

Testing EEMPA at the National Carbon Capture Center

Prepared as part of

“Engineering-Scale Test of a Water-Lean Solvent for Post-Combustion Capture”

Award No. DE-FE0031945

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October 30, 2025



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Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FE0031945.

Following people contributed to the collection and interpretation of the data in this report.

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RTI International

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Phillip Koech
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Deepika Malhotra
Richard Zheng

Paul M. Mathias Consulting, LLC

Paul Mathias

We would like to acknowledge the effort of the CCSI² team in helping develop the sequential design-of-experiments test segment and feedback based on their analysis of the test data.

We would like to acknowledge the contribution of the staff of the National Carbon Capture Center in the execution of this test campaign.

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Abbreviations

EEMPA	N-(2-ethoxyethyl)-3-morpholinopropan-1-amine
EPRI	Electric Power Research Institute
GC-FID	Gas chromatography flame ionization detection
GC-MS	Gas chromatography mass spectrometry
ICP-MS	Inductively-coupled plasma mass spectrometry
PTR-TOF MS	Proton transfer reaction time of flight mass spectrometry
NCCC	National Carbon Capture Center
NGCC	natural gas combined cycle
PNNL	Pacific Northwest National Laboratory
PSTU	Pilot Solvent Test Unit
PTFE	polytetrafluoroethylene
SDOE	Sequential design of experiments
SRD	specific reboiler duty

Executive Summary

Researchers at Pacific Northwest National Laboratory (PNNL) have developed a new water-lean solvent, N-(2-ethoxyethyl)-3-morpholinopropan-1-amine (EEMPA), for post-combustion capture of CO₂ from coal and natural gas flue gas. EEMPA has multiple characteristics that make it an interesting option for reducing the cost of CO₂ capture from these types of plants, including the potential to achieve specific reboiler duties (SRDs) below 2.5 GJ/t CO₂ and not requiring a diluent component even at very low (<10 wt%) water content.

EPRI, PNNL, RTI International, and their project collaborators developed an engineering-scale test of EEMPA using the Pilot Solvent Test Unit (PSTU) at the National Carbon Capture Center (NCCC), funded under U.S. Department of Energy award FE0031945. The primary objective of this test was to collect long-term data operating EEMPA with both coal- and natural gas-representative flue gases at the ~0.5 MW_e-equivalent scale (5–10 t CO₂/day captured).

Campaign overview and results

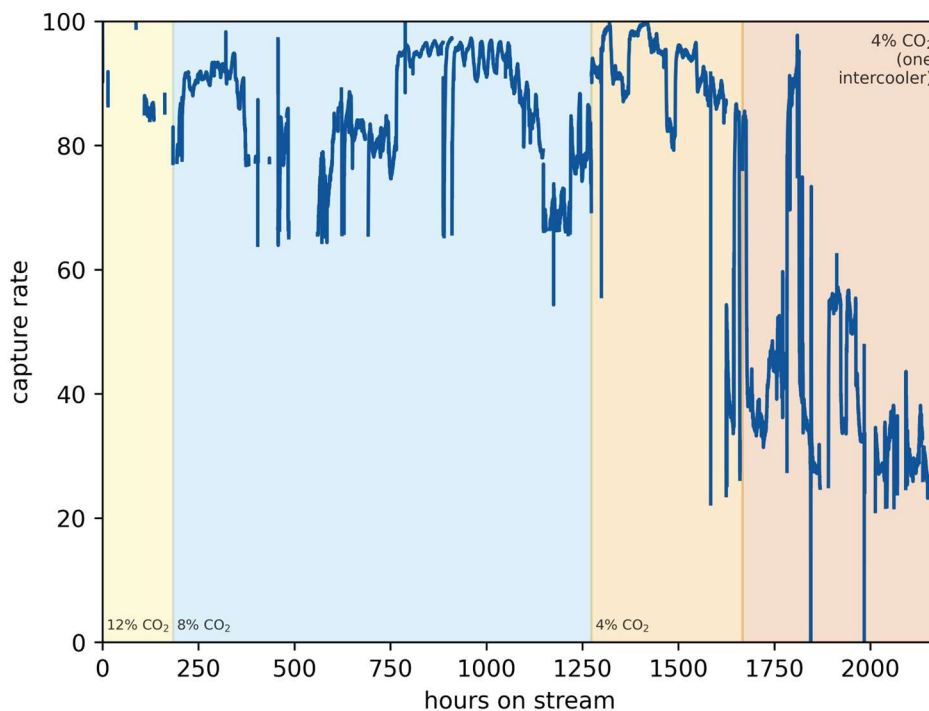
Over 2,300 hours on stream were accumulated over the course of the campaign across three different gas compositions. ES-Table 1 below summarizes the total operating hours and average CO₂ concentration, and source for each gas type used in the campaign. Over the course of the campaign, the CO₂ capture rate ranged widely across the flue gas conditions, including periods of operation above 90%. ES-Figure 1 below shows this data plotted against time on stream. Over 700 hours were at conditions above 90% capture, with approximately 318 of those hours above 95% capture.

ES-Table 1

Summary of time on stream and average CO₂ concentration for different gas sources used, as well as the specific reboiler duty (SRD) measured at key steady state points above 90% capture, while testing EEMPA in the PSTU.

Gas source	Average CO₂ concentration (vol.%, dry)	Hours on stream	Average SRD (GJ/t CO₂)
Gaston Unit 5 <i>coal</i>	12.14±0.415	167	-
Undiluted package boiler <i>natural gas</i>	8.28±0.226	1,197	4.5±0.4
Diluted package boiler <i>natural gas</i>	4.00±0.093	954	6.9±1.7
<i>Total hours on stream</i>		2,318	

ES-Table 1 also reports SRDs for the undiluted and diluted natural gas boiler conditions. SRDs were higher than anticipated due to lower-than-expected heat transfer performance, resulting in high absorber temperatures (and resulting lower than expected rich loading) and suboptimal heat recovery with the cross exchanger. In addition, solvent purity started below targets and declined more quickly than anticipated.



ES-Figure 1

Summary of CO₂ capture rates observed over the course of the testing of EEMPA at the PSTU. Data are shown for points where the absorber gas CO₂ mass balance could be verified with the concentration of CO₂ within the span of the gas sensors.

Observations

The test demonstrated the ability to control the water balance in the solvent, primarily through adjustments to the absorber inlet gas temperature. The solvent was operated with water contents as low as 0.9 wt.% and up to over 10 wt.% and achieved greater than 90% capture efficiency at all water content levels in between.

Early in the campaign, we discovered that the solvent had a propensity to form an aerosol or fog in the regenerator column. A variety of experiments were conducted to attempt to determine factors that lead to the fog, including varying reboiler circulation rate, changing reboiler output temperature, use of cold rich bypass to the top of the regenerator, variation in water content, regenerator operating pressure, and the presence of CO₂ in the regenerator. The only factor that appeared to directly

affect the presence of the fog was weather flue gas was being fed to the system, implying the presence of CO₂ was an important contributing factor.

A major factor in the test was the lower-than-desired starting purity of the solvent, starting at around 80 wt.%, which also continued to decline more rapidly than expected from prior tests. We suspected this decline in EEMPA concentration was due to a combination of essentially immediate dissolution of parts-per-million levels of iron and manganese in the solvent, the interaction of high solvent viscosity and high steam temperatures leading to potential high skin temperatures in the reboiler, and the complex mixture of impurities what may have contributed to previously unobserved side reactions.

Lessons learned

The test campaign verified the ability of EEMPA to achieve greater than 90% capture, even at suboptimal thermal conditions. Water control was successfully demonstrated, and solvent viscosity, although higher than expected, did not hinder stable operation of the PSTU.

The test highlighted the importance using high-purity solvent when the properties are based on a single amine component with a small amount of water. Elevated levels of impurities, especially morpholine, may have contributed significantly to the performance of the solvent, masking the specific attributes of EEMPA.

Heat exchange limitations were also an important factor, which highlights the need for careful consideration of the design and behavior of each exchanger while assuming solvent properties are not precisely as measured in the lab, but will be operating under the influence of degradation products and heat-stable salts that may raise the viscosity.

The test also lost time due to incompatibility between some of the pump seals and the solvent. This reinforces the need to do careful screening and testing of materials for compatibility, ideally with the exact solvent composition to be used in the test and not highly purified samples.

1 Introduction

1.1 Technology background information

Water-lean solvents have potential advantages—namely the potential to deliver competitive heat consumption and high chemical stability—that make them an interesting technology for post-combustion capture from electric generating units. Researchers at Pacific Northwest National Laboratory (PNNL) have developed a new water-lean solvent, N-(2-ethoxyethyl)-3-morpholinopropan-1-amine (EEMPA), whose structure is shown in Figure 1. Compared to many other water-lean solvents, EEMPA can be operated without a diluent component to manage viscosity; the solvent need only consist of EEMPA with a small (<10 wt.%) amount of water.¹

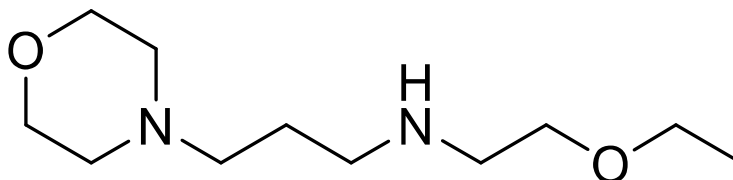


Figure 1
Chemical structure of N-(2-ethoxyethyl)-3-morpholinopropan-1-amine (EEMPA).

PNNL and its collaborators have tested EEMPA at the lab and bench scales, accumulating a few hundred hours on stream and demonstrating the capability of the solvent to achieve capture rates above 90% and specific reboiler duties between 2.1–2.4 GJ/t CO₂ captured. Beyond its thermal and mass transfer performance, EEMPA has significantly higher thermal and oxidative stability compared to monoethanolamine, as shown in dedicated degradation studies. In addition, EEMPA has been the subject of multiple techno-economic studies, which have projected the potential for EEMPA to achieve costs to capture CO₂ of less than \$40 per metric ton CO₂ captured^{2,3}.

¹ Zheng, R.F., et al., 2020. “A single-component water-lean post-combustion CO₂ capture solvent with exceptionally low operational heat and total costs of capture – comprehensive experimental and theoretical evaluation.” *Energy Environ. Sci.* 13, 4106–4113.

² Jiang, Y., et al., 2021. “Techno-economic comparison of various process configurations for post-combustion carbon capture using a single-component water-lean solvent.” *International Journal of Greenhouse Gas Control* 106, 103279.

³ Xu, S., et al., 2025. “Conceptual Techno-Economic Analysis of Water-Lean Solvent Carbon Capture Systems Enabling Low- and Negative-Emission Natural Gas Combined Cycle Power Plants.” *Ind. Eng. Chem. Res.* 64, 15023–15033.

1.2 Project objectives and scope

To further the validation of EEMPA as a new post-combustion capture technology, EPRI was awarded a project (FE003145) by the U.S. Department of Energy's National Energy Technology Laboratory to develop an engineering-scale test of EEMPA, subjecting it to testing with coal and natural gas-relevant flue gas at the approximately 0.5 MW-equivalent scale.

To conduct this test, EPRI and its collaborators developed a test plan using the Pilot Solvent Test Unit (PSTU) at the National Carbon Capture Center (NCCC). The scope of this test included manufacturing the required volume of solvent for the test, modifying the PSTU to accommodate EEMPA's characteristics, development of a test plan covering both coal and natural gas flue gases, and execution of the test.

This report details the observations collected during that test campaign and is structured as follows. Section 2 describes the preparatory work to develop the test, including details on the main modifications made to the PSTU. Section 3 provides a narrative overview of the test campaign and a summary of the primary observations. Section 4 reports an analysis of the test data, focusing on key metrics including the capture rates, specific reboiler duties, and viscosity of the solvent. Section 5 continues the report with an overview of specific observations and issues encountered during the test, and Section 6 reports the key findings and lessons learned.

2 Preparations for the Test

2.1 Solvent manufacturing

Prior to this project, the largest syntheses of EEMPA were conducted in laboratory-scale batches. As part of the first phase of the project, PNNL worked to develop potential alternative synthesis routes that would allow the use of cheaper starting reagents. However, given the relative immaturity of these routes, we elected to use the established laboratory-scale synthesis route, shown in Figure 2⁴.

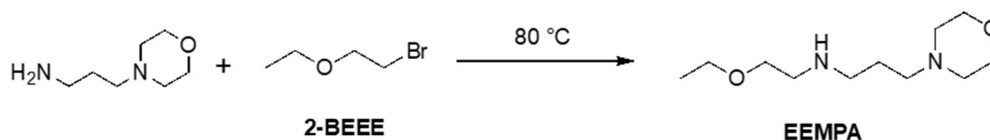


Figure 2

Reaction pathway used to synthesize EEMPA for the test from 3-aminopropylmorpholine (3-APM) and 2-bromoethoxyethyl ether (2-BEEE).

⁴ Cantu, D.C., et al., 2020. "Molecular-Level Overhaul of γ -Aminopropyl Aminosilicone/Triethylene Glycol Post-Combustion CO₂-Capture Solvents." *ChemSusChem* 13, 3429–3438.

Approximately 2,000 gallons of EEMPA were manufactured and delivered to the NCCC. The solvent was delivered in two shipments. A picture of the as-received solvent is shown in Figure 3. As expected, the solvent was pale yellow consistent with typical low levels of conjugated impurity typical for amines.

The color of the two samples shown in Figure 3 are slightly different, with the one on the right with a slightly darker yellow hue owing to different processing histories. The as-received batches themselves were a blend of smaller manufacturing batches, and there ended up being a large degree of variability in the purity of each manufacturing batch. We discovered later that the concentration of EEMPA was lower than expected, and the overall composition of the solvent will be discussed in section 4.5 (page 18).

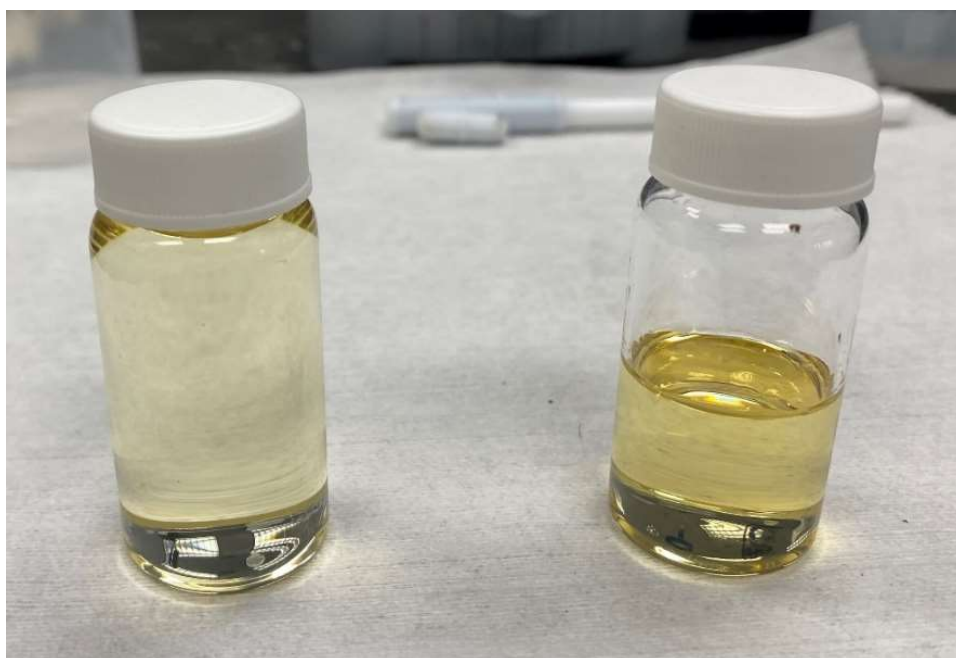


Figure 3
Photography showing samples of the as-received solvent taken after delivery to the NCCC slightly different colors are apparent resulting from composition differences between the batches (image courtesy of NCCC).

2.2 Gas cooling and chilled water

Maintaining the water content in the target range requires managing the quantity of water entering and leaving the PSTU. To achieve very low water contents (below 5 wt.%), it is necessary to remove water from the fed flue gas. This was achieved through cooling the gas to condense a portion of the water. For the very lowest water contents, we projected that gas temperatures lower than could be achieved with the typical range of cooling water temperatures at the NCCC (typically above 80 °F). We estimated that a 40-ton chiller would provide sufficient cooling capacity to achieve target gas temperatures.

To supply the cooling required, modifications were made to the pre-scrubber and cooler/condenser unit operation upstream of the absorber column. A new heat exchanger was added to the pre-scrubber's liquid circulation loop. This exchanger and the existing exchanger for the cooler/condenser were connected to a chilled water supply loop, which in turn was supplied by a rented air-cooled water chiller. These changes are shown schematically in Figure 4 (highlighted in orange).

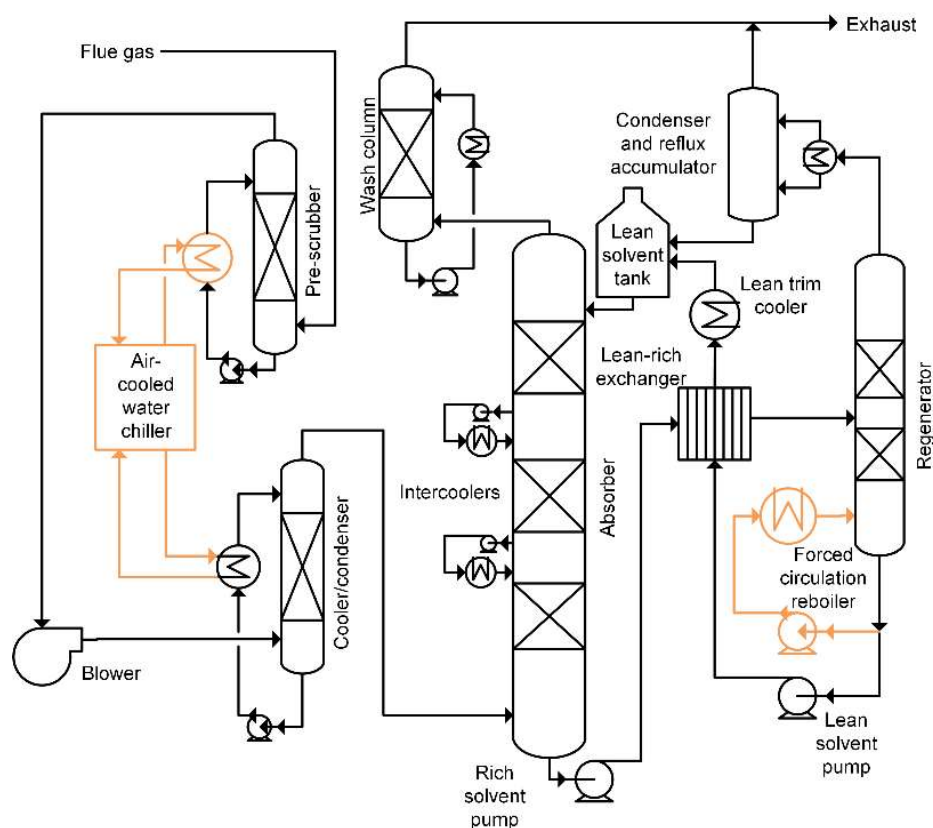


Figure 4
Process flow diagram of the main unit operations in the PSTU. Unit operations added or modified for testing EEMPA are shown in orange.

2.3 Forced recirculation reboiler

In analyzing the specifications of the heat exchangers in the PSTU, we determined that the standard thermosyphon reboiler was undersized for the duties required for the flow rates we planned to use. Owing to the significantly lower thermal conductivity of EEMPA compared to an aqueous solvent.

Through this evaluation, we determined that the steam heater from the prior GE amino-silicone solvent testing would have sufficient surface area. As reported in Table 1, the original reboiler was about 20% smaller than required for EEMPA, whereas the GE steam heater was estimated to be slightly larger than needed. As this

exchanger had not been used for several years, a thorough visual inspection of the exchanger was performed. Inspection of the inside of the exchanger tubes with a borescope revealed extensive corrosion and pitting on the inside surface of the tubes. We elected then to purchase a replacement exchanger with identical specification to the existing, damaged one.

Table 1

Comparison of the key design parameters of the existing PSTU reboiler and the new reboiler used in this test.

Property	PSTU existing reboiler	New reboiler
Design	NEN-type exchanger in thermosyphon operation	NEN-type exchanger in forced circulation
Surface area, ft ²	151.3	661.5
Relative proportion of required duty that could be provided	79%	105%

Owing to the location of the reboiler at an elevation above the regenerator vessel sump, a magnetic drive pump was also installed to circulate solvent from the sump of the regenerator column to the heater. Due to the location of the reboiler outlet above the regenerator sump, the return line included a section of large diameter piping to allow disengagement of vapor from liquid, with the liquid draining to the regenerator sump and the vapor fed to the top of the regenerator vessel just below the mist eliminator.

2.4 Caustic cleaning

As a relatively heavy amine molecule, we expected that EEMPA would preferentially adsorb on the steel surfaces in the PSTU, displacing other amines and other compounds from prior test campaigns. To eliminate this source of potential contamination, a protocol was developed to remove amines from the surfaces using a caustic solution. A 0.1 M NaOH solution was circulated in the PSTU, followed by subsequent rinsing with demineralized water.

2.5 Analytical equipment

Raman spectrometry

To test a new technique for tracking the state of the solvent during testing, a Raman spectrometer was installed in the PSTU laboratory. Periodically measuring the intensity of specific Raman peaks would allow a close-to-real time estimation of the loading and composition of the solvent. However, due to the solvent developing a very dark color within the first week of the test (described further in section 5.1), this

technique was abandoned as the signal-to-noise ratio was too low to acquire meaningful data.

Proton-transfer-reaction time-of-flight mass spectrometer

A proton transfer reaction time-of-flight mass spectrometer (PTR-TOF MS) was installed to sample the gas leaving the water wash. This technique is capable of quantifying parts-per-billion levels of organic compounds in humid gas streams. We used this instrument for approximately 10 weeks during testing with the purpose of quantifying the level of volatile emissions of EEMPA itself and other compounds that may be created via degradation of EEMPA over the course of the test.

Karl Fischer titration

To help track the concentration of water in the solvent during testing, a Karl Fischer titrator was installed in the PSTU laboratory. The project team would then measure the water content of periodic samples withdrawn from the lean and rich solvent.

2.6 Corrosion coupons

Corrosion coupons were installed at nine locations in the PSTU. In most solvent contact locations, four round coupons were installed, two carbon steel coupons (C1010) and two stainless steel coupons (304L). In areas expected to have wet CO₂ in it, namely the overhead and condenser section of the regenerator, the two 316L and two 304L coupons were installed. These coupons were installed immediately before the first fill of EEMPA into the SPTU and remained inside the PSTU for the duration of the campaign.

2.7 Test plan

We developed a test plan covering testing for coal-relevant and natural gas-relevant flue gasses. Coal flue gas would either be actual coal-fired boiler flue gas (from Plant Gaston Unit 5) or undiluted natural gas boiler flue gas (achieving 8–9 vol% CO₂, dry basis) when gas from Unit 5 was unavailable. These flue gases were meant to represent flue gas from a coal-fired electric utility boiler. The second phase of testing was planned to then use gas from the natural gas package boiler, diluted to approximately 4 vol.% CO₂ (dry basis). The original plan for both classes of flue gas were planned to include a staged set of experiments, including initial operation with the target gas composition, a period of L/G parametric testing, and periods of extended steady operation. As reported below, we ended up dedicating a larger portion of the test to parametric testing to attempt to explain unanticipated behaviors and to avoid problematic conditions.

3 Test campaign synopsis

The testing achieved a cumulative 2,318 hours on stream from late August 2024 to early March 2025. Testing was conducted using three different flue gas compositions ranging in concentration from over 12 vol.% CO₂ (dry) to about 4 vol.% CO₂ (dry). Table

2 summarizes the average compositions and the time accumulated testing on each gas source.

Table 2

Summary of observed CO₂ concentrations and hours on stream for the different flue gas sources used in the PSTU test campaign.

Gas source <i>fuel</i>	Average CO₂ concentration (vol.%, dry)	Hours on stream
Gaston Unit 5 <i>coal</i>	12.14±0.415	167
Undiluted package boiler <i>natural gas</i>	8.28±0.226	1,197
Diluted package boiler <i>natural gas</i>	4.00±0.093	954
	<i>Total hours on stream</i>	<i>2,318</i>

3.1 Chiller rating

Before loading the solvent into the PSTU, we conducted a brief test to determine the ability of the loop to cool the flue gas. We performed parametric tests to determine the achievable minimum temperatures and ensure reasonable operation of the chiller loop. This testing established that absorber gas inlet temperatures as low as 58 °F were achievable.

3.2 Coal flue gas

Testing with flue gas commenced on August 22, 2024. Testing with Unit 5 gas continued for about one week, then transitioned to using the concentrated package boiler gas as Unit 5 was turning off for an extended period. The initial water content of the solvent after loading into the PSTU was about 11 wt.%, a consequence of residual water in the system after the rinsing process. To bring the water content into the desired range below 5 wt.%, the PSTU was operated with the intercoolers bypassed. Initial capture rates started high then declined (Figure 5), although direct measurements using the CO₂ detectors on the inlet to the absorber and outlet of the water wash could not be used as the concentration of CO₂ leaving the wash was above the calibrated range of the instrument.⁵ As the water content declined, reaching a low point of around 0.9 wt.%, the intercoolers were put into service, and the capture rate increased.

⁵ This is indicated on Figures 5, 7, 8, and 9 using blue to indicate valid values and yellow to indicate points of time when the CO₂ concentration was too high leaving the wash to measure accurately.

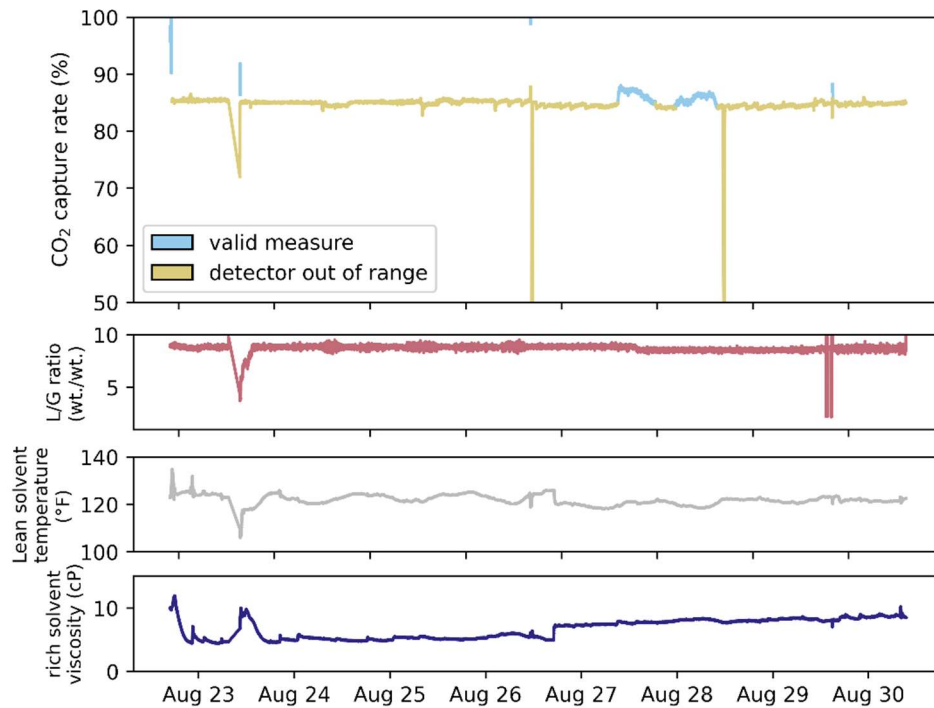


Figure 5
Overview of capture rate, L/G ratio, lean solvent temperature, and rich solvent viscosity during the testing with coal flue gas from Plant Gaston Unit 5.

Figure 6 reports the observed gross product flow rates out of the regenerator. Given the very low water content, the majority of this flow should have been CO₂. We have reported this data here instead of the fractional capture rate as the inlet gas flow rate was not measured correctly for approximately the first 100 hours on stream due to miscalibration of the gas flow meter. Consequently, we operated at a higher than desired L/G. Operating out of the target range placed the capture rate low enough that it could not be accurately computed from the CO₂ concentration leaving the water wash as it is typically done.

3.3 Concentrated package boiler gas

After a brief shutdown, the system was changed to use undiluted package boiler flue gas (8 vol.% CO₂). Figure 7 reports the CO₂ capture rate, lean solvent temperature and the L/G conditions used during this segment of testing. During this period, we were able to achieve capture rates above 90% for about half of the time on stream, including an extended period around 95% capture. The higher capture rates were achieved after we reduced the gross flow rates in the PSTU, reducing the lean solvent flow rate to around 10,000-15,000 lb./hr (instead of over 25,000 lb./hr) in an effort to achieve lower temperatures in the lean solvent entering the absorber by matching the flow rate of the solvent to the capacity of the exchanger to cool it.

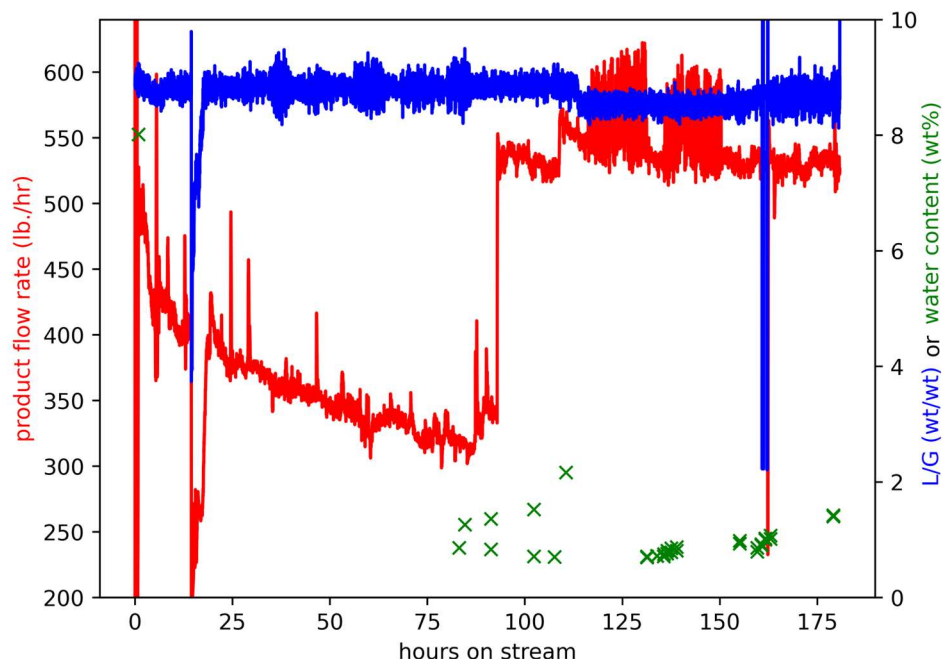


Figure 6

Plot of the product flow rate (gas flow out of the regenerator), L/G ratio, and water content during the first segment of testing, plotted against time on stream. Product flow is reported instead of capture rate due to the CO₂ concentration being out of the quantifiable range of the instrument during this period.

During this segment of this test, we discovered and started to try to understand two unexpected behaviors: carryover of liquid solvent into the CO₂ product line and formation of a persistent fog in the regenerator vessel. Within the first week of this test segment, NCCC staff discovered liquid draining out of a sample collection cabinet connected to the CO₂ product line. Further investigation revealed liquid in peripheral lines branching off the main product line flow. NCCC staff periodically checked these lines, drained any liquid present, and returned it to the process. This behavior is discussed further in section 5.2.

Coinciding with the observation of the solvent carryover, a persistent fog was observed in the regenerator vessel. At this point in the testing, the plan shifted to attempting to find process conditions that would cause the fog to dissipate while maintaining capture rates. These attempts were unsuccessful and are described in more detail in section 5.3.

The PSTU went into planned outage on October 23, 2024.

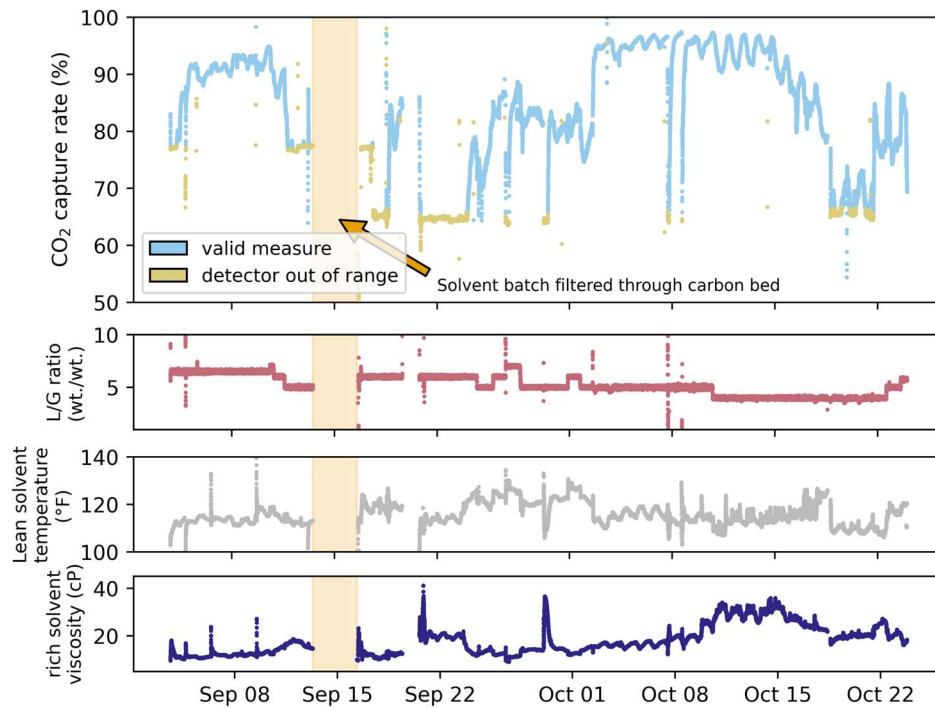


Figure 7
Overview of capture rate, L/G ratio, lean solvent temperature, and rich solvent viscosity during the testing concentrated (8 vol.% CO₂) natural gas-fired package boiler flue gas.

3.4 Diluted package boiler gas

Operation of the PSTU resumed on November 15, 2024, now using diluted natural gas boiler flue gas (4 vol.% CO₂). Prior to admission of flue gas, additional solvent from the reserve volume was added to provide sufficient operational buffer for safe control of circulation, and solvent was circulated and heated to see if fog became apparent in the absence of CO₂ in the system. Operation proceeded into brief operation to achieve a target water concentration of 3-4 wt.%, and then proceeded into parametric tests adjusting L/G. Figure 8 shows the capture rate, lean solvent temperature, L/G, and rich solvent viscosity during the first part of testing on the dilute boiler gas. Capture rates were typically high during this period and approached 100% at different points. During this segment, we inverted our approach to achieve a particular L/G ratio. Instead of fixing the gas flow rate and changing the liquid flow rate, we fixed the liquid flow rate around 10,000 lb./hr and varied the gas flow rate to achieve a particular L/G. With this change, and relatively cool weather in Alabama, lean solvent temperatures averaged around 112 °F, which led to higher capture rates through increased absorption capacity of the solvent.

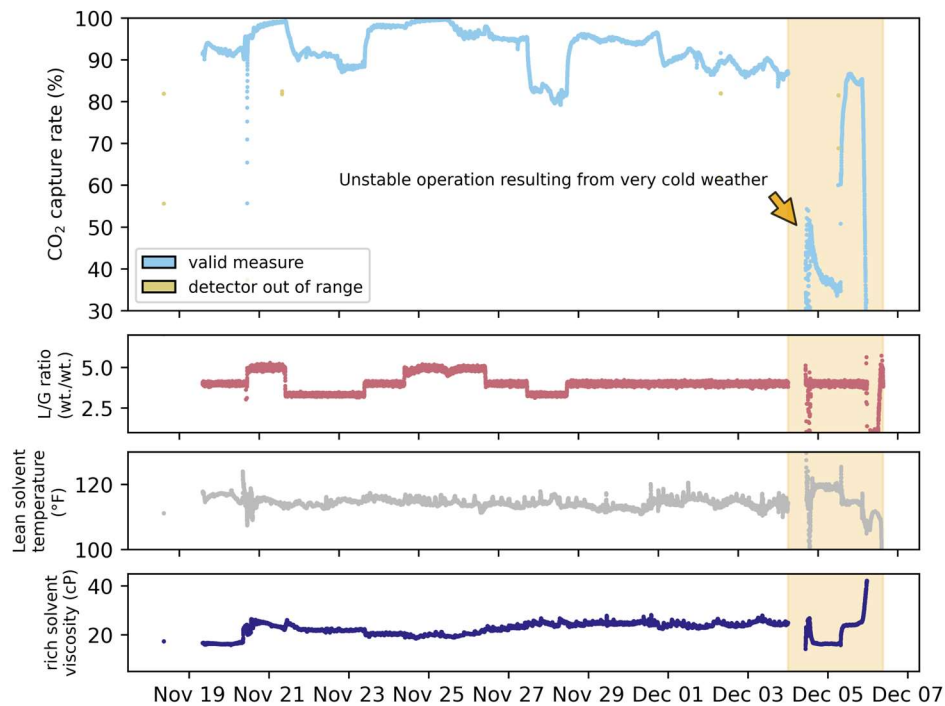


Figure 8
Overview of capture rate, L/G ratio, lean solvent temperature, and rich solvent viscosity during the first part of testing with diluted (4 vol.% CO₂) natural gas-fired package boiler flue gas.

On December 6th, worsening pump leaks forced the shutdown of the PSTU. Seals in multiple pumps had degraded, leading to small volume leaks, and the system was shutdown to avoid loss of a significant volume of solvent and to investigate the pump seals. The pumps were disassembled, and more resistant seal materials were procured (see section 0 for more details).

Operation of the PSTU restarted in January. The remaining reserve of solvent was added to the PSTU. Upon restart, intercooler pump seals appeared to develop leaks almost immediately and the PSTU was stopped again. The PSTU entered another temporary outage to assess the continuing leaks and to avoid trying to start up the PSTU during a stretch of unseasonably cold weather. Upon restarting circulation after this outage, it was observed that the pressure drop through the rich side of the cross exchanger had increased substantially, limiting the maximum flow rate that could be supplied through the rich solvent pump.

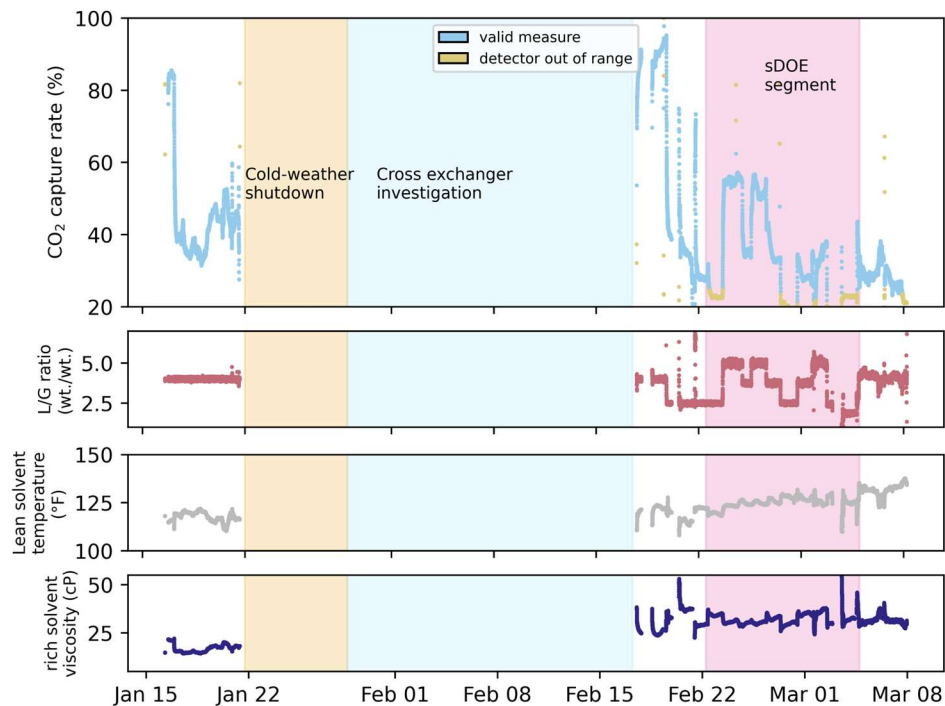


Figure 9

Overview of capture rate, L/G ratio, lean solvent temperature, and rich solvent viscosity during the second part of testing with diluted (4 vol.% CO₂) natural gas-fired package boiler flue gas.

We spent the next period attempting to diagnose and correct this pressure drop issue. It was hypothesized that solid precipitates of some form may have narrowed or blocked some flow paths, leading to the high pressure drop. Based on this hypothesis, we undertook to circulate lean solvent at increasing temperatures through the cross exchanger. Flue gas feed to the absorber was stopped, and solvent was circulated in the PSTU, with the reboiler temperature increased in progressive steps to achieve higher temperatures on the rich side of the exchanger. The pressure drop continued to increase, and the election was made to return to testing. More discussion of this is reported in section 5.5.

To complete testing, we returned flue gas feed to the PSTU. Figure 9 shows the capture rate, lean solvent temperature, L/G ratio, and rich solvent viscosity during this final segment. Due to the decline in solvent inventory, we elected to operate with only one intercooler in service, thus avoiding needing to fill the lines to and from the intercooler pump and exchanger.

Testing proceeded following a sequential design of experiments (SDOE) matrix developed in collaboration with the researchers in CCSI². Of note is that regenerator pressure was higher than typically used in prior parts of the test to exercise the models. After operating at 10 conditions in the SDOE matrix, we operated the PSTU at

a steady set of conditions, attempting to maximize hours on stream. As the concentration of EEMPA continued to decline and the total solvent inventory continued to decrease, solvent inventory approached minimum levels for safe operation and testing of EEMPA in the PSTU concluded on March 8, 2025.

4 Analysis of key campaign data

4.1 Capture rate and specific reboiler duties

Observed specific reboiler duties were higher than expected. To analyze this data, sample periods where the system was operating in relative steady state were identified. The criteria for inclusion in the SRD analysis was a mean value of key process variables (absorber temperature, capture rate, and reboiler output temperature) with a low standard deviation for at least 30 minutes of consecutive readings. Figure 10 shows this information graphically, and points included in the set of steady state periods are indicated in blue. Capture rates and steam consumption were averaged over these periods and used as an estimate of the specific reboiler duty. Calculated SRDs were averaged based on the gas source, and the mean and standard deviation is shown in Table 3.

Over the course of the campaign, the CO₂ capture rate ranged widely across the flue gas conditions, including periods of operation above 90%. Table 3 reports SRDs for the undiluted and diluted natural gas boiler conditions. The limited amount of time spent at >90% capture and the relatively high SRDs are suspected to be a consequence of lower-than-expected heat transfer performance, resulting in high absorber temperatures (and resulting lower than expected rich loading) and suboptimal heat recovery with the cross exchanger, all of which could have been influenced by the relatively impure starting composition of the solvent.

Table 3

Summary of average specific reboiler duties computed from PSTU campaign data, averaging data from periods of steady-state operation.

Gas source	Average SRD (GJ/t CO ₂)
Undiluted boiler gas <i>natural gas</i>	4.5±0.4
Diluted boiler gas <i>natural gas</i>	6.9±1.7

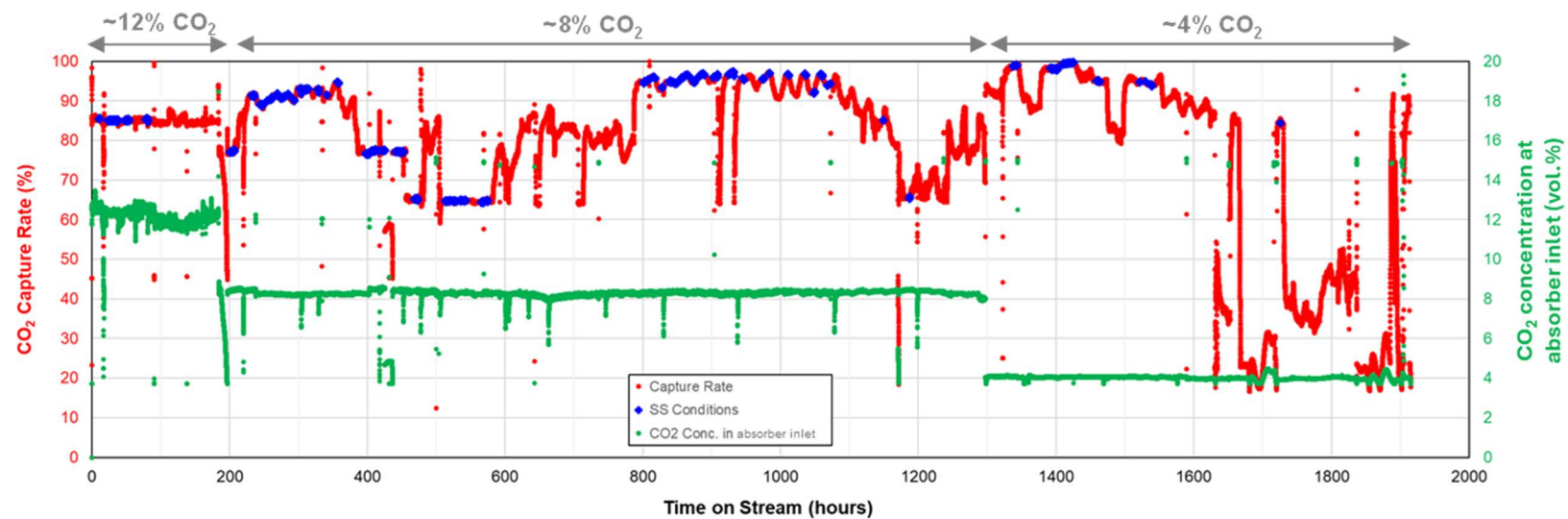


Figure 10

Overview of capture rates and CO₂ concentrations at the absorber inlet versus the hours on stream. Blue points highlight periods treated as steady-state observations for calculation of specific reboiler duties and other performance metrics.

4.2 Solvent temperatures

A leading factor contributing to relatively high SRDs was the higher than desired lean solvent temperatures. Lower than expected heat transfer rates in the cross exchanger and lean solvent trim cooler results in relatively high temperatures for the lean solvent entering the top of the absorber. Figure 11 show the lean solvent and intercooler output temperature over the course of the campaign. Note that the second intercooler was not used during the late stage of the campaign. Lean solvent return temperatures (blue line) were above the target temperature of 110 °F. The intercoolers were capable of cooling the solvent further, with output temperature typically between 80 °F and 100 °F.

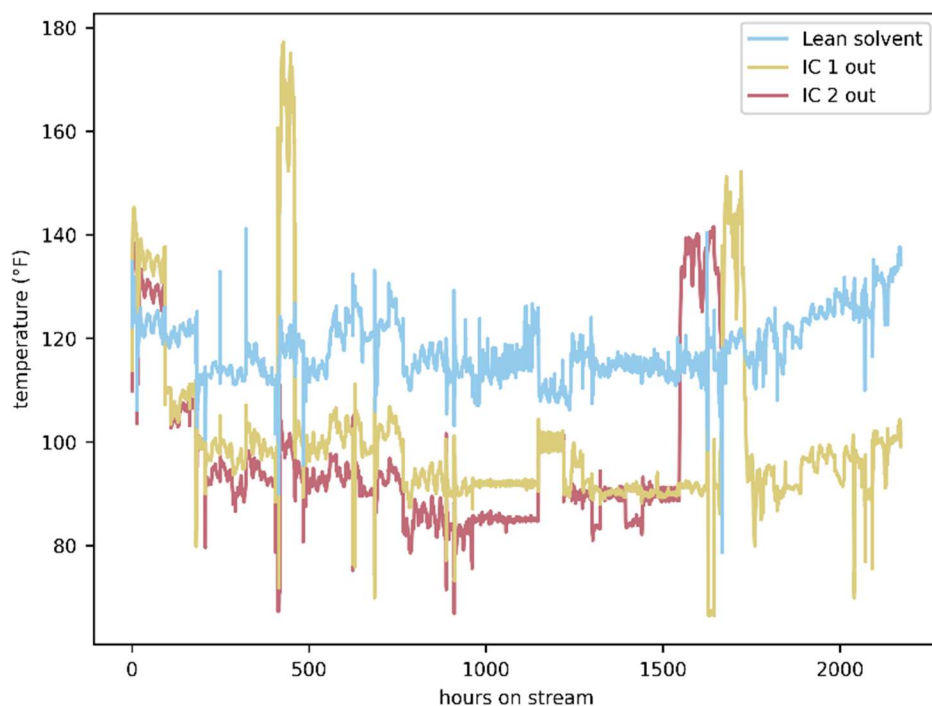


Figure 11

Observed temperatures of the lean solvent entering the absorber (blue) and cooled solvent temperature leaving intercooler 1 (yellow) and intercooler 2 (red). Note that intercooler 2 was not used past 1,700 hours on stream.

The spread of temperatures within the absorber had a significant effect on the achievable CO₂ capture rate at a given set of process conditions.

Figure 12 shows the temperature profile at four different times during testing, two on concentrated boiler gas (at 540 and at 900 hours on stream) and two on dilute boiler gas testing (at 1,200 and at 1,400 hours on stream). High CO₂ capture rates were observed when the temperatures were low. Consistent across all test conditions was the relatively high and flat temperature profile in the top bed of packing. The

temperatures here tended to stay close to the temperature of the lean solvent being fed into the absorber, and typically a bulge was not evident, indicating that the rate of CO₂ capture was likely very low, resulting in a low quantity of heat evolved. Once the solvent then passed through the first intercooler, the resulting colder solvent temperature increased the absorption capacity of the solvent.

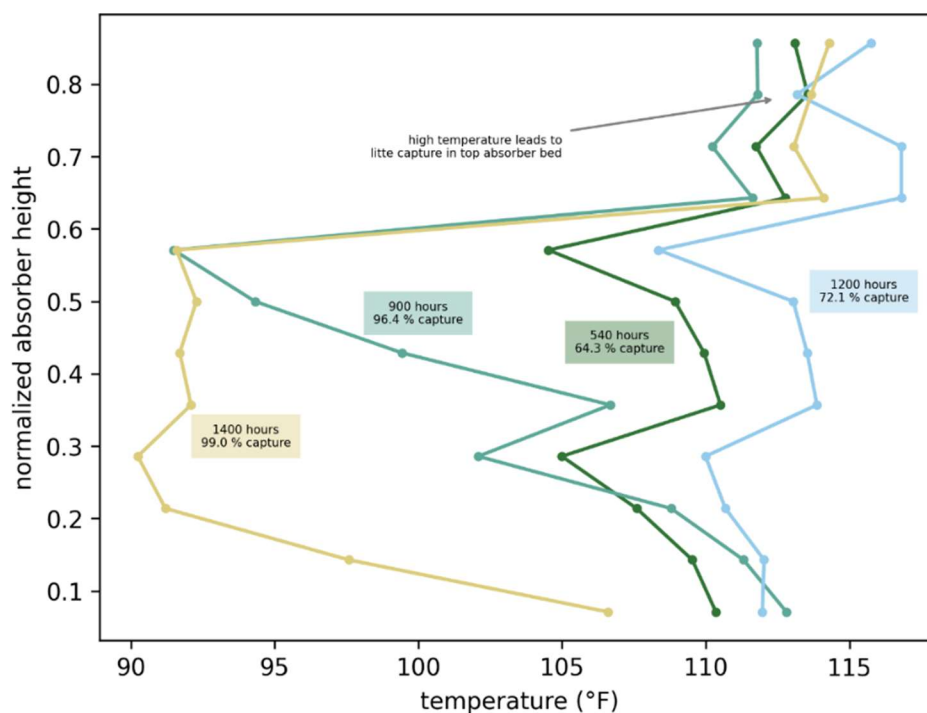


Figure 12
Plot of temperature profiles observed in the PSTU. Colors indicate the time (in hours on stream) the profile was observed and the CO₂ capture rate at that point in testing.

4.3 Water content

Figure 13 shows the water content of the solvent, as measured via Karl Fischer titration, at different points during the test campaign, against the temperature of the gas entering the absorber. This shows that controlling the temperature of the gas was an effective method for controlling the water content of the solvent, with water concentrations observed around 1 wt.% at around 58 °F inlet temperature and the highest between 8–10 wt.% water at around 98 °F. Within a given temperature range, the concentration of water was also controlled by the pressure of the regenerator, indicated by the color of the markers in Figure 13. The higher water contents were achieved with the pressure of the regenerator operated above 145 kPa, as this lead to a greater proportion of water vapor to be condensed in the regenerator at the same operating temperatures.

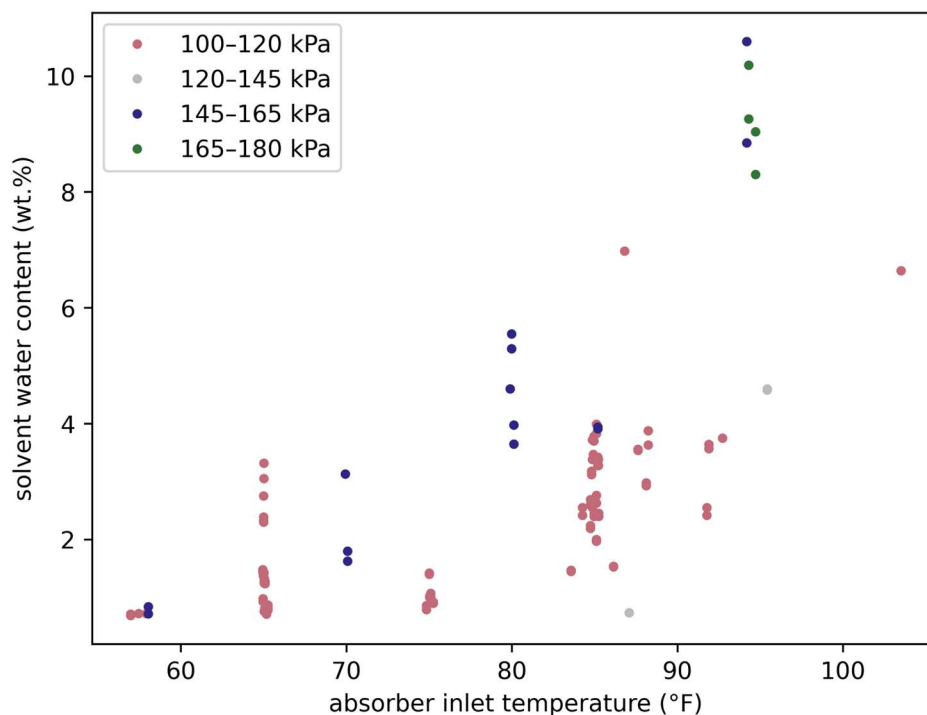


Figure 13

Plot of solvent water content with corresponding temperature of gas entering the absorber. At a given inlet temperature, the water content would vary also as a function of regenerator operating pressure.

4.4 Solvent viscosity

The viscosity of the lean and rich solvent streams were monitored in real time with in-line viscometers. Figure 14 reports the viscosities of the lean and rich solvent streams observed over the course of the entire test campaign, plotted against time on stream. As expected, the rich solvent viscosity was systematically higher than the lean solvent viscosity at any given point in time due to the effect of absorbed CO_2 raising the viscosity of the solvent. A few peaks stand out in the data, largely associated with large changes in operating conditions. Due to the sensitivity of viscosity to temperature and CO_2 loading, changes that cause a rapid change in water content would lead to a temporary spike in viscosity. This is also evident in the spike around 1,600 hours on stream when the PSTU had to shut down rapidly due to tripping of the steam supply system in very cold weather. Testing stopped at this point to deal with leaking pump seals, and the solvent was not leaned out before sending it to the storage tank, resulting in a very high spike in viscosity of around 120 cP.

One notable period is the time between approximately 900 hours and 1,100 hours on stream. During this interval, we raised the water content of the solvent, peaking at around 10 wt.%, in an effort to determine process conditions that might inhibit the formation of fog in the regenerator (see section 5.4 below). The solvent's viscosity peaked during this time, just below 35 cP. Even with this high viscosity (greater than

30 cP), the CO₂ capture was 92.3±1.94%. Although the higher viscosity may have slowed down mass transfer, it did not slow it down sufficiently to outweigh potentially increased absorption capacity associated with the higher water content, which was expected from how as-received solvent was expected to behave versus pure EEMPA.

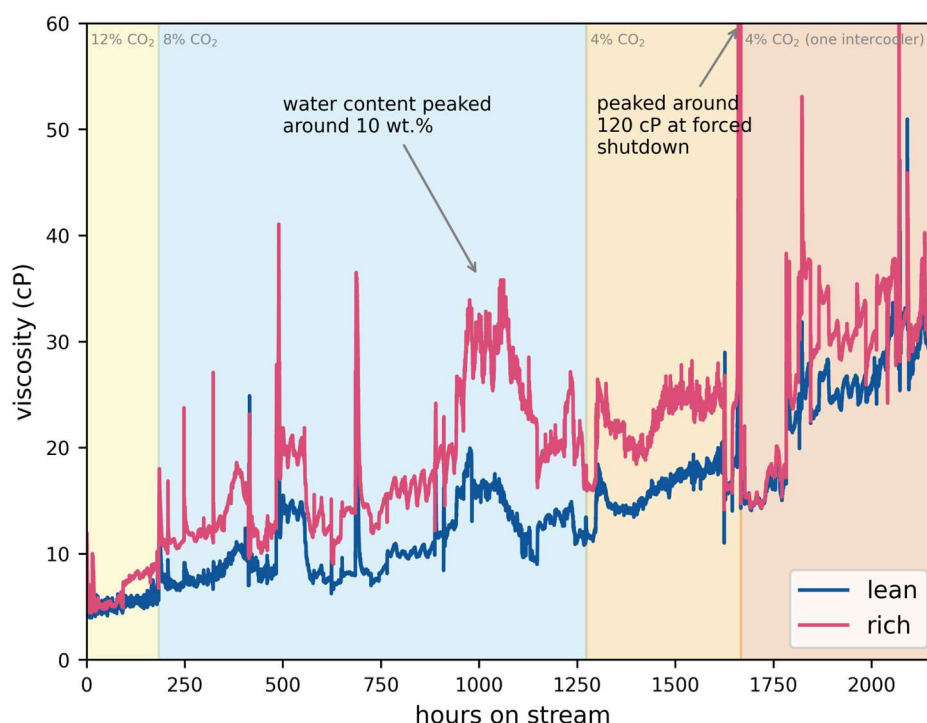


Figure 14

Observed viscosities for the lean (blue) and rich (red) solvent streams entering and exiting, respectively, the PSTU absorber plotted against the total campaign time on stream. The background colors correspond to different sections of the test campaign with different flue gas compositions or other configuration changes.

Figure 14 also shows a secular upward trend in solvent viscosity over the entire campaign. Looking past the spikes in viscosity and the period of high-water content just described, the baseline viscosity of the solvent appears to have increased substantially over the course of the campaign, starting at around 6 cP and ending around 28 cP. We expect that accumulation of heat stable salts played a role in this increase. We also hypothesized that there may have been a contribution of thermal degradation of EEMPA that led to higher molecular weight products that could have also increased the viscosity of the solvent (see sections 4.5 and 5.1)

4.5 Solvent composition over time

The concentration of EEMPA in the solvent steadily declined over the course of testing. Figure 15 plots the concentration of EEMPA in the lean solvent (measured via GC-FID) over the course of the campaign from periodic samples withdrawn from the system. The balance of the mass of the solvent contained absorbed CO₂, water, heat-

stable salts, and other impurities. Since water and CO₂ made up only a few percent of the total weight of any sample, the majority of the gap between the concentration of EEMPA at any given time and the mass of impurities made up the majority of the rest of the composition.

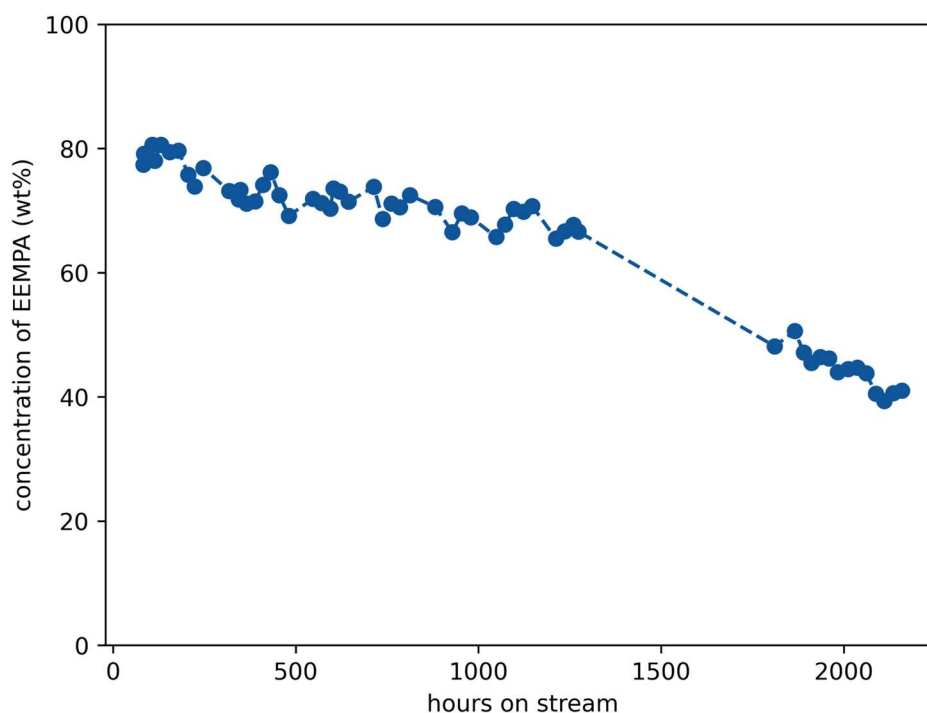


Figure 15
Concentration of EEMPA in the circulating solvent measured by GC-FID as a function of time on stream.

The precise composition of this mixture of impurities has not been conclusively determined. Figure 16 shows the concentrations of three key impurities that were tracked quantitatively during the campaign. Two of the impurities, 3-aminopropylmorpholine (3-APM) and bis-alkylated EEMPA were expected to be present in at least small quantities due to their connection to the synthesis reactions. 3-APM is one of the reagents used to make EEMPA using the lab-tested route and is typically provided in excess to push the reaction to completion. Bis-alkylated EEMPA represents an undesirable side product formed through a molecule of the other reagent, 2-BEEE, reacting with a molecule EEMPA rather than 3-APM. The third impurity is morpholine, a relatively low molecular weight amine, and potentially represents some amount of degradation that occurred during manufacturing.

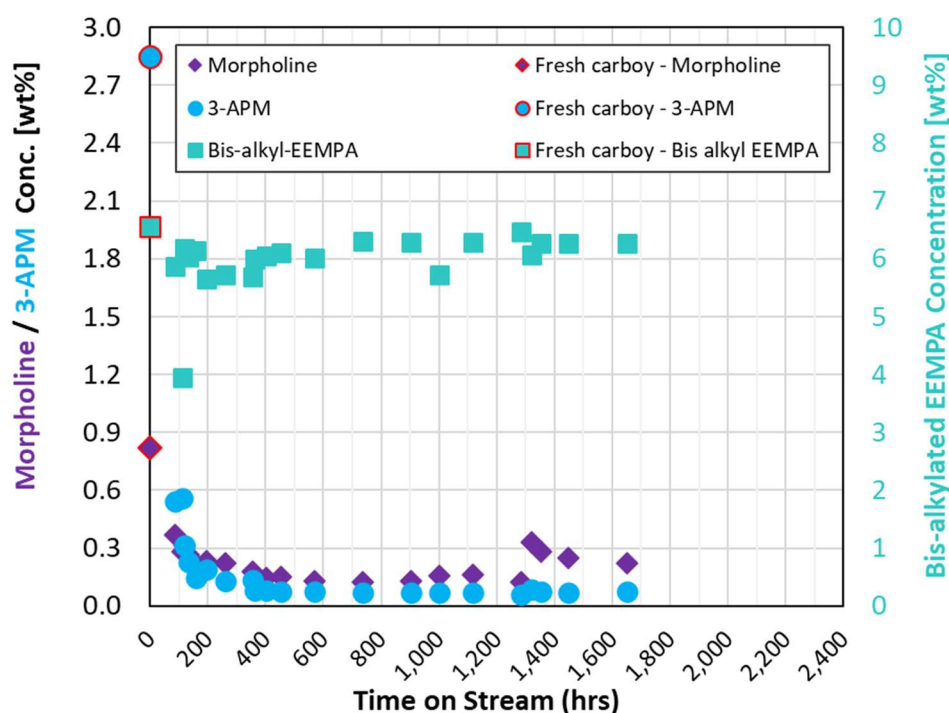


Figure 16

Concentration of key known impurities, morpholine, 3-aminopropylmorpholine, and bis-alkylated EEMPA versus time on stream.

The data plotted in Figure 16 shows the concentration of these three compounds over time. The two compounds with lower molecular weights than EEMPA, 3-APM and morpholine, started at relatively high concentrations, but declined quickly as they have higher vapor pressures than EEMPA, and thus are more likely to leave the PSTU via gas phase emissions, especially in the case of the primary amine 3-APM, due to oxidation reactions. This is reflected in emission data, discussed in section 4.7. On the other hand, the concentration of bis-alkylated EEMPA remained steady, which can likely be attributed to its likely lower vapor pressure than EEMPA, and, with two tertiary amine groups, lower rate of oxidation compared to the other compounds.

The quantities of these three compounds did not explain the entire composition of the solvent, though, and a significant proportion of the solvent was a mixture of components that have not been positively identified. Figure 17 shows the concentration of this mixture of unspecified components, and it increased steadily over time, reflecting likely a combination of oxidative degradation, thermal degradation, and formation of heat-stable salts.

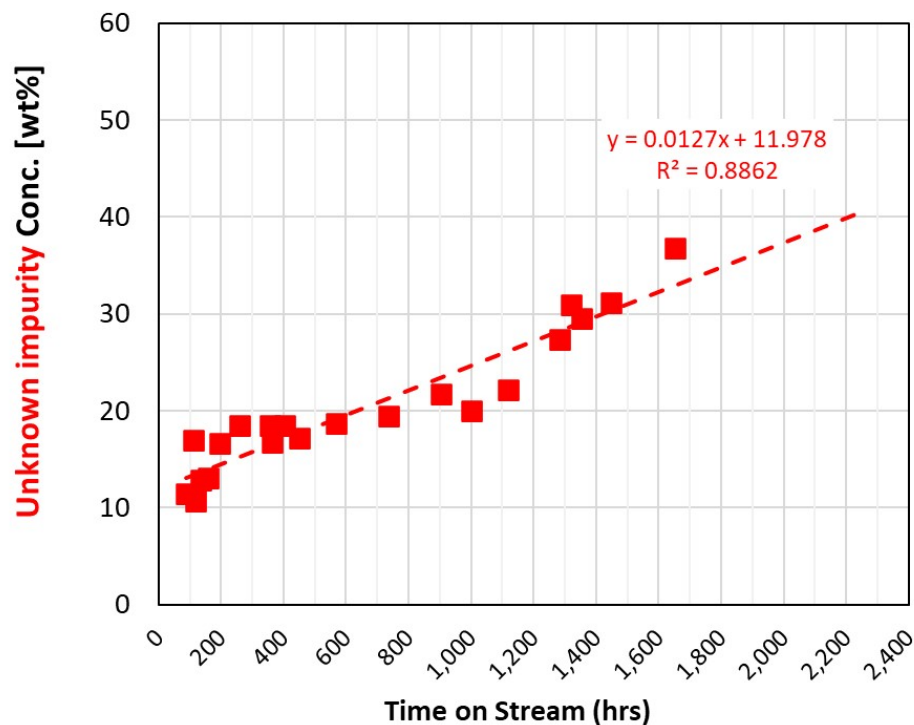


Figure 17

Estimate of total weight fraction of unknown impurities in circulating solvent over the course of the test campaign.

Qualitative observations suggest that the solvent may have undergone higher-than-expected thermal degradation. The primary evidence of this was the discovery of dark, viscous deposits in the PSTU, primarily in the bottom of the regenerator section. Figure 18 shows photographs of two of the corrosion coupons that were installed in the lean solvent line connecting the sump of the regenerator column with the lean solvent pump. They were coated with a viscous material presumed to originate from degradation of EEMPA.



Figure 18

Optical micrographs of corrosion coupons after removal from the bottom of the regenerator section at the end of the test campaign. They were coated with a very viscous material suspected to be formed via decomposition of the solvent.

4.6 Dissolved metals

In addition to tracking the composition of the solvent, the identity and quantity of dissolved metals was tracked over the course of the test. Figure 19 shows data for concentrations of iron (Fe), manganese (Mn), and sulfur (S) in the solvent versus time on stream. Measurements were made using ICP-MS, and no other metals were detected at quantifiable levels. Notably, the solvent appears to have quickly solubilized some iron and manganese upon first fill of the PSTU. Neither of these metals were at quantifiable concentrations in the as-received solvent. There is a chance that the approach to cleaning the PSTU with 0.1 M NaOH reduced the passivation of steel surfaces sufficiently to lead to an immediate dissolution of some metals. The concentrations of these two metals increased slowly over the first 60% of the test campaign. After switching to the diluted boiler flue gas, which had a higher proportion of oxygen, the concentration of iron appeared to increase substantially in each successive sample. Manganese jumped up briefly but did not continue to increase until the end of the test.

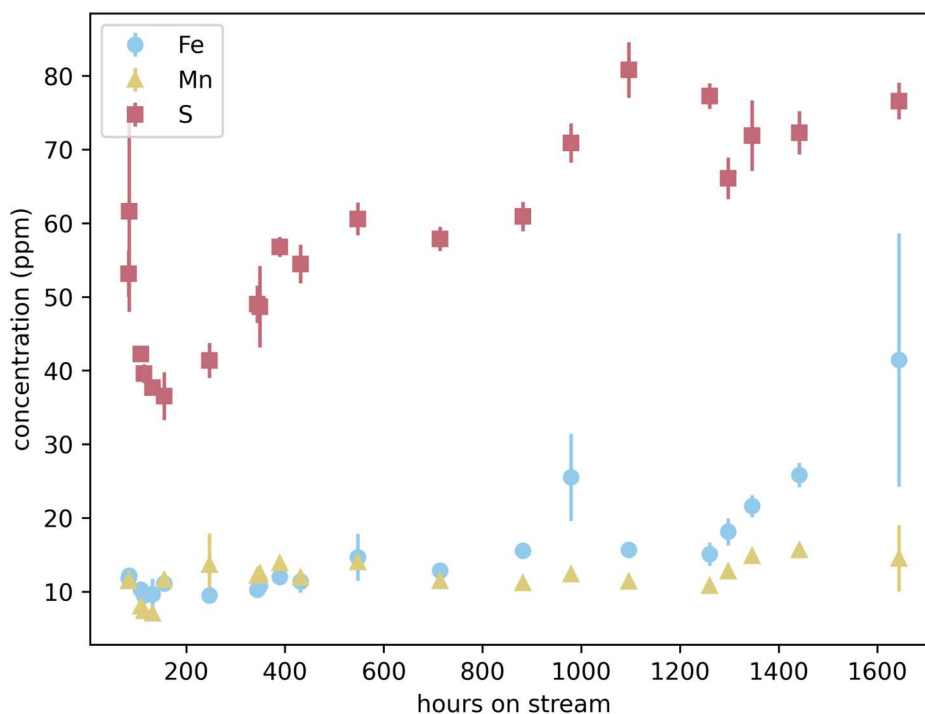


Figure 19
Concentration of iron, manganese, and sulfur in the solvent measured by ICP-MS over the course of the test campaign.

Figure 19 and Figure 20 show the concentration of sulfur in the solvent and wash water, respectively. The quantity of sulfur increased in both places in the early part of the campaign, while the trend in concentration appears to have become much flatter during the dilute boiler gas testing. We expected the solvent absorb pretty much any

SO₂ that it came into contact with, so the origin of the inconsistent trends is not clear at this point in time.

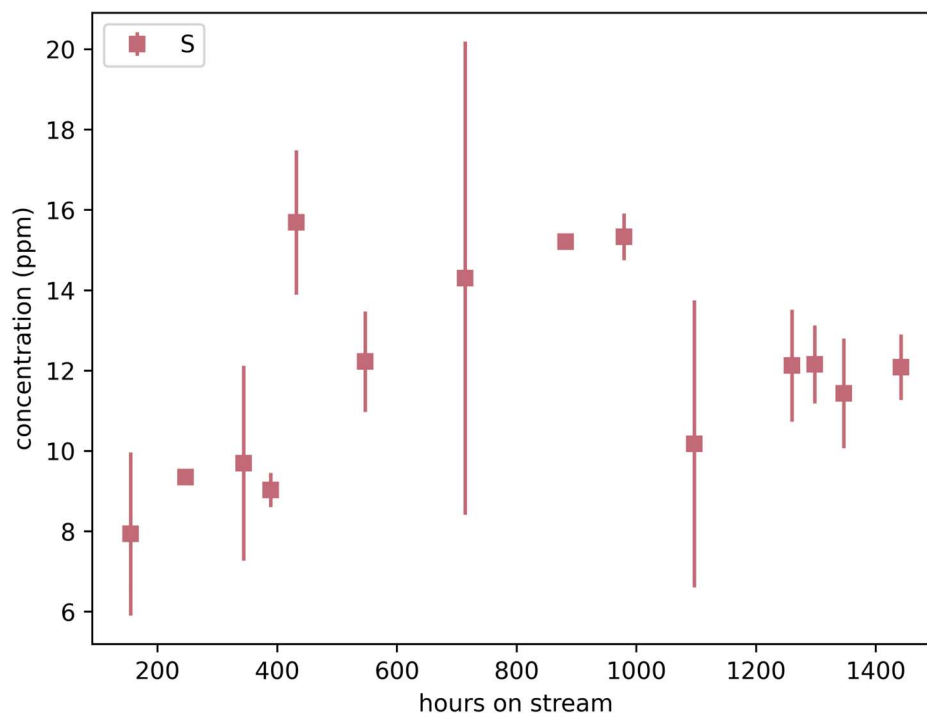


Figure 20
Concentration of sulfur in the wash water measured by ICP-MS over the course of the test campaign.

4.7 Volatile emissions

Concentrations of compounds in the exhaust gas stream after the wash were monitored with FTIR and PTR-TOF MS at different points in the campaign. Figure 21 and Figure 22 show data from the PTR-TOF MS and the temperature of the solvent leaving the reboiler, respectively, during the concentrated boiler gas (8 vol.% CO₂) test and the first part of the dilute boiler gas (4 vol.% CO₂) tests. These plots show data for EEMPA and the four compounds with the highest measured concentrations. Several other mass peaks were identified in the data, but assignment to particular compounds was considered tentative due to the number of them.

Concentrations of EEMPA (purple traces) were generally below 5 ppm and often closer to 2 ppm during the sampling period. Notably, around 760 hours on stream, the concentration of EEMPA almost doubled instantaneously. This corresponded to the point in the test where we lowered the circulation rate in the PSTU to achieve a colder lean solvent temperature. Since the flow rates were about halved, it suggests that the concentration of EEMPA was somehow related to either the residence time of the solvent in the PSTU or the additional evolution of heat with higher capture rates that was achieved with the lower solvent temperature improving the capacity of the

solvent. Ammonia and morpholine were the compounds with the highest observed concentrations. Initially high concentrations of morpholine were expected due to its presence in the as-received solvent. However, it may also be a product of oxidation of EEMPA and/or other impurities.

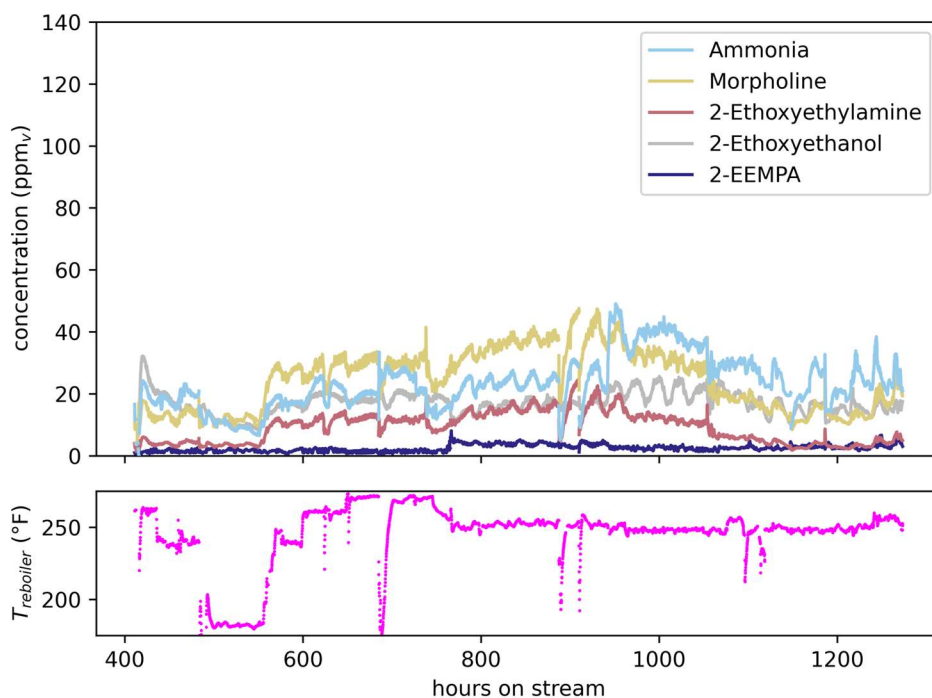


Figure 21

Plot of concentrations of major components and EEMPA detected in the PSTU wash outlet gas stream using PTR-TOF MS during the concentrated package boiler gas campaign.

There appears to have been a direct correlation between the concentration and the temperature of the solvent leaving the reboiler. At around 550 hours on stream, the reboiler output temperature was raised to achieve a lower lean loading and improve the capture rate while also lowering the circulation rate in the forced reboiler loop as a part of diagnosing the carryover and fog. Concentrations of the lightest emitted compounds shot up immediately and tended to correlate closely with changes in reboiler output temperature, at least for the next 200–250 hours.

In the dilute campaign data, emissions of the volatile compounds were initially very high, with morpholine and 2-ethoxyethanol peaking around 80 ppm and 120 ppm, respectively. This is likely linked to the addition of about 300 liters of as-received solvent before restarting testing in this section of the campaign. The concentration of 2-ethoxyethanol came down within two days of the peak and returned to a concentration of around 20 ppm, slightly higher than observed during the concentrated package boiler gas campaign.

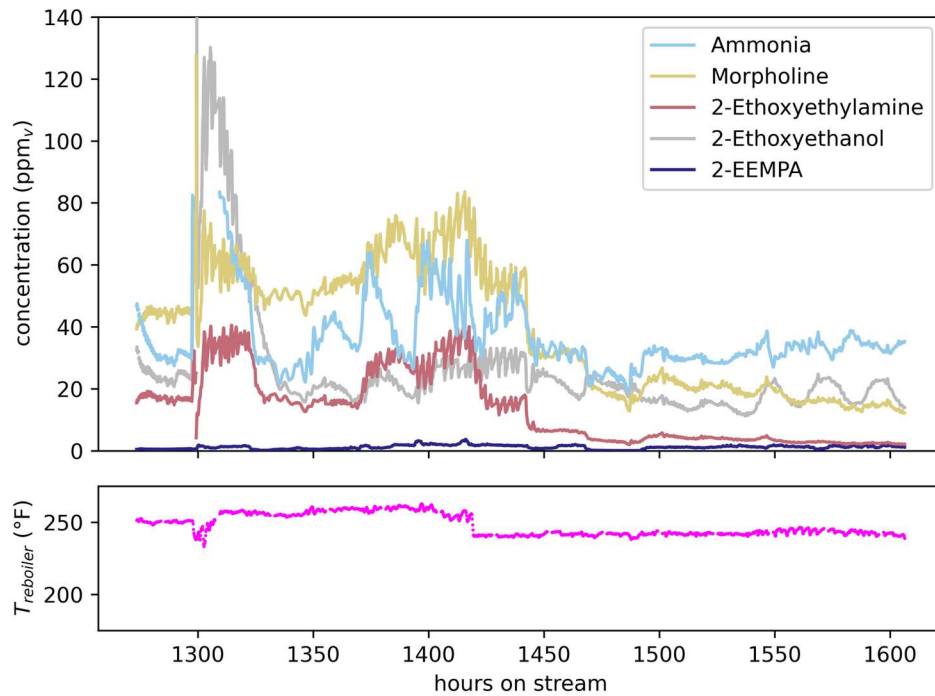


Figure 22
Plot of concentrations of major components and EEMPA detected in the PSTU wash outlet gas stream using PTR-TOF MS during the early part of the dilute package boiler gas campaign.

4.8 Corrosion coupons

The corrosion coupons installed at the start of the campaign were removed after its conclusion in March 2025. Figure 23 (next page) shows the corrosion rate data. In general, stainless steel coupons (304L and 316L) exhibited very low corrosion rates, with the highest rates at points in the regenerator vessel. Corrosion of carbon steel coupons varied widely, with relatively low rates in the absorber and wash sections, but high rates in the regenerator. In particular, the coupon in contact with the hot lean solvent leaving the regenerator sump showed by far the greatest corrosion rate, with a corrosion rate of about 23 mills per year.

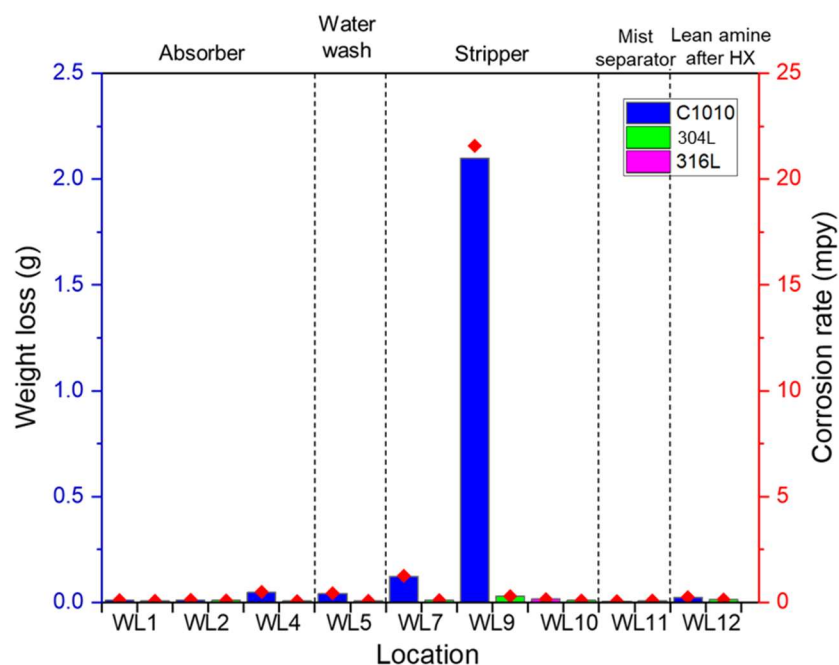


Figure 23

Overview of gross corrosion amounts and estimated corrosion rates for coupons installed in the PSTU. Bars indicate gross weight loss (left axis) and red diamonds indicate estimated corrosion rate (right axis).

5 Other Observations and Issues

5.1 Solvent color

Early in the test, the solvent developed a dark color. Compare the samples shown in Figure 3 (page 3) with those shown in Figure 24 below. By the second week of testing, the solvent color had increased to such an extent that use of the Raman spectrometer was discontinued as the background fluorescence of the solvent overwhelmed the target signal.

We hypothesized that the color is the result of very small concentrations of iron complexes. This is consistent with other observations that parts-per-million levels of such complexes can provide this color, and is correlated with the concentration of iron analyzed in the sample (see section 4.6).

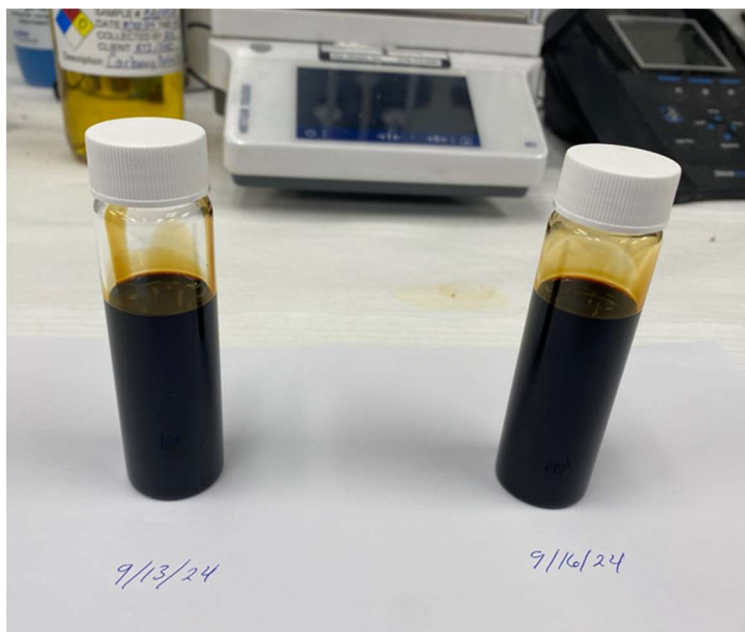


Figure 24

Samples of solvent before (left) and after (right) 50 hours of filtration through the PSTU's carbon bed (image courtesy of NCCC).

In an attempt to mitigate the color, we filtered the solvent in the PSTU through the carbon bed filter. Because of the large volume of the filters, we could not operate it continuously and maintain sufficient inventory in the PSTU. Instead, we stopped operation of the PSTU and circulated the solvent in a loop through the carbon bed. This took place over the weekend of September 14th, achieving about 50 hours of contact time in the filters. Unfortunately, this operation did not have any appreciable effect on the color. Figure 24 (previous page) shows samples of the solvent before and after this filtration operation; there is no visible difference between the samples.

5.2 Solvent carryover

Early in the campaign, solvent was discovered leaking out of small diameter sample lines connected to the main CO₂ product line. Initially, a couple of gallons of liquid were collected. Testing of this liquid indicated the EEMPA concentration was around 34% (presuming the balance was largely water).

Operators periodically monitored specific drain lines in the main CO₂ product line but downstream of the "mist separator" vessel. This carryover behavior also coincided with fog in the regenerator (see section below), so it was a working hypothesis that they may be related.

To control potential carryover into the line, the vapor return line from the reboiler outlet vapor-liquid disengagement section was blanked off near where the line entered the top of the regenerator vessel and the feed point of rich solvent to the regenerator was changed to the middle of the regenerator between the two beds of

packing. After this point, less carryover volume was observed, but we do not have conclusive evidence that this is what prevented major carryover.

A leading theory for the origin of the carryover would be unsteady operation of the reboiler loop as the water content and loading of the solvent changed. Combined with the blocking of vapor-liquid disengagement, pressure could have been built up that caused unsteady reliefs.

5.3 Fog in the regenerator

Concomitant with the observation of the liquid carryover into the product line, NCCC staff observed a dense fog inside the regenerator through three sight glasses installed at different points along the vessel. The fog appeared as a dense dispersion of fine white liquid droplets and typically completely obscured any ability to see into the regenerator vessel. At best, some liquid draining down the walls near the sight glass ports in the middle and bottom of the regenerator would be visible.

To understand the process factors that promoted the formation of fog, and potentially how to operate the PSTU while suppressing the formation of it, we preempted the test matrix and adjusted different process variables to determine the primary contributing factors, including:

- regenerator pressure
- water content of the solvent
- reboiler temperature
- use of cold rich bypass
- reboiler recirculation rate
- exposure to flue gas (implicitly leaning of the solvent)

Of these factors, only the last one had a qualitative effect on the density of the fog. When restarting operation and heating the solvent, but before admission of flue gas to the PSTU would not result in formation of fog. As flue gas was admitted, the fog was observed to gradually build in density within an hour. Conversely, when flue gas flow was stopped but solvent circulation and heating continued, fog would dissipate within an hour, then re-appear again after flue gas was re-admitted.

The fog was sampled a few times to understand if there was a specific trend with composition and EEMPA content. Early samples were conducted ad-hoc, removing gas from the regenerator and condensing it. With the persistence of the fog into the dilute gas campaign, a new sampling port was installed to allow controlled withdrawal of gas from the top of the regenerator vessel, above the mist eliminator and where the gases leave the vessel. Gas was withdrawn at a metered rate and cooled to 0 °C to capture condensable vapors. The liquid thus collected was then analyzed with gas chromatography to determine how much EEMPA was in each sample. Table 4 reports these observations. While EEMPA may have been present in all the samples, it was typically below the quantification limit of the GC method used for the samples taken in November and later.



Figure 25
Picture of fog taken October 18, 2024 (courtesy of NCCC).

Table 4
Compositional samples of the regenerator vapor space to quantify the composition of the fog. Note that the first two samples were taken ad-hoc, while the samples in November and December used a dedicated sampling port.

Sample collection date and time (U.S. Central Time)	EEMPA concentration (wt.%, by GC-FID)
9/5/2024 12:45p	9.861
9/12/2024 12:15p	2.7334
11/18/2024 6:13a	Not detected
11/18/2024 6:25a	1.58295
11/20/2024 10:00a	< 0.569
11/21/2024 9:25a	Not detected
11/21/2024 2:30p	Not detected
11/22/2024 10:00a	Not detected
11/25/2024 9:30a	Not detected
11/26/2024 9:30a	< 0.569
11/27/2024 8:00a	< 0.569
12/2/2024 8:25a	< 0.569

5.4 Pump seal failures

In the first week of December, NCCC staff noticed leaks in several of the PSTU's pumps, including the intercooler pumps and the rich solvent pump. Coinciding with unstable operation due to cold weather, the PSTU was shut down to investigate the pump seals and determine suitable replacement materials.

The team quickly tested a few potential seal materials. O-rings representing several candidates (PTFE, Kalrez 4079, and Kalrez 6375) as well as a control (EPDM 70) were procured. These were weighed then placed in individual sample tubes with some EEMPA sample taken from the PSTU from mid-October. These tubes were placed in a Parr reactor and heated to 150 °C under a CO₂ atmosphere. Periodically, O-rings were removed from the reactor and their weight measured to determine if any change in mass had taken place, indicating that the solvent could absorb into the seals and degrade them.

Some of the results of this test are shown in Table 5. Out of these tests, PTFE was revealed as potentially the most resistant material. EPDM 70 fared the worst as expected. This was similar to the material in some of the pump seals that failed.

Table 5

Summary of change in O-ring mass after exposure to 24 or 72 hours with partly degraded EEMPA under CO₂ atmosphere.

Material	% change in mass	
	24 hours	72 hours
PTFE	0	0
Kalrez 4079	6.1	10.6
Kalrez 6375	3.2	3.6
EPDM 70	43.8	32.2

NCCC staff worked with seal vendors to determine potential candidate materials, which considered the lead time for acquiring the materials and installing them into the pumps. Ultimately, Markez® #Z1352 was selected due to its potential resistance to concentrated amines and its immediate availability.

5.5 Cross exchanger pressure drop

Over the course of the campaign, the pressure drop on the rich side of the cross exchanger (HX20404) systematically increased. Figure 26 shows pressure drop data for both sides of the cross exchanger (lean and rich). While the lean side of the exchanger showed little to no trend over the course of the test, the pressure drop on the rich side increased over the course of the test. There appeared to have been a slight upward trend until very late in the concentrated package boiler gas campaign, after which the rate of increase in the pressure drop appeared to accelerate.

This acceleration in worsening pressure drop came to a head in January 2025. When attempting to restart operation of the PSTU after replacement of pump seals, NCCC staff noticed that the discharge pressure on the rich pump needed to be increased to drive the desired flow to an extent that risked approaching the set pressure of the safety relief valves around the cross exchanger.

We paused the test plan at this point to investigate and attempt to mitigate the pressure drop. Operating on the hypothesis that there might be some sort of slightly soluble precipitate that accumulated in the cross exchanger. We circulated solvent in the PSTU without admitting flue gas and attempted a set of operations where the temperature of the solvent flowing through both sides of the exchanger was raised through removal of cooling in an effort to dissolve potential deposits. This effort was unsuccessful, though, and the pressure drop continued to increase, so we returned to the test plan and operated at lower solvent circulation rates to keep pressures away from relief valve set points.

After the conclusion of the test campaign, NCCC disassembled the cross exchanger. Dark solid deposits were apparent inside the exchanger, shown in Figure 27. These deposits were likely the source of the high pressure drop, and their origin were still under investigation as of the writing of this report.

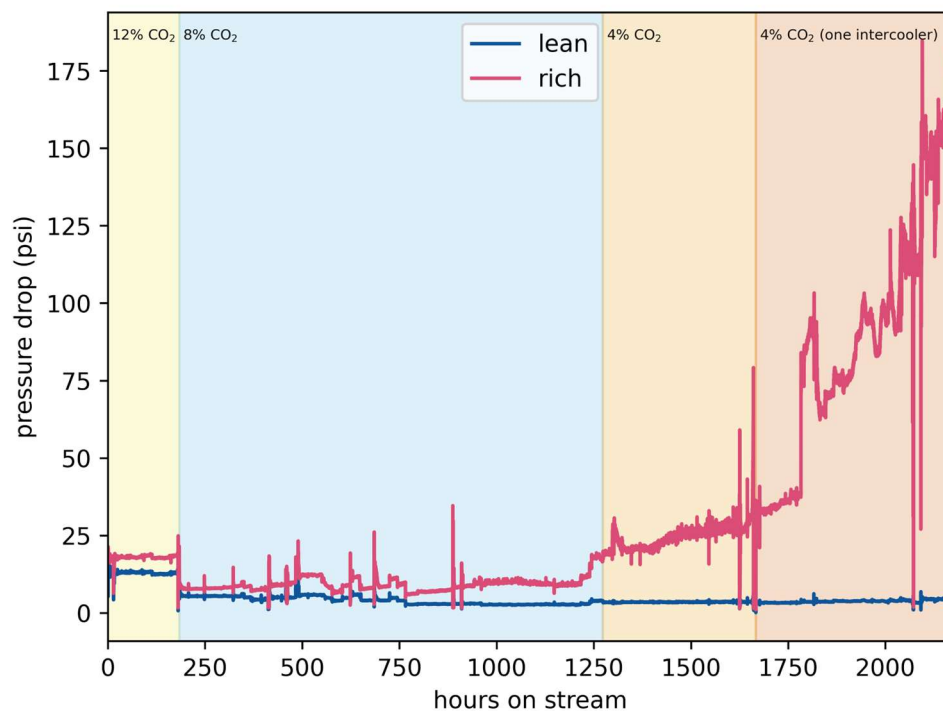


Figure 26
Observed pressure drop across the lean (blue) and rich (red) sides of the cross exchanger (HX20404) over the course of testing, plotted against the time on stream. The background colors in the plot indicate different flue gas test regimes.

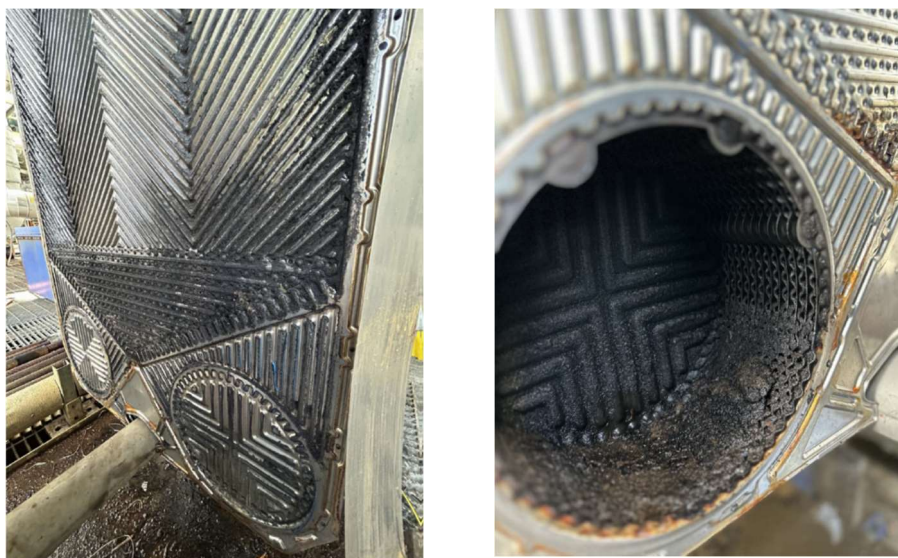


Figure 27
Photographs of deposits on the internal surfaces of the cross exchanger after the EEMPA test campaign (courtesy of NCCC).

5.6 Heat exchanger performance

To understand the high SRDs observed during the test, rigorous models of the heat exchangers were developed and used to interpret heat balance data around individual exchangers. Based on this analysis, we concluded that the exchangers tended to operate below their potential capacity. The model of the lean solvent trim cooler resulted in an estimated overall heat transfer coefficient of $99 \text{ W/m}^2\cdot\text{K}$, whereas the value computed from the experimental data was 38% lower at an estimated $72 \text{ W/m}^2\cdot\text{K}$. Regardless of the relative values, these values are on the low end of what would be expected for exchangers where cooling water is exchanging heat with organic or oil-like materials⁶.

In the case of the cross exchanger, agreement between modeled and experimental heat transfer coefficients depended on the time in the campaign and the solvent flow rate. Figure 28 shows this data. At the beginning of the campaign, there was very good agreement between the experimental and modeled values, however, by around hour 800, actual heat transfer coefficients were significantly lower than the experimental values. This discrepancy may be due to two factors: the deposits leading to higher pressure drop (discussed in 5.5) and operation of the cross exchanger at flow rates well below its design flow rate.

⁶ J.R. Welty, C.E. Wicks, and R.E. Wilson, *Fundamentals of Momentum, Heat, and Mass Transfer*, 3rd ed., John Wiley and Sons: New York, pp. 424.

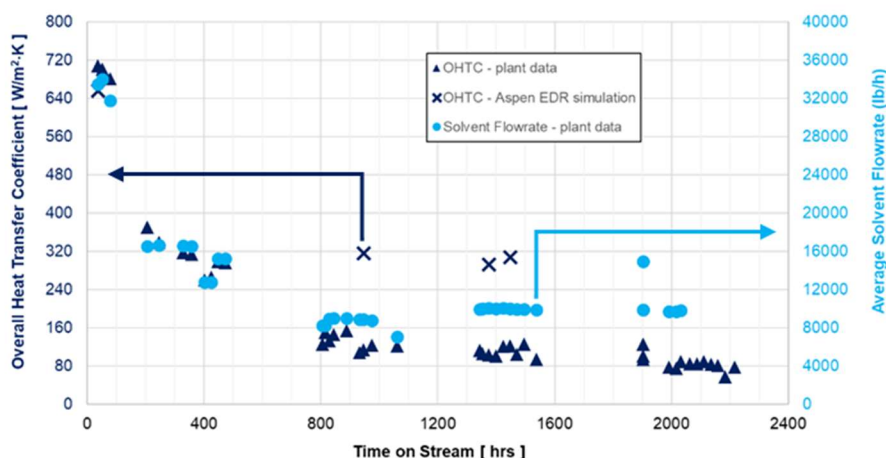


Figure 28

Plot of overall heat transfer coefficients (left axis), both experimental (triangles) and modeled (crosses), and solvent flow rate (circles, right axis) for the cross exchanger during the EEMPA test campaign.

6 Key findings and lessons learned

This project resulted in the largest-scale test of EEMPA as a water-lean solvent to date. Over 2,300 hours on stream were accumulated, and capture rates above 90% were demonstrated for over 700 of those hours, with 31 hours over 95% capture.

During the campaign, water content was successfully controlled over a wide range. Water content was controlled by a combination of inlet gas temperature (controlled by the direct contact cooler) and the regenerator pressure. Water content changes occurred relatively quickly. The system was able to operate stably even at high water content (8-10 wt.%) although this coincided with high viscosity (>25 cP).

The efficiency of the heat exchangers was a key factor in the overall performance results. The sensitivity of the capacity of the solvent to temperature means that even a few degrees higher than expected temperature could have a significant effect on the achievable rich loading, and recuperation of heat in the cross exchanger directly affects the achievable SRD. Heat exchangers should be modeled in detail with consideration of increased viscosity and off-design flow rates.

The results of the campaign were affected by the fact that the concentration of EEMPA started below the desired range and declined more quickly than anticipated. This underscores the importance of using high purity materials, and the original synthesis route for EEMPA is unlikely to be useful at this scale of testing if it is not possible to make EEMPA with sufficient purity and reasonable cost.

We encountered a higher level of solvent degradation than anticipated. Part of this may be due to higher than desired temperatures in the regenerator. Mechanisms of degradation of EEMPA should be investigated further, and special attention should be

paid to understand the range of temperatures that a particular configuration of the regeneration unit operations could potentially expose the solvent to.

We learned that EEMPA may have the potential to form an aerosol or fog at regenerator conditions. This conclusion is complicated by the fact that the solvent was relatively impure, and the potential effect of undesired components that may not be present if starting with a highly pure EEMPA solvent had an influence. Any further test of EEMPA should include careful consideration of the regeneration unit operations and their mechanical design to understand if there are situations that develop with sharp temperature gradients that promote homogenous condensation.

The prevalence of leaks in pumps due to incompatibility between the solvent and seal materials underscores the need to do systematic testing of elastomers with the actual material that is expected to go into the system and not just purified samples. It's unclear at this point how much the impurities in the solvent may have contributed to this rapid degradation of the seals, but if these degradation products are potentially going to be found in EEMPA used in practice, developing appropriate tests that take this into account is essential for avoiding downtime that could be mitigated by the use of proper seals.