂ loading which resulted in lower specific reboiler duty for the catalyzed solvent (as summarized in **Figure 3**).

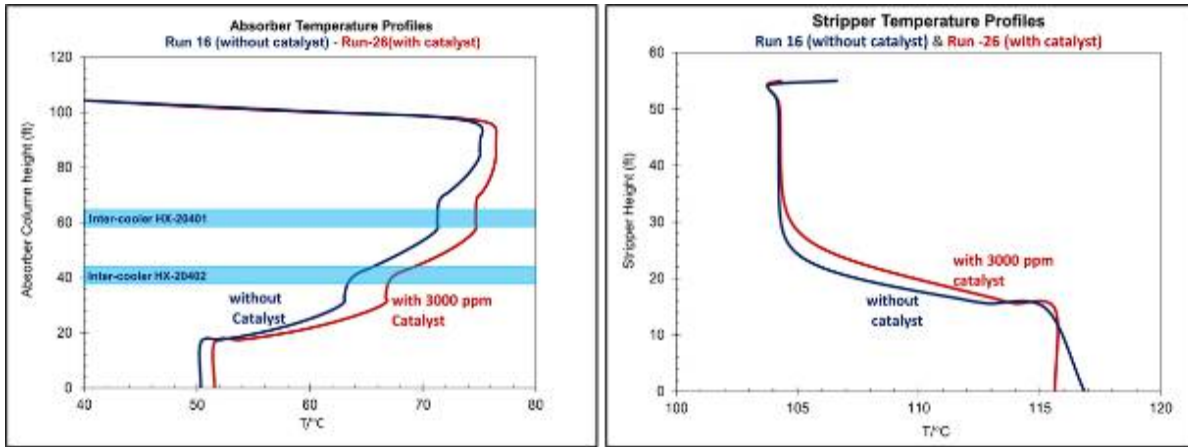


Figure 3. Noticed increase in reaction rate from the absorber temperature bulges due to the addition of catalyst (3000 ppm) and corresponding SRD reduction during NCCC campaign in simulated Coal flue gas Case (~9% CO₂)

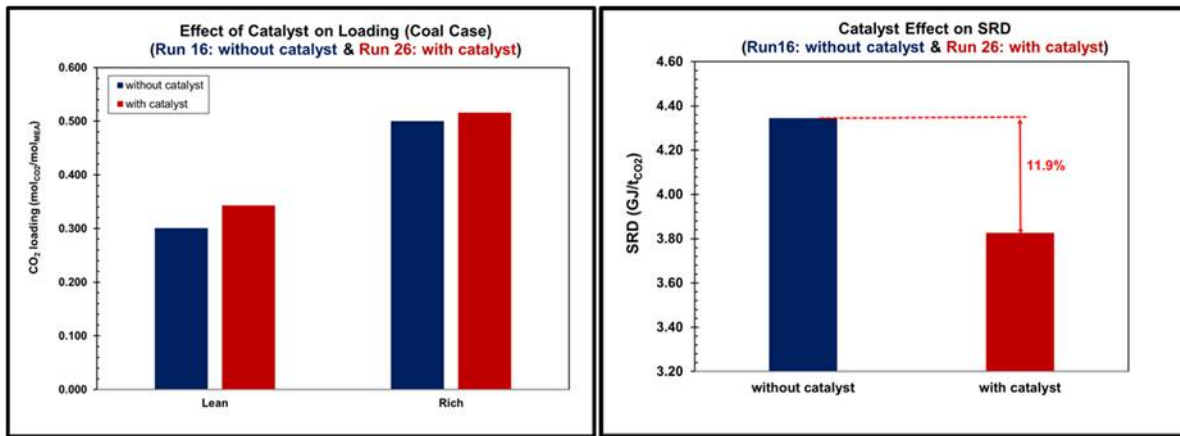


Figure 3. Noticed lean loading shift due to the addition of catalyst (3000 ppm) and corresponding SRD reduction during NCCC campaign in simulated Coal flue gas Case (~9% CO₂ using undiluted NG 10 flue gas)

Overall summary of the campaign due to the addition of catalyst to the baseline experiment with 30 wt.% MEA is given in **Table 2** below:

Table 2. Summary of CO₂ capture results using the PSTU with 30 wt.% MEA

Case	Inlet Flue Gas (%)	Capture (%)	L/G (mass/mass)	Stripper Temperature (°C)	Energy consumption (GJ/tonneCO ₂)		Improvement (%)
					without catalyst	with catalyst	
NGCC Flue Gas	4.41	82	0.83	119.8	3.96	3.52	11.0
	4.41	80	0.99	118.8	4.01	3.54	11.7
	4.41	81	1.24	118.2	4.10	3.61	11.9
Simulated Coal Flue Gas	8.95	81	2.48	117.5	3.72	3.54	4.8
	9.22	80	2.49	117.0	3.75	3.56	5.0
	9.20	91	3.44	117.4	4.34	3.83	11.9
	9.08	95	3.38	118.3	4.85	4.28	11.6

Susteon's IL catalyst showed 5% reduction in energy consumption for 80% CO₂ capture case for Coal flue gas and 11-12% reduction in energy consumption for NGCC flue gas, and 11-12% reduction in energy consumption at constant L/G ratio at 90-95% Capture for Coal flue gas.

Background of Susteon's catalyst technology

Susteon, in partnership with University of Wyoming, has developed a homogeneous ionic liquid catalysts which dramatically increase CO₂ adsorption and desorption rates for any amine solvent. Advantages of this proprietary catalyst are:

- It can significantly improve absorption and desorption rates of CO₂ in any amine solvents used for CO₂ capture as well as reducing regeneration energy for solvent regeneration
- It is stable, non-volatile, and non-toxic
- Only ppm levels of catalyst are needed to be added to the amine, thus it will not change any physical and chemical properties of capture solvents
- Catalyze solvent was tested for post-combustion capture in lab-scale units and showed improved in both capture rate and specific reboiler duty (SRD)
- Catalyze solvent was tested in small pilot unit for CO₂ capture from coal & NGCC flue gas and validated the confirmed lab test results.
- Only ppm levels of the catalyst are needed to improve CO₂ capture performance as compared to the performance of baseline solvents without catalyst.
- This catalyst was also shown to dramatically improve amine-based sorbents for direct air capture of CO₂.

Laboratory data for absorption of 10% CO₂ simulated flue gas in 20 wt.% monoethanolamine (MEA) solution with and without catalyst are shown in **Figure 4**. This figure shows that CO₂ breakthrough time is increased from 4446 seconds to 6350 second for 90% CO₂ capture when catalyst is added to the 20 w% MEA, an increase of ~43%. The amount of CO₂ absorbed increased from about 144 mmol to 210 mmol at 90% capture, an increase of 46%.

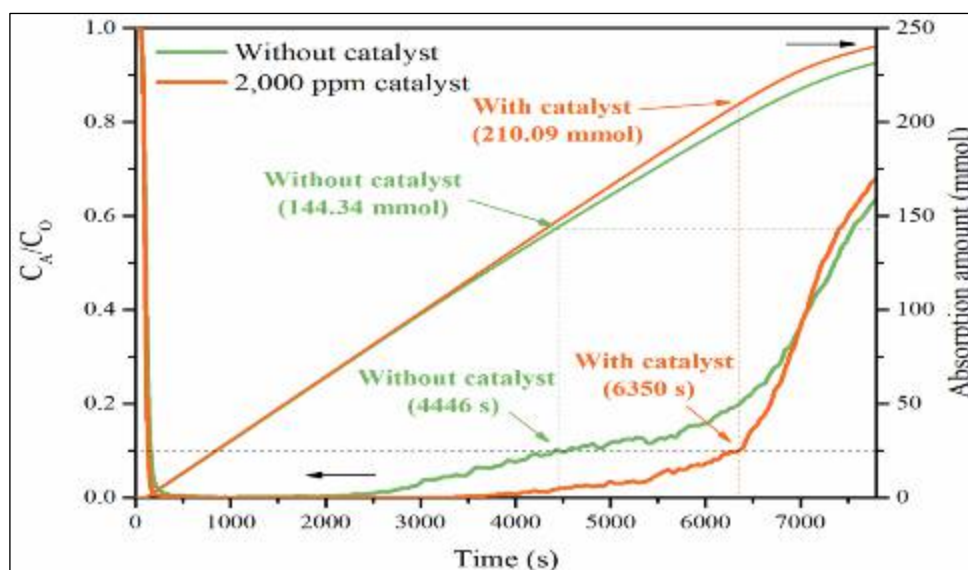


Figure 4. Breakthrough results from catalyzed monoethanolamine (MEA) compared to uncatalyzed MEA

More importantly, the addition of ionic liquid (IL)-based catalyst to aqueous MEA can significantly increase the absorption rate and solvent capacity as shown in **Figure 5** compares 30wt.% MEA solvent with and without IL catalyst in a breakthrough experiment using 4% CO₂ of simulated NGCC flue gas at 40°C. This figure clearly shows that both the absorption rate (along y-axis) and the CO₂ absorption capacity (along x-axis) with the addition of 3,000 ppmw of IL catalyst to the solution.

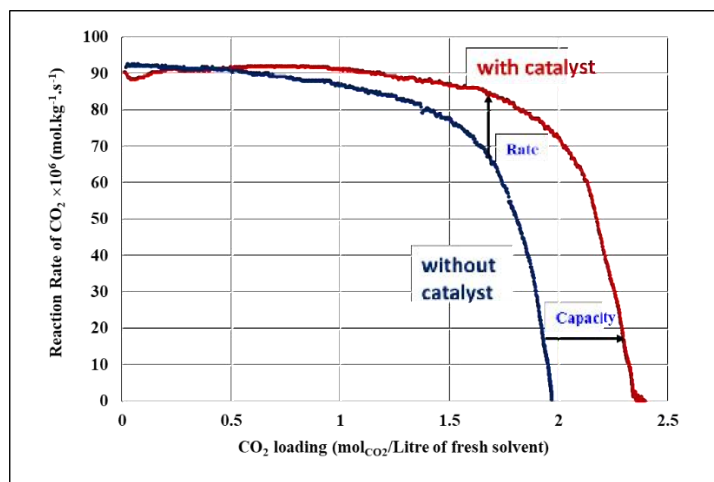


Figure 5. 30wt% MEA with 3000 ppmw IL catalyst addition as compared with that of MEA without IL catalyst

30wt% MEA with 3000 ppmw IL catalyst addition as compared with that of MEA without IL catalyst

We conducted weeklong continuous test of 30 wt.% MEA with and without IL catalyst using a small pilot test system. This system can be configured to run both coal derived flue gas and NGCC flue gas. Simplified system flow diagram is shown in **Figure 6** and system parameters are shown in **Table 3**.

Table 3. Small Pilot System Parameters for Post-Combustion CO₂ Capture Testing

Parameter	Value (unit)
Absorber diameter	0.1 (m)
Absorber packing height	2 x 3.25 (m)
Packing type	FLEXIPAC 250Y
Total Inventory	87 (lit)
Regenerator diameter	0.1 (m)
Inlet CO ₂ composition	4-15 % vol.
Lean solvent temperature	40 °C
Gas inlet temperature	40 °C

The absorber column is equipped with an interstage cooling towards the top of the column which can be used to reduce the temperature bulge. For solvent regeneration, a split feed configuration can be used to send a warm bypass stream to the top of the stripper column and a hot stream at a lower stage. This scheme lowers the stripper column exit stream temperature and reduces the regeneration energy of the process. A control valve is used to control the split ratios of the rich solvent and the two heat exchangers ensure desired temperature difference between the warm by-pass and hot streams is obtained.

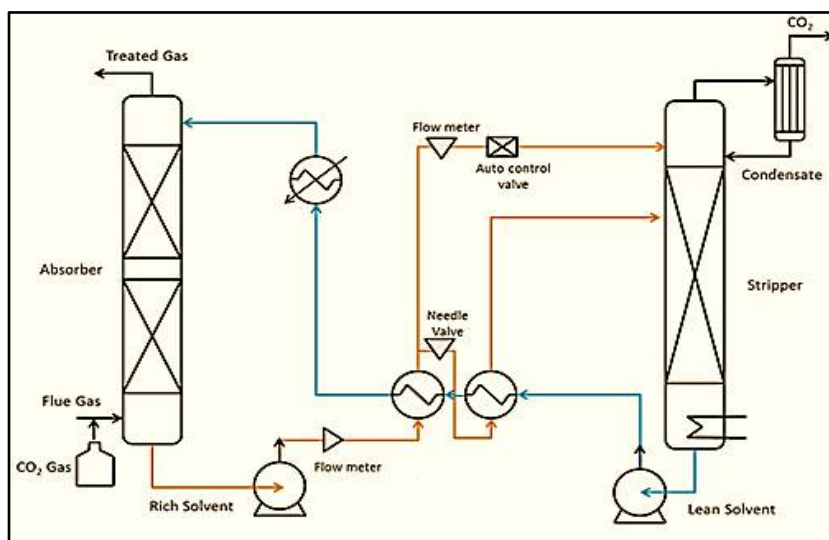


Figure 6. Simplified process flow diagram of the small pilot post-combustion CO₂ capture test system

Simulated coal derived flue gas and NGCC flue gas with ~14 vol% and ~4 vol% CO₂, respectively, was used in the test campaign. The test matrix is shown in **Table 4**. The objectives of the test campaign are:

- To quantify and confirm the impact of ionic liquid catalyst in increasing capture rate
- To quantify and confirm the impact of ionic liquid catalyst in reducing solvent regeneration energy
- To identify any operation issue in capture unit by adding IL catalyst – example: increased foaming

The test results for coal derived flue gas CO₂ capture are shown in **Table 5**.

Table 4. Test matrix for small pilot campaign

Parameter		Inlet CO ₂ % vol	L/G (kg/hr)/(kg/hr)	Test duration hr
Coal Flue Gas	Baseline (No catalyst)	14.03	2.9	5
	Test 1 (with 3,500 ppm catalyst)	14.03	2.9	10
NGCC Flue Gas	Baseline (No catalyst)	3.9	1.3	5
	Test 2 (with 3,500 ppm catalyst)	3.9	1.3	10

Table 5. CO₂ capture test results with coal derived flue gas

Parameter	Unit	Baseline	Catalyzed	% Improvement
Inlet CO ₂	% vol	14.03	14.03	
CO ₂ Capture	%	56	66	17.9
L/G	wt/wt	2.94	2.94	
Reboiler Bottom Temperature	°C	121.2	122.07	
Energy Consumption	MJ/kg-CO ₂	2.7	2.35	12.7

Table 5 shows that there is a 17.9% increase in CO₂ capture rate and a 12.7% decrease in solvent regeneration energy when all other test conditions are kept the same. We run at lower CO₂ capture rate to make sure we could observe the difference for tests with and without the catalyst. It should be noted that the solvent regeneration energy is a relative number due to the size of the test system. The increase in absorption rate is also confirmed by the absorber column temperature profile as shown in **Figure 7**. The temperature for solvent with catalyst at the top of the column is about 8°C hotter than that without catalyst indicating that the catalyst is increasing the rate of CO₂ reaction with MEA. The test results for the NGCC flue gas CO₂ capture is shown in **Table 6**. This table shows that there is an 8.8% increase in CO₂ capture rate and a 7.4% decrease in solvent regeneration energy when all other test conditions are kept the same for NGCC flue gas.

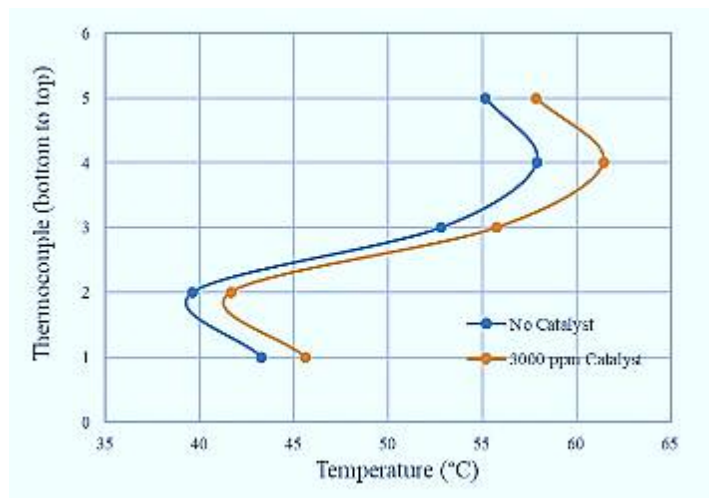


Figure 7. Temperature profile in the absorber column under coal flue gas CO₂ capture conditions

Table 6. CO₂ capture test results with NGCC flue gas

Parameter	Unit	Baseline	Catalyzed	Improvement (%)
Inlet CO ₂	% vol	3.97	3.99	
CO ₂ Capture	%	57	62	8.8
L/G	wt/wt	1.37	1.36	
Reboiler Bottom Temperature	°C	119.16	119.22	
Energy Consumption	MJ/kg-CO ₂	4.61	4.27	7.4

To answer the question of how these improvements in capture rate and reduction in SRD affect the cost of CO₂ capture, we employed the Integrated Environmental Control Model (IECM) to estimate the cost of CO₂ capture for a pulverized coal fired power plant and a NGCC power plant using the baseline and the improved solvent performance obtained from the small pilot testing. The IECM was used to estimate the cost of each plant on a consistent basis for a U.S. facility with a net power output of approximately 500 MW, a levelized capacity factor of 85%, and a carbon capture system removing 90% of the CO₂ and compressing it to 13.8 MPa. All coal-based plants used a bituminous coal with 2.1% sulphur. All costs were in constant 2016 US dollars and exclude the costs of CO₂ transport and storage. The estimated CO₂ capture costs are shown in **Tables 7 and 8** for coal and NGCC power plants, respectively.

Table 7. CO₂ capture cost for coal plant*

Parameter	Unit	Value
Capture Cost without Catalyst	USD/tonne-CO ₂	55.8
Capture Cost with Catalyst	USD/tonne-CO ₂	48.9

*Design Basis – Super Critical Pulverized Coal, Capacity: 550 MW Gross, CO₂ Capture Rate: 85%, Solvent: MEA (30 wt.%)

Table 8. CO₂ capture cost for NGCC plant*

Parameter	Unit	Value
Capture Cost without Catalyst	USD/ton-CO ₂	80.8
Capture Cost with Catalyst	USD/ton-CO ₂	75.9

*Design Basis – NGCC Case, Capacity: 592 MW Gross, CO₂ Capture Rate: 90%, Solvent: MEA (30 wt.%)

Tables 7 and 8 show that there is a 12.3 and 6.7% reduction in the cost of CO₂ capture from the coal and NGCC power plants using catalyzed 30 wt.% MEA as capture solvent. These cost reductions are substantial considering that there are millions of tonnes of CO₂ that can be captured from each power plant.

Objectives of NCCC test Campaign

Test at the National Carbon Capture Center (NCCC) using the Pilot Solvent test unit (PSTU) are aimed at further verification of the effectiveness of the catalysts. The objectives of the test campaign are:

- To quantify and validate the impact of ionic liquid catalyst in increasing capture rate
- To quantify and validate the impact of ionic liquid catalyst in reducing solvent regeneration energy
- To identify any operational issue in capture unit with IL catalyzed solvent (ex: increased foaming)

The test matrix of 12 × 2 (with and without catalyst) runs (shown in **Table 9**) were carried out for the campaign with NGCC and coal flue gas at different L/G ratios with constant CO₂ capture rate (80%) and at different CO₂ capture rate with constant L/G ratio to evaluate the effect of catalyst on CO₂ absorption enhancement and reduction in regeneration energy. All operations and on-site monitoring were performed by the NCCC team and remotely monitored and directed by Susteon team. It should be noted that the originally planned test matrix was more comprehensive than the one shown in Table 9. However, due to

water imbalance in the absorber, there was a large change in MEA concentration during the 4-week campaign. We skipped several runs for NGCC flue gas at 90, 95, and 98% capture.

Table 9. Test matrix for PSTU-NCCC campaign

Case	Parameter	Capture % to adjust steam flow	Inlet CO ₂ (vol.%)	L/G (kg/hr)/(kg/hr)	Packing Height of absorber (No. of Beds)
NGCC Flue Gas	Baseline (No catalyst) & Test with 3000 ppm catalyst	80%	10-14%	0.8	2
		80%	10-14%	1	2
		80%	10-14%	1.25	2
		90%	10-14%	1.25	2
		95%	10-14%	1.25	2
		98%	10-14%	1.25	2
Coal Flue Gas	Baseline (No catalyst) & Test with 3000 ppm catalyst	80%	4-5%	2.5	3
		80%	4-5%	3	3
		80%	4-5%	3.5	3
		90%	4-5%	3.5	3
		95%	4-5%	3.5	3
		98%	4-5%	3.5	3

Description of PSTU in NCCC

NCCC is one of the U.S. Department of Energy (DOE) funded test facility in Wilsonville, Alabama, USA, (shown in **Figure 8**, left), located adjacent to Alabama Power’s plant Gaston, receives commercially representative flue gas for testing from the Gaston plant. Additionally, a newly configured natural gas-fired boiler¹ to assist test programs to demonstrate viable reduction in both capital and operating expenses to support large-scale carbon capture

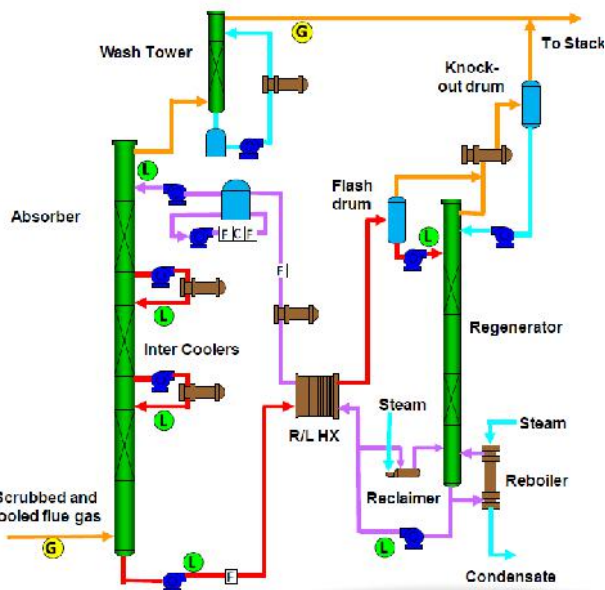


Figure 8. Pilot Solvent Test Unit with the gas-fired boiler (left) and schematic of absorber-desorber (0.5 MW) system (right)

¹ Meuleman, E., Validation of Transformational CO₂ capture solvent Technology with Revolutionary stability. ION Clean Energy, Inc., Final Project Report: National Carbon Capture Center Pilot Testing, Project award no. DE-FE0031727.

deployment. The Pilot Solvent Test unit (PSTU as shown in **Figure 8**, right)² is a 0.5 MW CO₂ capture pilot unit at NCCC.

The primary flue gas for the test campaign was provided from the natural gas boiler and has a concentration of 7-10% CO₂ (NG10) which was used as it is to simulate coal flue gas cases for the campaign and was cooled with air and diluted to NGCC flue gas CO₂ content (~4%CO₂, NG4) before introducing into the PSTU absorber. Pre-treated coal-derived flue gas was also used for tests at about 12%CO₂ (U5-12) and was diluted to NGCC condition (~4% CO₂, U5-4) when the natural gas boiler was down. Summary of flue gas usage and supply for the campaign are given in **Table 1** in the Executive summary.

Overview of PSTU Standard operations in NCCC

The PSTU absorber receives the flue gas of desired CO₂ inlet concentration (4% or 10% CO₂), which utilized three 6-meter height beds of Sulzer Mellapak™ 252Y structure packing for Coal case and 2 beds for NGCC case in Susteon's baseline campaign using 30 wt.% MEA. The flue gas flows in a counter-current direction up the column while the CO₂ lean solvent travels down the column, absorbing CO₂ along the packed-column. A water-wash tower cools the hot flue gas exit at the top of the column after exothermically reacted with aqueous MEA during CO₂ absorption to within a few degrees of inlet flue gas temperature and maintains water balance via recirculating cooled wash water and returns the condensed water and amine to the lean solvent. The purified CO₂-lean flue gas exits the PSTU through the NCCC or Gaston stack for release to atmosphere based on the flue gas used. The capture rate of the solvent depends on the lean condition entering the absorber top based on the steam flow set for regenerating the solvent in stripper side. The rich solvent after absorbing CO₂ collects in a surge tank by gravity and then pumped through a lean-rich cross exchanger to exchange heat with the lean solvent from the stripper reboiler and flows into the top of the regenerator. The preheated rich solvent rains down along the stripper column (23-inch and 40 feet packed height) and releases CO₂ to water vapor from the reboiler which flows counter-currently upward. The semi-lean solvent which reaches the stripper sump is recirculated through a forced-convection reboiler and utilizes steam to heat the solvent and strips CO₂ to achieve lean loading. The stripped CO₂ to the leaner condition is then recirculated back to the absorber through the lean-rich heat exchanger to the top of the absorber for continuous CO₂ capture. The CO₂ coming out of the top of the stripper is cooled and released to the atmosphere through stack along with the flue gas from absorber.

Testing and Data Analysis Methodology

The most critical parameters for the performance of the campaign are given below with the method of calculating them¹:

The percent of CO₂ capture was measured on the absorber side of the process as the difference between CO₂ flowing in and out of the absorber as follows:

$$CO_2 \text{ capture (\%)} = \left(1 - \frac{m_{CO_2,absout}}{m_{CO_2,absin}}\right) \times 100 \quad \text{Equation 1}$$

H₂O inlet and outlet in the absorber were calculated from the relative humidity measurements and inlet and outlet temperatures of the gas streams.

² Wheeldon, J., National Carbon Capture Center: Post-combustion CO₂ capture Program. NETL CO₂ Capture Technology Meeting, Pittsburgh, July 8 to 11, 2013.

$$P_{H_2O} = P_{satw}(T_{gas} + 273.15) \quad \text{Equation 2}$$

The mole fraction of water is calculated as:

$$f_{H_2O} = \frac{P_{H_2O}}{(P_{gas,barg} + P_{ambient,absolute,mbar}/1000)} \quad \text{Equation 3}$$

The mole fraction of CO₂ corrected for water content (f_{CO₂, wet}) is calculated as:

$$f_{CO_2,wet} = (1 - f_{H_2O}) \times \frac{\%CO_2,dry}{100} \quad \text{Equation 4}$$

The CO₂ mass flow (m_{CO₂}) is calculated as:

$$m_{CO_2} = f_{CO_2,wet} \times Q \times MW_{CO_2} \times \frac{P}{RT} \quad \text{Equation 5}$$

Where Q is Sm³/hr, T_{STD}=15°C, P_{STD}=1 bar and m_{CO₂} is calculated for both inlet and outlet gas flows. The specific reboiler duty (SRD) is calculated as follows:

$$SRD \left(\frac{GJ}{tonne CO_2} \right) = \frac{Reboiler Heat Duty - Ambient Heat Loss}{CO_2 Captured} \quad \text{Equation 6}$$

The reboiler duty was calculated from the overall flow of steam (m_{steam}) into the reboiler multiplied by the enthalpy difference between the steam conditions into the reboiler and the condensate conditions coming out as below:

$$Reboiler Heat Duty \left(\frac{GJ}{hr} \right) = m_{steam}(H_{steam} - H_{condensate}) \quad \text{Equation 7}$$

The captured CO₂ was measured on the absorber side of the process as the difference between CO₂ flow in and flowing out of the absorber which represented by CO₂ concentrations (C) as given below:

$$CO_2 captured \left(\frac{tonnes}{hr} \right) = m_{Flue Gas in} C_{CO_2 in} - m_{Flue Gas out} C_{CO_2 out} \quad \text{Equation 8}$$

Ambient heat loss accounted in the calculation of experimental SRD was taken from the value reported for PSTU from the work of ION engineering¹ as 60 MJ/hr.

Solvent Analysis

Solvent samples on both the lean and rich side were taken during each test condition after reaching the steady state. The CO₂ loading of the solvent was determined in the lab by Gas chromatography (GC) and Total Inorganic Carbon (TIC) analyzer in the lab. Additionally, an auto-titrator was used to calculate the amine concentration and CO₂ loading in the solvent by titrating against Hydrochloric acid (HCl) and potassium hydroxide (KOH).

Results and Discussion

Parametric Testing with NGCC and Coal flue gases

PSTU was operated approximately 600 hrs. at steady state with different CO₂ capture rates in absorption side and different steam flow rates for regeneration side. 280 hrs. of steady-state run for Simulated Coal flue gas (~9.21% vol.CO₂) were run to obtain CO₂ capture performance using uncatalyzed aqueous 30wt.% MEA and 90 hrs. of steady-state run using catalyzed aqueous 30wt.% MEA. 135 hrs. of steady-state run for simulated natural gas flue gas (~4.41% vol.CO₂) were run to obtain CO₂ capture performance using uncatalyzed aqueous 30wt.% MEA and 91 hrs. of steady-state run using catalyzed aqueous 30wt.% MEA. Catalyst was added to the solvent via the rich solvent tank at the bottom of the absorber after 445 hrs. of baseline runs for NGCC and Coal flue gas conditions using 30wt.% MEA. **Table 10** shows the summary of experimental solvent analysis, CO₂ capture rates and SRD calculation results obtained for NGCC and coal cases before and after the addition of catalyst. First 6 runs were performed with NG4 flue gas, 7 to 20 runs were tested with NG10 flue gas. Due to breakdown of natural gas boiler, U5-4 flue gas was used to perform 21-39 runs.

Figure 9 shows the variation of amine concentration during the campaign of 445 hrs. of runs with 30wt% MEA baseline without catalyst and 228 hrs. of runs with catalyst. First 134 hrs., NG4 flue gas diluted to 4% CO₂ was supplied for NGCC cases from natural gas boiler flue gas, where amine concentration averaged 31wt.% (unloaded with CO₂). Moisture content of NG4 flue gas was estimated to be ~4-10%. First 3 sets of runs were performed at 80% capture rate (constant steam flow rate in the stripper) at different L/G ratios (0.8, 0.9 and 1.5). Next 3 runs were performed at constant L/G ratio (1.5) to obtain different CO₂ capture rates (90%, 95% and >95%) by adjusting the steam flow rate in the stripper. Amine concentration dropped to 27wt.% (unloaded with CO₂) at the start of the coal case with 10% CO₂ (NG10, undiluted natural gas boiler flue gas) and the average amine concentration was maintained at 27wt% during the coal case runs. After 445 hrs. of baseline testing, Susteon's catalyst was added to the solvent via the rich solvent tank at the bottom of the absorber when amine concentration was at 27wt.%.

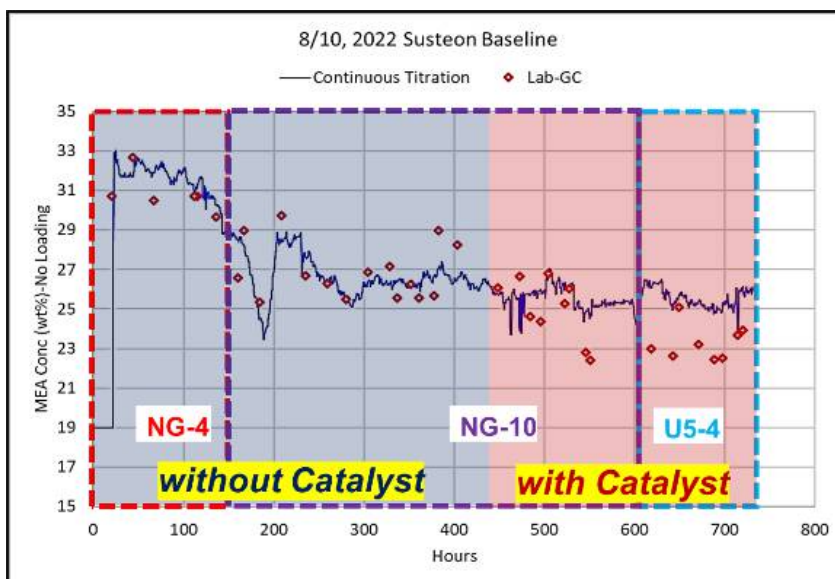


Figure 9. Variation of amine concentration during the campaign and flue gas conditions before and after the addition of catalyst. Red box – 134 hrs of NG4 flue gas (diluted, ~4%CO₂); Violet box – 311 hrs of NG10 (undiluted, ~10% CO₂); Blue box – U5-4 flue gas (diluted, ~4%CO₂); Grey shade – 445 hrs of runs without catalyst; Pink shade – 228 hrs of runs with catalyst.

Table 10. Solvent analysis for amine concentration and CO₂ loading with process conditions and regeneration energy (SRD) during Susteon' s catalyst campaign

Date	RunID	MEA (wt.%)	Lean mol _{CO2} /mol _{MEA}	Rich mol _{CO2} /mol _{MEA}	Working mol _{CO2} /mol _{MEA}	L/G (lb/lb)	SRD (GJ/t _{CO2})	CO ₂ Cap (%)	Beds # Nos.
Case Study 1: 30wt.% MEA Baseline Study for NGCC flue gas (NG4~4% CO₂, without catalyst)									
8/11/22 10:05 am	1	29	0.312	0.582	0.270	0.83	3.81	82.7	2
8/12/22 9:20 am	2	31	0.314	0.520	0.206	0.99	3.84	80.2	2
8/13/22 9:00 am	3	29	0.366	0.569	0.202	1.24	3.93	81.6	2
8/15/22 9:05 am	4	29	0.334	0.547	0.213	1.23	4.19	90.6	2
8/15/22 6:20 am	5	30	0.292	0.508	0.216	1.22	4.52	95.1	2
8/16/22 6:35 am	6	30	0.220	0.444	0.224	2.48	5.43	98.3	2
Case Study 2: 30wt% MEA Baseline Study for Coal flue gas (NG10~10% CO₂, without catalyst)									
8/17/22 6:20 am	7	26	0.361	0.607	0.246	3.49	3.97	80.5	3
8/17/22 12:45 am	8	26	0.396	0.545	0.149	3.49	3.88	81.2	3
8/18/22 6:05 am	9	24	0.390	0.558	0.168	3.45	3.96	80.4	3
8/19/22 6:50 am	10	27	0.307	0.453	0.147	2.84	4.67	87.1	3
8/20/22 9:20 am	12	26	0.274	0.463	0.190	3.40	4.23	95.1	3
8/21/22 9:00 am	13	27	0.204	0.411	0.207	3.34	5.32	97.7	3
8/22/22 6:30 am	13	25	0.196	0.412	0.216	3.34	6.52	97.7	3
8/23/22 6:10 am	14	28	0.182	0.387	0.205	3.41	6.47	98.1	3
8/24/22 6:25 am	15	27	0.244	0.437	0.193	3.44	5.18	98.1	3
8/24/22 2:55 pm	16	25	0.301	0.500	0.200	3.44	4.66	90.9	3
8/25/22 6:05 am	16	25	0.343	0.516	0.172	3.44	4.66	90.9	3
8/25/22 2:50 pm	17	24	0.360	0.523	0.163	3.46	4.75	80.6	3
8/26/22 7:25 am	18	25	0.332	0.526	0.193	2.98	4.13	81.0	3
8/26/22 1:00 pm	18	27	0.295	0.483	0.189	2.98	4.13	81.0	3
8/27/22 9:35 am	19	30	0.203	0.404	0.201	2.47	4.06	81.3	3
8/29/22 6:10 am	20	26	0.208	0.409	0.201	3.39	5.62	95.4	2
Case Study 3: 30wt% MEA for Coal flue gas (~10% CO₂, with catalyst)									
8/30/22 6:10 am	21	26	0.218	0.410	0.192	3.38	5.89	95.1	2
8/30/22 6:00 am	21	24	0.241	0.449	0.208	3.38	5.89	95.1	2
8/31/22 6:10 am	21	24	0.245	0.448	0.202	3.38	5.89	95.1	2
8/31/22 2:20 pm	22	25	0.291	0.506	0.215	2.48	4.30	78.8	3
9/1/22 8:25 am	22	23	0.299	0.517	0.218	2.48	4.30	78.8	3
9/1/22 1:10 pm	23	25	0.317	0.528	0.211	2.49	3.76	74.2	3
9/2/22 8:15 am	26	22	0.292	0.520	0.227	3.44	4.60	90.5	3
9/2/22 1:00 pm	26	22	0.206	0.322	0.116	3.44	4.60	90.5	3
Case Study 4: 30wt% MEA for NGCC flue gas (U5-4~4% CO₂, with catalyst)									
9/5/22 8:35 am	31	24	0.127	0.538	0.411	0.81	4.85	92.6	2
9/6/22 8:30 am	32	22	0.147	0.504	0.357	0.97	4.72	97.3	2
9/7/22 2:55 pm	33	24	0.258	0.478	0.220	1.24	4.07	81.8	2
9/7/22 12:45 pm	34	23	0.215	0.508	0.292	1.23	4.38	89.4	2
9/8/22 6:05 am	35	21	0.203	0.490	0.287	1.23	4.63	96.2	2
9/8/22 3:30 pm	37	22	0.268	0.510	0.242	1.25	3.99	81.8	2
9/9/22 7:45 am	38	23	0.229	0.506	0.276	1.00	4.01	79.8	2
9/9/22 1:30 pm	39	24	0.175	0.504	0.329	0.83	3.93	80.5	2

For coal cases, there was a shift in the lean loading and rich loading to higher value under the same run condition after adding the catalyst. NG flue gas from boiler was not available during the catalyst test period for NGCC cases, therefore U5-12 coal flue gas from Gaston unit 5 (~12%CO₂) was diluted to make U5-4 (~4%CO₂). Moisture content of the U5-4 varied from 13-16%. The amount of water accumulated in the solvent during the NGCC campaign with catalyst made it impossible for apple-apple comparison with baseline without catalyst. Amine concentration was approximately 26% lower than the amine concentration used initially to evaluate the baseline runs for aqueous MEA (31wt.%). The average amine concentration measured (unloaded with CO₂) at NGCC runs with catalyst for U5-4 flue gas was 23wt.%. But working capacity of solvent found to be higher in the runs with catalyst than the working capacity of the solvent in the runs without catalyst. Therefore, we can only compare the NGCC run results after normalizing amine concentration using the process model. On the other hand, the coal cases can be compared directly for runs with and without catalyst.

Process Model Validation

A steady-state process model developed for monoethanolamine (MEA ssm) by Carbon Capture Simulation Initiative (CCSITM)³ was employed to represent the process conditions and parameters to analyze and compare the performance of MEA solvent with and without catalyst in this work. General process flow diagram of the model is given in **Figure 10**. The model is validated by matching the model and run results for the temperature profiles of absorber and stripper, Liquid and Gas flow rates along with their conditions, % CO₂ capture rates and CO₂ working capacities (mol_{CO₂}/mol_{MEA}). The validated model is then used to calculate the specific reboiler duty of the process. In general, model predicted the performance within ± 8% as shown in **Figure 11**. Some deviations were caused mainly by variations in amine concentrations. Model was originally developed to accurately predict PSTU MEA CO₂ capture performance in MEA concentration range of 25 to 35 wt.%. The thermodynamic framework is based on Austin's Phoenix model which represented solution thermodynamics by ELECNRTL method in Aspen Plus Version 10. The kinetic model used is based on the simplified two equilibrium equations using the overall ionic speciation of the system as follows:

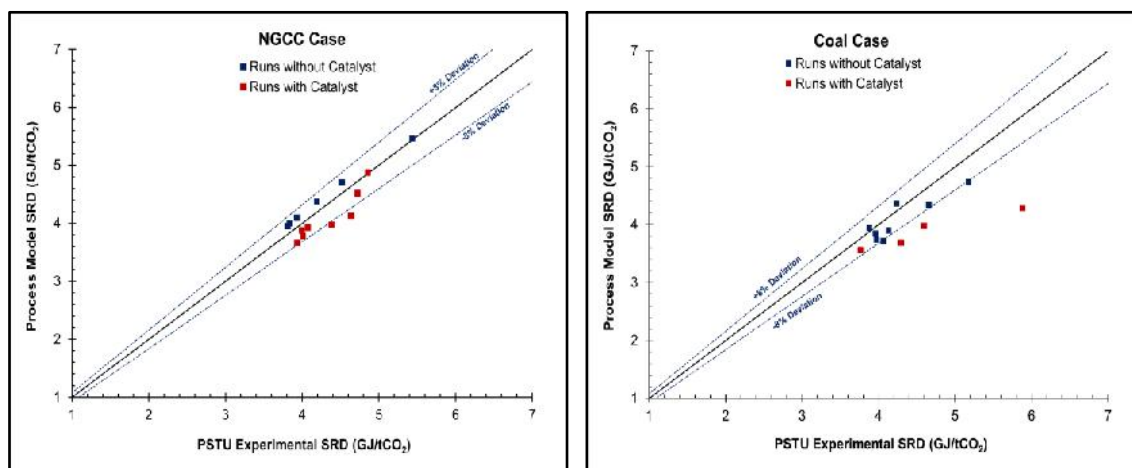


Figure 10. Parity plots of model predictions of CO₂ capture by MEA for NGCC and Coal flue gases (outliers due to lower amine concentrations)

³CCSI steady state MEA model (MEA ssm), User Manual Version 3.2.0, February 2021

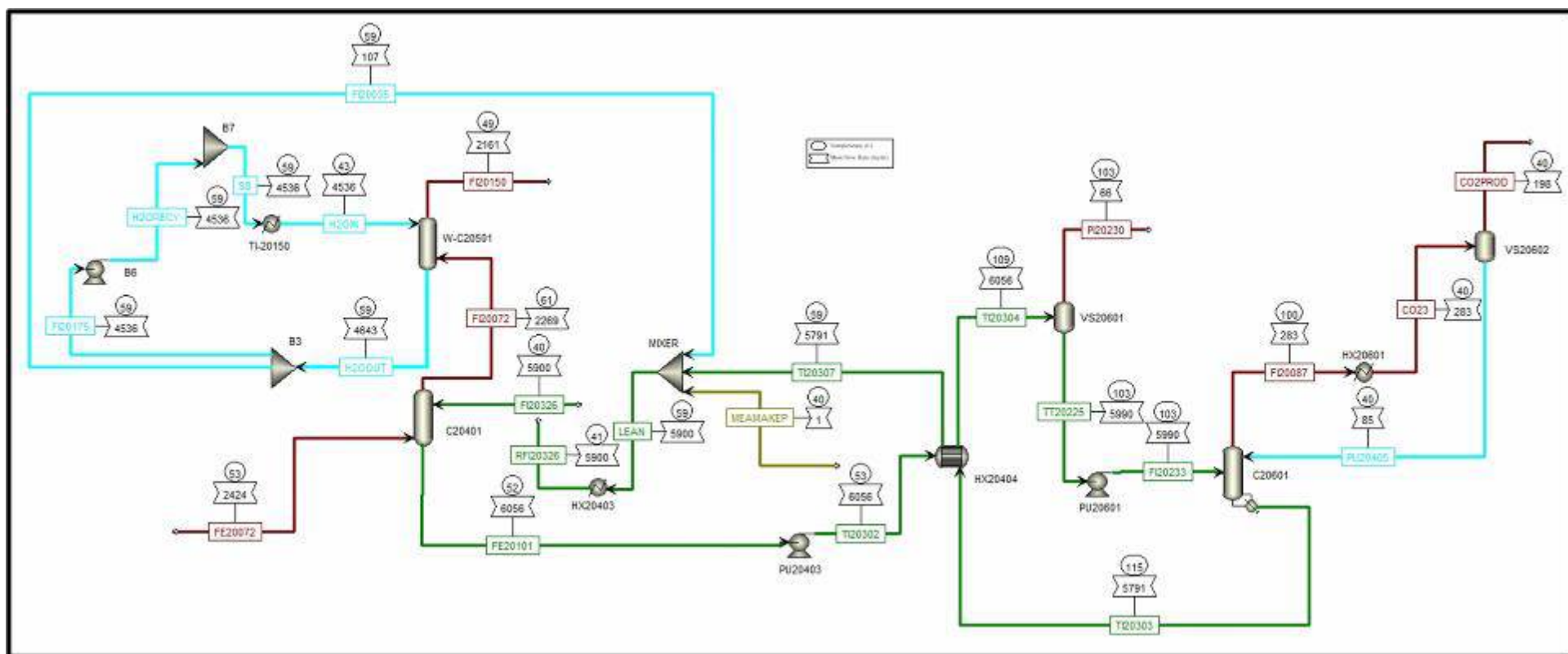


Figure 11. Process flow diagram of the NCCC-PSTU represented in the Aspen Plus process model with the absorber (C20401)-stripper(C20601) configurations with a wash-column (W-C20501)

Case Study 1: 30wt.% MEA Baseline Study for NGCC flue gas without catalyst

Initial three runs were done with constant 80% CO₂ capture rate with different L/G ratios (0.8, 1 & 1.2) using the NG4 flue gas from natural gas boiler. The average moisture content of the flue gas was 6.85 vol.%. The average amine concentrations of the runs were 31 wt.% (without CO₂ loading). Each steady-state run was maintained for at least for 8 hrs. before collecting samples for lean and rich CO₂ loading in the solvent. Typical steady state-run conditions at L/G ratio of 1.2 at 80% CO₂ capture rate are shown in **Figure 12**, **Figure 13** and **Figure 14**. Two absorber beds were used for these runs. One inter-cooler was used to control temperature bulge of the absorber beds. Temperature profiles in the absorber and stripper are matched using the model and shown in **Figure 13** for RunID-3. **Figure 14** shows the experimentally obtained SRDs and corresponding model predictions for runs with constant 80% capture rate. Values were found between 3.8-3.9 GJ/tonne_{CO₂}. Next 4-6 runs were performed at constant L/G ratio of 1.25 for different CO₂ capture rates as shown in **Figure 14** (right). SRD of 4.2 GJ/ GJ/tonne_{CO₂} was obtained for 90% CO₂ capture which is 7% higher than 80% capture. Increasing capture rate to 95% capture resulted in 4.5 GJ/ GJ/tonne_{CO₂} which is 8% higher than 90% capture and increase to 98% capture resulted in 5.4 GJ/tonne_{CO₂} which is 20% higher than 95% capture. Model predicted the experimental values within $\pm 8\%$ deviations. Approximately, 134 hrs. of runs were carried out using NG4 flue gas to represent the NGCC flue gas conditions for 30wt% baseline experiments to estimate the SRDs without catalyst.

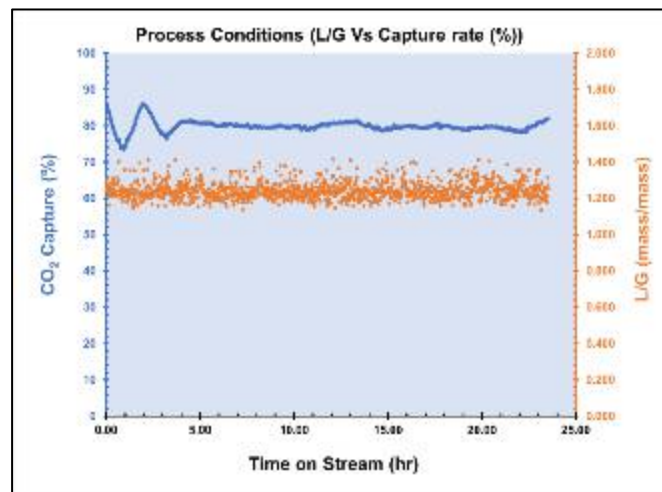


Figure 12. Typical steady-state run conditions for NGCC flue gas using NG4 flue gas (Run ID - 3; 80% Capture rate at L/G - 1.2)

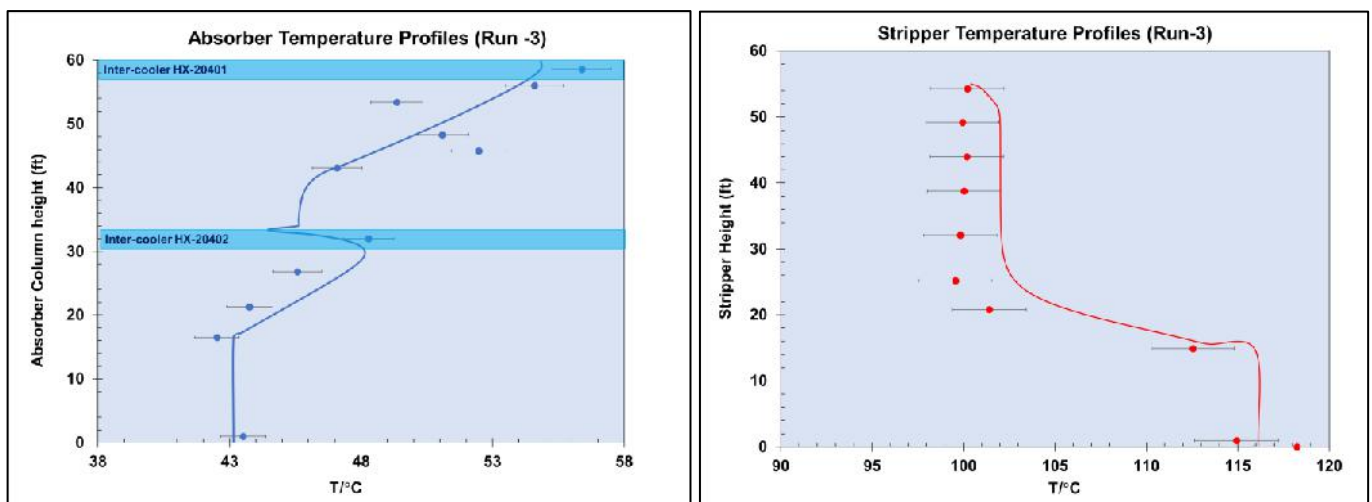


Figure 13. Model prediction of temperature profiles of absorber and stripper for NG4 NGCC flue gas

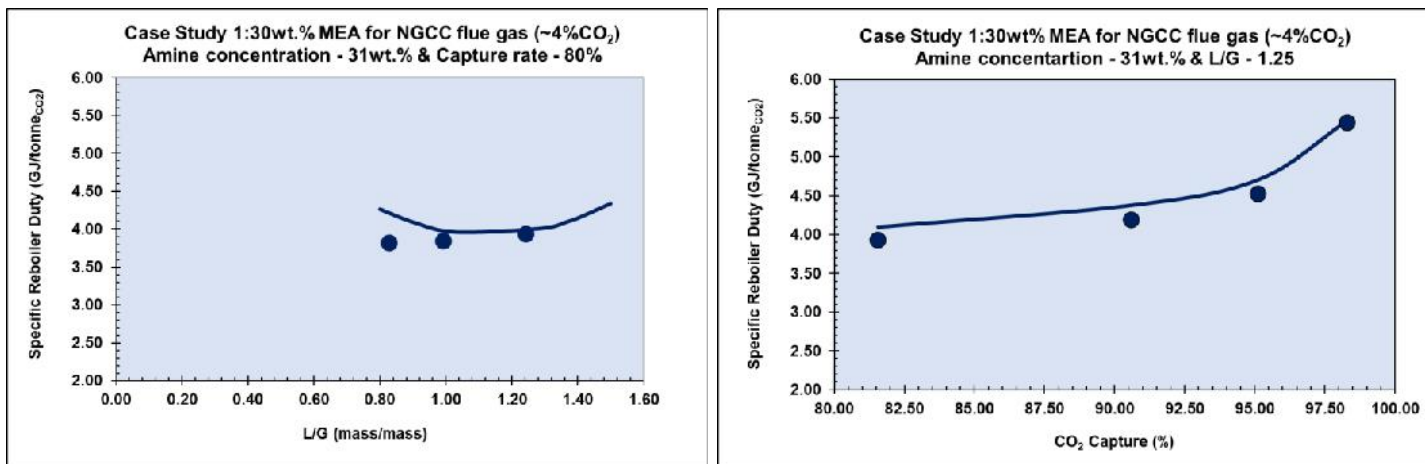


Figure 14. Model predictions of SRD after matching the process conditions and parameters for NG4 NGCC flue gas

Case Study 2: 30wt.% MEA Baseline Study for Coal flue gas without catalyst

Runs 7-20 were performed using NG10 flue gas to represent coal flue gas conditions using NCCC natural gas boiler with 3 beds in the absorber for CO₂ capture. Runs 7-9 & 17-19 were run at constant 80% capture rate with different L/G ratios (2.5, 3 & 3.5). The average moisture content of the flue gas was 12.4 vol.%. The average amine concentrations of the runs were 27 wt.% (without CO₂ loading). Each steady-state run was maintained for at least for 8 hrs. before collecting samples for lean and rich CO₂ loading in the solvent. Typical steady-state run conditions at L/G ratio of 2.5 at 80% CO₂ capture rate are shown in **Figure 15**, **Figure 17** and **Figure 17**. The temperature profiles of the absorber and stripper are matched and shown in **Figure 17** for RunID-7. Two inter-coolers were used to control temperature bulge of the absorber beds. **Figure 17 (left)** shows the experimentally obtained SRDs and corresponding model predictions for constant 80% capture rate. Values were found between 4-4.8 GJ/tonne_{CO2}. Runs 10-16 & Run 20 were performed at constant L/G ratio of 3.5 for different CO₂ captures as shown in **Figure 17 (right)**. SRD of 4.2-4.6 GJ/tonne_{CO2} was obtained for 90% CO₂ capture which is 2-9% higher than 80% capture. Increasing capture rate to 95% capture resulted in 5.2-5.6 GJ/tonne_{CO2} which is 22-33% higher than 90% capture and increase to 98% capture resulted in 6.5 GJ/tonne_{CO2} which is 15-16% higher than 95% capture. Model predicted the experimental values within $\pm 8\%$ deviations. Approximately, 311 hrs. of runs were carried out using NG10 flue gas to represent the coal flue gas conditions for 30wt% baseline experiments to estimate the SRDs without catalyst.

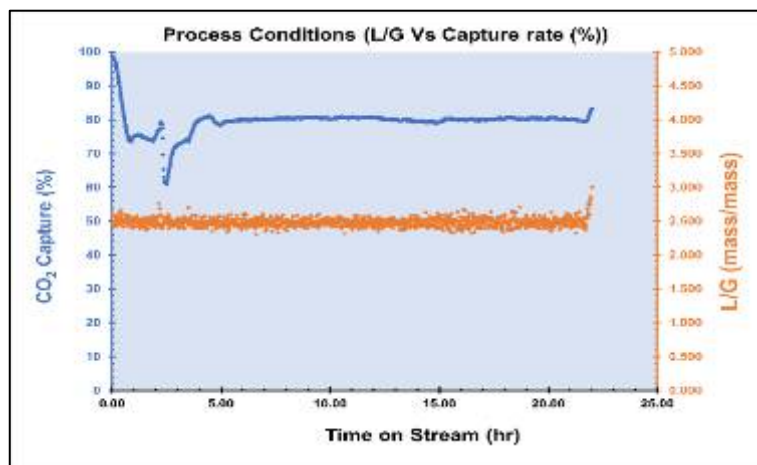


Figure 15. Typical steady-state run conditions for coal flue gas using NG10 flue gas (Run ID - 7; 80% Capture rate at L/G -2.5)

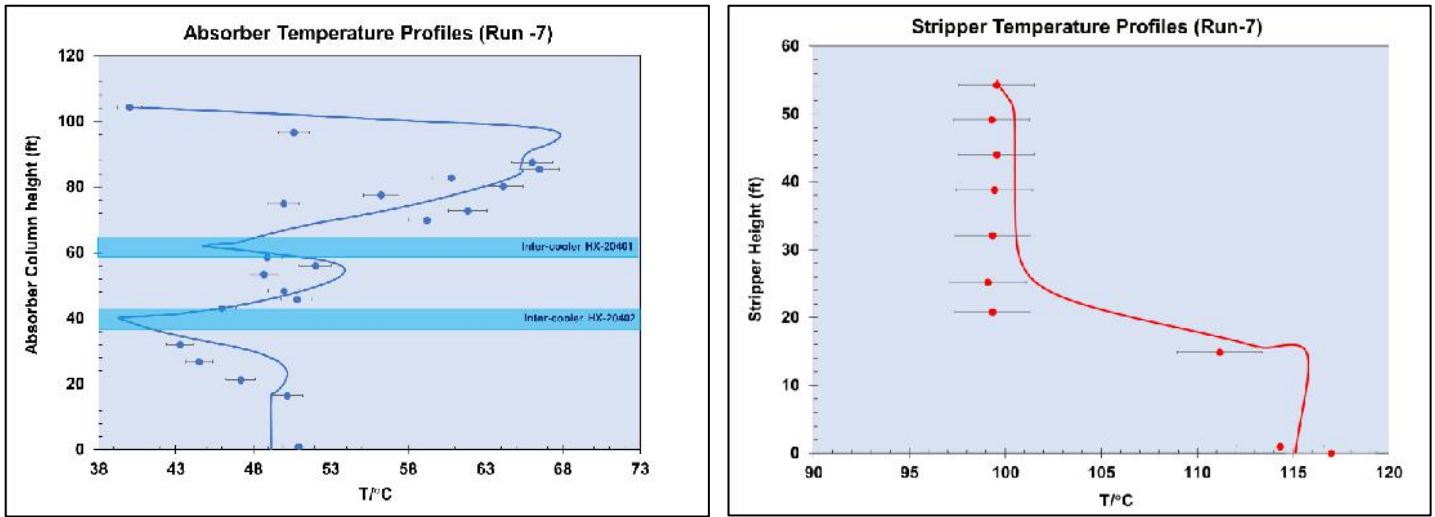


Figure 17. Model prediction of temperature profiles of absorber and stripper for NG10 Coal flue gas

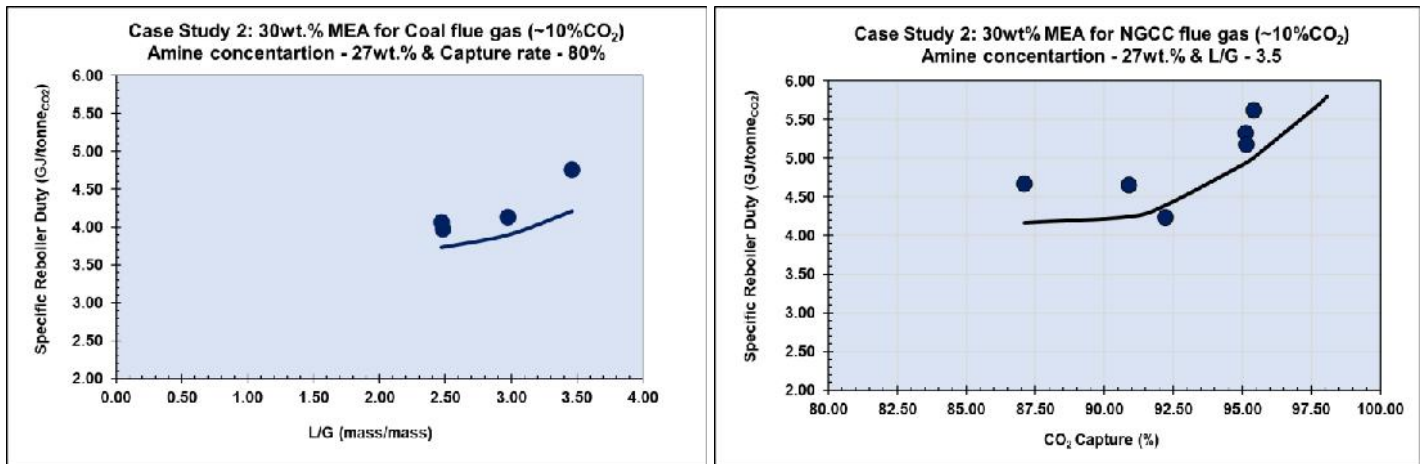


Figure 17. Model predictions of SRD after matching the process conditions and parameters for NG10 Coal flue gas

Case Study 3: 30wt.% MEA Baseline Study for Coal flue gas with catalyst

After 445 hrs. of baseline runs without catalyst, while keeping 95% capture at L/G of 3.5 using NG10 coal flue gas Susteon' s IL catalyst (3000 ppm) was added to the solvent through rich tank in the absorber with two packed-beds and mixed well at the same condition for 48 hrs. Immediate response observed because of catalyst addition is the increment in the absorber temperatures. The average moisture content of the flue gas was 12 vol.%. The average amine concentrations of the runs were 27 wt.% (without CO₂ loading). Typical steady-state run for Run 26 is presented in **Figure 18**. Model predictions of increased absorber and temperature profiles of Run ID 26 compared to the same condition of Run ID 16 are shown in **Figure 19**. As shown during the coal case run with catalyst, model couldn't be able to represent the process variability after the addition of catalyst in the stripper due to the variation caused by amine and water. In general, it was observed that 22% shift in lean and rich loading to higher values as shown in **Figure 20**. Experimental and predicted SRDs during the campaign are shown in **Figure 21**. SRD obtained at 95% capture is 4.6 GJ/tonne_{CO₂}, model predicted 3.97 GJ/tonne_{CO₂} which is 14% lower. Run 22-26 were performed at different capture rates to see the trend in SRDs keeping the same experimental conditions and steam flow rates as

runs without catalyst. During these periods of campaign, more uncertain absorber and stripper temperature profiles were obtained. Some of the planned test matrices were skipped during these periods.

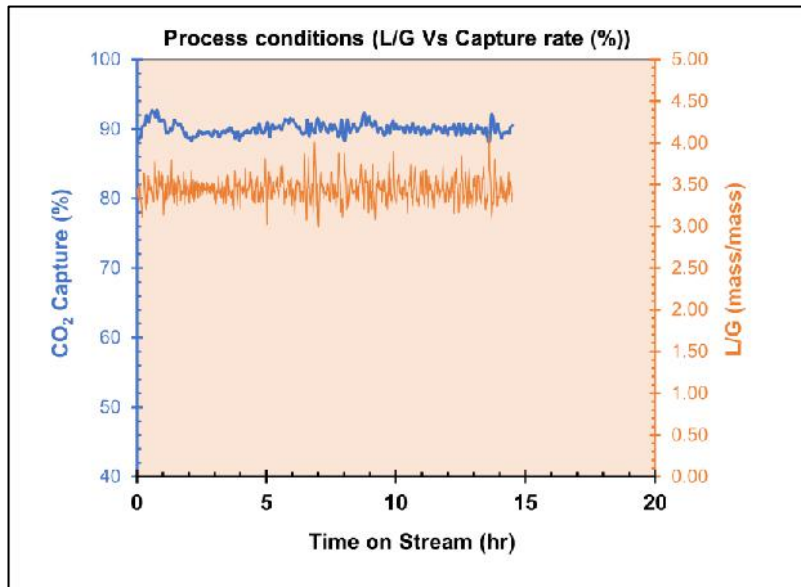


Figure 18. Steady-state run for Coal using NG10 flue gas during the addition of catalyst at 90% CO₂ capture rate

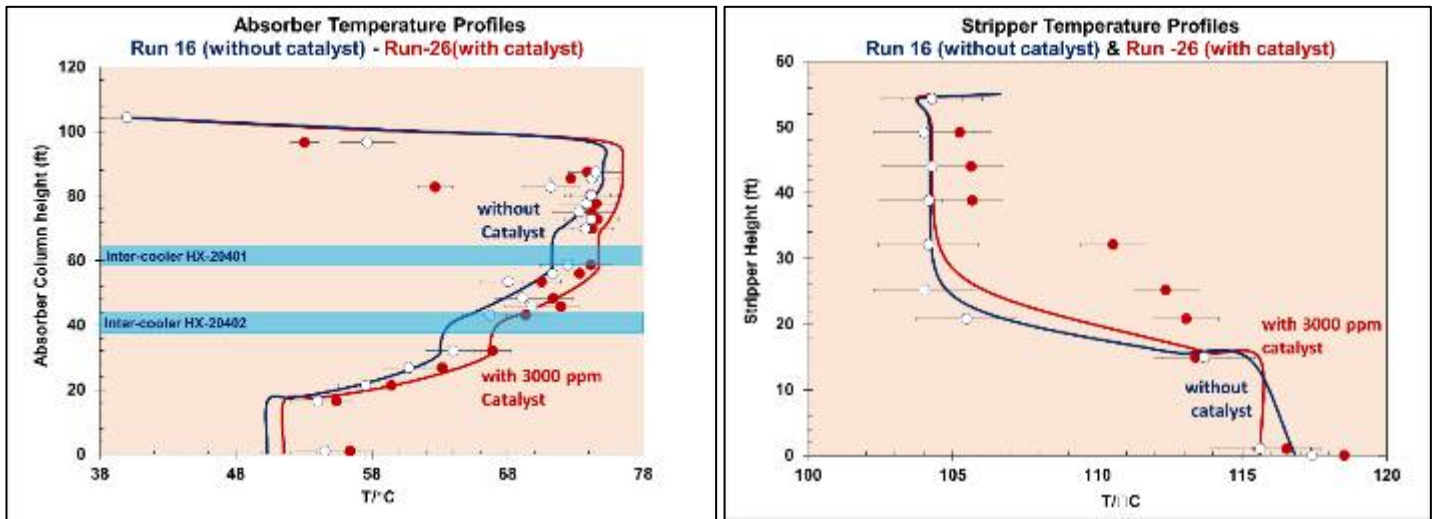


Figure 19. Temperature profiles of absorber and stripper during NG10 flue gas campaign after the addition of catalyst (3000 ppm)

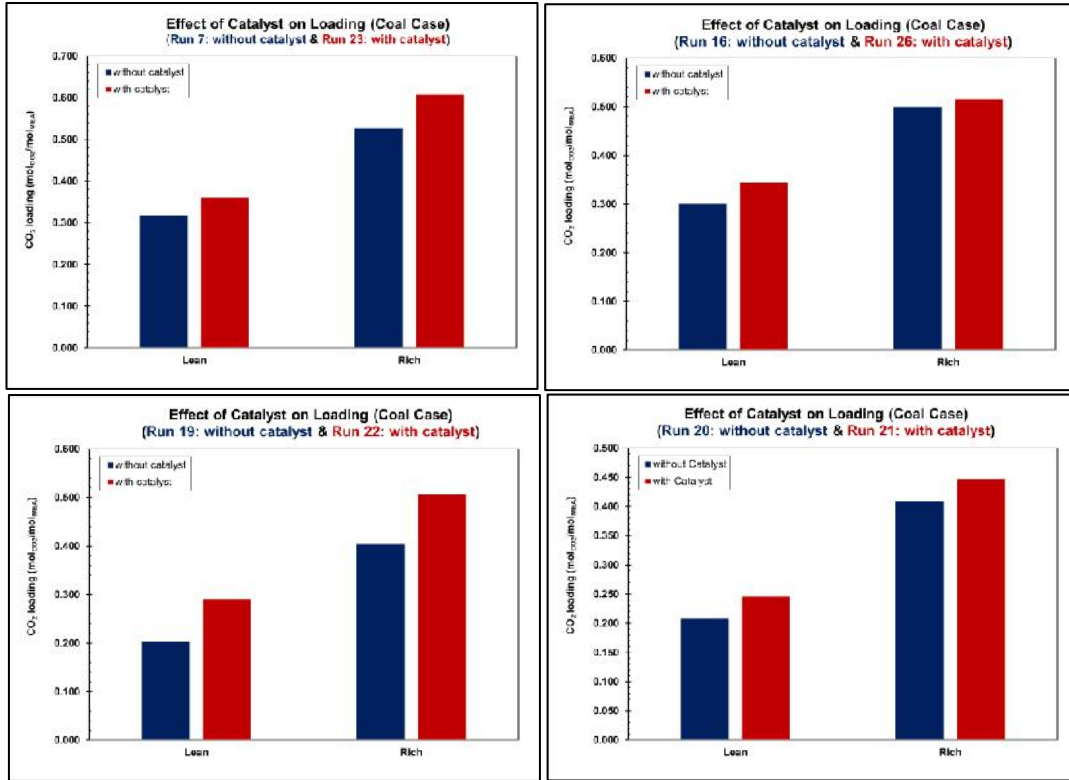


Figure 20. Shift in CO₂ loading zone after the addition of 3000 ppm catalyst

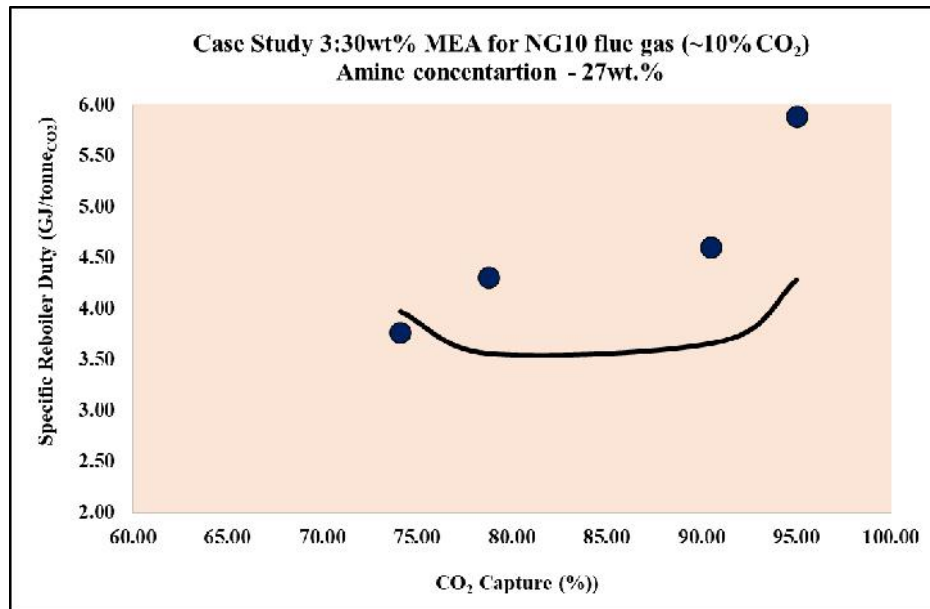


Figure 21. Model predictions of SRD after matching the process conditions and parameters for NG10 Coal flue gas after the addition of Susteone's IL catalyst (3000 ppm)

Case Study 4: 30wt.% MEA Baseline Study for NGCC flue gas with catalyst

Since NCCC boiler break down during this period of campaign and amine concentrations dropped due to accumulated water, runs 31 and 32 were tested with U5-4 flue gas (~4% CO₂) to simulate NGCC flue gas using the diluted coal flue gas coming from Gaston Unit 5, which is U5-12 (~12% CO₂). Runs were

conducted at CO₂ capture rates of 92% and 97% without inter-cooling to estimate the SRDs of MEA solvent (23wt.%) with catalyst and stop accumulation of more water into the solvent. As shown in **Figure 22 (left)**, after running for 16 hrs. 90% capture rate at L/G of 0.81 resulted in SRD of 4.85 GJ/tonne_{CO₂} and model estimated SRD of 4.88 after matching the experimental process conditions. As shown in **Figure 22 (right)**, after running for 16 hrs. 97% capture rate at L/G of 0.97 resulted in SRD of 4.72 GJ/tonne_{CO₂} and model estimated SRD of 4.52 after matching the experimental process conditions. The trend in SRDs predicted by model is shown in **Figure 24**. U5-4 found to supply more stable NGCC flue gas for the campaign with catalyst at the same steam flow rates as those used for NG4 flue gas runs with Run IDs 1-6.

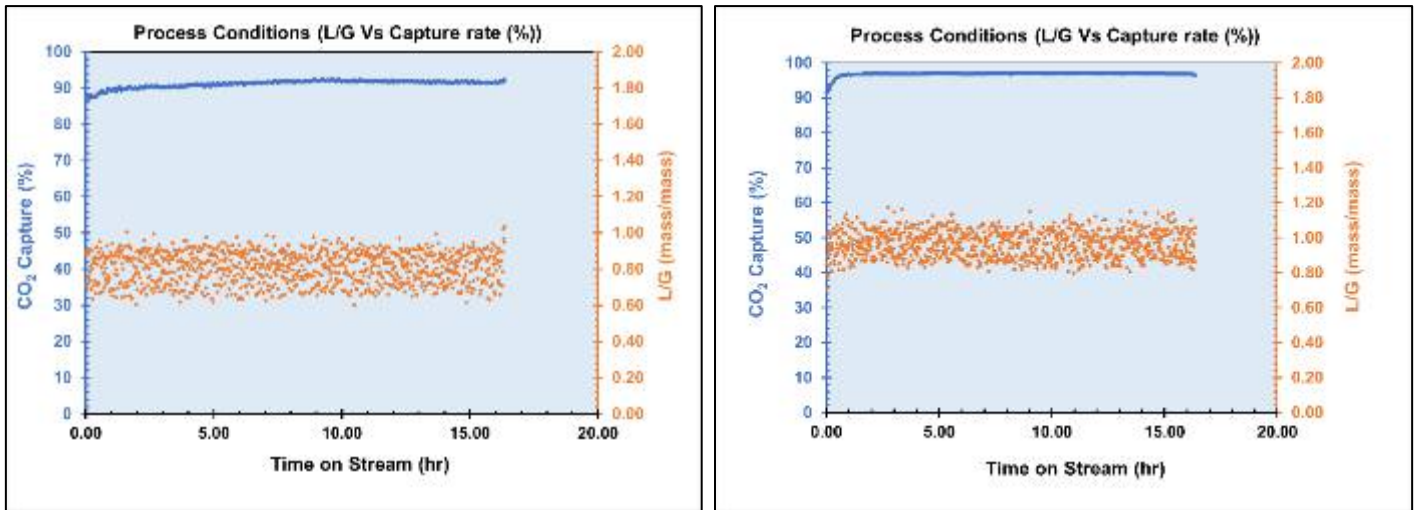


Figure 22. Process conditions of 90% (left) and 97% (right) capture rates using U5-4 flue gas

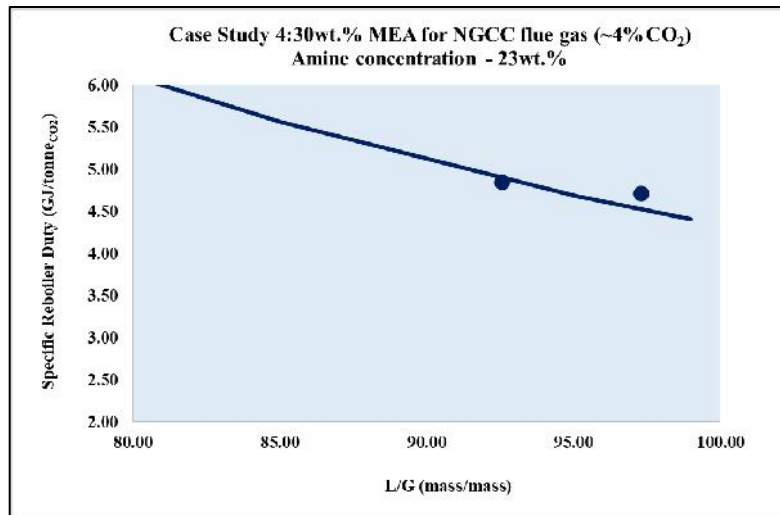


Figure 23. Model predictions of SRD after matching the process conditions and parameters for U5-4 flue gas after the addition of Susteon's IL catalyst (3000 ppm)

Runs 33-35 were performed at constant L/G ratio of 1.24 for different CO₂ capture rates. Typical steady-state run conditions with catalyst using U5-4 flue gas for Run ID 35 is presented in **Figure 24**. As shown in **Figure 25** absorber profiles of Run ID-35 which was run with the same conditions and steam flow rate of Run ID-5, temperature profile of the absorber was observed to be higher than the absorber profile obtained without catalyst, indicating catalytic activity of enhancing CO₂ reaction rate with MEA. Absorber bottom temperature was 8°C higher than the run without catalyst. SRD of 4 GJ/ GJ/tonneCO₂ was obtained for 82% capture with catalyst. Increasing capture rate to 90% resulted in 4.4 GJ/ GJ/tonneCO₂ which is 10% higher than 82% capture and increase to 96% capture resulted in 4.6 GJ/tonneCO₂ which is 5.7% higher than 95% capture. Model predicted SRDs with catalyst for NGCC flue gas are shown in **Figure 26 (left)**. Inter-cooling flow was increased in Run IDs 36-39 at constant 80% CO₂ capture rate. SRD of 3.9-4.1 GJ/ GJ/tonneCO₂ was obtained for 80% CO₂ capture by varying L/G ratios from 0.8-1.23 as shown in **Figure 26 (right)**. By changing the inter-cooling, absorber bottom temperatures can be controlled to match the run without catalyst run as shown in **Figure 27**. In general, it was found that the working capacity of CO₂ loading in the solvent increased 25% compared to campaign without catalyst as shown in **Figure 28**. The average amine concentration at this period of campaign was 23wt.% and average moisture content in the U5-4 flue gas was 10%. Due to lower amine concentrations, apple to apple comparisons with run results were not possible.

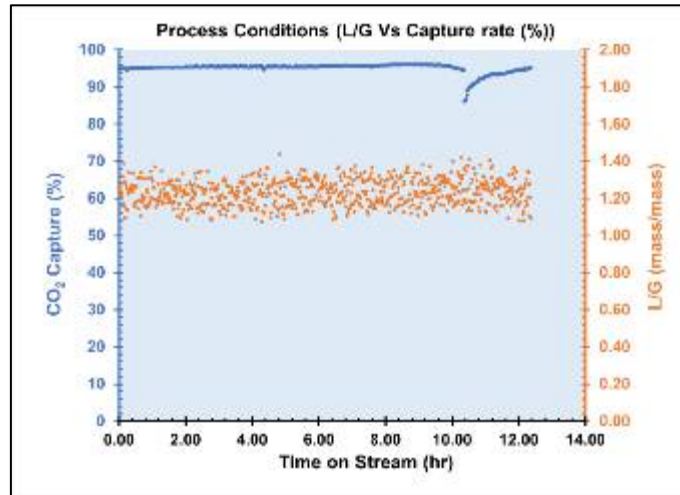


Figure 24. Steady-state run for Coal using U5-4 flue gas during the addition of catalyst at 95% CO₂ capture

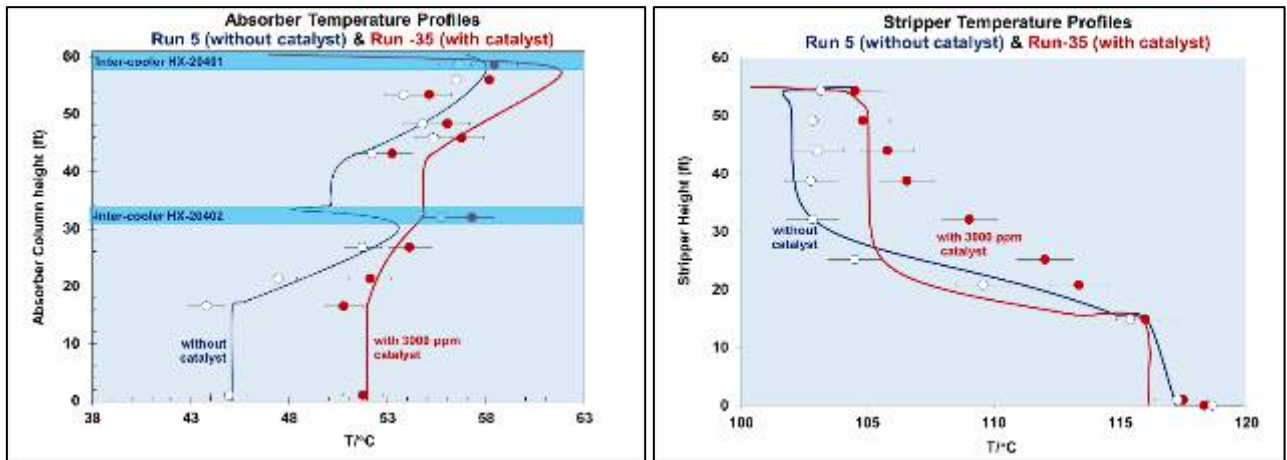


Figure 25. Model prediction of temperature profiles of absorber and stripper for U5-4 NGCC flue gas without adjusting inter-cooling

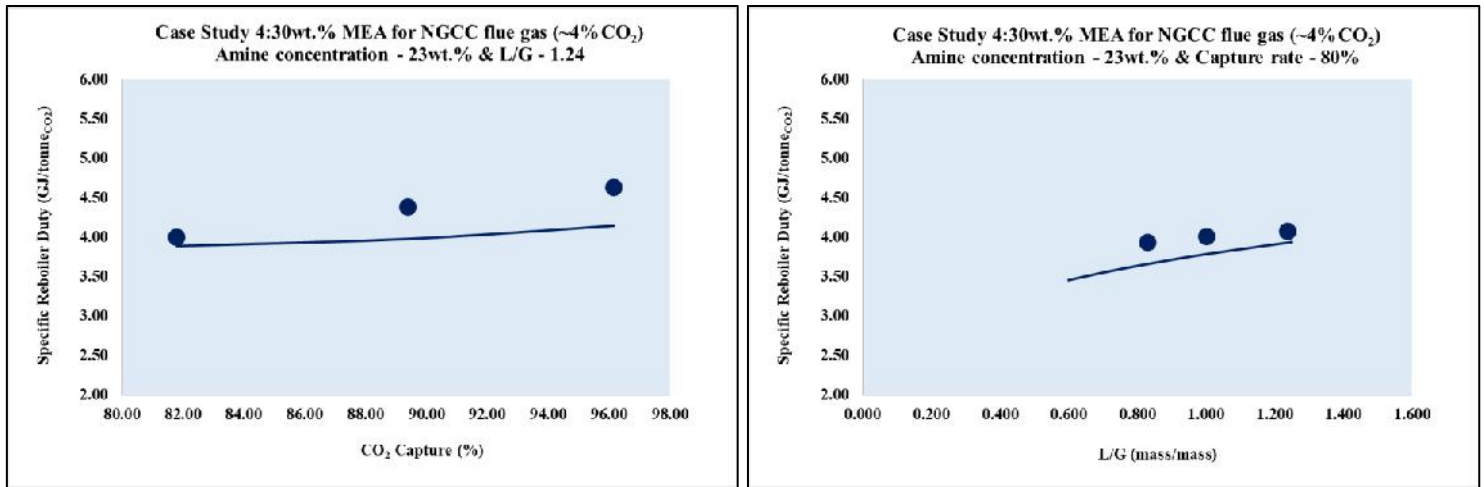


Figure 26. Model predictions of SRD after matching the process conditions and parameters for U5-4 NGCC flue gas

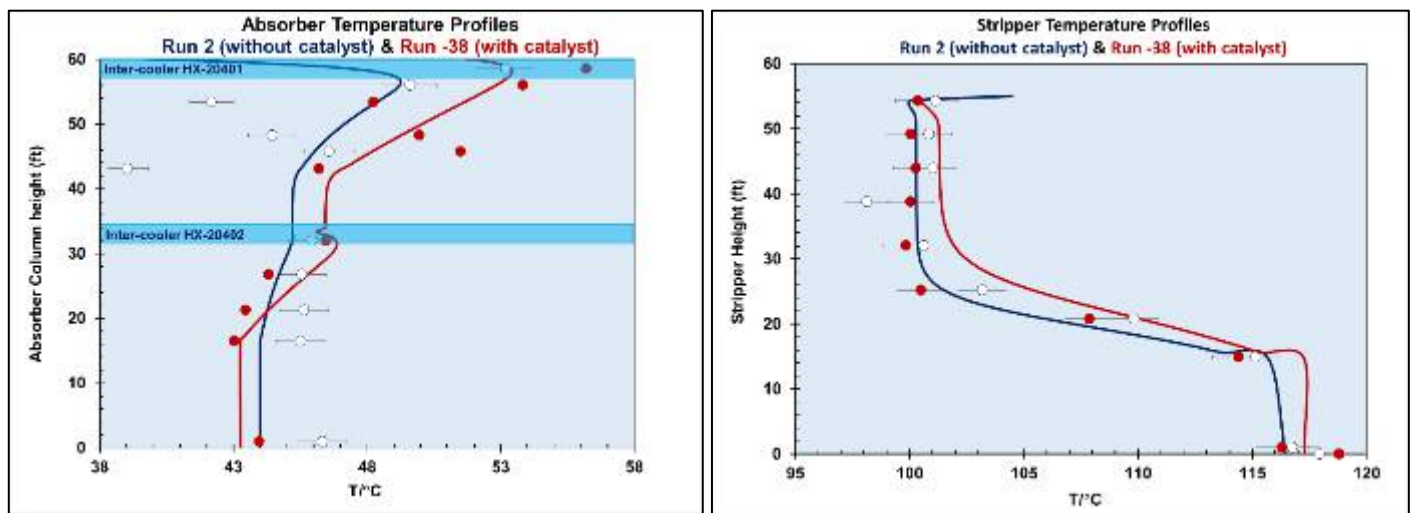


Figure 27. Model prediction of temperature profiles of absorber and stripper for U5-4 NGCC flue gas with adjusted inter-cooling

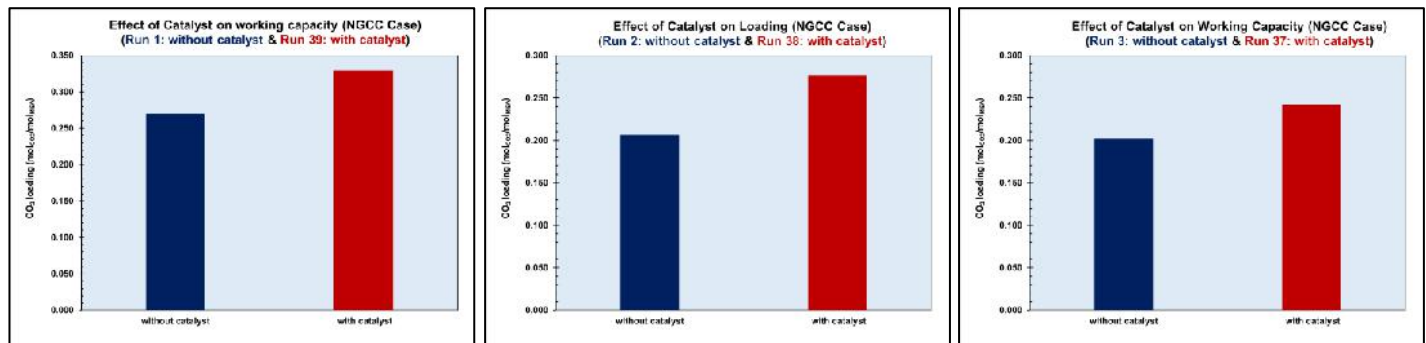


Figure 28. Increase in working capacity of aqueous MEA due to the addition of 3000 ppm catalyst

Normalization for direct comparison for MEA with and without catalyst

To do an apple-to-apple comparison, the validated process model was used to normalize using lower amine concentration observed at the time of catalyst addition to higher amine concentration and higher amine concentration at the time of campaign without catalyst to lower amine concentration by matching other process parameters such as temperature profiles of absorber and stripper, L/G ratio, CO₂ capture rates (%) and working capacity. As shown in **Figure 29**, when amine concentration (31wt.%) for **RunID-2** adjusted

to 23 wt.% (*RunID-2a*) to compare to the RunID-38 (23 wt.%), the SRD for MEA with catalyst is 12.4% lower than the SRD for MEA without catalyst. Similarly, when amine concentration (23 wt.%) for **RunID-38** was adjusted to 31wt.% to compare to the RunID-2 (31 wt.%), the SRD for MEA with catalyst is 11.7% lower than the SRD for MEA without catalyst. Similar procedure was applied to 6 runs of NGCC flue gas conditions and 8 runs of coal flue gas. Summary of the finding is presented in **Table 11**. Susteon’s catalyst showed 5% reduction in regeneration energy for 80% CO₂ capture removal for coal flue gas at L/G of 2.5. Susteon’s catalyst showed 11-12% reduction in regeneration energy for 90-95% CO₂ capture removal for coal flue gas at L/G of 3.5. Susteon’s catalyst showed 11-12% reduction in regeneration energy for 80% CO₂ capture removal for NGCC flue gas with varying L/G of 0.8-1.24.

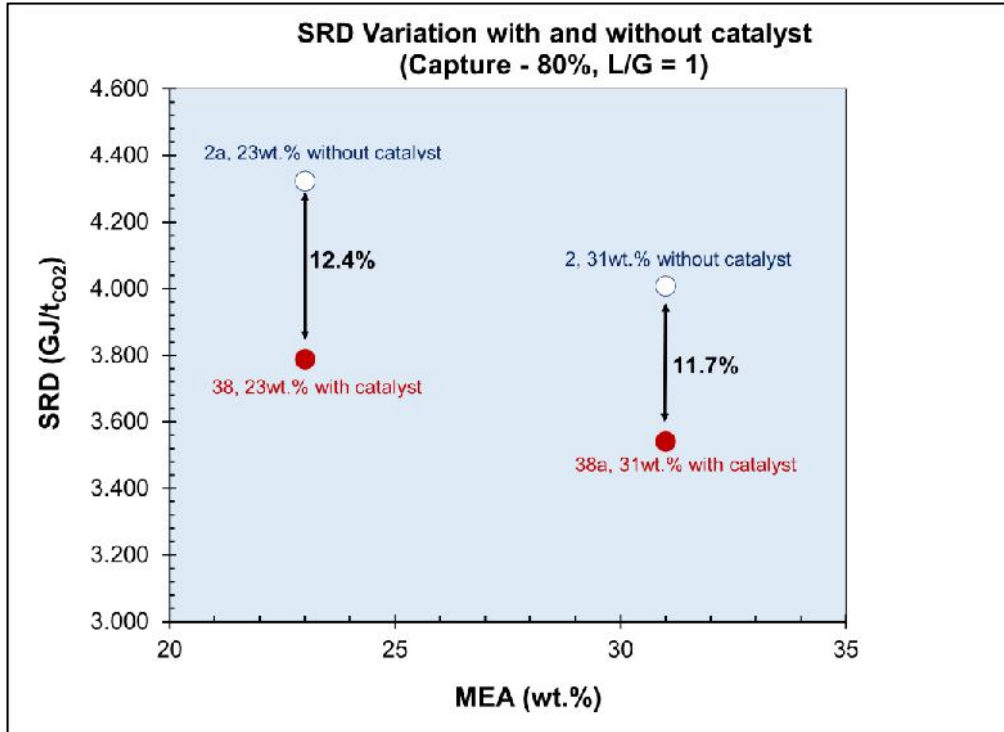


Figure 29. Model prediction of SRDs with normalized amine concentrations

Table 11. Summary of improvement in SRDs due to the addition of Susteon’s catalyst to 30wt.% MEA after normalization

Case	Inlet Flue Gas (%)	Capture (%)	L/G (mass/mass)	Stripper Temperature (°C)	Energy consumption (GJ/tonneCO ₂)		Improvement (%)
					without catalyst	with catalyst	
NGCC Flue Gas	4.41	82	0.83	119.8	3.96	3.52	11.0
	4.41	80	0.99	118.8	4.01	3.54	11.7
	4.41	81	1.24	118.2	4.10	3.61	11.9
Coal Flue Gas	8.95	81	2.48	117.5	3.72	3.54	4.8
	9.22	80	2.49	117.0	3.75	3.56	5.0
	9.20	91	3.44	117.4	4.34	3.83	11.9
	9.08	95	3.38	118.3	4.85	4.28	11.6

Conclusion

Susteon conducted four weeks of campaign to test the IL based catalyst on 30wt.% aqueous monoethanolamine (MEA) to verify the reduction in regeneration energy in coal derived flue gas and NGCC flue gas observed in small pilot column test at UKy, specifically we are:

- ✓ To confirm and quantify the impact of IL catalyst in increasing CO₂ capture rate
- ✓ To confirm and quantify the impact of IL catalyst in reducing capture plant energy consumption
- ✓ To identify any operational issues in capture unit by adding IL catalyst (example: increased foaming)

Susteon has completed 4 weeks testing campaign to confirm those findings using the Pilot Solvent Test Unit (PSTU) at NCCC (Absorber with 26-inch diameter and 60 feet packed height) and 0.5 MW regenerator system using 30 wt.% MEA solvent. PSTU was operated approximately 600 hrs. at steady state with different CO₂ capture rates in absorption side and different steam flow rates in the regeneration side. 280 hrs. of simulated Coal flue gas (~9.21% vol.CO₂ undiluted NG10 flue gas) were tested to obtain CO₂ capture performance using uncatalyzed aqueous MEA and 90 hrs. using catalyzed aqueous MEA. 135 hrs. of simulated NGCC flue gas (~4.41% vol.CO₂) were tested to obtain CO₂ capture performance using uncatalyzed aqueous MEA and 91 hrs. using catalyzed aqueous MEA.

Concentration of aqueous MEA dropped from 31 wt.% to 23wt.% (unloaded with CO₂) during the 4-weeks campaign due to water imbalance in the absorber. Due to the MEA concentration change for NGCC flue gas conditions, we cannot directly compare the results from the PSTU runs. However, there was clear evidence of the CO₂ reaction rate enhancement with catalyzed MEA solvent as indicated by the larger temperature bulge in the absorber column. To do an apple-to-apple comparison for NGCC case, the concentration of the catalyzed and uncatalyzed solvents were normalized to the same amine concentration using the Aspen Plus model developed by CCSI™. This model was used to match the temperature profiles of absorber and stripper and other run parameters. Based on the observation, under same amine concentration we obtain 5-12% reduction in SRD (GJ/tCO₂) for both coal and NGCC flue gases. For NGCC and coal flue gas, observations made during catalyst addition to the solvent in campaign are as follows: (a) Increase in CO₂ reaction rates in solvent were evidence by the increase in temperature bulge in the absorber (b) There is a 20% shift in measured lean CO₂ loading that lowered the SRD for the catalyzed solvent (c) working CO₂ loading capacity increased in the case of NGCC flue gas conditions. Overall summary of the campaign due to the addition of catalyst is given in **Table 12** below:

Table 12. Concluding summary of CO₂ capture tests using the PSTU with 30 wt.% MEA

Case	Inlet Flue Gas (%)	Capture (%)	L/G (mass/mass)	Stripper Temperature (°C)	Energy consumption (GJ/tCO ₂)		Improvement (%)
					without catalyst	with catalyst	
NGCC Flue Gas	4.41	82	0.83	119.8	3.96	3.52	11.0
	4.41	80	0.99	118.8	4.01	3.54	11.7
	4.41	81	1.24	118.2	4.10	3.61	11.9
Coal Flue Gas	8.95	81	2.48	117.5	3.72	3.54	4.8
	9.22	80	2.49	117.0	3.75	3.56	5.0
	9.20	91	3.44	117.4	4.34	3.83	11.9
	9.08	95	3.38	118.3	4.85	4.28	11.6

Thus, the NCCC testing data are further proof of the catalyst effectiveness in enhancing CO₂ capture process by transforming conventional amine technologies to much high efficiencies and at lower costs for widespread global adoption. Furthermore, IL catalyst can be added to any amine-based solvents for improved absorption and desorption kinetics and can reduce the overall CO₂ capture cost by 5 to 20%. NCCC test results after normalized to the same MEA concentration are consistent with lab and small pilot test results. IL catalyst tested in the NCCC campaign has been successfully scaled up to kilogram scale.

Future catalyst testing in NCCC

More rigorous test campaign with MEA and other post-combustion amine-based solvents is needed for direct comparison of run results with and without catalyst before the catalyst can be commercialized. Future test campaign at NCCC could be aimed at:

- Further validating the benefit of the catalyst at constant amine concentration with better water balance and minimal process variations
- Testing the durability and stability of the catalyzed solvent with longer test campaign period (~1000 to 2000 hours) at constant CO₂ capture rates
- Testing the thermal and oxidative degradation and emission rates during catalyst durability campaign
- Testing a different amine solvent (other than MEA) with and without IL catalyst to confirm catalytic activity for enhancing CO₂ absorption and desorption rates

Acknowledgements

Susteon team gratefully acknowledges the financial and technical support provided by DOE/NETL. We want to also thank the NCCC technical and management teams for running the test campaign, reporting the data, and providing support to the Susteon team for data analysis and project management.