FINAL TESTING REPORT TO NCCC
January 27, 2017

SUBMITTED TO

National Carbon Capture Center (Host Site)
and
U.S. Department of Energy
National Energy Technology Laboratory

SLIPSTREAM PILOT-SCALE DEMONSTRATION OF A NOVEL AMINE-BASED POST-COMBUSTION TECHNOLOGY FOR CARBON DIOXIDE CAPTURE FROM COAL-FIRED POWER PLANT FLUE GAS

WORK PERFORMED UNDER AGREEMENT

DE-FE0007453

Author: Devin Bostick, Linde LLC, Murray Hill, NJ

SUBMITTED BY

Linde LLC
DUNS Number: 805568339
100 Mountain Avenue
Murray Hill, NJ 07974-2097

PRINCIPAL INVESTIGATOR

Krish R. Krishnamurthy, Ph.D.
Phone: 908-771-6361
krish.krishnamurthy@linde.com

Signature of Submitting Official:
Head of Group R&D – Americas
Technology & Innovation, Linde LLC

Table of Contents

Abbreviations List

PCC	Post Combustion CO_2 Capture
aMWh	Annual net megawatt-hours of power generated at 100% capacity factor
CCF	Capital Charge Factor for a levelized period of 20 years (0.124 in this study)
CF	Plant Capacity Factor (0.85 in this study)
DCC	Direct Contact Cooler
FGD	Flue Gas Desulfurization
LB1	Linde-BASF PCC option previously reported upgraded to supercritical PC power plant using BASF OASE® blue solvent technology and advanced PCC process
SIH	Linde-BASF PCC option using BASF OASE® blue solvent technology with advanced stripper interstage heater PCC process configuration
LB1-CREB	Linde-BASF PCC option using BASF OASE® blue solvent technology with advanced main CO_2-rich/CO_2-lean heat exchanger and cold CO_2-rich bypass exchanger design
COE	Cost Of Electricity, \$/MWh
PCC	Post Combustion Capture
SP-S	Single Parameter Scaling methodology for TPC estimates
TPC	Total Plant Cost, \$
TOC	Total Overnight Cost, \$
OC_{FIX}	Fixed Operating Costs
OC_{VAR}	Variable Operating Costs
MT	Metric tonne
TPD	Metric tonnes per day
TSM	CO_2 Transportation, Storage and Monitoring
DOE	U.S. Department of Energy
NETL	National Energy Technology Laboratory
FRP	Fiberglass Reinforced Plastic
GC	Gas Chromatography
LP	Low Pressure
PC	Pulverized Coal
HHV	Higher Heating Value

Executive Summary

Post-combustion CO_2 capture (PCC) technology offers flexibility to treat the flue gas from both existing and new coal-fired power plants and can be applied to treat all or a portion of the flue gas. Solvent-based technologies are today the leading option for PCC from commercial coal-fired power plants as they have been applied in large-scale in other applications. Linde and BASF are working together to develop and further improve a post-combustion capture technology incorporating BASF's novel aqueous amine-based process. This technology offers significant benefits compared to other solvent-based processes as it aims to reduce the regeneration energy requirements using novel solvents that are very stable under the coal-fired power plant feed gas conditions. BASF has developed the desired solvent based on the evaluation of a large number of candidates. In addition, long-term small pilot-scale testing of the BASF solvent has been performed on a lignite-fired flue gas. In coordination with BASF, Linde has evaluated a number of options for capital cost reduction in large engineered systems for solvent-based PCC technology.

Pilot-scale demonstration on a coal-fired power plant flue gas at a 1-1.5 MWe scale has been completed in Wilsonville, AL at the National Carbon Capture Center (NCCC) under a project supported by the U.S. DOE (project award DE-FE0007453). Mechanical completion of the pilot plant was achieved in July 2014, and final commissioning activities were completed to enable start-up of operations in January 2015. Parametric tests were performed from January to December 2015 to determine optimal test conditions and evaluate process performance over a variety of operation parameters. A long-duration 1500 hour continuous test campaign was performed from May to August 2016 at a selected process condition to evaluate process performance and solvent stability over a longer period similar to how the process would operate in a continuously running large-scale PCC plant. The pilot plant integrated a number of unique features of the Linde-BASF technology aimed at lowering overall energy consumption and capital costs.

Highlights of parametric testing and long-duration continuous testing of the pilot plant will be discussed in this report. The pilot plant incorporated significant instrumentation and control features that enabled automated and stable operation as well as the ability to reliably check and verify mass and energy balance closures with adequate redundancies. Results and significant findings from parametric and long-duration testing will be discussed; these tests were aimed at validating the performance of the PCC technology against targets determined from a preliminary techno-economic assessment. The stability of the solvent with extended operation in a realistic power plant setting was measured with performance verified. Additionally, general solvent classification information, process operating conditions, normalized solvent performance data, solvent stability test results, flue gas conditions data, CO_2 purity data in the gaseous product stream, steam requirements, process flow diagrams, and process economic data for a scaled up 550-MWe power plant with CO_2 capture will be presented and discussed.

During the overall test period including start-up, parametric testing and long-duration testing, the pilot plant was operated for a total of 6,764 hours out of which testing with flue gas was performed for 4,109 hours. The pilot plant testing demonstrated all of the performance targets including CO_2 capture rate exceeding 90%, CO_2 purity exceeding 99.9 mol% (dry), flue gas processing capacity up to 15,500 lbs/hr (equivalent to 1.5 MWe slipstream), regeneration energy as low as 2.7 GJ/tonne CO_2, and regenerator operating pressure up to 3.4 bar absolute. The emission control feature incorporated in BASF's patented dry-bed configuration was validated during long-duration testing. During parametric testing, significant research was performed in conjunction with NCCC and Southern Research to characterize aerosol particle number concentration and size distribution in the flue gas as well as the impact of aerosol particles on amine emissions from the plant. Pilot plant operating parameters that minimize amine emissions during operation with flue gas containing high concentrations of aerosol particles have also been identified through tests performed. Pilot testing has validated the performance benefits of several unique equipment features incorporated in the pilot plant design, including high-capacity structured packing, gravity-driven absorber inter-stage cooler, blower positioned downstream of absorber, and a unique reboiler configuration that minimizes solvent inventory and promotes a fast response to energy input requirements.

1. General Solvent Classification

The advanced Linde-BASF PCC technology tested at NCCC is a result of BASF's comprehensive R&D efforts since 2004 to develop advanced **aqueous amine-based solvents** for efficient CO_2 recovery from low-pressure, dilute flue gas streams from power plants and industrial processes combined with a joint Linde/BASF collaboration since 2007 to design and test advanced PCC technologies. This section provides highlights of the key characteristics of BASF's CO_2 capture solvent.

With climate change becoming an increasing concern globally, BASF's gas treatment team has been actively leveraging its expertise to become a leading contender in the race to make carbon capture and storage (CCS) commercially viable. Over the years, BASF's gas treatment portfolio has continuously expanded. Beyond extensive offerings in technology and gas-treating chemicals, the world's largest chemical company can supply additional technical support services, such as customized onsite training of its customers' personnel on the optimized operations of gas treatment processes and equipment. BASF recently began marketing its entire gas-treating portfolio under the trade name OASE®, where OASE® blue is the brand for flue gas CO_2 capture. The team considers carbon capture and sequestration (CCS) as the most effective measure in the mid-term to combat further increase of CO_2 emissions into the atmosphere. Based on the success of more than 250 gas treatment plants over several decades for ammonia, oxo-syngas, natural gas, and liquefied natural gas applications as well as experiences in iron ore gas and selective sulfur gas treatment, BASF decided to systematically develop a new chemical solvent technology targeting the specific requirements of large-scale carbon capture applications. Besides low pressure and large volume systems that need to consider emissions to meet environmental requirements, PCC from power plants presents the additional challenge of very low driving forces for CO_2 mass transfer. The oxygen-containing atmosphere is aggressive to amines, and high energy efficiency is absolutely critical to the commercial success of such CO_2 capture processes. Consequently, the most important parameters for the development of solvent-based PCC technologies are energy demand, cyclic capacity, solvent stability, reactivity, volatility, environmental sustainability, and availability.

BASF's screening process assessed over 400 substances, which were pre-selected based on molecular weight, vapor pressure, alkalinity, and safety data. About half of the candidates were further investigated for vapor-liquid equilibrium, reaction kinetics, and stability data. About 20 component mixtures were then subjected to a proof-of-concept run in BASF's mini plant where the complete CO_2 capture process was verified. This valuable tool showed early on in development whether or not a chemical solvent had the potential for further testing at the pilot scale using real power plant off gases containing CO_2.

In parallel, BASF monitored the energy industry's approaches towards carbon capture and also contributed to several research projects within the 6th and 7th integrated framework programs of the European Union. During the CASTOR and CESAR projects, the BASF team exchanged experiences with relevant players in the community and transferred significant gas treating know-how from the petrochemical industry to the energy and energy-related institutes.

Together with Linde, BASF is a partner in a pilot project steered by RWE Power at the German energy provider's Coal Innovation Center in Niederaussem, Germany, near Cologne. The post-combustion CO_2 capture pilot plant using coal-fired off gas was constructed, commissioned, and started up in 2009. Despite the relatively small dimensions of the pilot and capacity to capture only 7.2 tonnes of CO_2 per day from a flue gas slipstream of the power plant, several critical process parameters were successfully tested. In particular, reliable data on energy consumption and long-term stability were generated, which helped to serve as an experimental basis for the Linde-BASF PCC pilot plant tested in Wilsonville, AL at NCCC in 2015 and 2016.

Based on this work and the invaluable feedback from experience at over 300 plants operating with OASE® technology, BASF can already guarantee excellent performance at today's state of development. Process performance parameters verified from past experience include CO_2 capture rate, flow rate/capacity, reboiler duty, process emissions, circulation rate, and CO_2 product purity. Today, an OASE® blue process can be safely and reliably operated to achieve these performance objectives. Integration of the aqueous amine-based OASE® blue solvent with advanced Linde design and equipment innovations offers further potential for process optimization improvements and overall capital and operating cost reductions for the PCC process.

2. General Process Description and Process Flow Diagram

The Linde-BASF PCC plant constructed and tested in Wilsonville, AL from 2015-2016 was designed to recover 90 percent of the CO_2 contained in the flue gas from a coal-fired power plant downstream of a flue gas desulfurization (FGD) unit and purify the CO_2 product (> 99.9 vol% CO_2 on a dry basis with < 100 vol. ppm O_2). The major sections of the PCC plant included: a flue gas cooler upstream of the absorber, a flue gas blower downstream of the absorber, a CO_2 absorber column with a gravity-flow interstage cooler and two absorption sections with structured packing and internals, two water wash sections at the top of the absorber, and a solvent stripper column operable at higher pressure (3.4 bara) with a unique level-controlled reboiler. The Linde-BASF PCC pilot plant components were designed and operated with the final goal of minimizing the energy requirements for CO_2 removal and compression relative to DOE/NETL Case 12 reference conditions [Ref. 1]. A simplified process flow diagram for the Linde-BASF PCC technology pilot plant is shown in Figure 1. This process flow diagram highlights the major technology improvements for the Linde-BASF PCC pilot that result in significantly enhanced energy performance and overall capital and operating cost reductions compared to a standard MEA solvent-based PCC plant. These technology innovations are further described below.

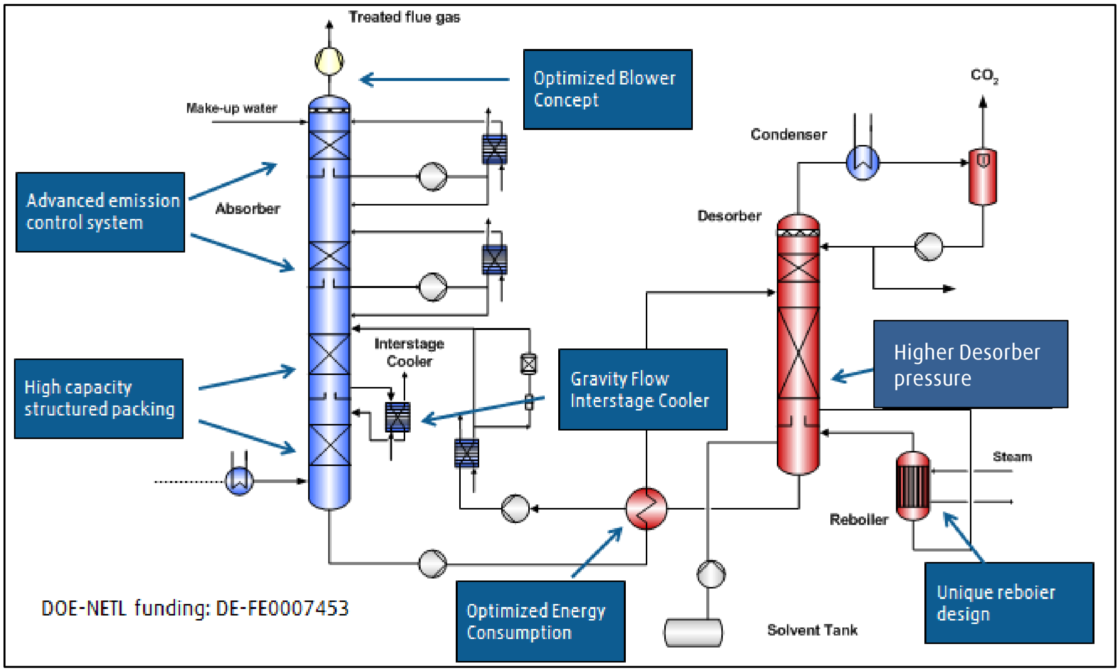


Figure 1: Process flow diagram of Linde-BASF PCC Pilot Plant in Wilsonville, AL at NCCC.

Flue Gas Blower Placed Downstream of Absorber

The following benefits are afforded for the Linde-BASF PCC process through use of a flue gas blower positioned downstream of the absorber column.

- Significantly reduced cooling duty requirements (~30% reduction compared to DOE/NETL Case 12 reference for equivalent PCC plant integrated with 550 MWe coal-fired power plant) since it is not necessary to cool down the flue gas stream beyond the CO_2 absorption requirements, as is normally done to compensate for a significant temperature rise (up to 30°F) across the flue gas blower.

- Notably reduced separation system electrical power requirement (~13% compared to DOE/NETL Case 12 reference), due to the substantially lower molar flowrate of CO_2-depleted flue gas downstream of the absorber as compared to the flue gas flow rate upstream of the absorber. This difference in flowrate is a result of the 90% absorbed CO_2 from the flue gas within the absorber bed into the BASF OASE® blue solvent.

CO_2 Absorber with Gravity-Flow Interstage Cooler

The CO_2-lean BASF OASE® blue amine-based solvent flows down through the absorber bed and absorbs CO_2 from the flue gas, which flows from the bottom to the top of the column and to the water wash units. Since the exothermic absorption reaction of CO_2 into amine-based solvents increases the temperature of the flue gas inside the absorber and consequently reduces the equilibrium content of CO_2 in the liquid-phase, it is of utmost importance to maintain a low, relatively constant temperature throughout the entire absorber. In addition to cooling the CO_2-lean amine solvent solution within an external cooler before it is injected to the top of the absorber, a significant solvent temperature rise within the column can be efficiently suppressed through use of an interstage cooler, as shown above in Figure 1. Linde's gravity-driven interstage cooler design eliminates the need for an external interstage cooler pump and control components, and consequently leads to a simplified design as well as a reduced capital cost for the absorber integrated with interstage cooler when implemented at scale.

High-Performance Structured Column Packing

The Linde-BASF PCC technology also utilizes the most advanced structured packing for the absorber to promote efficient hydraulic contact of gas and liquid phases, which along with increased CO_2 reaction rates with BASF's OASE® blue solvent, facilitates a fast approach to the equilibrium CO_2 concentration in the solvent liquid-phase. Consequently, the capacity of the absorber, one of the most critical parameters for a large-scale CO_2 absorption plant, is dramatically increased. In addition, the advanced structured packing reduces the pressure drop across the column, which decreases the flue gas blower capital cost and electrical power consumption. The structured packing selection was determined by optimization of various structured packing options offering higher capacities while trading off on the mass-transfer efficiency.

Absorber Water Wash Section

Within a certain range of flue gas aerosol particle concentrations, an efficient reduction in solvent emissions from the process can be achieved through use of a patented dry-bed configuration consisting of two water wash sections at the top of the absorber. In addition, design improvements upstream of the PCC plant that minimize solvent-carrying aerosol formation in the flue gas to the CO_2 absorber can substantially suppress solvent losses. The CO_2-depleted flue gas that leaves the absorber bed still carries a small amount of solvent. Cold water sprayed from the top of the wash units effectively scrubs the solvent from the flue gas - an effect that is enhanced by a significantly reduced equilibrium composition of the solvent components in the vapor-phase as a result of the reduced outlet temperature at the top of the absorber. An external plate and frame heat exchanger in the water recirculation loop transfers the required cooling duty to the absorber water wash sections from the cooling water supplied by the central cooling water system.

High Desorber Column Pressure

Long-duration testing of the Linde-BASF PCC technology at the Wilsonville, AL pilot in 2016 demonstrated the feasibility of using elevated desorber/stripper column pressures. While the absorber operated at slightly sub-atmospheric pressure, solvent regeneration during the long-term test campaign was performed in the stripper at an operating pressure of 3.4 bara (49.3 psia) at the top of the column. Compared to CO_2 desorption at atmospheric pressure, this higher pressure operation significantly reduces electrical power requirements (33.77 MW required for CO_2 compression using the Linde-BASF PCC technology integrated with a 550 MWe PC power plant vs. 44.89 MW for DOE/NETL Case 12 reference) and capital cost for CO_2 compression at the commercial-scale PCC plant. 3.4 bara was chosen as the upper limit for stripper pressure considering the increasing solvent degradation expected at higher stripper temperatures, which correspond to higher stripper pressures. The significant difference in compression energy required for the DOE/NETL Case 12 reference vs. the tested Linde-BASF PCC process technology is a result of the substantially lower inlet CO_2 compression pressure for Case 12 compared to the Linde-BASF process (24 psia vs. 49.3 psia) for a CO_2 compression pressure ratio of 2 per compression stage.

Unique Reboiler Design

The reboiler tested at the Wilsonville, AL Linde-BASF pilot utilized a unique design aimed at reducing overall capital costs and solvent inventory inside the reboiler during operation. Reduced solvent inventory in the reboiler offers faster responses to dynamic changes in CO_2 product flow rate requirements compared to standard reboiler designs. In addition, a novel reboiler control loop was used to control the level of condensed steam in the reboiler as a means of controlling the surface area of steam contacting the reboiler walls in the heating process, leading to enhanced flexibility and optimization of steam condensation heating duty input into the reboiler. In addition to the reboiler, which used a plate and shell exchanger, an advanced plate and frame heat exchanger design was used for the CO_2-lean/CO_2-rich solution cross exchanger that recovered heat from the CO_2-lean solution to give to the CO_2-rich solution entering the stripper column. The advanced Linde-BASF cross exchanger design tested at the Wilsonville, AL PCC pilot reduced capital costs and maximized heat transfer surface area and associated efficiency compared to previous designs.

Process boundary limits and associated elements describing how the Linde-BASF PCC pilot plant was integrated with the E.C. Gaston power plant at NCCC are illustrated in Figures 2 and 3.

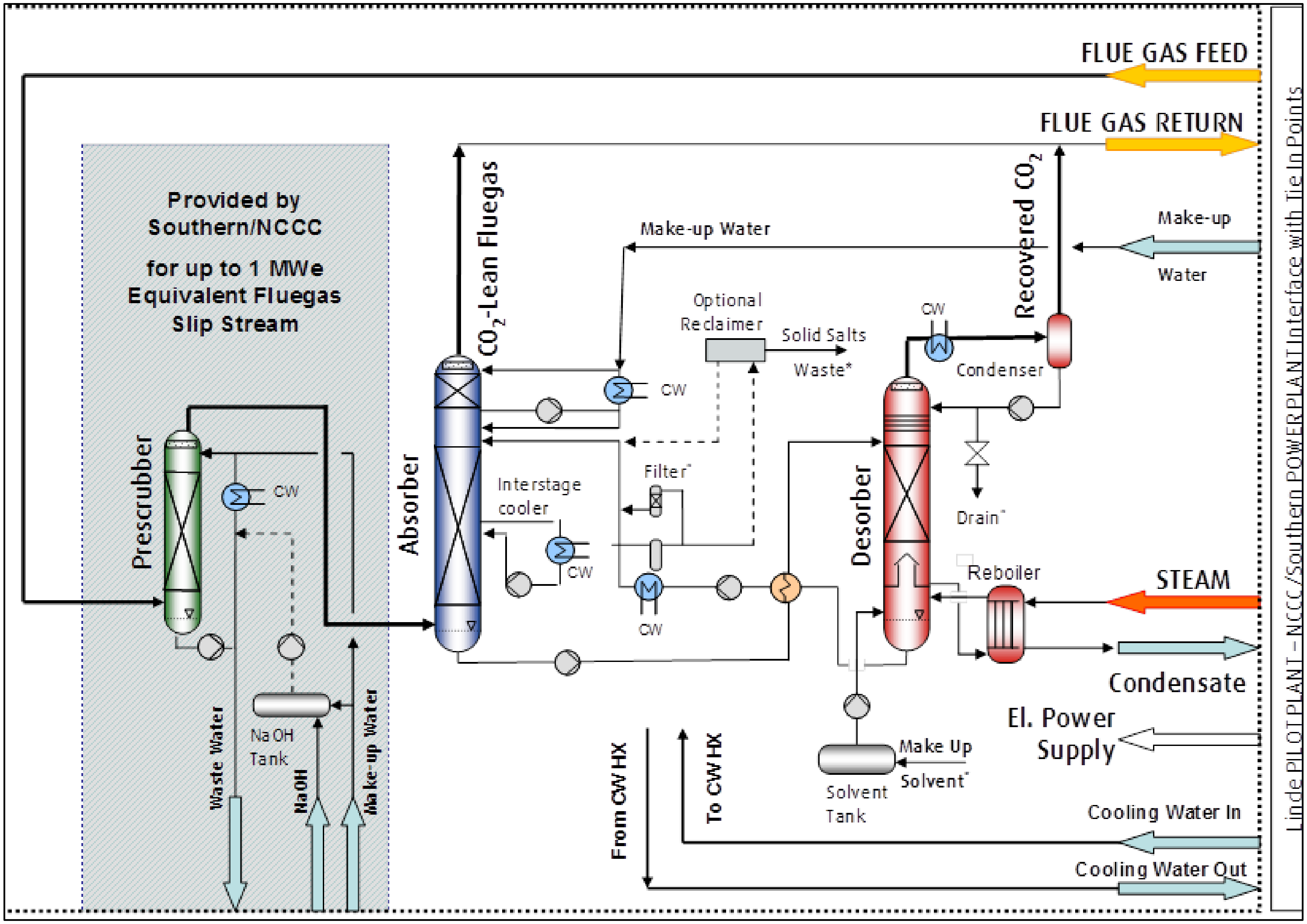


Figure 2: Integration of Linde-BASF pilot plant with E.C. Gaston power plant from pilot perspective.

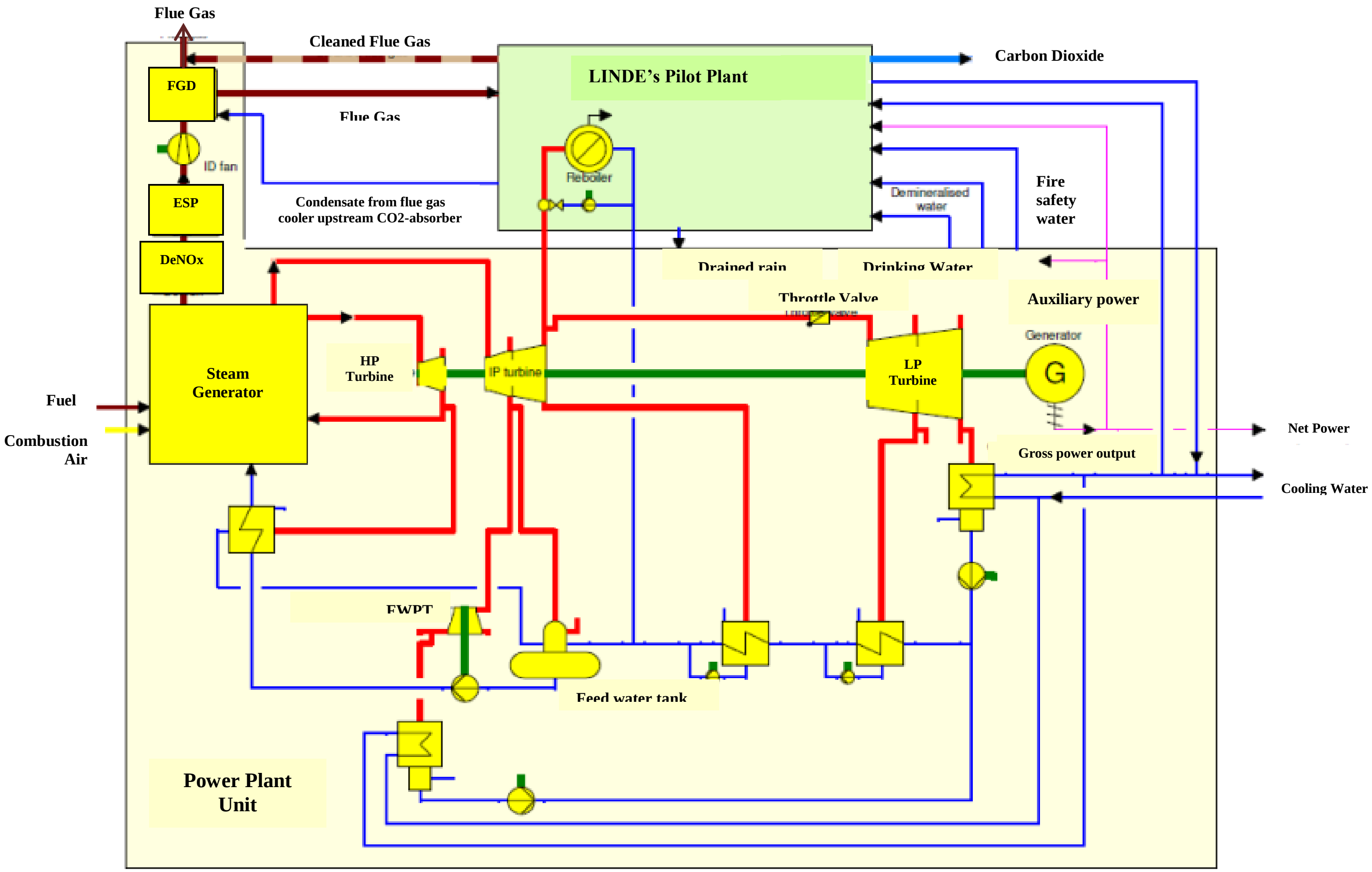


Figure 3: PCC pilot integration with E.C. Gaston power plant from power plant perspective.

3. General Process Operating Conditions

Process condition ranges from the Linde-BASF PCC pilot testing in Wilsonville, AL are summarized in Table I. The daily CO_2 mol% in the flue gas varied significantly in magnitude, ranging from 11 to 12 mol% CO_2 (dry) in the early morning and peaking to as much as 13 to 13.5 mol% CO_2 in the early afternoon. The resulting daily fluctuations in CO_2 recovery rate were controlled as closely as possible to achieve stable and consistent operation while maintaining low specific regeneration energy relative to a standard MEA solvent-based PCC plant. The hourly average fluctuations of the flue gas CO_2 mol% (dry basis) are presented in Figure 4 from long-duration testing. The discontinuity in data during the following periods was caused by interruptions in the flue gas supply: 5/20/16 through 5/24/16, 6/3/16 through 6/4/16, 6/12/16 through 6/14/16, and 7/8 through 7/10/16.

Table I: Typical operating ranges during pilot testing in Wilsonville, AL.

Flue gas into absorber	
Flowrate (lb/hr)	7,500 to 15,750 (10,500 base)
Temperature (˚F)	86 to 104
Pressure (psig)	-0.3 to 0.5
CO_2 mol% (dry)	11 to 13.5
CO_2-depleted gas out of absorber	
Flowrate (lb/hr)	5,800 to 13,000
Temperature (˚F)	86 to 115
Pressure (psig)	-0.6 to 0.2
CO_2 mol% (dry)	0.5 to 2
CO_2 product gas out of stripper	
Flowrate (lb/hr)	1,300 to 2,300
Temperature (˚F)	70 to 100
Pressure (psig)	14.7 to 34.6
CO_2 mol% (dry)	99.9
CO_2-lean solution cooler	
CO_2-lean solution temperature to absorber (˚F)	104 to 140
Absorber inter-stage cooler	
Absorber inter-stage cooler operation	On (104 ˚F) / Off
Solvent circulation and CO_2 capture	
Solvent circulation rate	Varied from 80% to 120% of design
CO_2 capture rate	90% typical; varied from 85% to > 95%

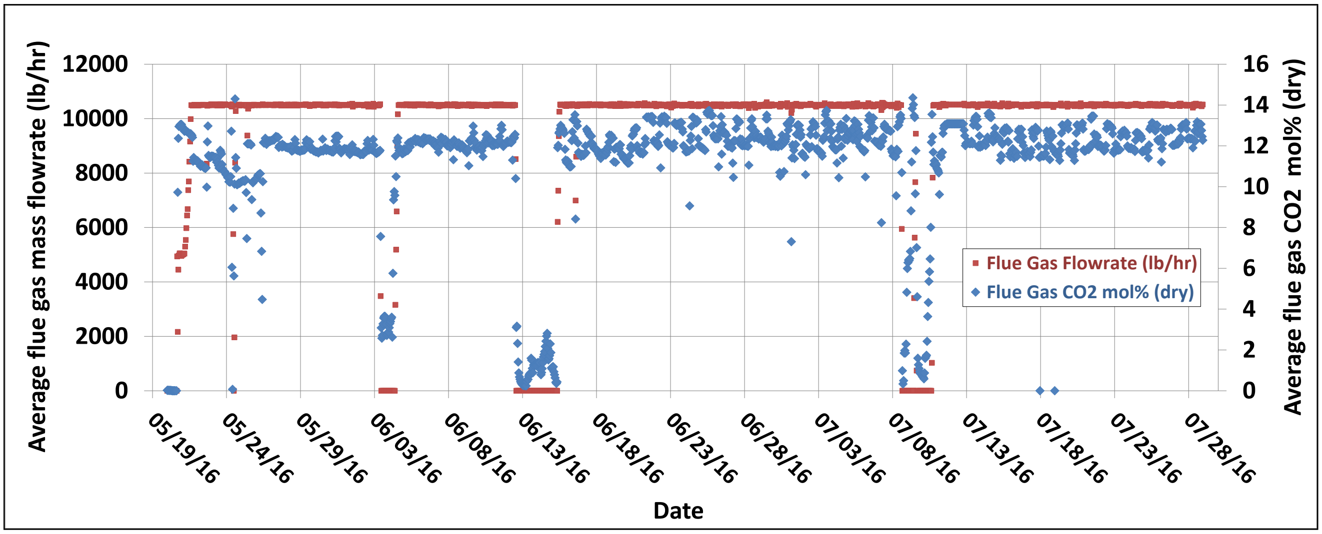


Figure 4: Hourly average flue gas mass flowrate (lb/hr) and CO_2 mol% (dry) during long-duration test campaign in 2016.

Table II presents a summary of the Linde-BASF PCC pilot performance against its targets along with noteworthy accomplishments based on measured operating data from parametric and long-duration test campaigns.

Table II: Pilot plant performance against targets.

Performance Attribute	Current achievement against target	Remarks
1. CO_2 Capture rate	> 90% per target	Achieved. Capture rate can be optimized for specific energy.
2. CO_2 Product Purity	99.9 mol% (dry) per target	Achieved. Low O_2 impurity level for EOR applications.
3. Plant Capacity	> 1.5 MWe per design target (> 15,500 lb/hr flue gas)	Achieved. Higher capacity testing performed – 10 days in May-June. An additional week of testing in Nov. 2015.
4. Regenerator steam consumption	~2.8 GJ/tonne CO_2 (same as Niederaussem consumption)	Energy as low as 2.7 GJ/tonne CO_2 observed.
5. Emissions control validation	Validation of dry bed (BASF patented) operation per design	Detailed isokinetic measurements (flue gas & CO_2-depleted gas) performed
6. Regenerator operating pressure	Testing performed up to 3.4 bar absolute	Pressure parametric testing completed in Nov. 2015. Long-duration testing was performed at 3.4 bar(a).
7. Validation of unique features	(i) High-capacity packing (ii) Gravity-driven inter-stage cooler (iii) Blower downstream of absorber (iv) Unique reboiler design	Design options for regenerator heat reduction through heat integration identified. Stripper inter-stage heater design can result in ~2.3 GJ/tonne CO_2.

4. Normalized Solvent Performance Data and Results from Testing

Figure 5B presents specific regeneration energy data (MJ/tonne CO_2) for the Linde-BASF PCC plant measured during parametric testing in 2015. The Linde-BASF technology clearly enables reduced energy consumption compared to a standard MEA-based PCC process (which typically operates at an average of 3610 MJ/tonne CO_2), and can achieve specific regeneration energies below 2800 MJ/tonne CO_2 depending on solvent and process conditions. The regenerator was operated at 14.7 psig for most of the 2015 test campaign, but its pressure was increased to 34.6 psig in November 2015 to evaluate the impact of higher pressure on specific regeneration energy. The Niederaussem OASE® blue data series shown is used as a comparison with the measured data at the Linde-BASF PCC pilot plant in Wilsonville, AL to illustrate process and data consistency. The Niederaussem MEA data series is shown to present a performance comparison between baseline MEA-based PCC and the Linde-BASF PCC process technology demonstrated at Niederaussem [Ref. 2]. The Linde-BASF pilot at Niederaussem used a similar absorber wash section and structured packing design, and is comparable to the PCC technology tested at the Wilsonville, AL pilot. Although some differences in the solvent composition occurred on a day to day basis at the Wilsonville, AL PCC plant, all data shown for the 2015 parametric test campaign was collected using a fixed, desired amine content in the BASF OASE® blue solvent on a CO_2 free basis. As described in Figure 4 above, significant fluctuation in the flue gas CO_2 content (mol%, dry) on a day to day basis caused temporary deviations away from the 90% CO_2 capture target (+/- 4% maximum absolute CO_2 recovery change away from 90%) due to the time required for reboiler steam flowrate adjustments to bring the CO_2 recovery back to 90%. These daily process fluctuations resulted in significant variation of the specific regeneration energy, which was closely maintained as low as possible for the process conditions provided. Despite this process variability, the average CO_2 capture rate for the entire duration of pilot testing was kept at 90%. Full capacity operation of the pilot plant at the higher flue gas flowrate (15,500 lb/hr, corresponding to a 1.5 MWe slipstream) was conducted during parametric testing in late May, early June, and early November of 2015. The performance data evaluated at the higher flue gas flowrate cannot be directly compared to data from testing conducted at or below 10,500 lb/hr flue gas flowrate since the measured solvent amine content was significantly lower during the periods of the higher flue gas flowrate operation. The lower solvent amine content during higher flue gas flowrate testing was due to greater amine emissions in the treated gas during parametric testing, and resulted in significantly higher specific energy consumptions for the PCC process compared to performance data collected from periods when the solvent contained the target amine content. Figure 5A shows the normalized amine content of the CO_2-lean solution during testing in 2015 and 2016, where the value of 1 on the y-axis indicates the target amine content of the pure BASF OASE® blue solvent. The pilot was operated at 10,500 lb/hr during the long-duration test period as amine carryover from the absorber was minimal.

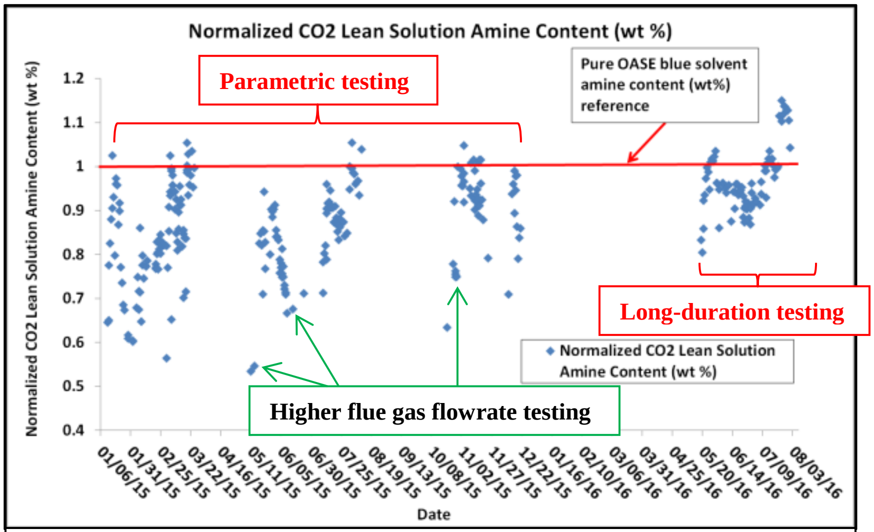


Figure 5A: Normalized CO_2-lean OASE® blue solution amine content (wt %) measured during testing.

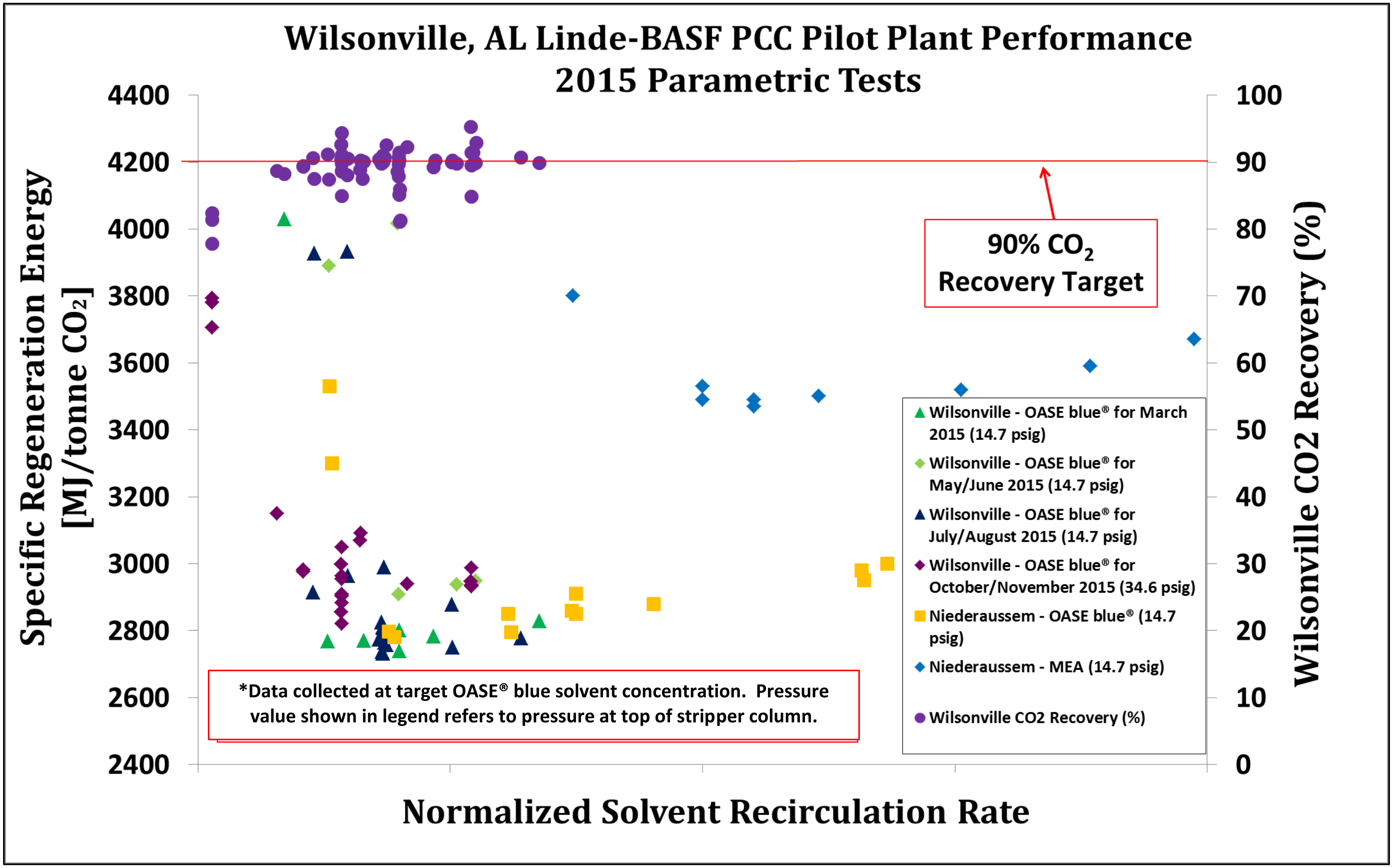


Figure 5B: Specific regeneration energy for Linde-BASF pilot tested at Wilsonville, AL during parametric testing in 2015.

Figure 6A demonstrates consistently low average specific energy consumption (~2.84 GJ/tonne CO_2) for the Linde-BASF PCC technology measured during long-term testing in 2016 compared to the equivalent DOE/NETL Case 12 MEA-based PCC process reference. The operations team strengthened the solvent slightly at the end of July 2016 by reducing its water content, and the specific energy consumption for the PCC process was reduced further to ~2.72 GJ/tonne CO_2, as presented in Figure 6B for a 2-day period. A large fraction of the reboiler heat duty required for aqueous amine-based PCC processes is the energy required to vaporize water in the solvent to desorb CO_2 in the stripper column. As shown, reducing the solvent's water content decreased the steam energy input required to regenerate the solvent and produce high purity CO_2. The minimum achievable water content in the solvent was determined through discussions between Linde and BASF as a safe condition for long-duration operation. More thorough and longer evaluation at reduced water contents below the level tested is required to confirm the feasibility of increasing the amine content of the OASE® blue solution for commercial Linde-BASF PCC plants. The rationale behind identifying the minimum safe water content for the operating conditions at the pilot plant is that reducing the water content below this minimum can cause precipitation of amine solids in the solvent at lower temperatures inside the absorber and CO_2-lean solution cooler. These solids can build up in plant equipment and cause blockages and other operational issues. As a reference, temperatures below 25ºC for the solvent will cause precipitation of solids. Notably, no operational issues occurred during the 4 days of lower water-content solvent testing that indicated any solids buildup or solvent degradation in the process.

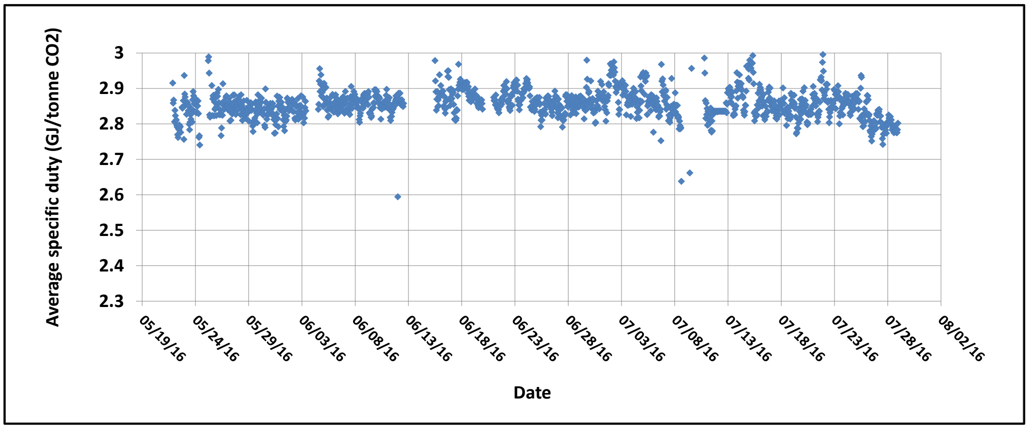


Figure 6A: Hourly average specific energy consumption (GJ/tonne CO_2) during pilot plant long-duration testing.

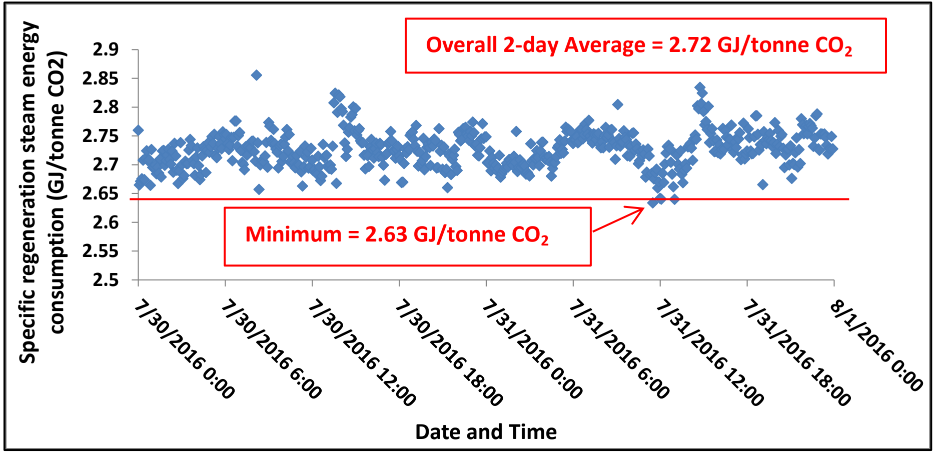


Figure 6B: Average specific energy consumption (GJ/tonne CO_2) for 2 days at the end of pilot plant long-duration testing.

5. Test Results on Solvent Stability

Solvent stability can be measured in terms of both the energy consumption, used as an indicator of solvent performance, and via solvent composition measurements including analysis of known solvent degradations components such as heat stable salts (HSS). During each testing period, major components of the solvent (amine, water, and CO_2) were analyzed daily, and the results were compared to a desired solvent composition on a CO_2-free basis. Process parameters, such as the treated gas temperature, were adjusted daily to provide a stable plant water balance as needed to maintain the desired solvent composition. In addition, batch samples of CO_2-lean and CO_2-rich solvent liquid were collected on a regular basis and shipped to BASF Corporation analytical laboratories in Wyandotte, Michigan for detailed analysis of contaminants and heat stable salts (HSS). As shown in Figure 7, the measured heat stable salt content in the solvent during testing was consistently far below an HSS threshold that BASF has experimentally determined to be a degradation level above which the energy consumption of the process per kg of CO_2 captured begins to increase. The low HSS content indicated that no significant solvent degradation occurred during testing in 2015 and 2016. HSS in the solvent does not leave in the treated or CO_2 product gas streams, and the HSS concentration is not reduced when new solvent is added to the process, so it accumulates over time during routine operation. Demonstrating the accuracy and consistency of HSS measurement methods, the Linde and BASF experimental HSS data show excellent uniformity during both 2015 and 2016 testing periods. These results confirm the superior stability performance of the OASE® blue technology compared to other PCC solvents for commercial plants. Based on the solvent stability data measured during parametric testing, the solvent inventory only needs to be replaced after several years as a result of HSS buildup in the process.

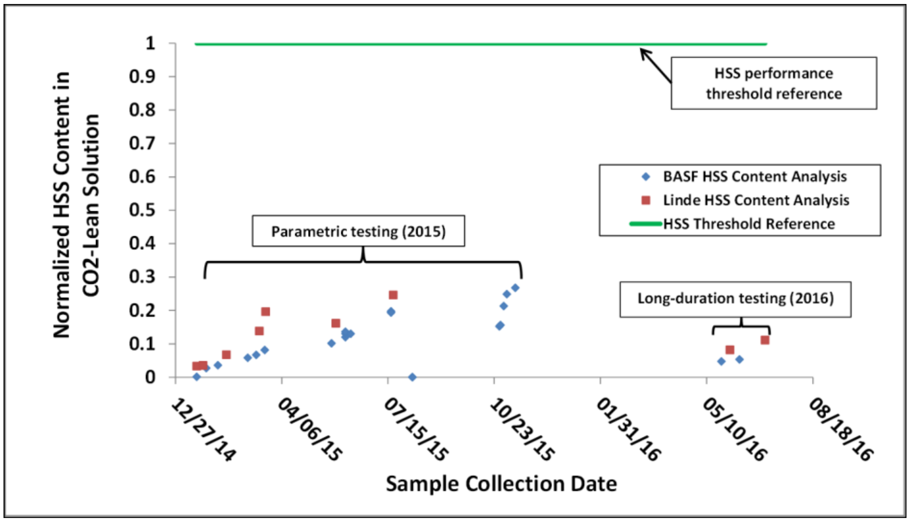


Figure 7: Heat stable salt (HSS) analysis results conducted during parametric and long-term test campaigns for Linde-BASF pilot plant.

6. Flue Gas Conditions Before and After Absorber

Figure 4 in Section 3 illustrated that the CO_2 mol% (dry) in the flue gas measured at the inlet to the absorber fluctuated significantly in response to power plant load changes throughout the day. The CO_2 mol% of the CO_2-depleted gas exiting the top of the absorber also changed as a result of the varying flue gas CO_2 mol% as well as changes in the steam flowrate to the reboiler to maintain 90% CO_2 capture. These changes are illustrated in Figures 8 and 9 below for a typical day during the long-term test campaign (07/05/2016) for flue gas and CO_2-depleted gas process conditions parameters.

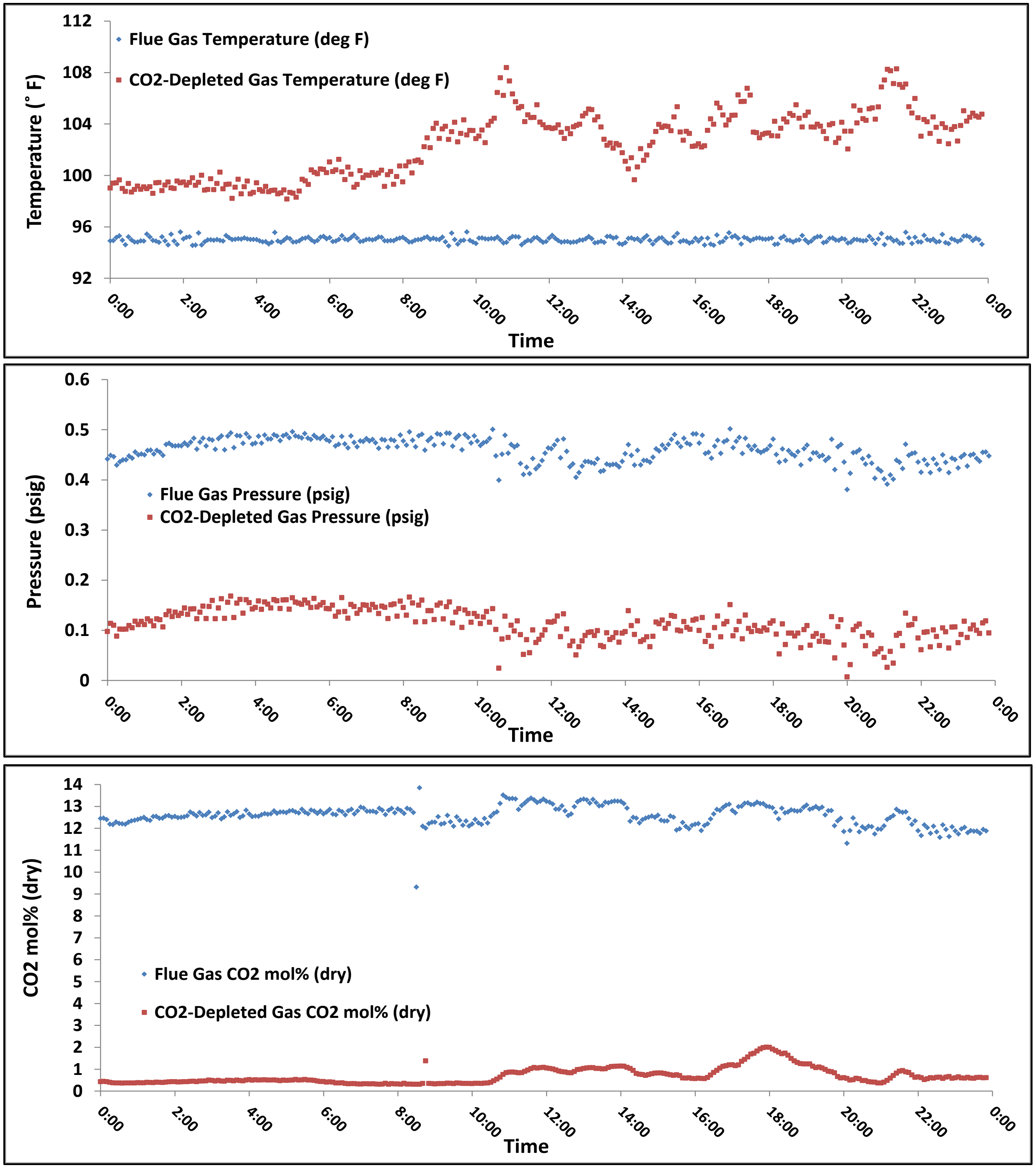


Figure 8: Typical flue gas and CO_2-depleted gas process conditions (temperature, pressure, and CO_2 mol%) on 07/05/2016 during long-duration PCC testing.

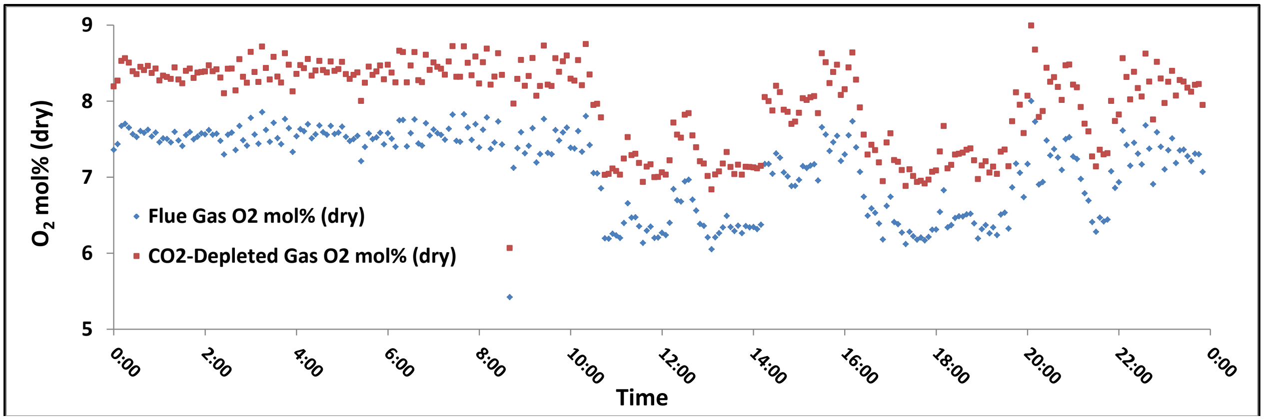


Figure 9: Flue gas and CO_2-depleted gas O_2 mol% on 07/05/2016 during long-duration PCC testing.

7. CO_2 Purity in Gaseous Product Stream after Regeneration

The Linde-BASF technology can purify the CO_2-product off of the stripper column up to 99.9 mol% CO_2 on a dry basis. Essentially all of the nitrogen and nearly all of the oxygen leaves through the top of the absorber in the CO_2-depleted gas, resulting in an extremely low concentration of O_2 in the CO_2 product gas leaving the stripper column on the order of 0 to 100 ppm during operation. Figure 10 presents the O_2 concentration (ppm) in the CO_2 product gas for a typical day during the long-duration test campaign, which shows that the O_2 concentration can be brought within limits required for CO_2 utilization applications such as enhanced oil recovery.

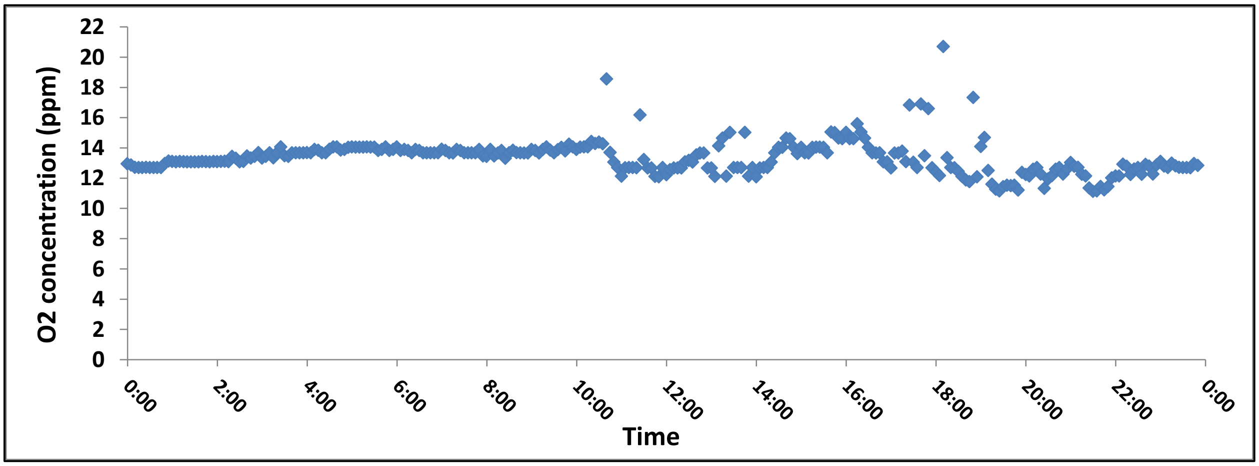


Figure 10: O_2 concentration (ppm) in CO_2 product gas leaving top of stripper column on 07/05/2016 during long-duration test campaign (daily average = 13.34 ppm).

8. Steam Requirements

Figures 6A and 6B in Section 4 demonstrated that the specific energy consumption is reduced from 3.61 GJ/tonne CO_2 for MEA solvent-based PCC processes to as low as 2.70 GJ/tonne CO_2 for the Linde-BASF PCC pilot operating at 3.4 bara stripper pressure in Wilsonville, AL. Figures 11 and 12 below depict the steam requirements (lb/hr) and corresponding CO_2 recovery (%). Here, CO_2 recovery is defined as the CO_2 mass flowrate in the gaseous CO_2 product exiting the stripper divided by the CO_2 mass flowrate in the flue gas. An average of 90% CO_2 recovery was maintained throughout long-duration testing along with consistently low specific energy consumption over the same period. Notably, the CO_2 recovery was also maintained at 90% during the last week of testing in July 2016 when the solvent strength was slightly improved due to a small reduction in its water content. This consistent 90% CO_2 recovery indicates that the reduction in specific energy consumption to ~2.72 GJ/tonne CO_2 measured at that time can be directly compared to the rest of the data from long-duration pilot testing.

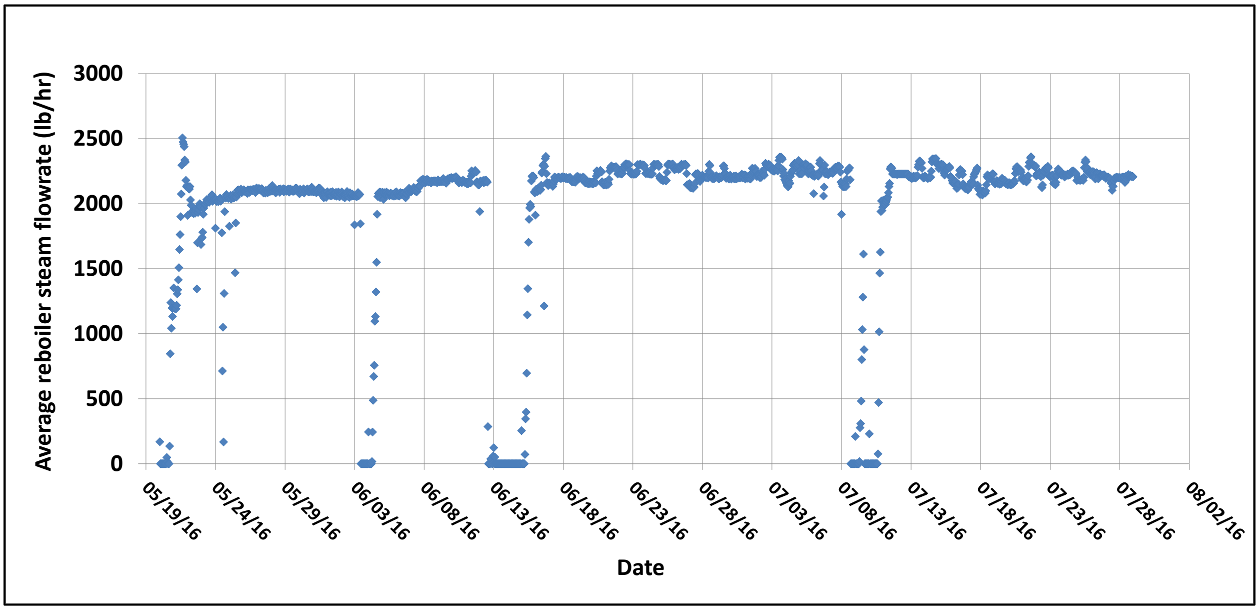


Figure 11: Hourly average steam flow rate (lb/hr) into reboiler long-duration testing.

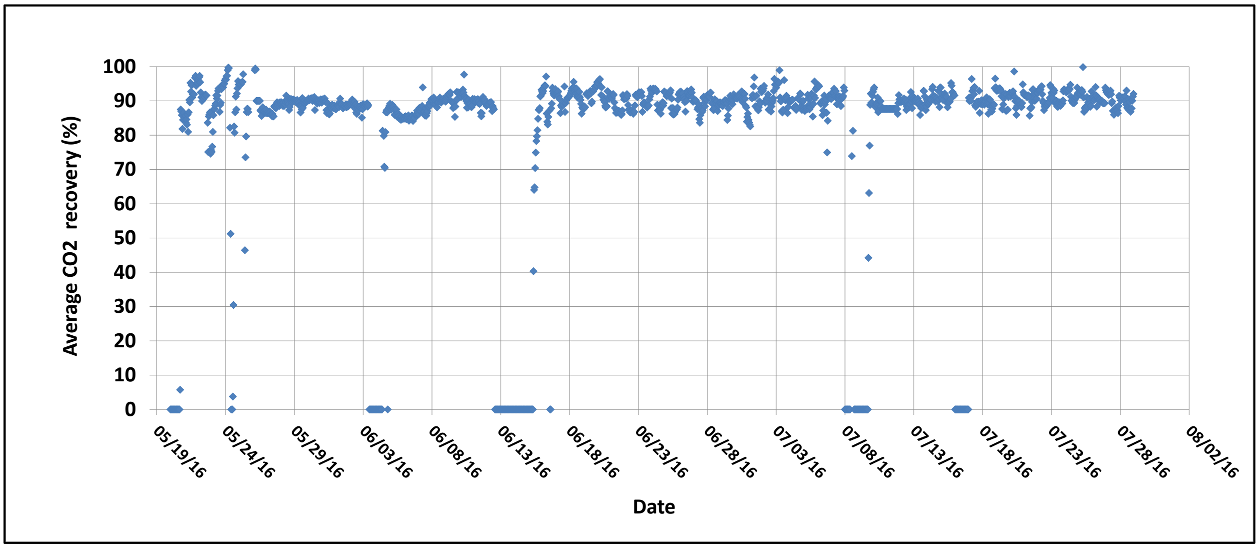


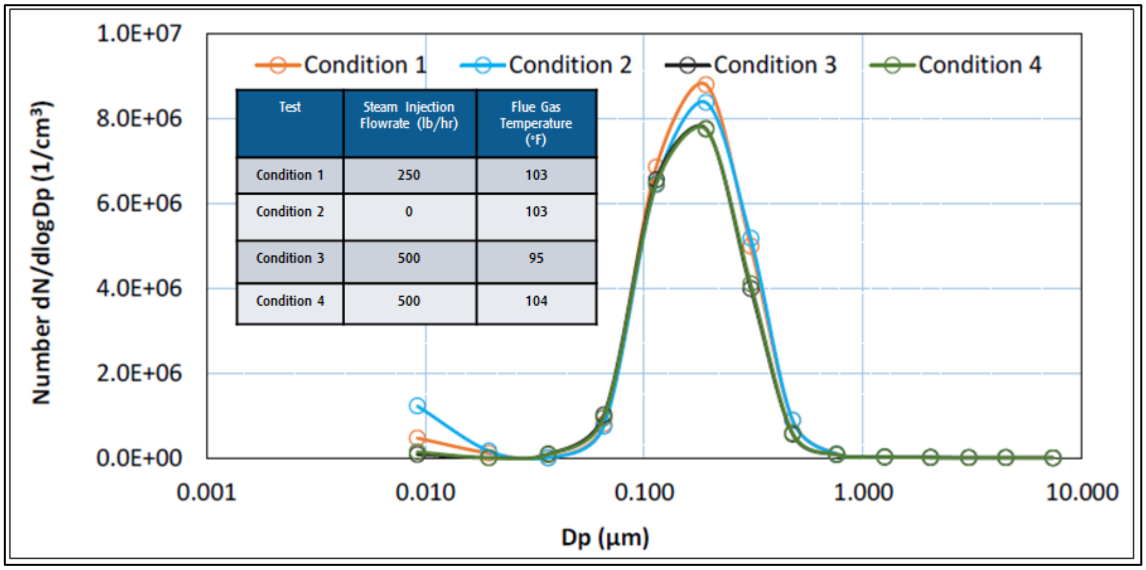
Figure 12: Hourly average CO_2 recovery (%) during long-duration testing.

9. Relevant Process Findings and Learnings

Significant process findings gained from the Linde-BASF PCC pilot testing include 1) the impact of high concentrations of nano-sized aerosol particles in the flue gas on solvent emissions with the CO_2-depleted gas, 2) an understanding of the mechanisms and operational strategies for maintaining the water balance of the process and solvent, and 3) evaluation of process parameters that have significant impact on reducing the specific energy consumption (GJ/tonne CO_2) for the PCC process. Other notable learnings included the importance of reducing vaporization of CO_2-rich solvent after the CO_2-lean/CO_2-rich solvent heat exchanger by throttling of the inlet valve to the stripper column, and the development of methods to mitigate the operational challenges caused by daily fluctuations of the flue gas CO_2 mol% composition.

9.1 Impact of high concentrations of nano-sized aerosol particles in flue gas on solvent emissions

During parametric testing, measured rates of solvent losses (kg amine/MT CO_2 captured) were higher than expected, leading to a number of operational challenges including more solvent deliveries to the plant than planned, difficulty in controlling the stripper column sump level on a day to day basis, and high variation in specific regeneration energy due to constantly changing pilot plant solvent amine composition. Based on earlier testing conducted at the Linde-BASF PCC pilot in Niederaussem, Germany, it was determined that aerosol particles in the flue gas were contributing to the solvent losses at the Wilsonville, AL pilot. The previous testing conducted in Niederaussem revealed that high concentrations of very fine nano-sized aerosol particles (< 50 nm diameter particles) in the flue gas fed to the absorber of the PCC plant could bind to solvent amine and carry significant volumes of amine out of the absorber with the treated gas. Based on these studies, it was discovered that if the concentrations of very fine aerosol particles (< 50 nm diameter) in the flue gas are maintained below 10^4 particles/cm^3, then the volume of aerosol-driven solvent losses could be greatly reduced. Figure 13 presents the results of flue gas aerosol particle concentration and particle size distribution measurements conducted by Southern Research at the Wilsonville, AL pilot in 2015 using advanced electric low pressure impactor (ELPI) analysis equipment. As shown, the average aerosol particle concentration for 100 nm-diameter aerosol particles is roughly 5×10^6 particles/cm^3, which is significantly above the safe threshold of 10^4 particles/cm^3 for very fine aerosol particle sizes. The aerosol characterization measurements during parametric testing were conducted in December 2015 for a flue gas flowrate of 9,000 lb/hr and an average flue gas CO_2 content of 11.4 mol% (dry). The four test conditions evaluated during testing are shown in the table accompanying Figure 13. Here, steam injection into the flue gas using a specialized nozzle was assessed as a potential method to reduce the flue gas aerosol particle concentration, but its use had little to no measurable impact.

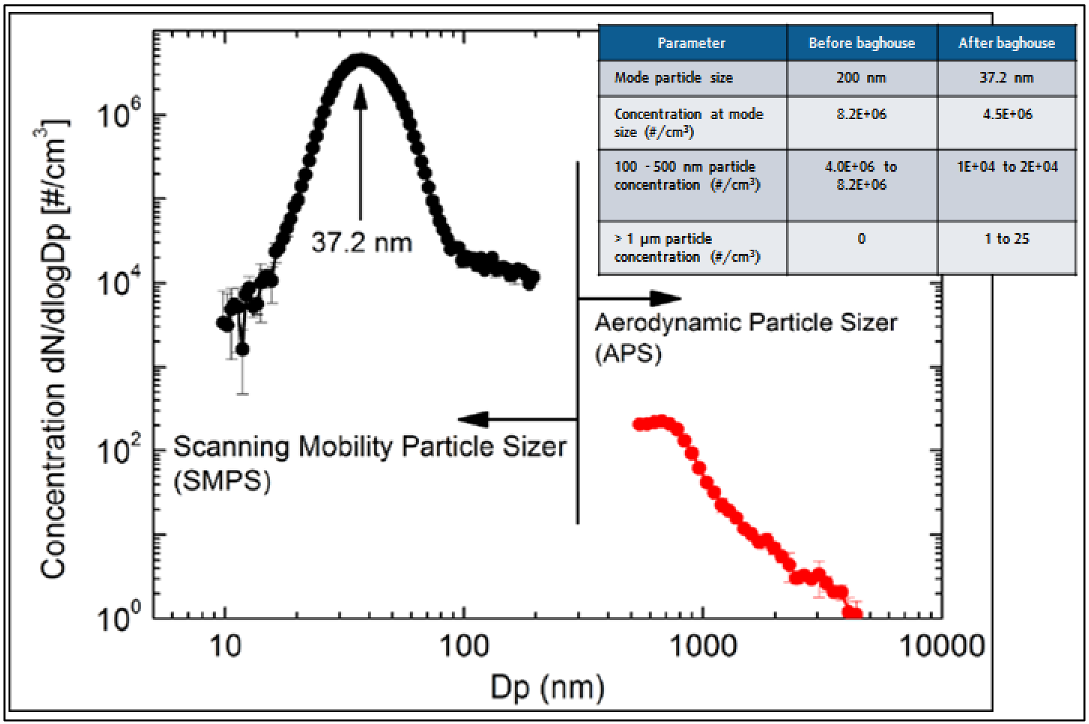


Test	Steam Injection Flowrate (lb/hr)	Flue Gas Temperature (°F)
Condition 1	250	103
Condition 2	0	103
Condition 3	500	95
Condition 4	500	104

Figure 13: Aerosol particle number concentration (# of particles/cm^3) and particle size distribution measured at Linde-BASF pilot in Wilsonville, AL in December 2015 during parametric testing before baghouse installation.

For isokinetic measurements needed to quantify solvent emissions, a sampling probe was inserted into a 4" FRP pipe connected to the treated gas stream with the inlet of the probe facing directly towards the oncoming treated gas flow. The flow rate of the treated gas sampled was controlled using a pump and the gas was cooled in an ice bath to 0ºC so that liquid condensate (containing water and trace amounts of amine) could be collected for amine content analysis via laboratory gas chromatography (GC) and titration methods.

An activated carbon injection baghouse was installed in the E.C. Gaston power plant delivering flue gas to the Linde-BASF pilot in 2016 before the start of long-duration testing. After the baghouse installation, the measured aerosol particle concentrations in the inlet flue gas to the absorber decreased significantly (Figure 14), especially for particle sizes in the range of 100-500 nm in diameter. Based on measured process data, the baghouse provided an effective mechanism to reduce the number of small to medium-sized aerosol particles in the flue gas (due to carbon in the baghouse adsorbing the SO_3), leading to substantially reduced aerosol-driven solvent emissions from the PCC pilot evaluated during long-duration testing compared to those measured during parametric testing in 2015. The aerosol characterization measurements from the long-term test period were conducted by PhD students from Washington University St. Louis in July 2016 using a novel scanning mobility particle sizer for smaller diameter particles (< 200 nm) and an aerodynamic particle sizer for larger particles (> 500 nm). In contrast to the work performed by Southern Research, the analysis conducted by Washington University St. Louis used equipment specifically designed to measure particles below 100 nm. The Washington University St. Louis analysis consequently showed higher concentrations of particles < 100 nm in diameter relative to the data measured by Southern Research in 2015, indicating that these smaller particles were not fully quantified during parametric testing. The table accompanying Figure 14 summarizes the differences in aerosol concentration measurements before and after the baghouse installation.



Parameter	Before baghouse	After baghouse
Mode particle size	200 nm	37.2 nm
Concentration at mode size (#/cm³)	8.2E+06	4.5E+06
100 - 500 nm particle concentration (#/cm³)	4.0E+06 to 8.2E+06	1E+04 to 2E+04
> 1 µm particle concentration (#/cm³)	0	1 to 25

Figure 14: Aerosol particle number concentration (# of particles/cm^3) and particle size distribution measured at Linde-BASF pilot in Wilsonville, AL in July 2016 during long-duration testing after baghouse installation.

Table III summarizes analysis results of isokinetic gas and liquid condensate sampling of the treated gas stream leaving the top of absorber during the parametric and long-duration test campaigns.

Table III: Specific amine losses (kg amine/MT CO_2) evaluated from isokinetic sampling and amine content measurements of treated gas leaving top of absorber during parametric and long-duration testing campaigns at Linde-BASF PCC pilot in Wilsonville, AL.

Parametric Test Campaign (before baghouse)		
Isokinetic Test #	**Isokinetic Sample Collection Date**	**Specific Amine Emissions (kg amine/MT CO_2)**
1	08/04/15	1.43
2	08/04/15	0.47
3	08/05/15	0.25
4	08/05/15	0.17
5	08/06/15	0.16
6	08/06/15	0.22
7	08/07/15	0.15
8	08/07/15	0.06
9	10/30/15	0.27
10	10/30/15	1.15
11	11/02/15	0.39
12	11/02/15	0.40
13	11/03/15	0.32
14	11/04/15	0.28
15	11/04/15	0.90
16	11/05/15	0.74
17	12/17/15	1.01
18	12/17/15	0.75
19	12/18/15	0.24
20	12/18/15	0.27
21	12/18/15	0.27
22	12/21/15	0.24
23	12/21/15	0.25
Long-Duration Test Campaign (after baghouse)		
Isokinetic Test #	**Isokinetic Sample Collection Date**	**Specific Amine Emissions (kg amine/MT CO_2)**
24	07/21/16	0.0116
25	07/21/16	0.0100
26	07/22/16	0.0074
27	07/22/16	0.0090

9.2 Understanding mechanisms and operational strategies for maintaining the water balance

A consistent water balance for the Linde-BASF CO_2 capture process tested at NCCC could be maintained through temperature control of the treated gas leaving the top of the absorber column. Inlet water flows to the PCC pilot consisted of water contained in the flue gas entering the absorber, demineralized water fed to the upper wash water sections of the absorber, and water in the solvent that was added to the process from the solvent storage tank. Outlet water flows consisted of water leaving the process through the treated gas at the top of the absorber and water drained from the reflux drum of the stripper. Water was only occasionally drained from the reflux drum during the parametric test campaign to assist in control of the stripper sump level; water was never drained from the reflux drum during the long-duration test campaign as it was not necessary for level control. Due to the NCCC pre-scrubber operating upstream of the Linde-BASF PCC pilot, the flue gas fed to the flue gas cooler of the PCC process was saturated with water at the measured pressure and temperature. Based on water saturation correlations, the water content in the flue gas was determined from the measured pressure and temperature to evaluate the mass flow rate of water entering the absorber in the flue gas. Likewise, due to use of the wash water sections located at the upper half the absorber column, the treated gas was saturated with water and the mass flow rate of water leaving the absorber in the treated gas was similarly calculated. The mass flow rates of demineralized water entering the wash sections and water drained from the reflux drum were measured using calibrated mass flowmeters and controlled via automatic flow control valves. Due to the exothermic absorption of CO_2, an expected temperature rise in the absorber occurred during operation. The absorber interstage cooler mitigated this temperature rise in the column's lower sections, but the absorption of CO_2 into the CO_2-lean solution entering the absorber above the interstage cooler still increased the temperature of the CO_2-depleted gas flowing up the column. To control the temperature of the gas exiting the absorber, wash water sections with water-cooled plate and frame heat exchangers were positioned at the upper half of the column to reduce the temperature of the CO_2-depleted gas flowing up the absorber. Since the temperature of the treated gas saturated with water at the given absorber pressure determines the water content in the gas leaving the absorber, the water balance of the PCC process was maintained by controlling the treated gas temperature at the top wash section.

At the Linde-BASF PCC pilot at NCCC, the absorber column used automatic level control. In contrast, the stripper level was not directly controlled and fluctuated based on process conditions. The overall process water balance was evaluated using the measured liquid level of the stripper column once the correct solvent water composition was obtained after pilot plant startup. The liquid level in the stripper sump was accurately determined by a differential pressure measurement using the dimensions and positions of the level measurement probes along with the density of the solvent. As the stripper level decreased during operation below a desired threshold (30%, for example), the treated gas temperature leaving the absorber was subsequently reduced by increasing the cooling water flow to the top water wash section heat exchanger of the absorber. This temperature reduction at the top of the absorber allowed more water to be retained in the absorber and moved to the stripper sump through action of the automatic absorber level control valve. Similarly, a decrease in the stripper level was observed when the cooling water flowrate to the top absorber section heat exchanger was reduced. The solvent composition (amine, water and CO_2 wt%) was evaluated with daily GC and titration measurements of CO_2-lean and CO_2-rich solution samples. Based on the results of daily solvent water content analysis, the stripper level was adjusted to meet the desired solvent composition by changing the treated gas temperature. Control of the stripper level was much easier during long-duration testing since the amine content of the solvent was more stable compared to that measured during parametric testing when significant aerosol-driven solvent emissions were experienced. In addition, inherent process stability was improved during long-duration testing because only one operating condition was maintained in contrast to parametric testing when several process variables were changed on a day-to-day basis according to the parametric test schedule.

Figures 15 and 16 illustrate the differences in absorber and stripper levels measured over the course of several days during parametric and long-duration test periods. The stripper level was much more stable during long-duration testing at around 40%. In addition, the absorber was allowed to be maintained at one level for a much longer period without having to adjust it to allow the stripper level to remain in a controllable range necessary for process stability and safety. These results reflect the fact that the water content of the solvent and the overall process water balance was maintained within a narrower, more stable range during long-duration testing relative to the parametric testing campaign. The increased process stability during long-duration testing is a result of the reduced aerosol-driven solvent losses measured after the power plant baghouse was installed.

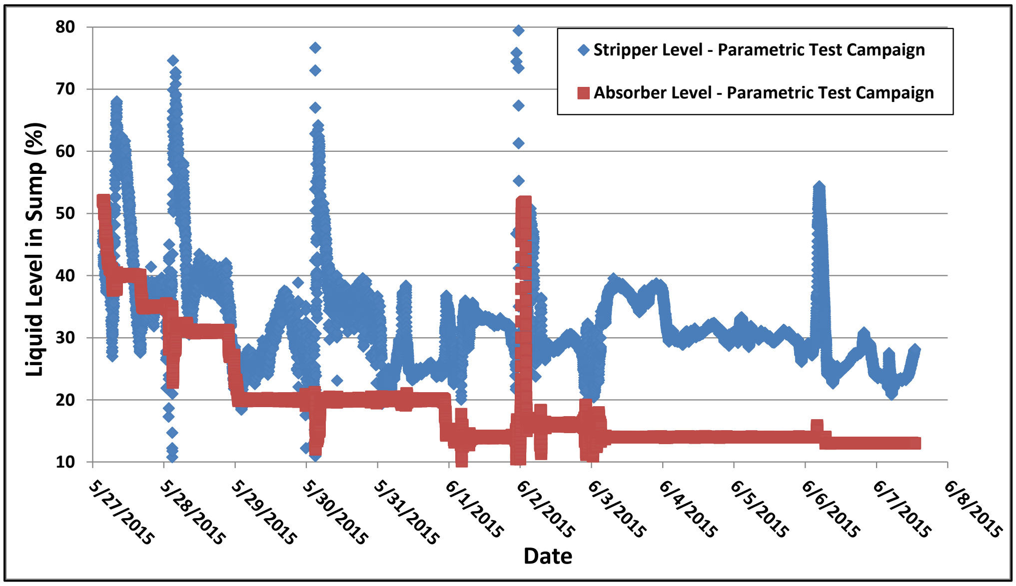


Figure 15: Stripper and absorber sump levels over the course of several days during parametric testing at the Linde-BASF PCC pilot in Wilsonville, AL.

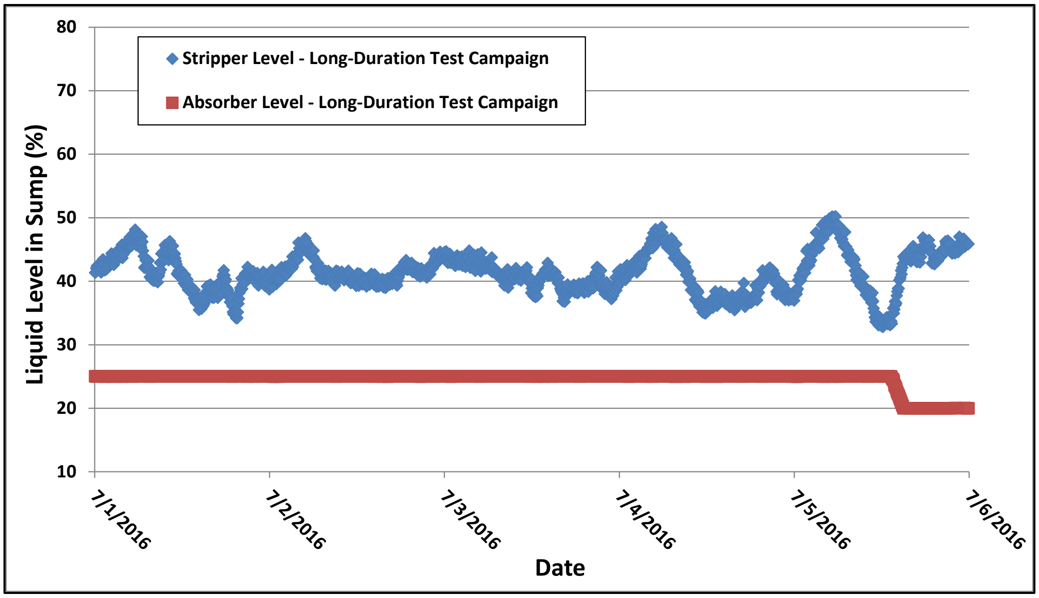


Figure 16: Stripper and absorber sump levels over the course of several days during long-duration testing at the Linde-BASF PCC pilot in Wilsonville, AL.

9.3 Evaluation of process parameters with high impact on reducing regeneration energy

The impact of process variables tested on the specific regeneration energy consumption (GJ/tonne CO_2) evaluated during the parametric test campaign in 2015 is summarized in Table IV.

Table IV: Impact of process variables tested on the specific regeneration energy consumption (GJ/tonne CO_2) evaluated during the parametric test campaign.

Test Parameter	Impact on specific regeneration energy (GJ/tonne CO_2)
Flue Gas Temperature (ºF)	Flue gas temperatures between 92-96 ºF provide improved specific regeneration energy (~5%) compared to higher flue gas temperatures (104 ºF and above)
Absorption Intermediate Cooler Temperature (ºF)	Reduced temperature appears to be beneficial by ~2-4%. Absorption intermediate cooler outlet temperature equal to 104 ºF offers optimum specific regeneration energy based on test results. It should be noted that the absorption intermediate cooler outlet temperature was only varied as a parameter for 34.6 psig stripper pressure.
CO_2-lean Solution Cooler Temperature (ºF)	CO_2-lean solution cooler outlet temperature equal to 104 ºF appears to provide improvement (~3%) compared to higher temperatures.
Treated Gas Temperature (ºF)	Reduced temperature appears to be beneficial. Treated gas temperatures equal to or below 100 ºF provide improved specific regeneration energy (~4%) compared to higher temperatures.
Pressure at top of regenerator column (psig)	34.6 psig (3.4 bara) stripper top pressure increases specific regeneration energy slightly (~2.2%) compared to 14.7 psig (2 bara) stripper pressure based on comparison between parametric tests conducted at 14.7 psig stripper pressure and long-duration tests performed at 34.6 psig.

The optimum solvent circulation to flue gas flowrate (L/G) ratio was determined during the parametric test campaign and applied during long-duration testing. Figure 17 compares energy consumption data collected during long-duration testing against data collected during parametric testing. Only one data point was chosen as an average, representative measurement for the specific regeneration energy measured during the long-term test campaign since the L/G ratio was not varied. The entire long-duration test was conducted using a stripper pressure of 34.6 psig (3.4 bara). The red square shown in Figure 17 corresponding to the long-duration test campaign indicates a lower specific regeneration energy than the average of the test points measured in October and November 2015 during parametric testing at 34.6 psig stripper pressure (depicted as purple diamonds in Figure 17). This difference indicates that the specific energy measured during parametric testing at 34.6 psig stripper pressure was not representative of the true minimum energy consumption of the process at the higher desorption pressure. This discrepancy can be attributed to the negative impact of higher water content in the solvent experienced during parametric testing relative to the long-duration test campaign as well as use of non-optimal L/G ratios at the higher stripper pressure during parametric tests. Results from the parametric testing studies described in Table IV are illustrated in Figures 17, 18, 19, 20, and 21.

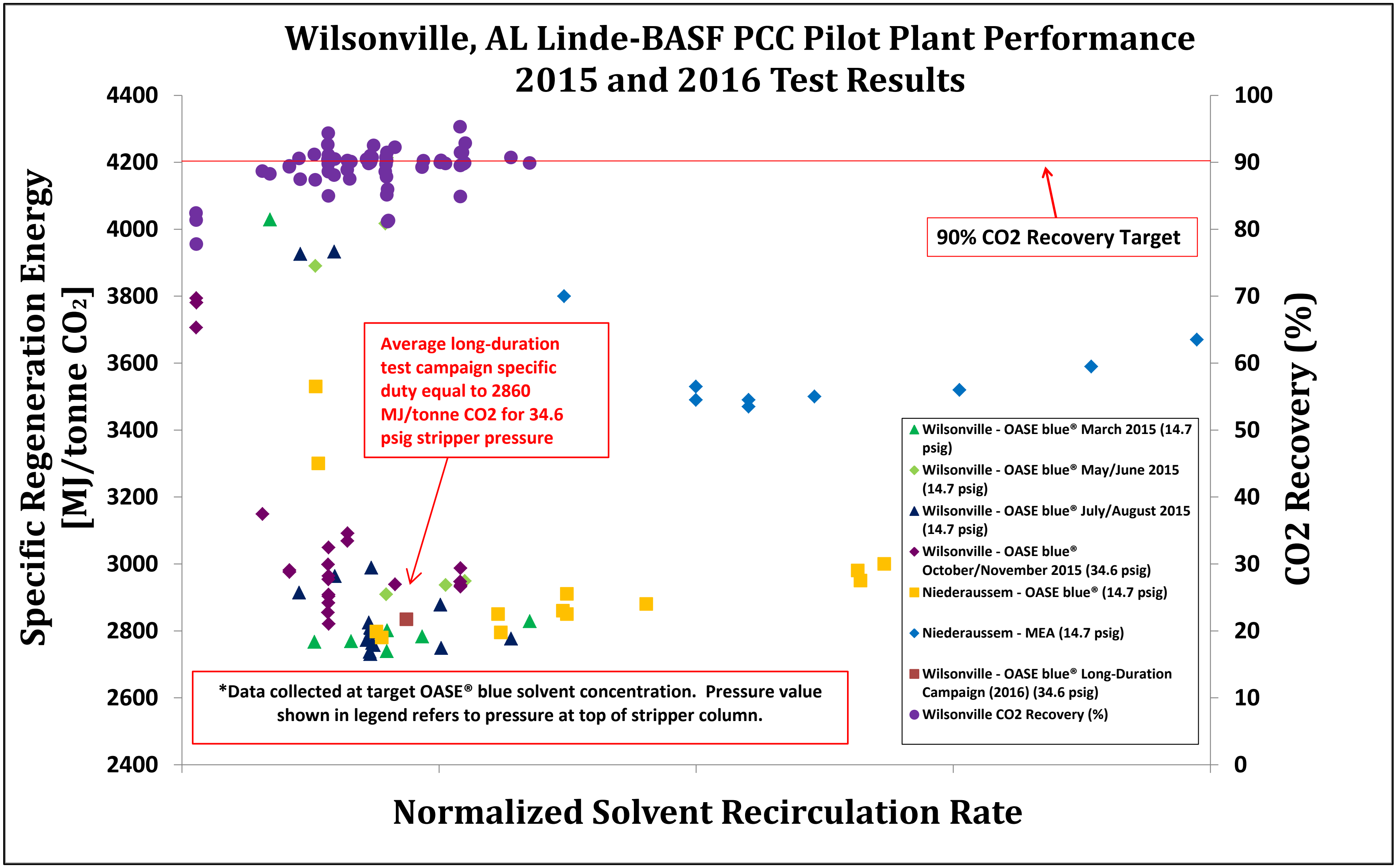


Figure 17: Comparison between parametric and long-duration test campaign results for specific regeneration energy consumption.

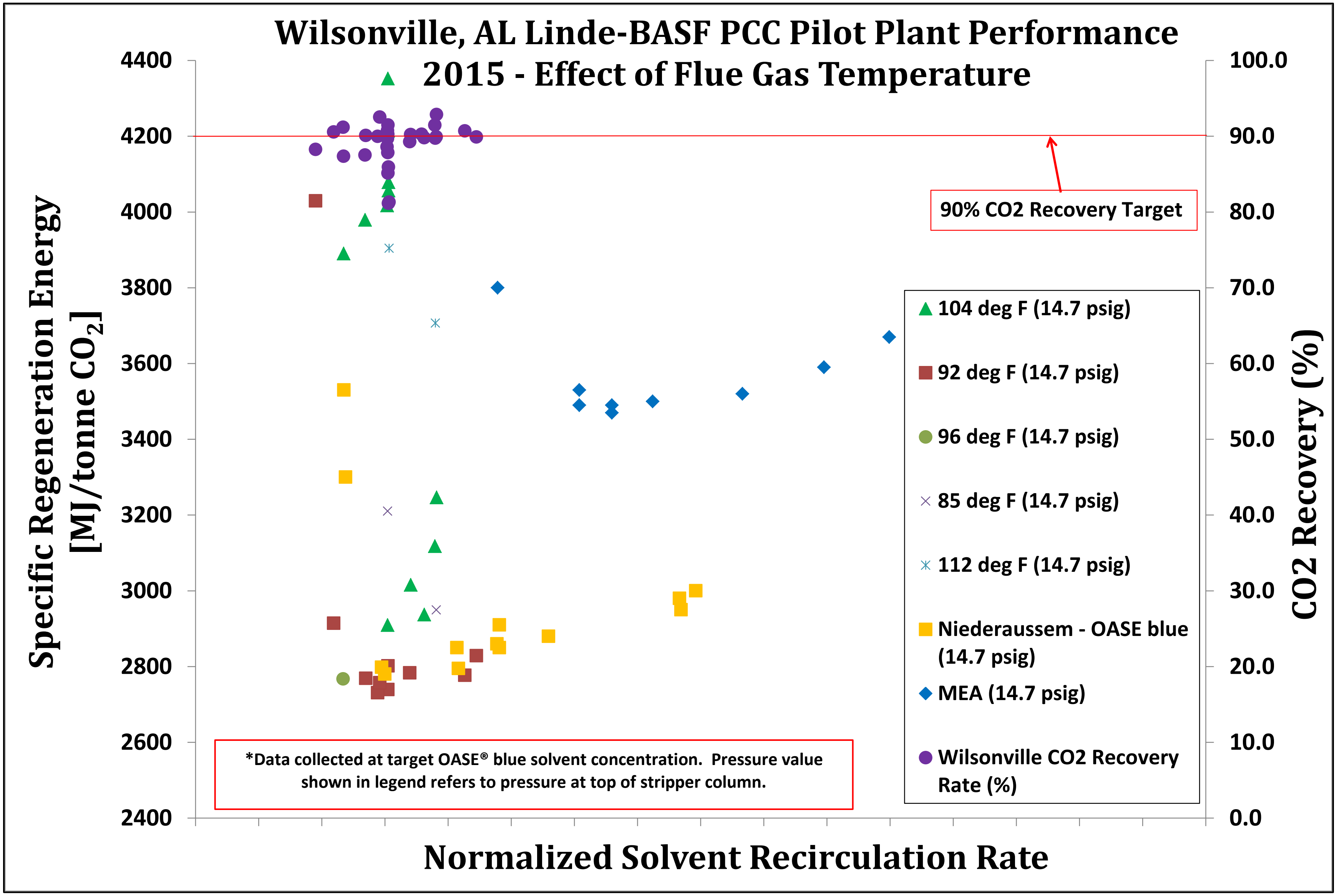


Figure 18: Effect of flue gas temperature on specific regeneration energy consumption during parametric test campaign in 2015.

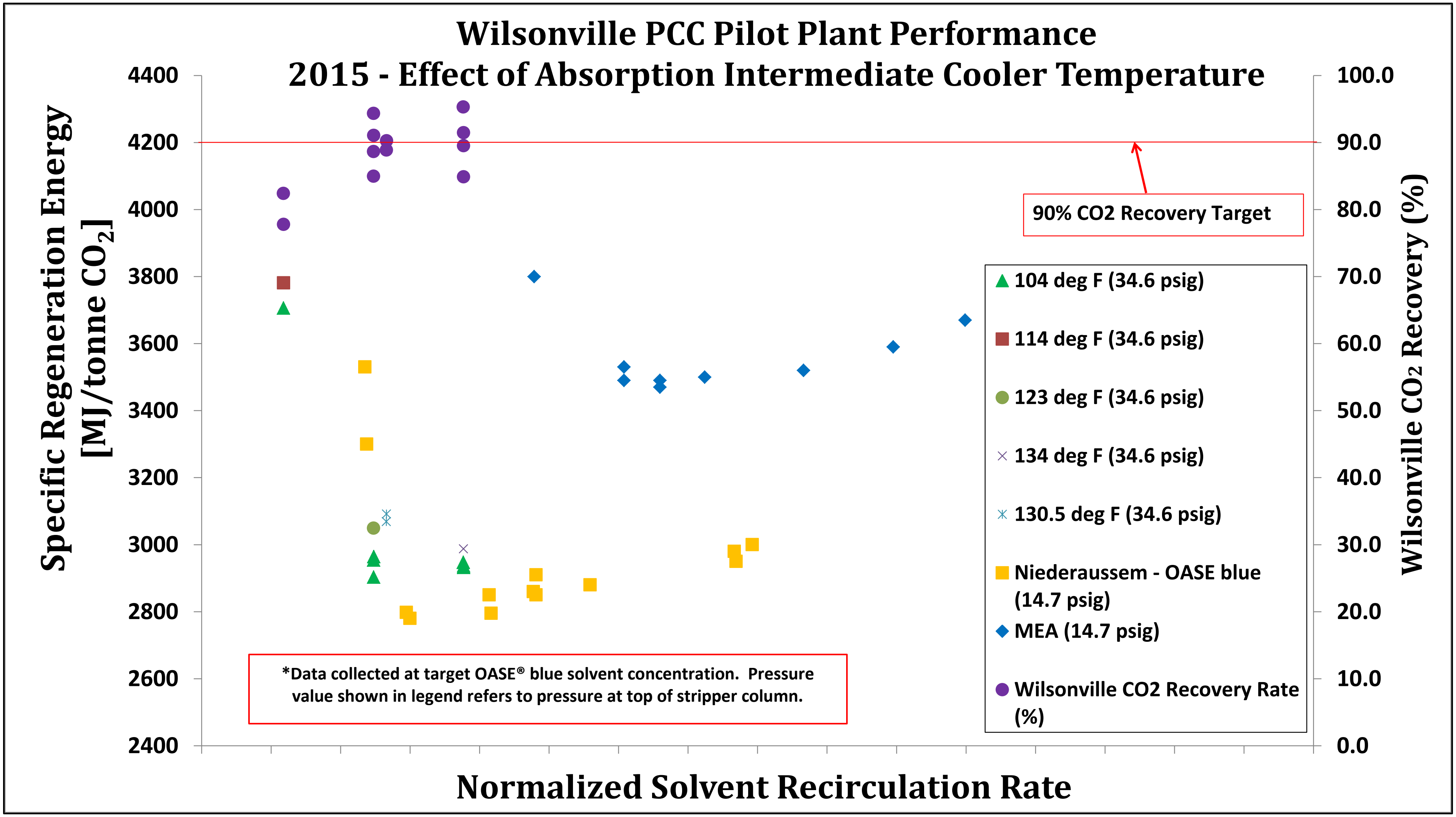


Figure 19: Effect of absorption intermediate cooler outlet temperature on specific regeneration energy consumption during parametric test campaign in 2015.

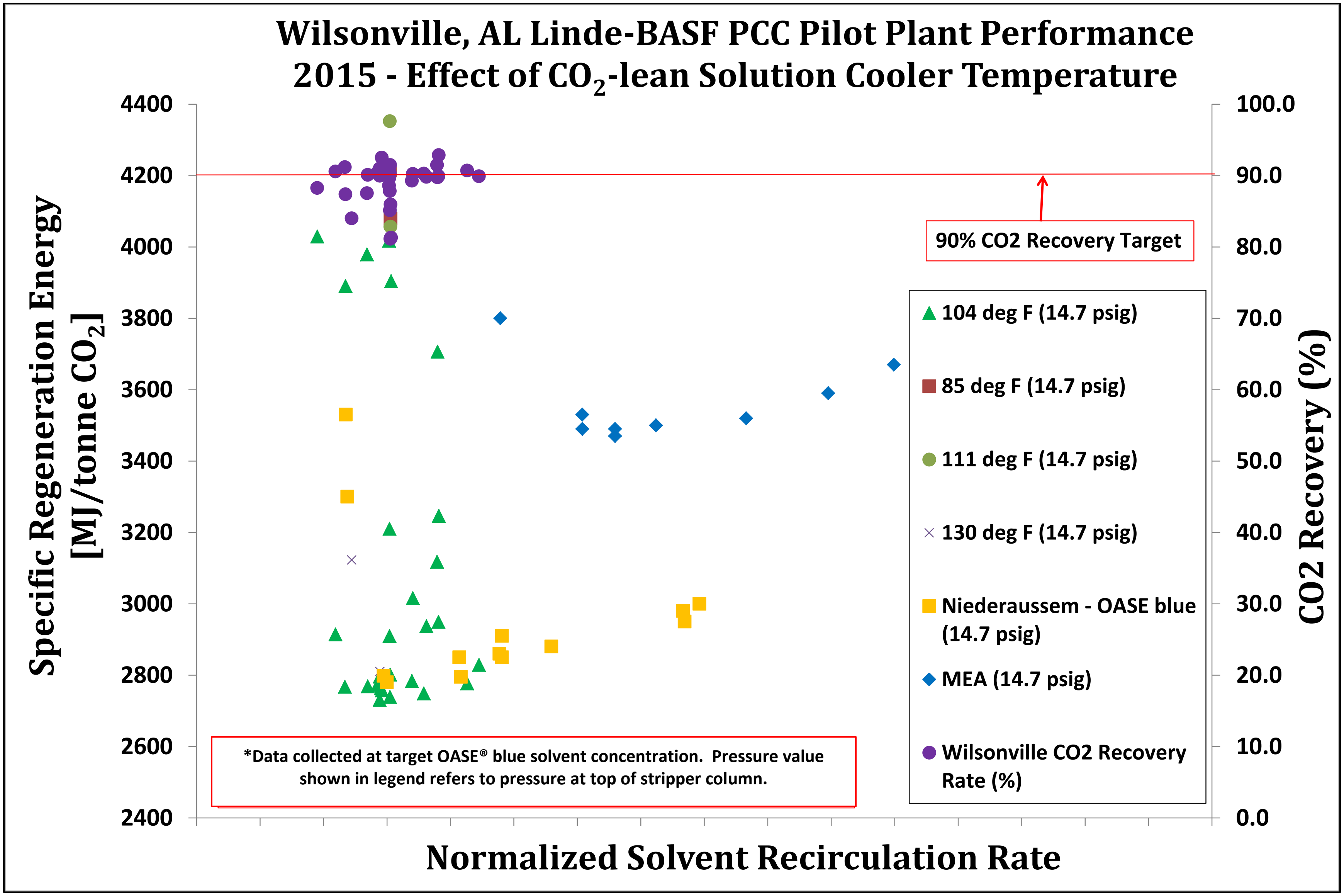


Figure 20: Effect of CO_2-lean solution cooler outlet temperature on specific regeneration energy consumption during parametric test campaign in 2015.

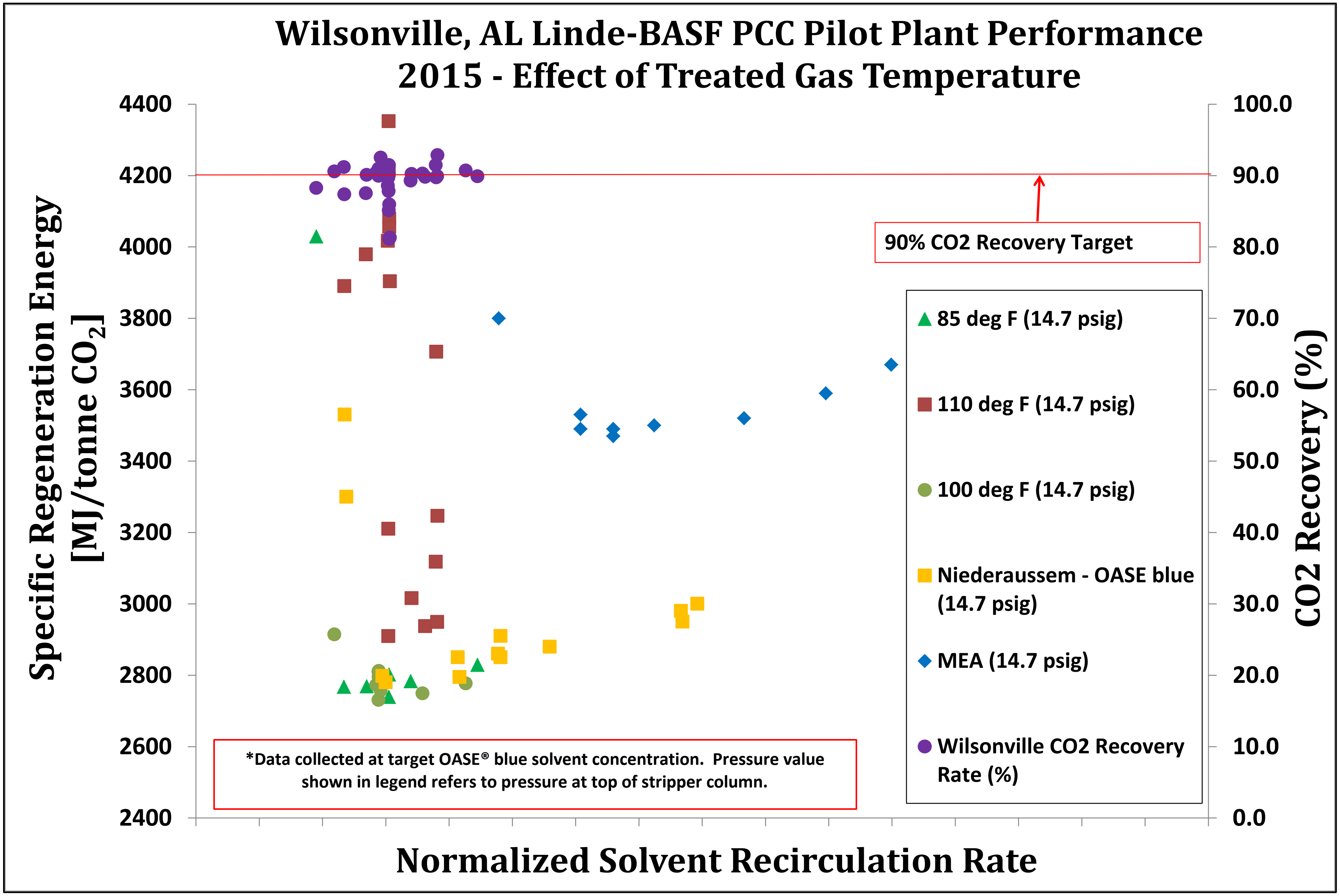


Figure 21: Effect of treated gas temperature on specific regeneration energy consumption during parametric test campaign in 2015.

9.4 Importance of throttling inlet valve to stripper column

It is known that the CO_2-rich solvent inside the pipe at the outlet of the CO_2-lean/CO_2-rich solution cross exchanger can be partially vaporized during operation depending on the pressure of the liquid in the pipe due to its high temperature (~228 °F as illustrated in Figure 22). In addition to causing process disturbances, the vaporization of CO_2 from the CO_2-rich solution to the stripper column also reduces the energy efficiency of the CO_2-lean/CO_2-rich cross exchanger by using heat from the CO_2-lean solution to vaporize CO_2 as opposed to directly increasing the temperature of the CO_2-rich solution.

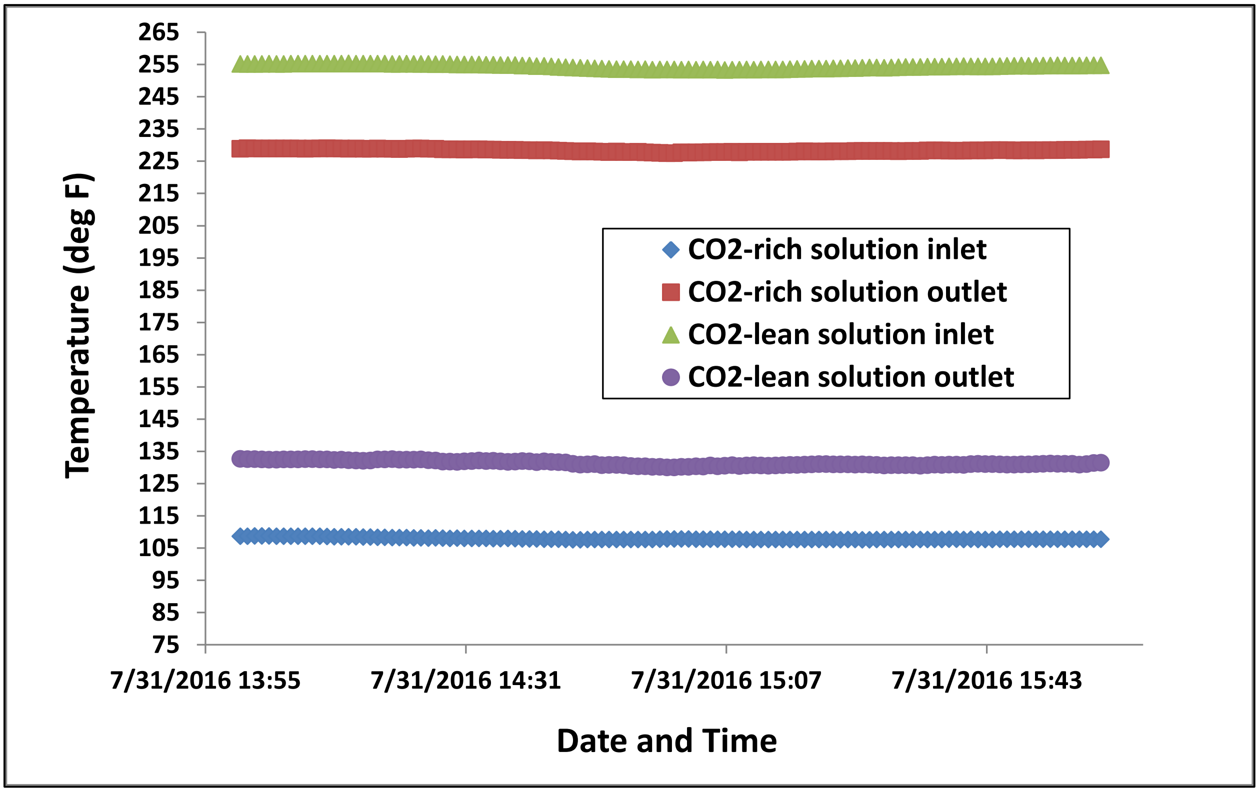


Figure 22: Typical CO_2-lean/CO_2-rich solution cross exchanger temperature profile during long-duration testing in 2016.

During operation, the vaporization of CO_2 from the CO_2-rich solution inside the pipe to the stripper caused process disturbances in the stripper and reboiler due to inconsistent liquid flow of the CO_2-rich solution into the stripper column. Normally, the pressure of the CO_2-rich solution inside the outlet pipe from the CO_2-lean/CO_2-rich solution cross exchanger is significantly higher than the pressure inside the stripper column due to expansion across a throttle valve at the inlet to the stripper. Sufficiently increasing the pressure of the solution inside the pipe to the stripper suppresses vaporization of CO_2, enabling the solvent to remain liquid in the pipe and to flash as it crosses the throttle valve and enters the lower pressure atmosphere inside the stripper column. This flashing of the CO_2-rich solution inside the stripper releases CO_2 gas and water vapor. When the pressure in the pipe leading to the stripper is too low, excessive vaporization of CO_2 from the CO_2-rich solution inside the pipe can occur. This CO_2 vapor can buildup in the pipe over short periods of time and result in large, irregular bursts of liquid and vapor into the stripper column that cause rapid fluctuations in the stripper pressure and CO_2 recovery rate even when tuned stripper pressure control is used. In addition, these bursts were audibly observed during operation through vibrations of the pipe, creating loud noises. Towards the middle of parametric testing at the end of May 2015, the Linde operations team decided to further reduce the opening of this CO_2-rich solution inlet valve from ~50% open (as it was positioned when the plant first started up in January 2015) to 2% open to observe its effect on the process. Throttling the inlet valve significantly improved the stability of the stripper column, and enhanced the steadiness of important process parameters such as stripper pressure, CO_2 recovery rate, CO_2 production flow rate, stripper liquid level, reboiler steam flow rate, and specific regeneration energy by reducing the frequency and magnitude of measured process data fluctuations. The beneficial results of throttling the CO_2-rich solution inlet valve to the stripper column are illustrated in Figures 23, 24, 25, 26, 27, and 28. The 2% throttle valve opening was maintained for the rest of the testing in 2015 and 2016.

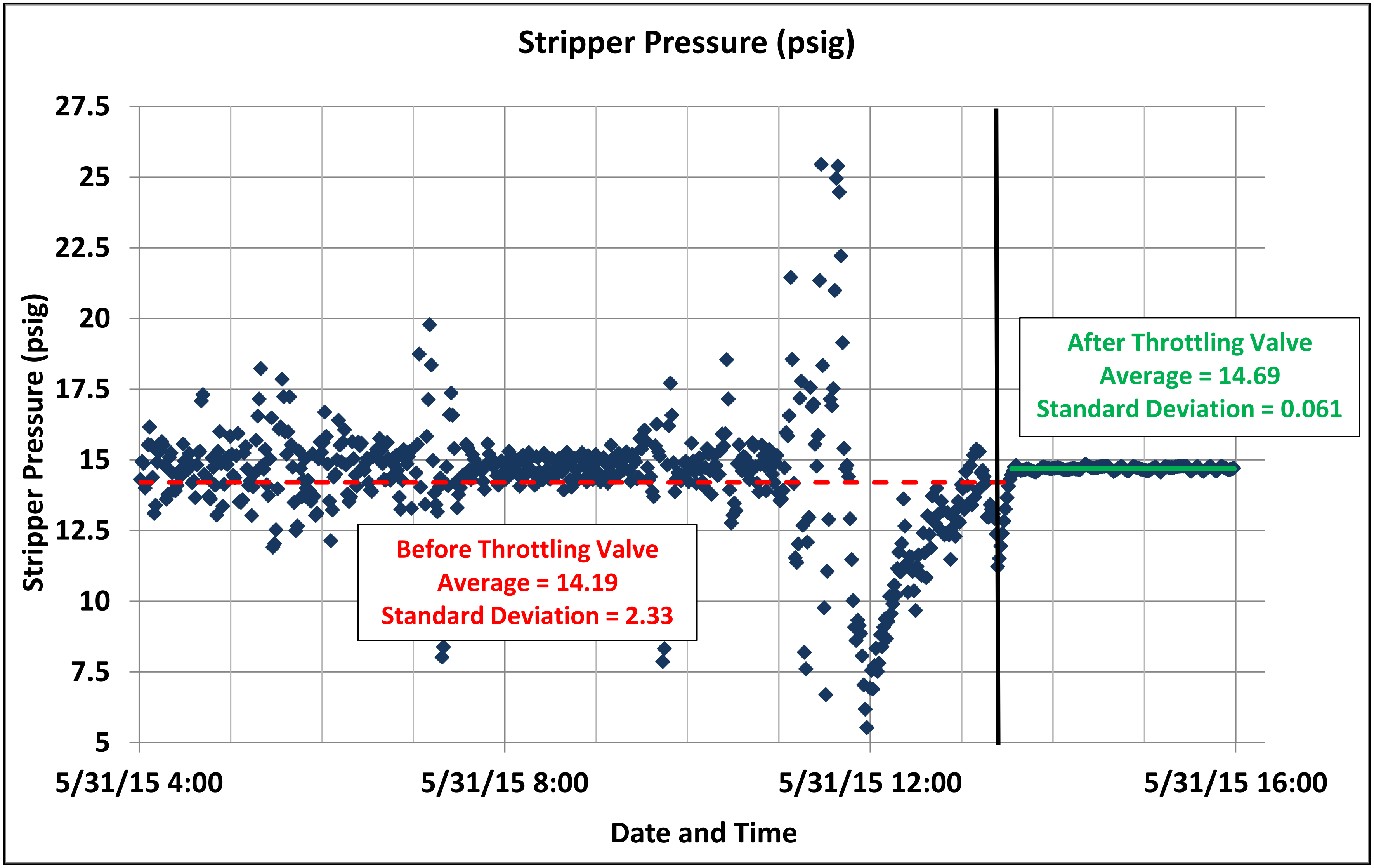


Figure 23: Stripper top pressure (psig) before and after throttling CO_2-rich solution inlet valve to stripper column.

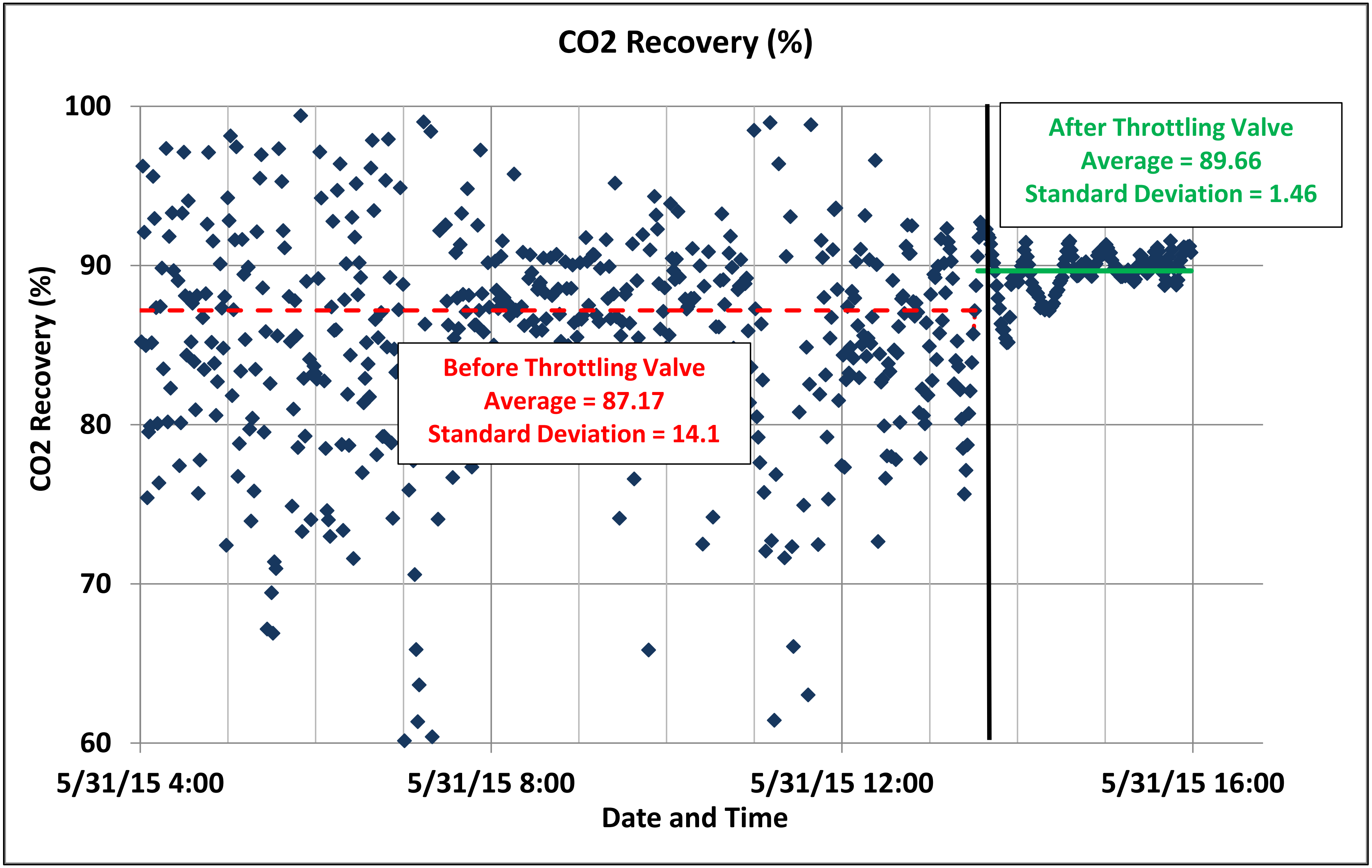


Figure 24: CO_2 recovery (%) before and after throttling CO_2-rich solution inlet valve to stripper column.

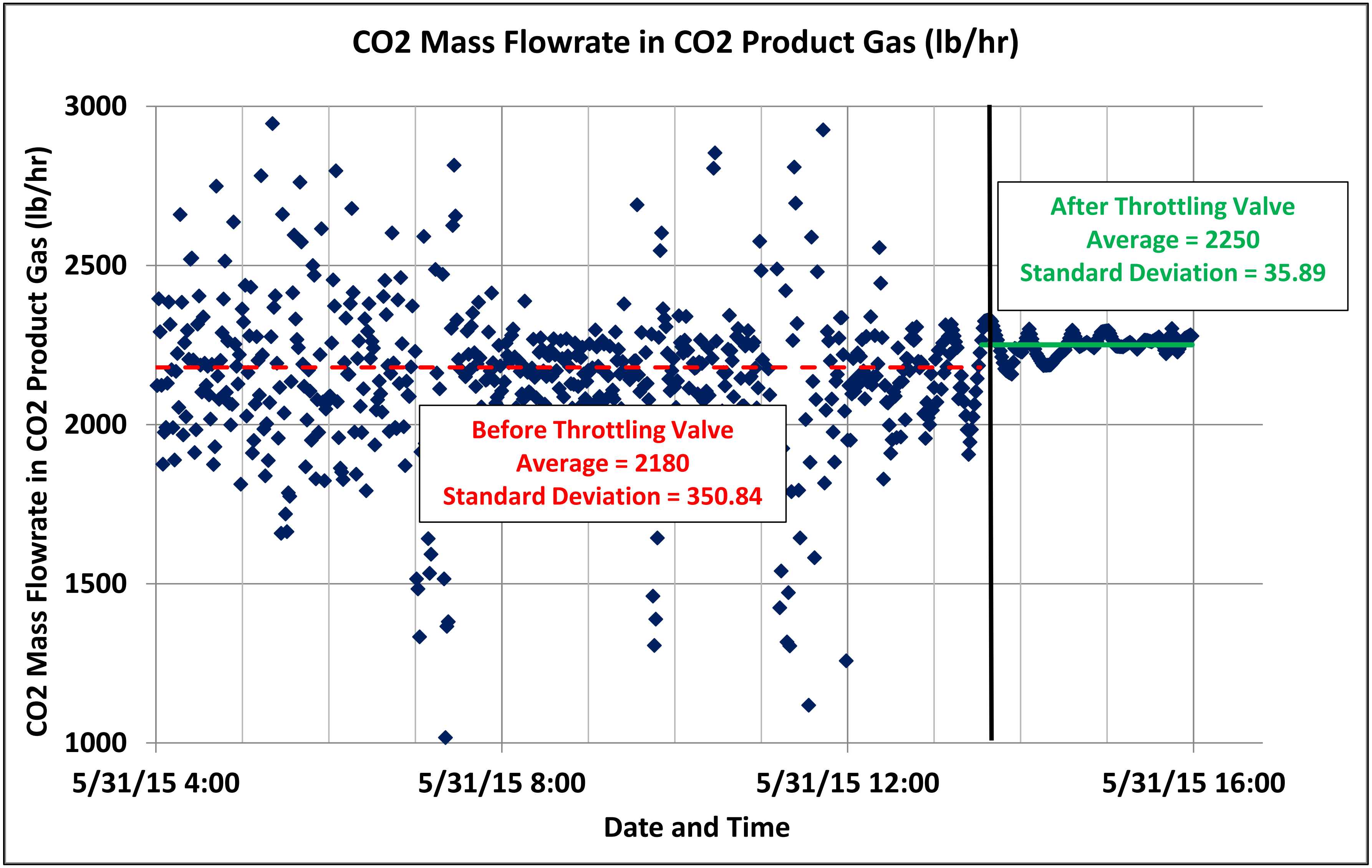


Figure 25: CO_2 mass flowrate in CO_2 product gas (lb/hr) before and after throttling CO_2-rich solution inlet valve to stripper column.

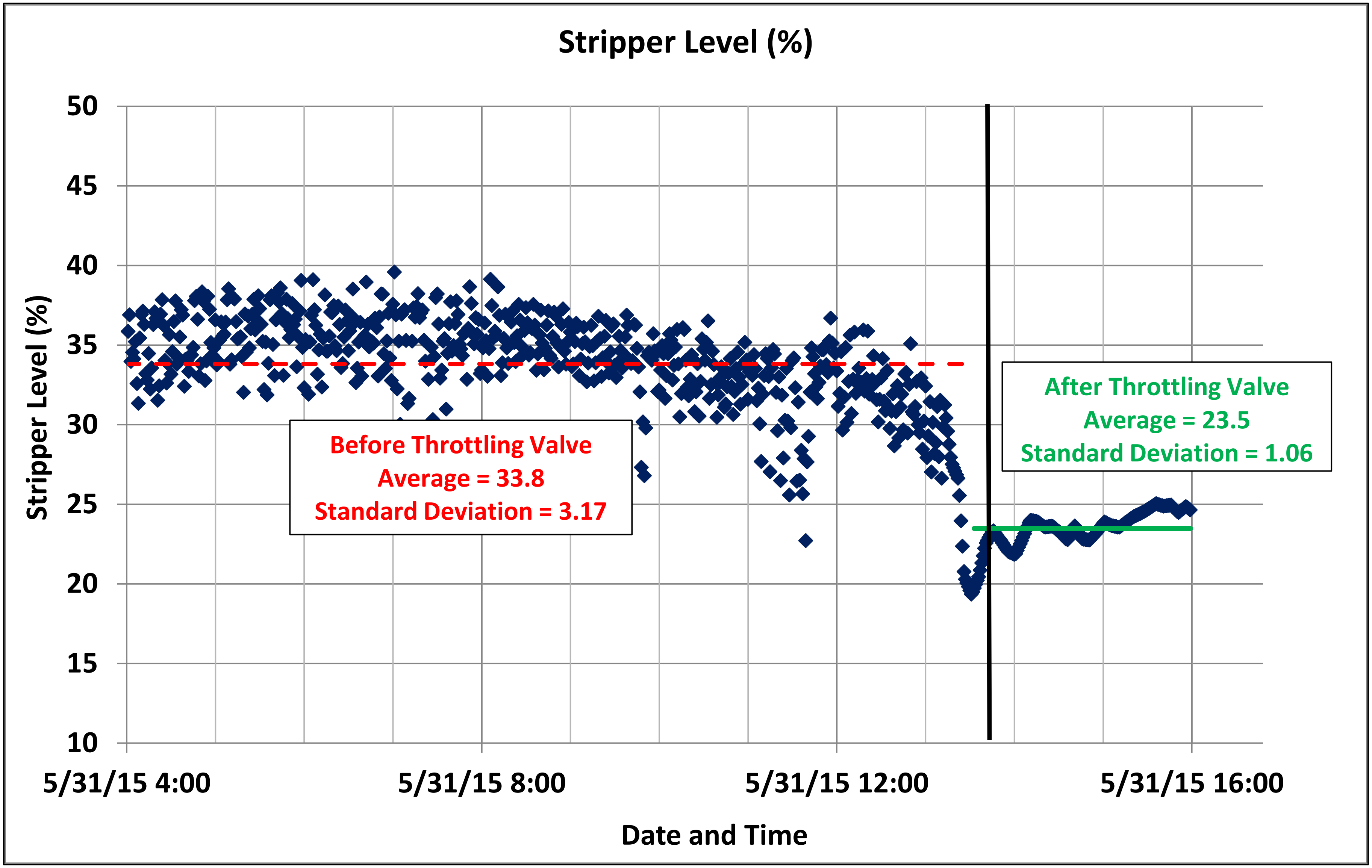


Figure 26: Stripper level (%) before and after throttling CO_2-rich solution inlet valve to stripper column.

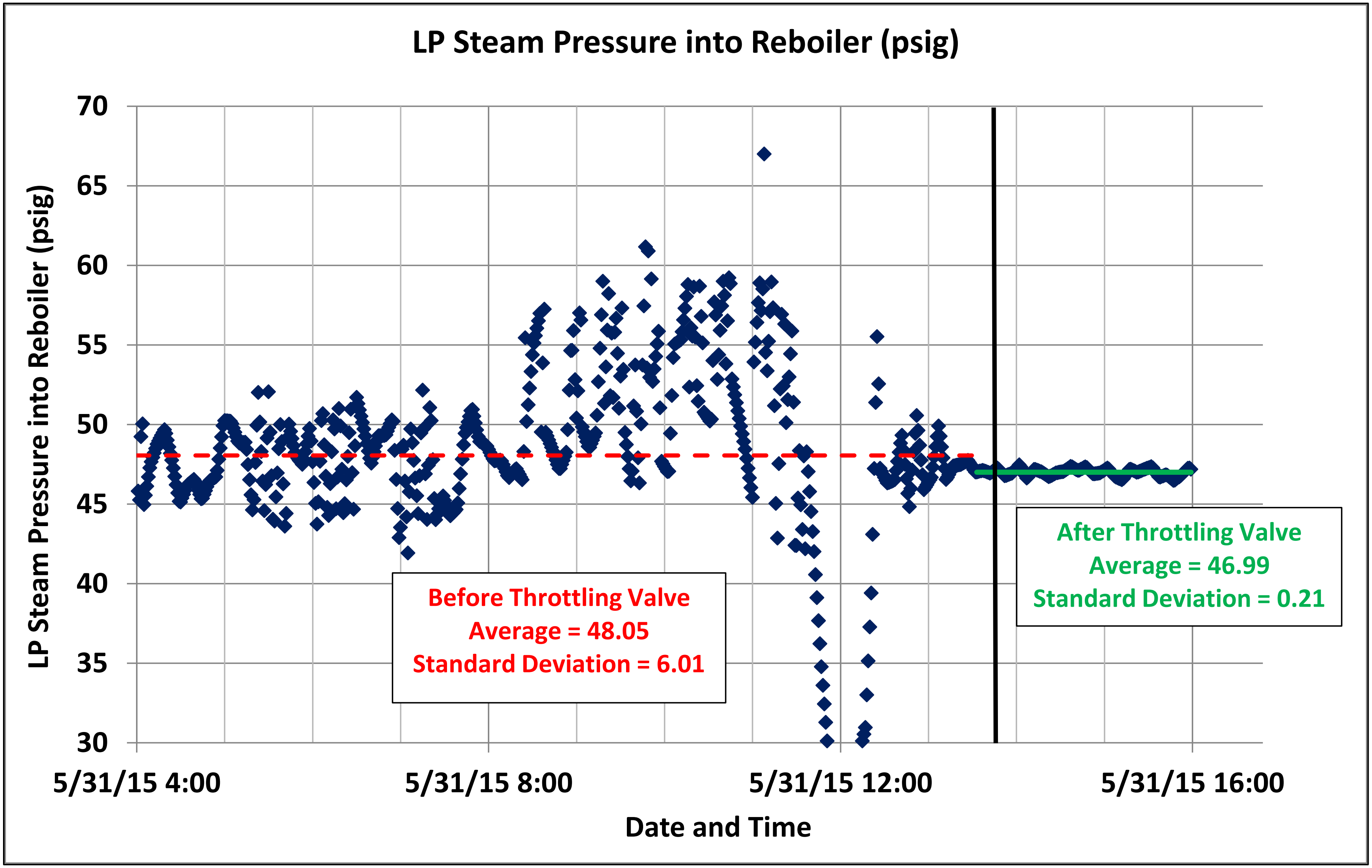


Figure 27: LP steam pressure into stripper reboiler (psig) before and after throttling CO_2-rich solution inlet valve to stripper column.

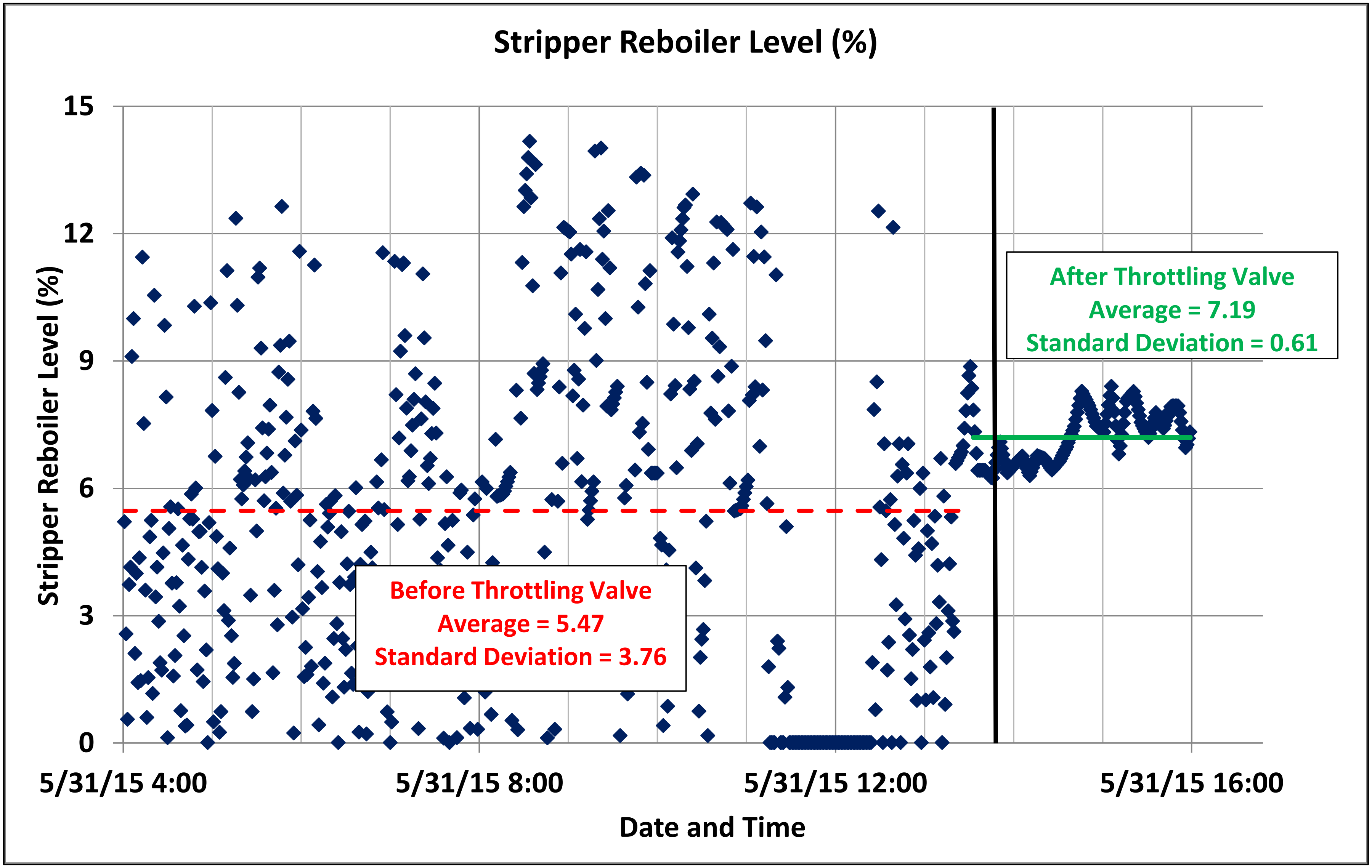


Figure 28: Stripper reboiler level (%) before and after throttling CO_2-rich solution inlet valve to stripper column.

9.5 Operational strategies to counter daily fluctuations of flue gas CO_2 mol% composition

The magnitude and frequency of daily fluctuations in the flue gas CO_2 composition were shown in Figure 4 and Figure 8 for the long-duration test campaign in 2016. A representation of typical daily flue gas CO_2 mol% variations during the parametric test campaign (03/15/2015 to 03/16/2015) is shown in Figure 29.

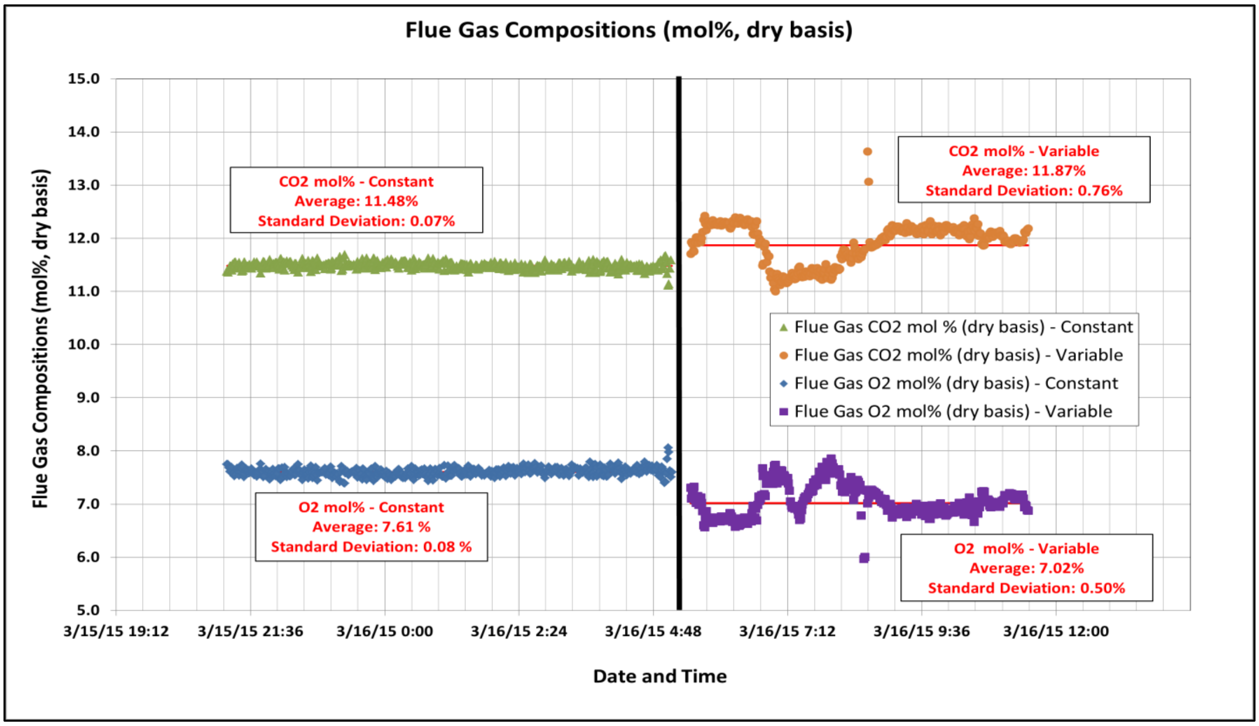


Figure 29: Typical fluctuations in flue gas CO_2 and O_2 mol% compositions (dry basis) during parametric test campaign in 2015.

Normally during both parametric and long-duration testing periods, the flue gas CO_2 mol% composition would begin to increase in the early to mid-morning of each day (7:00 am to 11:00 am). The flue gas CO_2 mol% would then decrease in the evening between 8:00 pm and 10:00 pm by a corresponding magnitude and settle to a constant low point due to reduced power plant load demands at night. After understanding and documenting these fluctuations over the course of several days at the beginning of the parametric test campaign, the operations team would anticipate the changes in the early morning and late evening every day and accordingly adjust the steam to the reboiler to meet an average of 90% CO_2 recovery for a full 24-hour period. Because an increase in the flue gas CO_2 mol% increased the temperature inside the absorber column due to an elevated rate of the exothermic CO_2 absorption reaction with the OASE® blue solvent, the operations team learned to combat this slight temperature rise every morning by preemptively increasing the cooling water to the top wash water section of the absorber. This routine maintained the water balance of the process as the absorber temperature rose slightly every morning and prevented an unnecessary reduction in the water content of the OASE® blue solvent due to a higher rate of water leaving with the treated gas than over the previous night. Similarly, the operations team learned to prevent an unnecessary increase in the solvent water content towards the late evening when the flue gas CO_2 mol% decreased and caused a slight drop in absorber column temperatures as the late night shift was ending after 10:00 pm. The operations personnnel prevented any significant change in the solvent composition by changing the absorber temperature profile through adjustments to the cooling water flow rate to the wash water circulation cooler at the top of the absorber. Figure 30 illustrates the rise in temperature in the morning and corresponding drop in temperature in the late evening of the absorber top, upper middle, and lower middle sections caused by variation in exothermic CO_2 absorption in proportion to the change in flue gas CO_2 content. Figure 30 can be consistently compared with Figure 8 showing the changes in flue gas CO_2 mol% over the same day (07/05/2016) during the long-during test campaign.

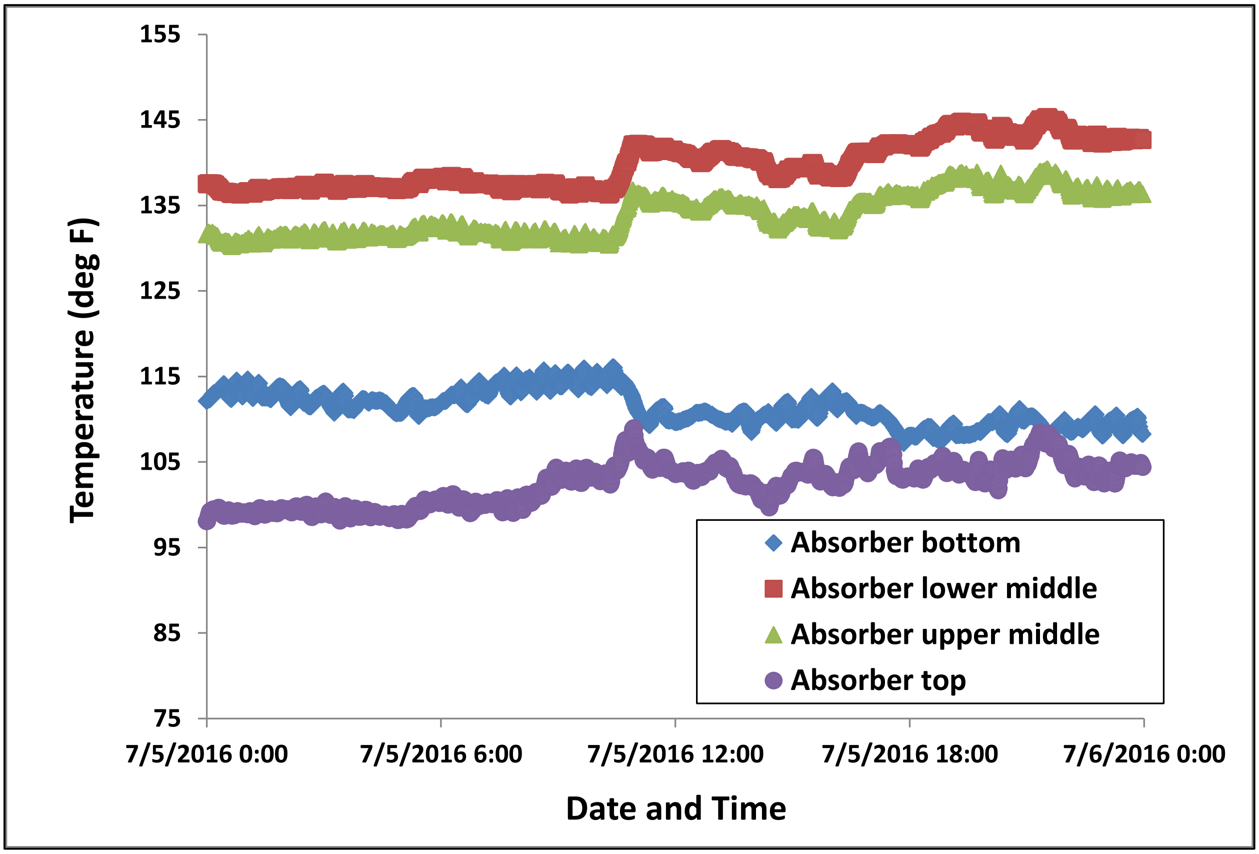


Figure 30: Temperature profile variation in absorber column for typical day during long-duration test campaign (07/05/2016) as a result of daily fluctuations in the flue gas CO_2 mol% composition.

10. Process Economic Data for 550 MWe Power Plant with CO_2 Capture

Main highlights from a techno-economic analysis (TEA) conducted in 2016 for the Linde-BASF PCC technology integrated with 550-MWe power plant are described in the section below. These details, along with explanation of all acronyms and terms, are thoroughly elaborated upon in the techno-economic report to be submitted along with this project summary report. For the purposes of this summary, the LB1 process option describes a supercritical 550 MWe pulverized coal-fired (PC) power plant integrated with a Linde-BASF PCC plant that offers a PCC reboiler duty of 2.61 GJ/tonne CO_2. In addition, the SIH process option describes a supercritical 550 MWe PC power plant integrated with Linde-BASF PCC plant utilizing an advanced stripper interstage heater (SIH) design that optimizes heat recovery in the PCC process to further improve energy performance to provide 2.30 GJ/tonne CO_2. Lastly, the LB1-CREB process configuration refers to a supercritical 550 MWe PC power plant integrated with Linde-BASF PCC plant incorporating an advanced CO_2 rich - CO_2 lean solvent cross exchanger and cold CO_2-rich exchanger bypass design that further improves energy performance [Ref. 3 and 4]. The LB1-CREB process configuration can offer as low as 2.10 GJ/tonne CO_2 PCC reboiler steam consumption based on conceptual modelling results. The specific energy consumption values for the three process configurations described were determined using process models simulated with BASF's proprietary PCC mathematical modelling software combined with Linde process innovations and techniques.

Rigorous simulation models of the LB1, SIH, and LB1-CREB process configurations have been developed to accurately predict material and energy balances as well as power production and auxiliary consumptions for a 550 MWe supercritical PC power plant integrated with selected PCC technology options. These results of these models have been verified against published results from the DOE/NETL Case 12 reference.

A comprehensive set of simulations of different options for the post-combustion capture and compression of 90% of produced CO_2 from a 550 MWe PC power plant was performed. The performance results obtained confirm the superior performance of the Linde-BASF PCC technology compared with the DOE/NETL Case 12 reference. Specific utility energy requirements (reboiler heating duty plus cooling duty) for the PCC plant with the Linde-BASF LB1 and SIH process options are reduced by more than 27% than MEA-based DOE/NETL Case 12 reference, and reduced as much as 42% when Linde-BASF process option LB1-CREB is utilized. These savings translate to an impressive reduction (13.4 – 14.1%) of incremental energy for CO_2 capture and compression from the 550 MWe supercritical power plant when compared with Case 12.

The Linde-BASF PCC technology options, integrated with a 550 MWe subcritical PC power plant, lead to increased net power plant efficiency from 28.4% reported in reference Case 12 to 30.9% (LB1) and to 31.4% (SIH).

The increased efficiency and innovative, cost-effective design of the Linde-BASF PCC plant lead to significant reductions of total plant cost for the overall PCC plant integrated with 550 MWe coal-fired power plant (17.72% reduction for the LB1 option and 18.97% reduction for the SIH option) when compared with DOE/NETL Case 12 reference.

The calculated COE for a 550 MWe PC power plant with CO_2 capture and compression is \$18.76/MWh to \$21.75/MWh lower than in DOE/NETL Case 12 reference. Capital cost components are based on a single parameter scaling (SP-S) methodology using the ratio of the coal feed rates for each process option relative to Case 12 and an exponential scaling factor of 0.669.

Calculated COE values of \$128.49/MWh and \$126.65/MWh for LB1 and SIH options (including \$10/MT CO_2 TSM costs), respectively, while utilizing SP-S methodology for TPC estimates based on coal feed flowrates, are equivalent to incremental COE increase for carbon capture and storage of 58.73% (LB1) and 56.46% (SIH), respectively, relative to the \$80.95/MWh estimated for a 550 MWe power plant without CO_2 capture.

The cost of CO_2 captured including CO_2 compression decreases from \$56.49/MT CO2 for the DOE/NETL Case 12 reference to \$41.85/MT CO_2 and \$40.66/MT CO_2 for Linde-BASF options LB1 and SIH, respectively. Incorporating LB1-CREB technology further reduces the cost of CO_2 captured to \$39.90/MT CO_2, directly in line with the DOE target to reduce the cost of CO_2 captured from post-combustion capture technologies integrated with coal-fired power plants to less than \$40/MT CO_2.

Figure 32 below illustrates the itemized breakdown of the COE composed of fixed operating costs, variable operating costs, capital costs, fuel costs, and CO_2 TSM costs for each of the Linde-BASF PCC technology options determined from a thorough techno-economic analysis. Additionally, the cost of CO_2 captured for each of the evaluated Linde-BASF PCC technologies is shown in Figure 33. As summaries of the techno-economic details just described, Figures 32 and 33 reveal the significant cost savings and advantages of using Linde-BASF PCC technologies compared to MEA solvent-based CO_2 capture processes. In addition, Tables V and VI below describe the impact of Linde-BASF PCC technologies on overall coal-fired power plant energy/utility consumption as well as the complete itemized breakdown of total plant capital costs for each process case described, respectively. Lastly, Table VII details a breakdown of the annual operating and maintenance costs for a supercritical 550 MWe power plant integrated with Linde-BASF PCC technologies.

One major reason the cost of CO_2 captured is significantly reduced in moving from DOE/NETL Case 12 reference to Linde-BASF LB1 is due to the higher inlet CO_2 gas pressure for CO_2 compression (48 psia for LB1 vs. 24 psia for Case 12) afforded by elevated regenerator pressure, which reduces downstream compression energy and capital costs. The SIH and LB1-CREB process cases also use the elevated regenerator pressure (48 psia).

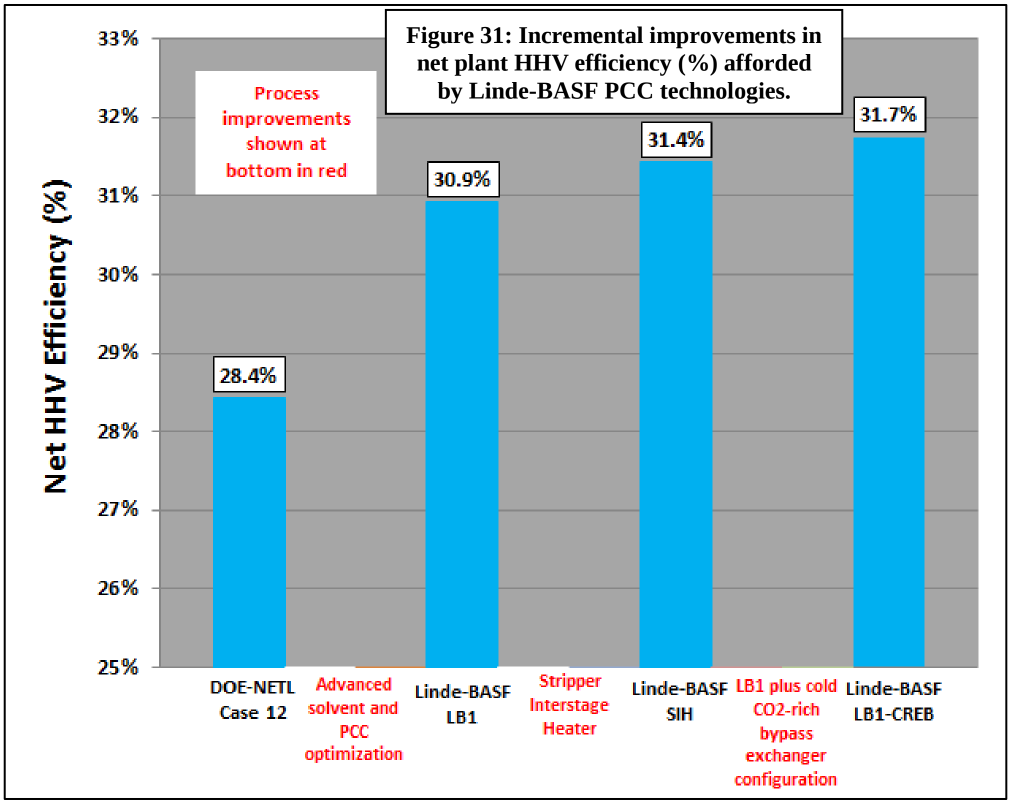


Figure 31: Incremental improvements in net plant HHV efficiency (%) afforded by Linde-BASF PCC technologies.

As power plant efficiency increases (shown in Figure 31 for the process configurations evaluated in the techno-economic study), the flow rate of CO_2 produced decreases due to a reduced coal flow rate needed for the same power production. This leads to increasingly smaller incremental reductions in cost of CO_2 captured for each Linde-BASF process improvement. This reduced coal requirement is shown for consumables in Table V.

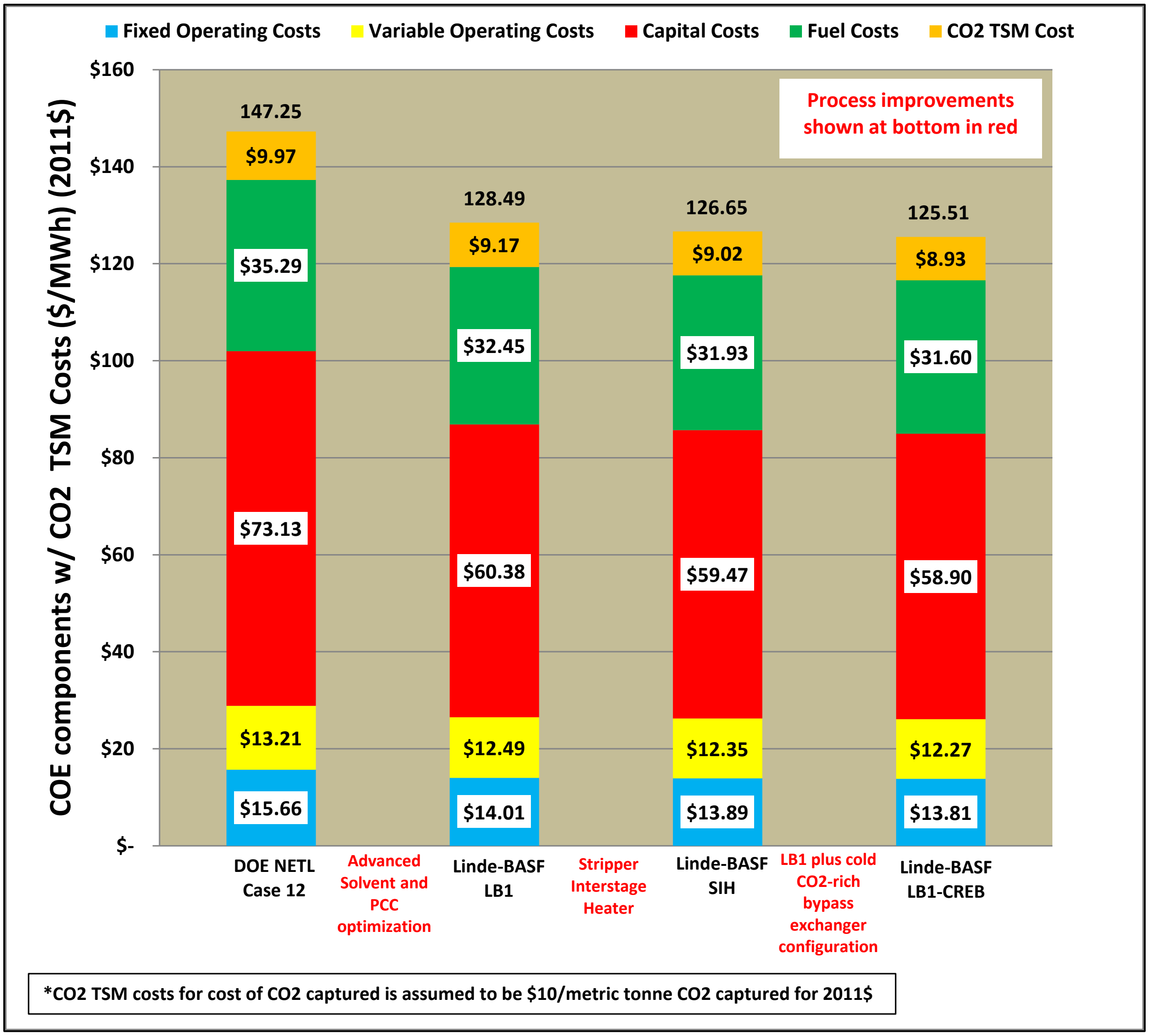


Figure 32: COE components ($/MWh) for different PCC options (SP-S methodology for TPC; CO_2 TSM Cost = \$10/tonne CO_2).

$$COE = \{(CCF)*(TOC) + OC_{FIX} + (CF)*(OC_{VAR})]\}/ [(CF)*(aMWh)]$$

OC_{FIX} = *Fixed Operating Costs*

OC_{VAR} = *Variable Operating Costs*

CF= Capacity Factor (0.85 in this study)

CCF = Capital Charge Factor (0.124 in this study)

TOC = Total Overnight Cost

aMWh = Annual net megawatt-hours of power generated at 100% capacity factor

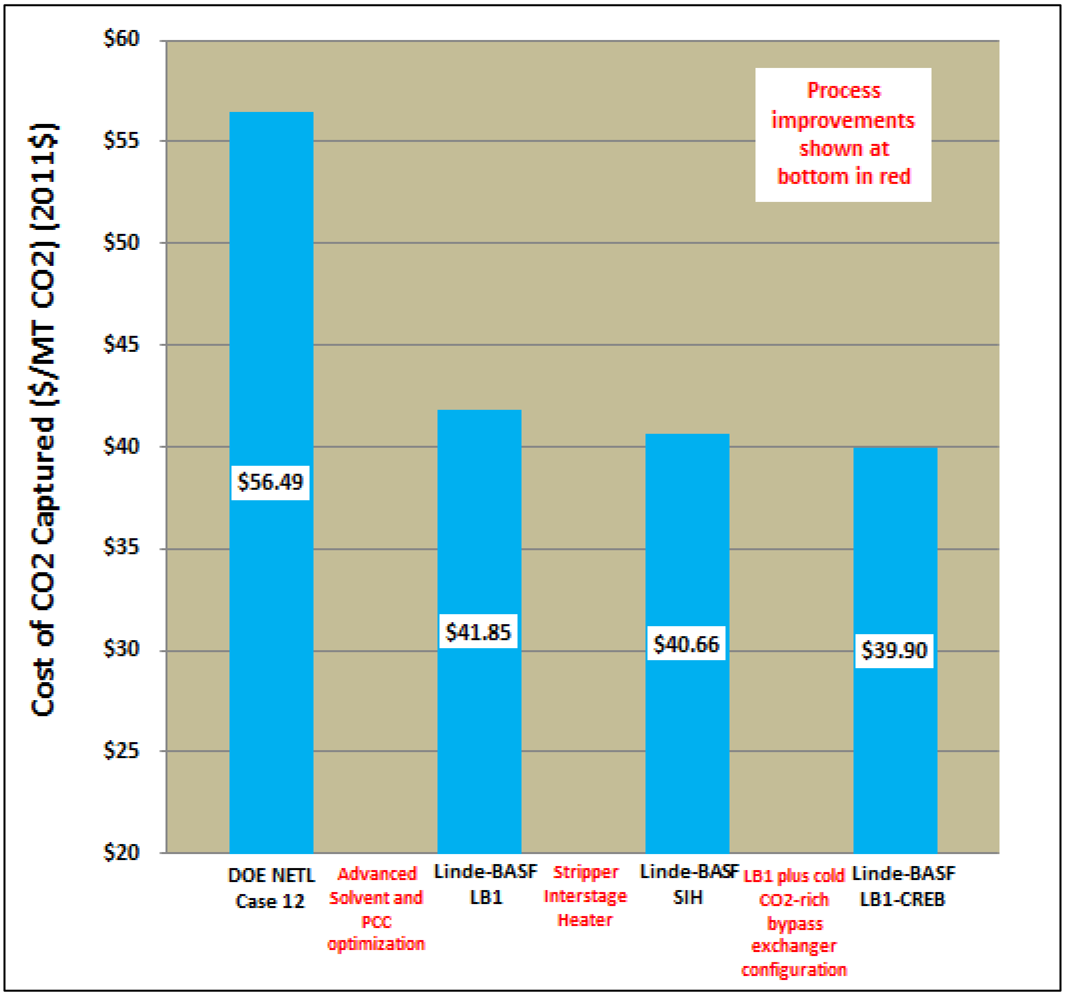


Figure 33: Cost of CO_2 captured ($/tonne CO_2) for different PCC options (SP-S methodology for TPC).

Cost of CO_2 Captured =$\{COE - COE_{reference}\}$\$/MWh / $\{CO_2$ Captured$\}$ tonnes/MWh

Table V: Influence of Linde-BASF PCC technology options on pulverized coal power plant performance.

Process Case	DOE NETL Case 11	DOE NETL Case 12	Linde-BASF LB1	Linde-BASF SIH	Linde-BASF LB1-ASFC
	kWe	kWe	kWe	kWe	kWe
TOTAL STEAM TURBINE POWER, kWe	580,400	662,800	638,857	637,637	636,748
AUXILIARY LOAD SUMMARY					
Coal Handling & Conveying	440	510	469	461	457
Pulverizers	2,780	3,850	3,540	3,483	3,447
Sorbent Handling & Reagent Preparation	890	1,250	1,149	1,131	1,119
Ash Handling	530	740	680	669	663
Primary Air Fans	1,300	1,800	1,655	1,628	1,612
Forced Draft Fans	1,660	2,300	2,115	2,081	2,059
Induced Draft Fans	7,050	11,120	10,224	10,060	9,956
SCR	50	70	70	70	70
Baghouse	70	100	100	100	100
Wet FGD	2,970	4,110	3,779	3,718	3,680
Econamine FG Plus Auxiliaries	-	20,600	10,890	10,716	10,605
CO_2 Compression	-	44,890	33,768	33,227	32,882
Miscellaneous Balance of Plant	2,000	2,000	2,000	2,000	2,000
Steam Turbine Auxiliaries	400	400	400	400	400
Condensate Pumps	800	560	515	507	501
Circulating Water Pumps	4,730	10,100	9,286	9,138	9,043
Ground Water Pumps	480	910	910	910	910
Cooling Tower Fans	2,440	5,230	5,230	5,230	5,230
Transformer Losses	1,820	2,290	2,105	2,072	2,050
TOTAL AUXILIARIES, kWe	30,410	112,830	88,885	87,602	86,784
NET POWER, kWe	549,900	550,019	549,973	550,035	549,964
CO_2 Capture	0%	90%	90%	90%	90%
Net Plant Efficiency (HHV)	39.3%	28.4%	30.9%	31.4%	31.7%
Net Plant Heat Rate (BTU/kWh)	8,688	12,001	11,036	10,859	10,747
Condenser Cooling Duty (GJ/hr)	2,298	1,737	2,094	2,187	2,244
CO_2 Captured (MT/hr)	0	548.38	504.19	496.12	490.97
CONSUMABLES					
Coal As-Received, kg/hr	185,759	256,652	235,971	232,196	229,790
Limestone Sorbent Feed, kg/hr	18,437	25,966	23,874	23,492	23,248
Thermal Input, kWt	1,400,162	1,934,519	1,778,854	1,750,398	1,732,262
Raw Water Withdrawal, m^3/min	20.1	38.1	35.0	34.5	34.1
Raw Water Consumption, m^3/min	16	29.3	26.9	26.5	26.2

Table VI: Itemized total plant capital cost for supercritical 550 MWe pulverized coal power plant integrated with Linde-BASF PCC technologies ($x1000, 2011$ price basis).

Capital Cost Element	Case 12 (2011$)	Linde-BASF LB1 (2011$)	Linde-BASF SIH (2011$)	Linde-BASF LB1-CREB (2011$)
Coal and Sorbent Handling	56,286	53,209	52,638	52,273
Coal and Sorbent Prep & Feed	27,055	25,576	25,302	25,126
Feedwater & Misc. BOP Systems	123,565	116,811	115,558	114,755
PC Boiler	437,215	413,317	408,882	406,043
Flue Gas Cleanup	196,119	185,399	183,410	182,136
CO_2 Removal	505,963	257,191	247,961	243,415
CO_2 Compression & Drying	87,534	63,738	62,401	60,324
Heat and Power Integration	0	0	0	0
Combustion Turbine/Accessories	0	0	0	0
HRSG, Ducting & Stack	45,092	42,627	42,170	41,877
Steam Turbine Generator	166,965	157,839	156,145	155,061
Cooling Water System	73,311	69,304	68,560	68,084
Ash/Spent Sorbent Handling Syst.	18,252	17,254	17,069	16,951
Accessory Electric Plant	100,255	94,775	93,758	93,107
Instrumentation & Control	31,053	29,356	29,041	28,839
Improvements to Site	18,332	17,330	17,144	17,025
Buildings & Structures	72,402	68,445	67,710	67,240
TPC without PCC	1,365,902	1,291,242	1,277,387	1,268,517
PCC Cost	593,497	320,928	305,866	303,739
Total Plant Cost (TPC)	1,959,399	1,612,170	1,587,748	1,572,255
Preproduction Costs	60,589	53,070	52,476	52,098
Inventory Capital	43,248	39,283	38,753	38,415
Initial Cost for Catalyst and Chemicals	3,782	3,111	3,064	3,034
Land	899	740	729	722
Other Owner's Costs	293,910	241,826	238,162	235,838
Financing Costs	52,904	43,529	42,869	42,451
Total Overnight Costs (TOC)	2,414,731	1,993,728	1,963,801	1,944,814

Table VII: Annual operating and maintenance costs for supercritical 550 MWe pulverized coal power plant integrated with Linde-BASF PCC technologies (2011$).

Cost Element	Case 12	Linde-BASF LB1	Linde-BASF SIH	Linde-BASF LB1-CREB
Total Fixed Operating Cost	64,137,607	57,356,056	56,867,612	56,557,758
Maintenance Material Cost	19,058,869	18,017,114	17,823,784	17,700,023
Water	3,803,686	3,595,777	3,557,193	3,532,493
Chemicals (including solvent)	24,913,611	23,551,836	23,299,117	23,137,338
SCR Catalyst	1,183,917	1,119,204	1,107,195	1,099,507
Ash Disposal	5,129,148	4,848,789	4,796,760	4,763,454
By-Products	0	0	0	0
Total Variable Operating Cost	54,089,231	51,132,721	50,584,050	50,232,815
Total Fuel Cost (Coal @ 68.60$/ton)	144,504,012	132,858,628	130,733,327	129,378,772

11. Future Plans

The Linde-BASF technology tested at the Wilsonville, AL pilot at NCCC has been further developed for the purposes of another DOE funding opportunity for a Linde-BASF PCC large pilot anticipated to be built at the Abbott Power Plant near the University of Illinois Urbana-Champaign pending award [DE-FE0026588]. This 15 MWe large pilot would be integrated with the coal-fired Abbott Power Plant to capture 90% of the CO_2 emitted from the power plant, and would be operational by 2019. The large pilot would be permanently kept at the power plant to be used to capture CO_2 following the DOE funding period. It is proposed that this PCC large pilot would be integrated with a CO_2 compression and liquefaction plant that would produce liquid CO_2 to be used for numerous CO_2 utilization applications in the greater Urbana-Champaign, IL area, including Chicago. The large pilot would serve as a CO_2 source to facilitate the growth and expansion of long-term CO_2 utilization clusters in the greater Urbana-Champaign, IL region, such as concrete plants that would benefit from using CO_2. In this regard, a related Linde proposal for a CO_2 utilization effort using CO_2 in concrete and concrete wastewater applications in the greater Urbana-Champaign, IL region was submitted to the DOE on October 3, 2016 as part of DE-FOA-0001622. If awarded, the proposed CO_2 utilization project would create several CO_2 utilization clusters in the greater Chicago area that would be able to use CO_2 captured from the Linde-BASF PCC large pilot to be built and operated at the Abbott Power Plant pending award.

The Linde-BASF SIH PCC process configuration will be evaluated at the 15 MWe large pilot pending DOE award. Results from testing of the SIH process configuration will be evaluated and compared against findings from the techno-economic analysis conducted for this summary report. Additionally, further process performance improvements will be investigated during testing, and relevant learnings will be documented and shared to progress advancement and optimization of the Linde-BASF PCC technology.

Appendix 1: References

[1] *“Cost and Performance Baseline for Fossil Energy Plants – Volume 1: Bituminous Coal and Natural Gas to Electricity*”, DOE/NETL-2010/1397 Study, Final Report, Rev. 2a, (September 2013).

[2] P. Moser, S. Schmidt, G. Sieder, H. Garcia, T. Stoffregen, V. Stamatov, *The post-combustion capture pilot plant Niederaussem – Results of the first half of the testing programme*, GHGT10, Energy Procedia, Volume 2, Issue 2, September 2010.

[3] Rochelle, Gary; Madan, Tarun; Lin, Yu-Jeng. “*Apparatus for and method of removing acidic gas from a gaseous stream and regenerating an absorbent solution*” United States Patent Application. Pub. No.: US 2015/0246298 A1, September 3, 2015.

[4] Rochelle, Gary; Madan, Tarun; Lin, Yu-Jeng. “*Regeneration with Rich Bypass of Aqueous Piperazine and Monoethanolamine for CO_2 Capture*” I&EC Research, February 18, 2014.