Research Article

Post-combustion slipstream CO_2-capture test facility at Jiangyou Power Plant, Sichuan, China: facility design and validation using 30% wt monoethanolamine (MEA) testing

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Abstract

Given the dominant share of coal in China's energy-generation mix and the fact that >50% of the power plants in the country are currently <15 years old, efforts to significantly reduce China's CO_2 footprint will require the deployment of CO_2 capture across at least part of its fleet of coal-fired power plants. CO_2-capture technology is reaching commercial maturity, but it is still necessary to adapt the technology to regional conditions, such as power-plant design and flexible operation in the China context. Slipstream facilities provide valuable field data to support the commercialization of CO_2 capture. We have built a slipstream facility at Jiangyou power plant in Sichuan that will allow us to explore China-relevant issues, especially flexible operation, over the next few years. We plan to share our results with the broader CO_2-capture and CO_2-storage (CCS) community to accelerate the deployment of CCS in China. This paper describes the design of the slipstream facility and presents results from our steady-state qualification tests using a well-studied benchmark solvent: 30% wt monoethanolamine (MEA). The results from our MEA tests compare favorably to results reported from other slipstream-test facilities around the world, allowing us to commission our system and establish a reference baseline for future studies.

Graphical Abstract
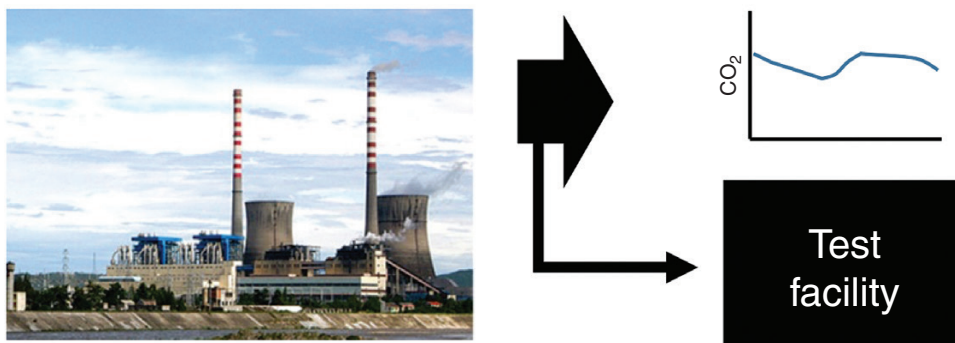
Keywords: CO_2 capture; coal-fired power plant; CCS; monoethanolamine; MEA; pilot

Introduction

Urgent action is needed to address the effects of climate change driven by anthropogenic emissions of greenhouse gases, particularly CO_2. China accounts for about one-third of global CO_2 emissions, with about half of these due to the use of coal for power generation. The government has committed to reduce CO_2 emissions by 60~65% per unit GDP by 2030 [1]. To this end, a national carbon market will launch in 2020, with the power sector obligated to comply at a 550-g CO_2/kWh intensity target [2]. Given the size (over 1000 GW installed capacity) and relatively young age of the coal-fired power-plant fleet (half <15 years old), CO_2 capture and storage (CCS) is an important option for meeting this goal [3, 4].

The retrofitting of post-combustion CO_2-capture facilities at existing coal-power plants is of particular interest given the age profile of the fleet in China. Solvent absorption is currently the most mature technology option, with full-scale commercial operations at power plants active at Boundary Dam in Canada and Petra Nova in the USA [5, 6]. In addition, a wide range of demonstrations have been performed with solvent capture around the world. In China, pilots have been conducted at a number of locations, including demonstrations by large state-owned enterprises Huaneng at Gaobeidian Thermal Power Plant and Shidongkou Power Plant and State Power Investment Company at Shuanghuai Power Plant [7–10]. Coal-fired power plants in China operate under a range of conditions. Nationwide, the average capacity factor is ~50%, meaning there is significant operation at reduced loads, with load following or semi-frequent start-up/shutdown cycles [11]. In addition, arid provinces operate power plants with dry cooling and provinces in the north have a significant fraction of combined heat and power plants that are must-run during the winter season. These features present challenges for the operation of CO_2-capture systems.

There is growing interest around the world in the flexible operation of CO_2-capture systems [12–16]. This includes work on model-based simulations of operating dynamics and economics, as well as experimental validation in pilot testing systems. To date, there have not been any studies on how flexible operation might differ in China. While the chemical-engineering principles underlying the design and operation of CO_2-capture systems are universal, specific cases related to the load-ramping requirements in different Chinese provinces, in-country regulatory constraints and economic incentives, and technology-development opportunities unique to the Chinese ecosystem need to be analysed.

A number of test centres have been established to accelerate learning around the operation of CO_2-capture systems and to accelerate the validation of emerging technologies [17–20]. These test centres also play an important role in knowledge diffusion to advance the overall maturation of CCS globally. The National Institute of Clean-and-Low-Carbon Energy (NICE) has built a slipstream-test facility at a power plant in Sichuan province for the purpose of accelerating the development of CCS in China. The facility is intended to generate performance and cost data for capture technologies under conditions that are representative of power-plant operation in China. This includes flexible operation at reduced loads and with load following. The facility is equipped with the ability to produce data using the 'natural' operating rhythms of the host plant, as well as with 'idealized' synthetic testing profiles to be generated from data on power-plant operation in other regions of China. The facility will also support the validation of emerging separation technologies.

This paper describes the design of the NICE facility and presents results from initial validation testing of the solvent-capture test system under steady-state conditions. The discussion is organized into two parts. In the first part, we describe the test facility and its subcomponent systems. Details of the facility layout and equipment design are presented. In the second part, we describe experimental trials with the solvent-capture system performed as part of the commissioning process. These tests were performed with

30% wt monoethanolamine (MEA). There is a wide body of literature describing testing with MEA and we compared our results to these benchmarks to establish a performance baseline for our system [6, 21–23].

1 Facility description

1.1 Host-facility description

The capture slipstream facility is hosted at Shenhua Sichuan Jiangyou power plant, located in Jiangyou city, in the north-east of Sichuan province. The plant comprises four subcritical boiler units: two 300-MW (Units 31 and 32) built in 1988 and two 330-MW (Units 33 and 34) built in 2005. The plants were equipped with ultra-low emissions (ULE) pollution-control systems by the end of 2018. The power plant is connected to the Southern China grid. Seasonal hydropower accounts for nearly 70% of annual power generation in the province and this forces the coal-fired power plants to operate at reduced loads during the rainy seasons (typically May to September). Fig. 1 shows a layout of the plant and the generating operating profile for one unit during the first 8 months of 2019.

The layout of the test facility is shown in Fig. 2. The pilot system includes two parts: a pretreatment system to reduce sulphur content and three separation bays. Pad 1 hosts a solvent-absorption system; Pads 2 and 3 have general hook-ups to allow temporary testing of skid-mounted systems and are currently unoccupied. Flue gas is obtained from the ductwork after the flue gas desulphurization (FGD)

systems of Units 33 and 34. Separate insulated lines deliver ≤200 Nm³/hr (400–500 kg/hr; 0.1 MW$_e$) of gas at 80°C. The gas is delivered to the pretreatment system, which removes sulphur oxides. An optional bypass allows the delivery of untreated flue gas directly to any of the test bays. For reference, the slipstream-test facility is comparable in scale to the bench-testing facilities at the National Carbon Capture Center (NCCC) [24].

1.2 Pretreatment system

Sulphur oxides are known to accelerate corrosion and degrade amine-based solvents, including precipitation of solids and acceleration of oxidative degradation [25–29]. Previous experience with amine solvent-based CO_2 capture suggests 5 ppmv as an upper limit for SO_x to minimize these effects [30]. The ULE systems installed at the host plant are designed for compliance with the regulatory standard of 35 ppmv SO_x [31]. To comply with international best practices, we installed a pretreatment scrubbing system at the facility to ensure the SO_x concentration remains below the 5-ppmv threshold.

A process flow diagram for the pretreatment system is shown in Fig. 3. There are three subsystems: an alkaline wash using 5% wt NaOH aqueous solution; a water wash to remove entrained NaOH; and a cooling tower to reduce the temperature of the gas to ~30°C. The exit temperature of the flue gas from the pretreatment system is determined by the temperature of the industrial water supplied by Jiangyou power plant (20–25°C) and the wash-system
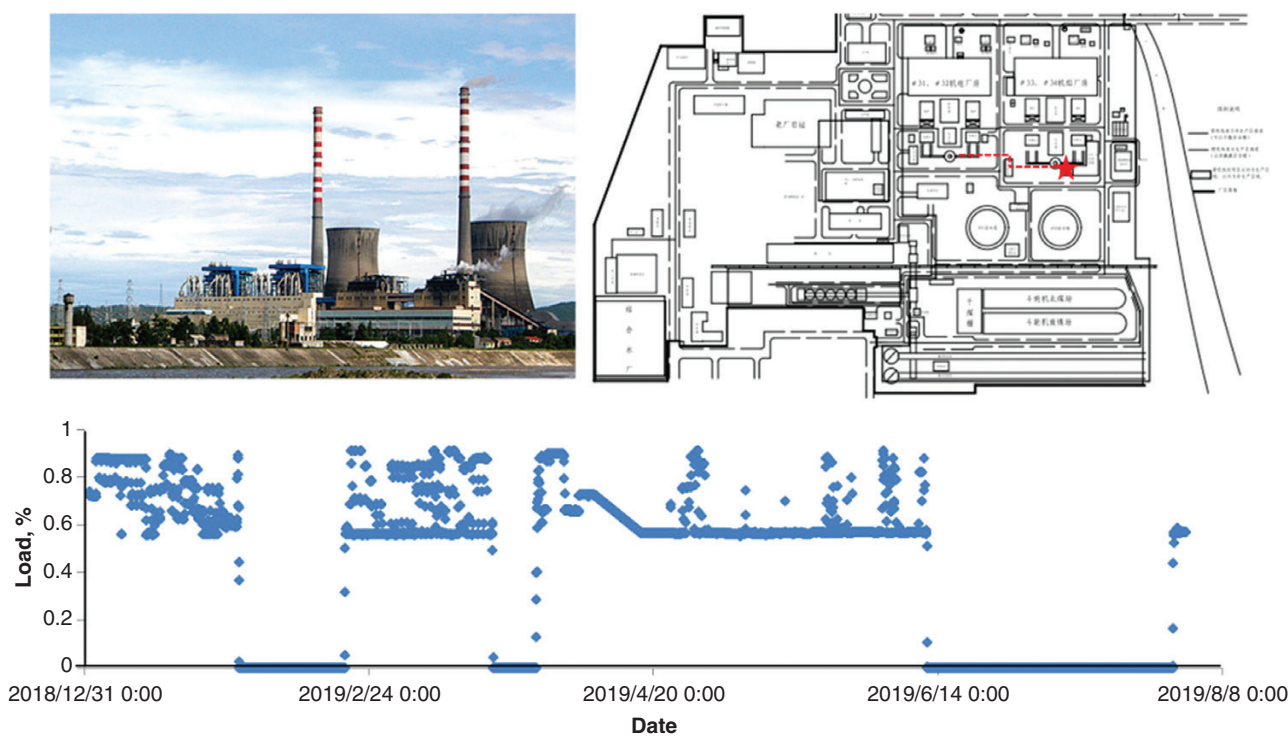

Fig. 1: Plant layout and load-operating profile during the first 8 months of 2019. The red star on the plot plan indicates the location of the capture facility.
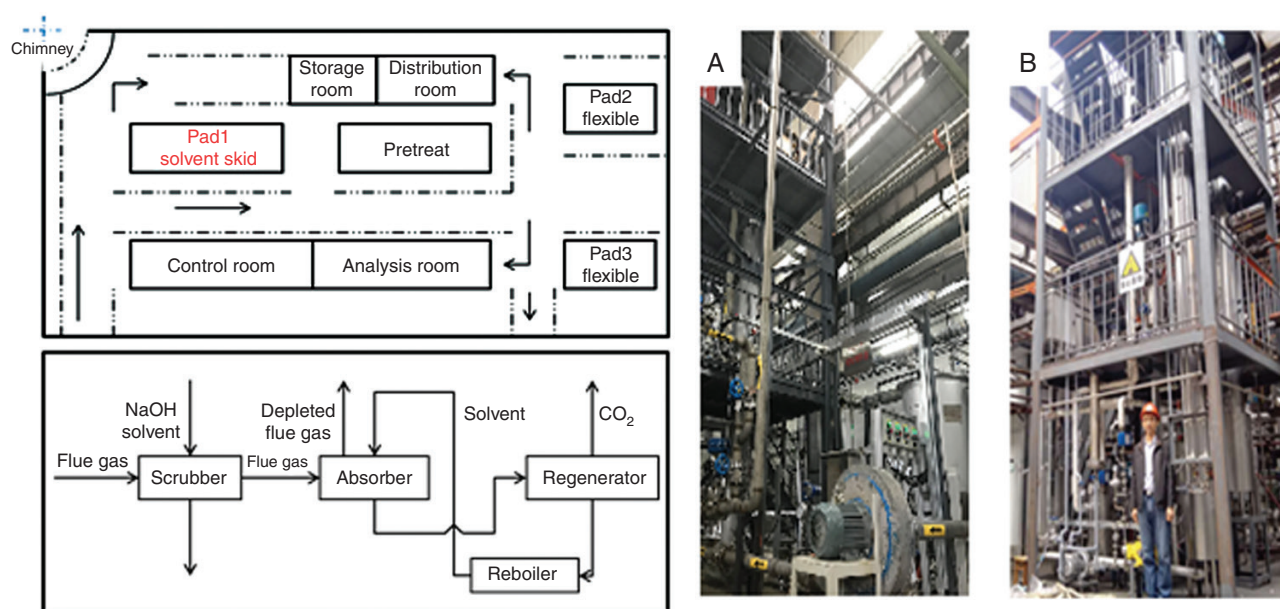
Fig. 2: Layout of the test facility, with photos of the pretreatment system and solvent skid
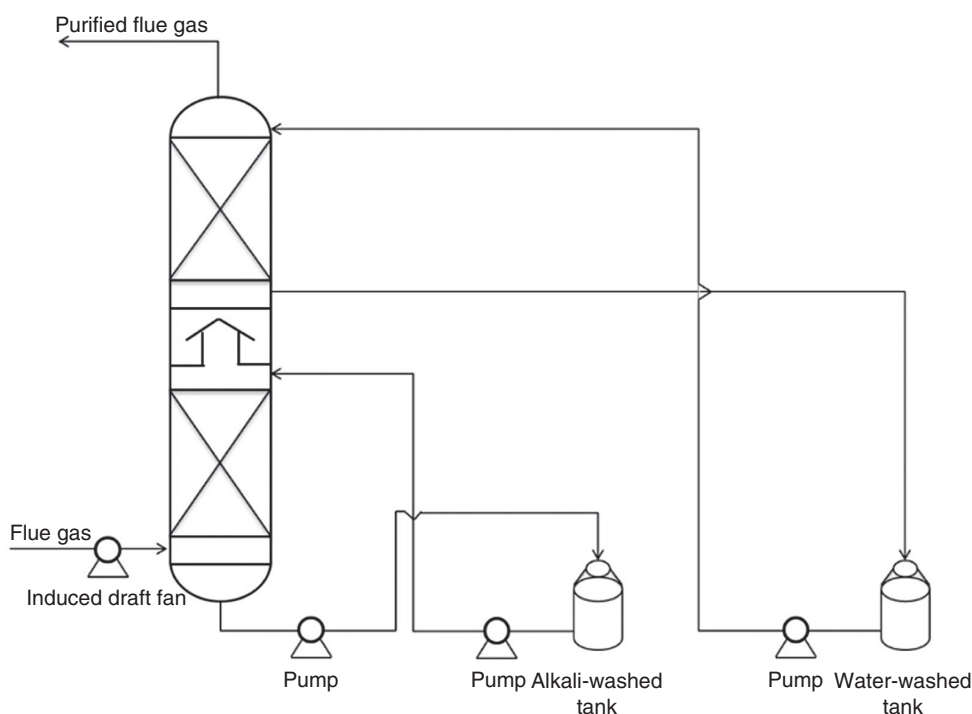

Fig. 3: Process flow diagram of pretreatment system

design. For comparison, the NCCC PC5 inlet flue-gas temperature and inlet temperature at the absorber are ~70°C and 37–43°C, respectively. The system also has an optional bypass to allow testing of flue gas without pretreatment.

1.3 Solvent-capture system

A process diagram of the solvent-capture system is shown in Fig. 4. The system comprises an absorber tower, regeneration column, a lean–rich heat exchanger and a reboiler.

Table 1 lists the key design parameters of the system. The flue-gas flow rate was controlled by the induced-draft fan and could be adjusted to over the listed range within 28 Nm³/h. The solvent flow rate was controlled by varying the absorber-column pump and could be controlled within 320 L/h. A static mixer was deployed between the draught fan and the absorber to mix and cool the flue gas, ensure the flue-gas temperature was introduced at a temperature <30°C and maintain a temperature of ~40°C during the CO_2-capture process.
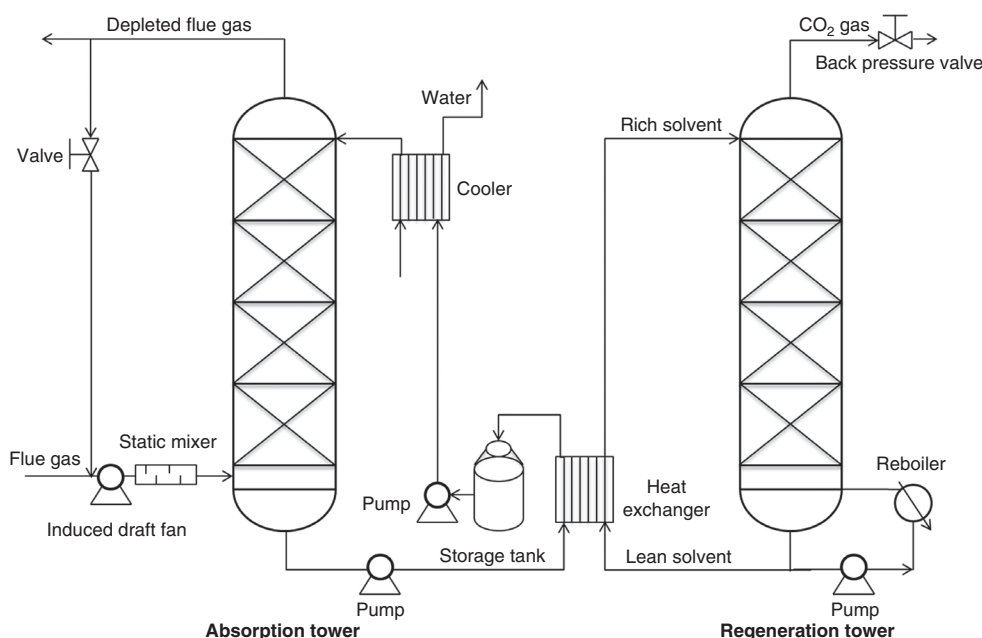
Fig. 4: Process flow diagram of solvent-capture skid

Table 1: Key parameters of the solvent-capture-skid system

Items	Unit	
Flue-gas flow rate	Nm³/h	≤28
CO_2 concentration	% vol	9–14
O_2 content	% vol	≤6
Solvent flow rate	L/h	30–320
Lean–rich-solvent heat exchanger	Type	Plate
Reboiler	Type	Tube
Absorber		
Diameter	mm	110
Number of packing sections	#	4
Packing height	m	1.1
Packing type		Pall Ring:φ10*10
Materials of construction		304ss
Regenerator		
Diameter	mm	110
Number of packing sections	#	4
Packing height	m	1.1
Packing type		Pall Ring:φ10*10
Materials of construction		304ss

1.4 Dynamic-testing capability

The system is designed to accommodate two types of dynamic testing. The first mode is 'natural profiles', which is the baseline operation of the host power plant. Here, the dynamics of the flue-gas inlet are measured and the CO_2-capture system can be operated at steady state or in a manner that targets a particular capture rate. For the qualification tests during this study, the system was operated in a 'natural profile' mode, but with measures taken to identify periods during which the natural fluctuations of the host-plant load were minimized. Future work will consider 'natural operations' in which the power-plant load

has more variation in time, with the CO_2-capture system operated both at steady state and during active control.

The second mode is using 'synthetic profiles'. Here, the objective is to simulate host-plant profiles that are different from the 'natural profiles' generated by the host plant. Synthetic profiles will be defined using an analysis of plant-operating data in plants across China and will include well-defined ramping and partial-load-operating events that are representative of the overall data. During a 'synthetic profile', the flue-gas concentration from the host plant will be adjusted using a recirculation loop that returns a fraction of the CO_2-depleted flue gas from the absorber outlet back to the inlet of the absorption tower. The recirculation line is equipped with a blower that is able to recycle ≤50% of the flue gas. A thermocouple has been installed after the recirculation loop valve to monitor the temperature, but currently there is no mechanism for active control of the temperature of the recirculated gas. No recirculation experiments were performed for the qualification study; a separate qualification campaign is planned after validation of the system under the 'natural profile' mode with steady-state operation of the capture system.

2 Experimental

2.1 Chemicals

MEA (97% wt purity) was bought from BASF-YPC Co., Ltd. Flaky sodium hydroxide with a 99%-wt purity was obtained from Sinopharm Chemical Reagent Co., Ltd. These chemicals were diluted or dissolved by industrial water from Jiangyou power plant. Solvent-capture experiments were performed using 30% wt MEA.

2.2 Characterization

We monitored the concentration of SO_2 and other components of the flue gas before and after the pretreatment system using a MSK6300 Fourier Transform Infrared (FTIR) spectrometer [32, 33]. CO_2 concentration of the flue gas, depleted gas and product CO_2 gas are monitored by online GXH-3011 CO_2-concentration analysers. Three different ranges were used for the online GXH-3011 CO_2-concentration analysers used to monitor inlet flue gas (0–20%), depleted flue gas and product CO_2 (0–100%).

The flue-gas and solvent flow rates are continuously measured using an orifice flowmeter and metal-tube rotameter, respectively. The error in the gas-flow rates measured by orifice flowmeters was estimated to be 2% and the error in the liquid-flow rates measured by the metal-tube rotameters was estimated to be ~0.5%. The data-sampling rate was 5 Hz and the data are recorded digitally. The MEA concentration and CO_2 loading of the solvent are analysed using standard acid–base titration methods [32]; methyl orange was used as the acid–base indicator. Samples were collected manually and analysed every 2 hours during experimental test campaigns.

2.3 CO_2-capture test trials with 30% wt MEA

Capture test trials were performed under a variety of test conditions. Each test in the validation campaign was run for 12 hours, with the CO_2-capture rate, energy consumption, CO_2 loading and MEA concentration calculated every 2 hours. Values are reported as averages and standard deviations over each 12-hour test.

The MEA concentration used for the test was 30% wt (~5 M). Tests were performed using a steady flue-gas flow rate of 28 Nm^3/h. Tests were performed to identify the optimal regeneration pressure, liquid-to-gas (L/G) ratio and regeneration temperature for our system under steady-state conditions. The single-variable method was used to study the selected parameters. For example, when we studied the influence of the regeneration pressure on energy consumption, we kept the other key parameters as constant.

The regeneration-pressure test was performed over a range of 0.12–0.18 MPa. A back-pressure valve was used to control the pressure. The L/G ratio was controlled by adjusting the frequency of the variable-frequency pump. During testing, the solvent flow rate was varied to produce L/G ratios from 2 to 4.5 kg/Nm^3. The regeneration-temperature test was performed by changing the steam rate to the reboiler to control the temperature from 110°C to 118°C.

2.4 Analysis and calculation

2.4.1 CO_2 loading
Lean and rich solvents were sampled every 2 hours manually; each sample was analysed three times. Lean- and rich-solvent CO_2 loading was calculated by the acid–base titration method in the Jiangyou site, during which 0.5 M HCl solvent was used to react with the base in the sampled solvent and methyl orange was used as the indicator. The CO_2 loading can be calculated by the following Equation 1:

$$\alpha_{CO_2} = m_{CO_2 \, captured} / m_{Amine} \tag{1}$$

where α_{CO_2} is the CO_2 loading and $m_{CO_2 \, captured}$ and m_{Amine} are the mole CO_2 captured and mole amine used, respectively.

2.4.2 CO_2-removal efficiency
Infrared gas analysers were used to monitor the volumetric concentration of the CO_2 concentration of the flue gas, depleted flue gas and product CO_2 gas. The CO_2-removal efficiency, η_{CO_2}, was computed by

$$\eta_{CO_2} = \frac{V_{in}y_{in} - V_{out}y_{out}}{V_{in}y_{in}} = 1 - \frac{1 - y_{in}}{1 - y_{out}} \frac{y_{out}}{y_{in}} \tag{2}$$

where v_{in} and v_{out} are the flow rates and y_{in} and y_{out} are the volumetric concentrations of the CO_2-volume ratios at the inlet and outlet, respectively. Here, we assume ideal gas behaviour and isothermal conditions, since the sampled gas was cooled before measurement.

2.4.3 Energy consumption
Energy consumption was estimated from the steam used by the reboiler. In an ideal situation, the energy consumption can be computed from an energy balance using the flow rate and initial steam conditions (saturated temperature or pressure) and the outlet condensate flow rate and temperature. In reality, this calculation is complicated by three features.

First, there is variability in the initial conditions in the inlet steam. Utility steam was delivered from the power plant as saturated steam at 120–130°C. It was difficult to accurately meter the steam use directly, so we accounted for the steam use by weighing the quantity of condensate water after the heat-exchange process in the reboiler every 2 hours. The temperature and pressure were measured using a thermocouple and a pressure gauge in real time, respectively. Pressure was measured using the metal pressure gauge with 1% accuracy. All the temperature-measuring instruments of the solvent skid were T-type thermocouples with 0.5% accuracy. The values were tracked in real time and so it was possible to correct for this issue using the known relationship between the saturated-steam pressure and the latent heat of vaporization (Equation 3):

$$\Delta H_{vap} \left[\frac{kJ}{kg} \right] = -3.3811T + 2623.5 \tag{3}$$

where T is temperature in degrees Celsius.

Second, cooling in the utility steam line caused some condensate formation ahead of the reboiler. Since only the energy from condensate from the steam sent into the reboiler should be counted in the energy-consumption calculation, we installed a micro gas–liquid separator ahead of the reboiler. The steam flow rate was corrected to account for liquid condensate from the utility source.

Finally, there was some uncertainty about the temperature of the condensate, which introduced the need for a correction to account for sensible heat contributions to the energy consumption. The measured inlet temperature of the steam varied from 120°C to 130°C and the measured outlet temperature of the condensate ranged from 100°C to 115°C. The accuracy of the temperature gauges was ±0.5%. The energy delivered to the reboiler was the sum of the latent heat of vaporization from condensation of the steam and the sensible heat contribution of the condensate. The sensible heat contribution associated with temperature uncertainty was <1% of the latent heat of vaporization. Since the contribution from sensible heat is smaller than the uncertainty associated with the temperature gauges, we chose to exclude it from the calculation.

For this study, the energy consumption, E_{steam}, was calculated using Equation 4:

$$E_{steam} = \frac{m_{steam} \times H}{1000 \times m_{CO_2}}, \tag{4}$$

where m_{steam} and $m_{CO_2\ captured}$ are the mass of the steam consumed and CO_2 captured, respectively.

3 Results and discussion

This section presents the results from the tests performed during the commissioning of the solvent-capture system using 30% wt MEA. The first subsection describes the inlet flue-gas characteristics. This is followed by separate sections describing optimization studies for the regeneration pressure, L/G ratio and regeneration temperature. We then report system-stability data for a 24-hour test. The section concludes with a discussion of how results from our system compare with results reported by other test facilities using MEA.

3.1 Inlet flue-gas characteristics

The compositions of the raw flue gas are affected by the operation of the power plant. Relative to full-load operation, the CO_2 concentration drops and the O_2 concentration increases when the plant is run at reduced load. Power-plant operation also impacts the efficacy of the FGD system and, consequently, the SO_x content in the flue gas.

There was significant variation in flue-gas CO_2-concentration data, which was directly correlated to the power-plant generation load (not shown). The CO_2 concentration ranged from 9% vol. to 14% vol. during the selected window. The CO_2 concentration was only ~9% vol. at the beginning of May 2019 because the plant was ordered to operate at a reduced power load to allow dispatch from hydroelectric facilities during the wet season. Variations in the hydropower generation resulted in load-ramping by the host facility, resulting in observed fluctuations in the CO_2 concentration. In order to study the MEA performance of this CO_2-capture system, we performed our tests

during a period when the power-plant load was relatively steady and the CO_2 concentration was ~12% vol. This was possible by consulting power-plant operators, who had day-ahead knowledge of the anticipated loads required by the dispatch command centre. Fig. 5 displays the raw flue-gas CO_2-, O_2- and particulate matter (PM)-concentration data over the test campaign. Despite relatively steady operation, there was still some variability in the inlet flue-gas content. The flow rate for tests was held constant at 28 Nm³/h. This did not change because the slipstream extracted from the flue-gas duct was only a small fraction of the total flue-gas flow rate of the power plant. In future studies of load-following performance, we have the option of using the natural variation of the power plant or simulating synthetic load profiles using recirculation loops, as described in Section 1.4.

Fig. 6 shows the SO_2 concentration and the SO_2-reduction ratio before and after pretreatment. All the four power units of Jiangyou power plant are equipped with ULE technology; the maximum SO_x concentration detected during the test campaign was 12 ppmv. The exit SO_x concentration from the pretreatment system was consistently <3 ppmv. There was still some variation in the SO_x concentration due to fluctuations in the O_2 concentration and flow-rate change, lime concentration and spray density in the desulfurization tower, but the outlet SO_x concentration remained below the target threshold of 5 ppmv during the entire test campaign. Potential degradation effects in the solvent were ignored due to the low levels of SO_x and the relatively short duration of the test campaign.

3.2 MEA-solvent testing

3.2.1 Regeneration-pressure study

Regeneration pressure is one of the most important parameters used to control lean-solvent CO_2 loading and optimize energy consumption. For preliminary tests, we held the flue-gas flow rate (28 Nm³/h), regeneration temperature (114.5°C), solvent flow rate (100 L/h) and L/G ratio (3.6) constant. Fig. 7 shows the effects of regeneration pressure on the energy consumption and CO_2-capture rate. Energy consumption in GJ/tCO₂ ranged from 4.0 to 5.8 (highest value), with the minimum value of 4.0 observed at a regeneration pressure of 0.15 MPa. The corresponding CO_2-capture rate at this pressure was 93%. The variation in the energy consumption reflects the combined effects of the utility steam quality and variation in the power-plant load. The error bars represent the uncertainty associated with steam quality and instrument error, and the variation in the average values at each pressure corresponds primarily to fluctuations in CO_2 concentration and water content in the flue gas. We expect that, for longer-duration tests, the contribution of these factors will decline, due to averaging over a wider range of plant conditions. The apparent outlier in energy consumption at 0.15 MPa may be due to a physical feature of the system. We hypothesize that the solvent may be near its boiling point
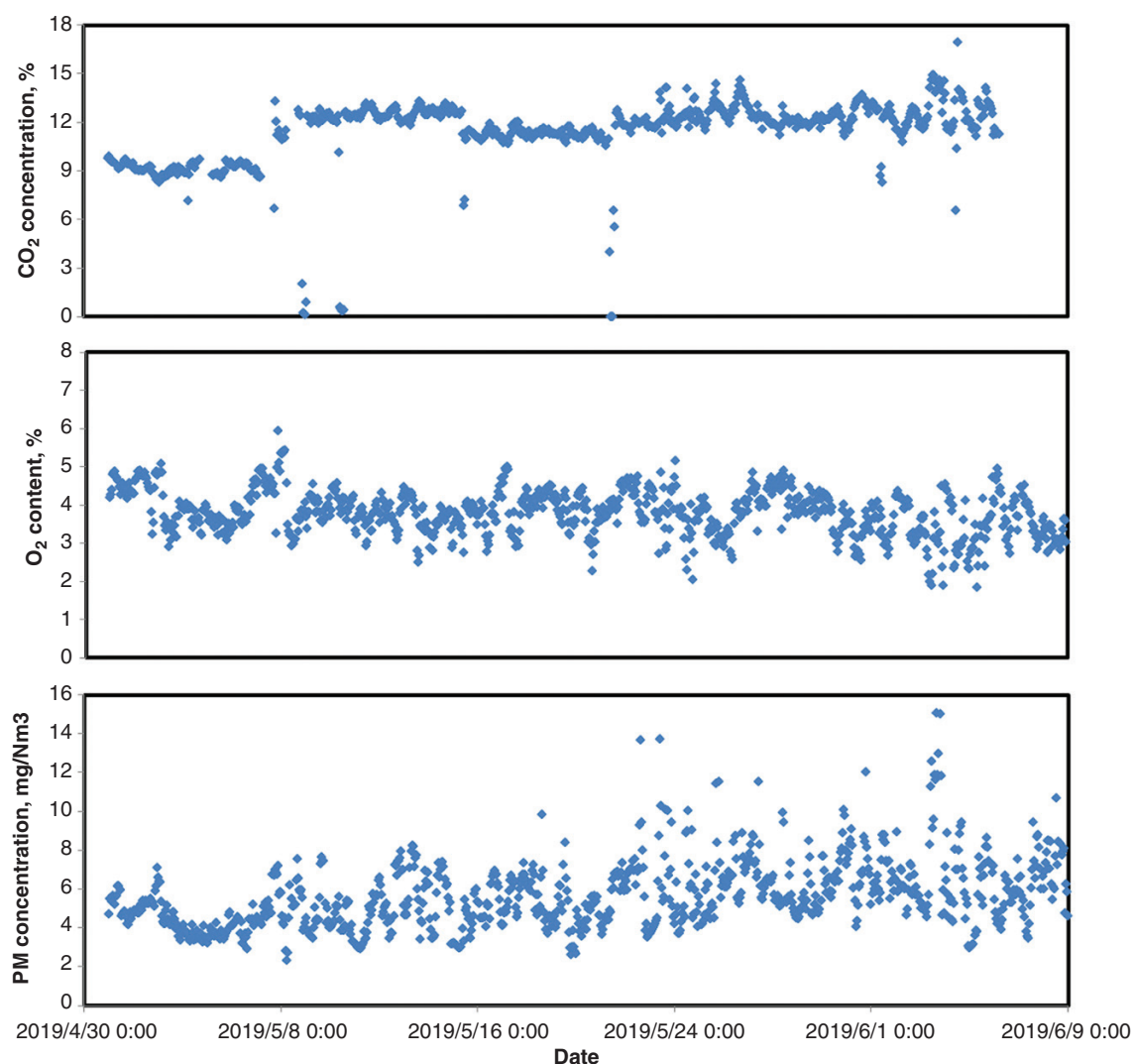
Fig. 5: Inlet flue-gas CO_2, O_2 and PM data

at this pressure and that the data at this point represent a transition between a condition with excessive boiling (at lower pressures) and inadequate boiling (at higher pressures). Subsequent tests were performed using a regeneration pressure of 0.15 MPa, corresponding to the lowest energy-consumption case; sensitivity studies performed at other L/G ratios and regeneration temperatures showed that this pressure resulted in a fairly robust minimum across a wide range of conditions.

3.2.2 Liquid-flow-rate/flue-gas-flow-rate ratio study

The second parametric test involved the liquid-flow-rate/flue-gas-flow-rate (L/G) ratio. The L/G ratio is determined within the absorber column and is constrained by the physical limits of poor absorption efficiency at low L/G ratio and column flooding at high L/G ratio. In this study, the regeneration pressure was held constant at 0.15 MPa, the regeneration temperature at 114.5°C and the flue-gas flow rate at 28 Nm³/h. The L/G ratio was varied from 2 to 4.2 kg/Nm³.

Fig. 8 plots the energy consumption and CO_2-capture rate over this range of interest. The CO_2-capture rate

increased monotonically with the L/G ratio, as expected. At the lowest L/G ratio tested, the lower capture rates result in lower absolute and specific steam consumption. At the highest L/G ratio of 4.2, the energy consumption increased dramatically to 8.2 GJ/tCO_2. Over the intermediate range of L/G from 2.4 to 4.0, the energy consumption was relatively stable at ~4.0 GJ/tCO_2. We chose L/G ratios of 3.2 and 3.6 for further testing, since these values were within the stable range and consistent with values reported from similar test campaigns in the literature [33–35]. The CO_2-capture rate at L/G = 4.0 deviated unexpectedly from the overall trend. Upon further investigation, the root cause of this effect was an increase in the industrial feed-water temperature at the inlet lean-solvent cooler. This resulted in a higher CO_2 concentration in the solvent sent to the absorber during this trial.

3.2.3 Regeneration-temperature study

The final parametric study involved the regeneration temperature. Figs 9 and 10 plot the energy consumption at temperatures from 110°C to 114.5°C for L/G ratios of
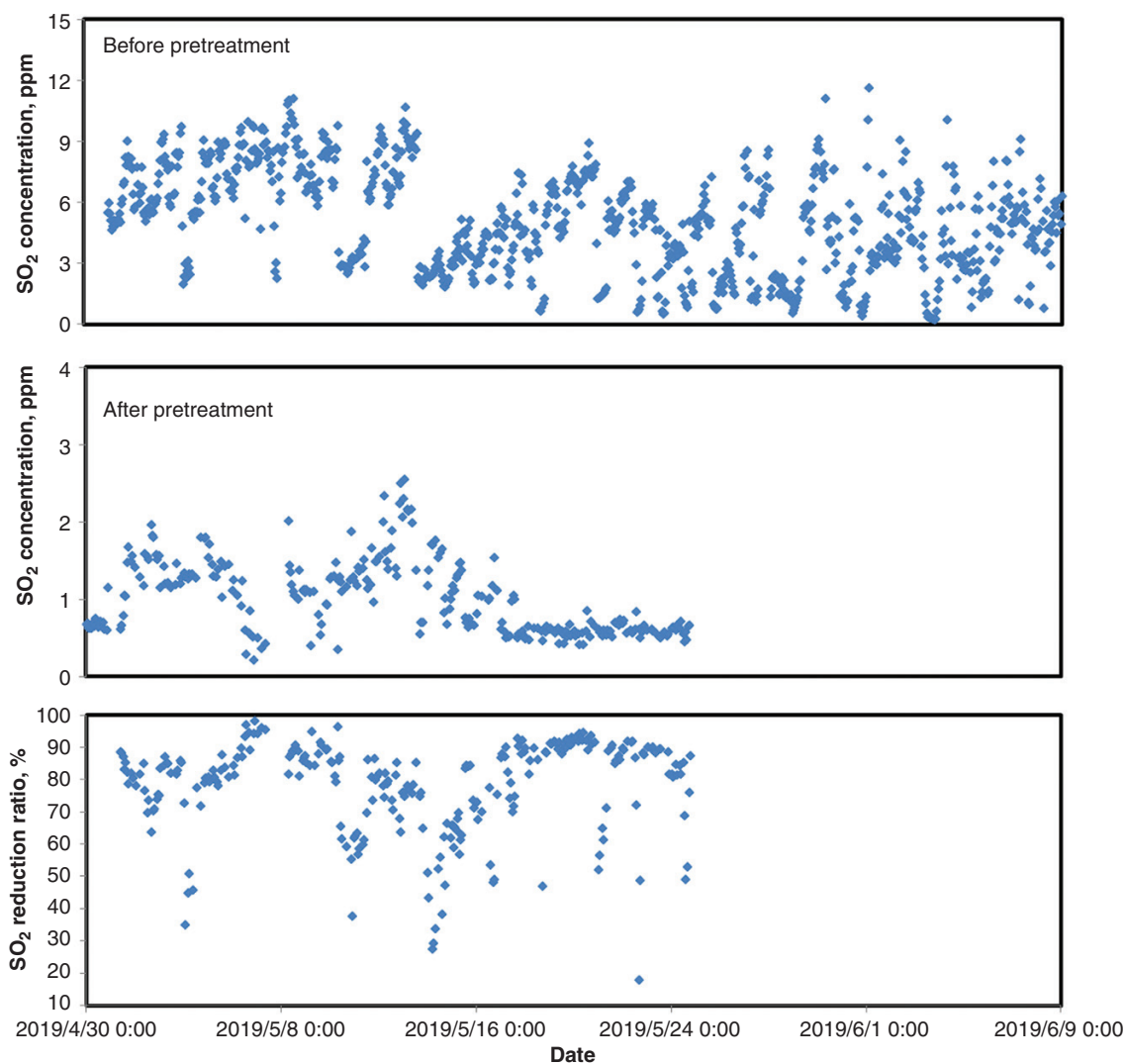
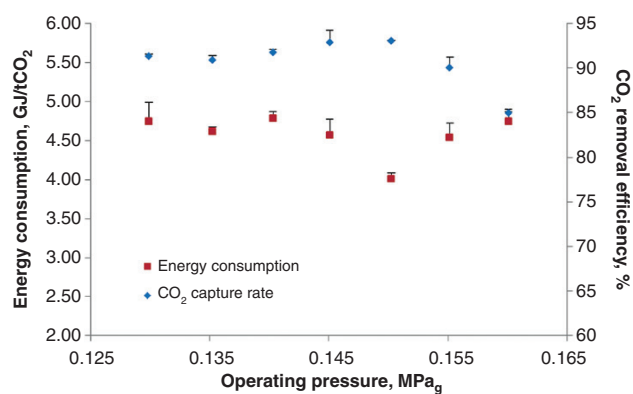**Fig. 6:** SO_2 concentration before and after pretreatment

Fig. 7: Effect of regeneration pressure on energy consumption and CO_2-removal efficiency (regeneration temperature = 114.5°C, flue-gas flow rate = 28 Nm³/h, and solvent flow rate = 100 L/h)
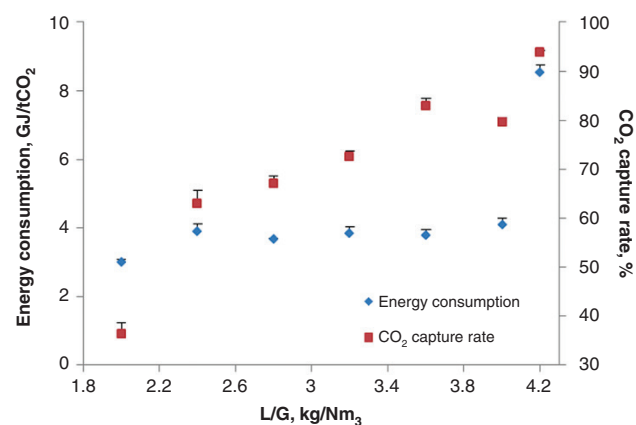

Fig. 8: Effect of L/G on energy consumption and CO_2 removal

3.2 and 3.6. The upper limit for temperature in this study was 115°C, due to difficulties in maintaining stable temperatures above this level. The regeneration pressure was held constant at 0.15 MPa. The energy consumption trends

lower with increasing temperature, reflecting the stronger driving force for desorption. There are slight differences between the results at the two L/G ratios, but these were not statistically significant. An important caveat is that the
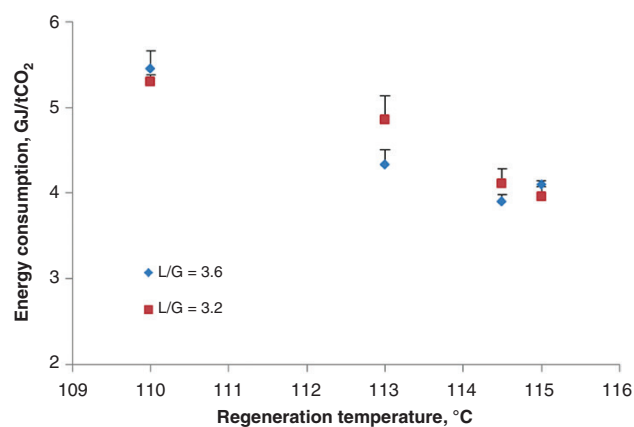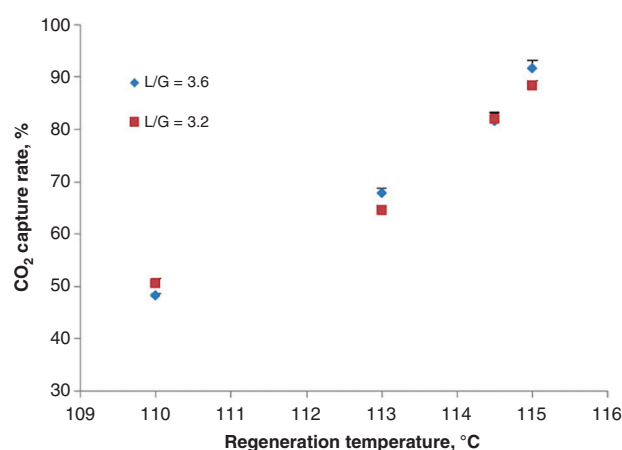
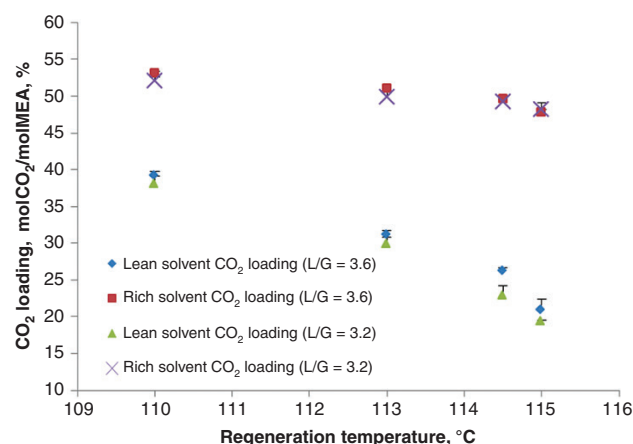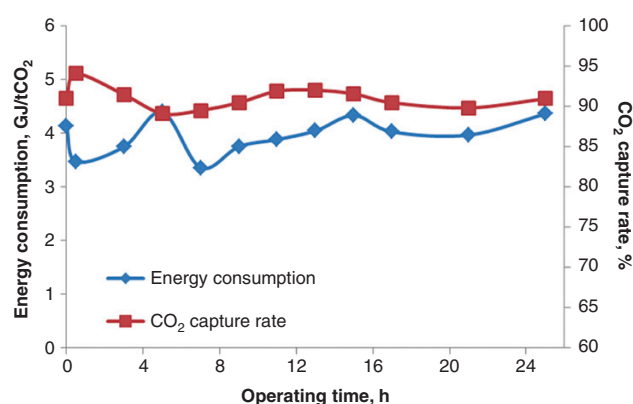Fig. 9: Effect of regeneration temperature on energy consumption

Fig. 11: Effect of regeneration temperature on CO_2 loading

Fig. 10: Effect of regeneration temperature on CO_2-capture rate

Fig. 12: Energy consumption and CO_2-capture rate during a 24-hour test

variations in inlet flue-gas composition and temperature, as well as the temperature of the utility steam, contributed to higher variability in the data over each 12-hour trial; this can be seen in the larger error bars in some of the data points. The CO_2-capture rate increases monotonically with the regeneration temperature, reflecting the lower CO_2 content in the lean solvent. This trend is plotted in Fig. 11.

3.3 CO_2-capture-system reliability verification

To evaluate the stability of the capture system, we operated the solvent-capture system for 24 hours. This test used the optimal values obtained from the parametric studies: regeneration pressure of 0.15MPa, L/G ratio between 3.2 and 3.6, and regeneration temperature between 113°C and 115°C.

Fig. 12 plots the specific energy consumption and CO_2-capture rate. The energy consumption fluctuates around a mean value of 4.1 GJ/tCO_2, within the range 3.4–4.5 GJ/tCO_2. The capture rate fluctuates around 90.7%, with a range of (low) to (high) value. Fig. 13 shows the CO_2 loadings in the rich and lean solvent. The average rich-solvent CO_2 loading is about 0.49 molCO_2/molMEA and the average

lean-solvent CO_2 loading is about 0.24 molCO_2/molMEA. There is less variability in the CO_2-loading curves, ostensibly due to the fact that the equilibrium CO_2 loading is driven more by the temperature and pressure conditions in the system, making it less sensitive to variations in the inlet stream.

During the extended testing, there was a greater degree of variation in the energy consumption (seen in Fig. 12) than in the CO_2 loading levels (seen in Fig. 13). This is consistent with the physical operation of the system. As seen during the parametric studies, variations in the utility steam quality manifested as variability in the energy-consumption data. The solvent-loading levels were less sensitive to plant variations given the good mixing of solvent in the columns and the relatively stable temperature controls for the reboiler. While meaningful average values were obtained over the course of the extended test, improvements in controls and monitoring will be needed to accommodate testing under dynamic conditions to ensure sufficient data quality to understand flexible-operation capabilities.

Table 2 shows the results of a CO_2-mass-balance calculation over the 24-hour test. The mass balance between

the CO_2 captured from the gas phase and removed in the liquid phase closes to within 0.5%. This level of closure in the mass balance lends confidence for the system.

3.4 Comparison with literature results

Table 3 compares our test results against relevant results from the literature [19, 36–38]. We see good agreement in the CO_2-capture rates, lean- and rich-solvent loadings, and energy consumption. Our optimal temperature is lower than those reported in the literature. This is due to limitations in our test system rather than fundamental differences in system behaviour; our observed trends suggest temperatures >115°C are desirable, but the reboiler was not capable of controllably maintaining higher temperatures
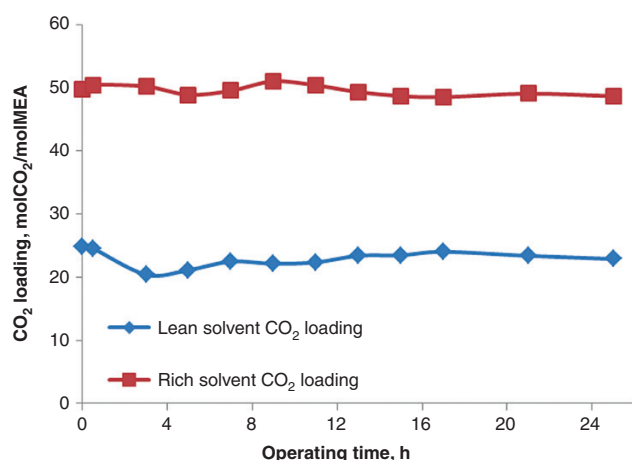

Fig. 13: CO_2 loading change during the 24-hour test

due to limitations in the quality of the utility steam. Since the temperature in our study was slightly lower than those reported, the pressure was correspondingly lower.

3.5 Next steps

The reasonable level of agreement between our solvent-system tests using 30% wt MEA with previous literature studies provides confidence for future testing. Going forward, there are two priorities for solvent testing at the Jiangyou test facility. The first is further improvements in test-system capability and the second is to evaluate more advanced solvent technologies.

3.5.1 Improvements in capability

In the upcoming year, additional system upgrades and continued operator training will be conducted to improve data quality and expand capability at the site. Among equipment upgrades, priorities include installation of a more powerful induced-draft fan to increase the maximum flow-rate capability, upgrading of the lean–rich heat exchanger to improve heat integration and installation of an inter-stage cooler to accelerate the CO_2-absorption rate.

A key priority will also be to improve the accuracy of the energy-consumption measurement. This includes the development of automated data-analysis tools to correct for variations in the utility steam quality and also possible upgrades to the system to improve the accuracy of the condensate flow-rate measurements. These upgrades will be crucial as the testing moves to non-steady-state operation, to ensure quantitative relationships can be extracted from

Table 2: CO_2-mass-balance calculation

	Inlet flue-gas rate	Inlet CO_2 concentration	Depleted flue-CO_2 concentration	CO_2-capture rate	Product CO_2/24 h
	m³/h	%	%	%	Kg
Gas phase	28	12.28	1.28	90.7	147.02
Liquid phase	Flow rate	Lean-solvent CO_2 loading	Rich-solvent CO_2 loading	MEA concentration	CO_2-capture capacity/24 h
	L/h	molCO$_2$/molMEA		%	Kg
	97	0.23	0.49	33.1	146.4

Table 3: Comparison of Jiangyou-system results against literature benchmarks

	Operation conditions			CO_2 loading		CO_2-capture rate	Energy consumption
	Temp.	Press.		Rich solvent	Lean solvent		
Reference	°C	MPa	L/G	molCO$_2$/molMEA, %		%	GJ/tCO$_2$
Our work	114.5	0.15	3.5 kg/Nm₃	49 ± 0.5	24 ± 0.2	91% ± 1.2	4.0 ± 0.1
[37]	117	–	1.2 kg/kg	49	25	85	4.0
[20]	–	0.19	2.5 kg/kg	–	–	90	3.6
[38]	–	0.19	–	–	–	85	4
[39]	115		3.2 L/Nm³	–	–	80%	4.1

the data. Modelling efforts will also be used to inform the operation under the dynamic conditions to be used in flexible-operation testing.

The immediate next step will be to evaluate the performance of the system at lower capture rates, and then to measure responsiveness during load-ramping scenarios. Simulated ramping profiles will be achieved using the recycle loops to adjust the CO_2 concentration in the blended feed to the absorber.

3.5.2 Technology development and validation

The Jiangyou test facility will also be used to support the development of new solvent technologies. The facility includes two additional test bays that can accommodate non-solvent capture technologies such as systems based on membranes or sorbents. These will be commissioned at a future date.

4 Conclusion

NICE has constructed and commissioned a slipstream test facility for post-combustion capture in Sichuan, China. The facility can accommodate small-scale solvent capture testing on real flue gas, and has been designed to operate under flexible operating conditions expected for coal-fired power plants in China. A first step towards system validation has been taken with testing using 30% wt MEA to show that the solvent capture system performs consistently with literature benchmarks under steady state operation. Next steps involve evaluating solvent capture system performance when the host power plant is operating under more dynamic load-following conditions, establishing guidelines for operating the solvent capture system at lower capture rates and under load-following scenarios, and benchmarking the performance of advanced solvents that are currently under development by NICE and other technology providers.

Nomenclature

Symbol	Meaning
α_{CO_2}.	CO_2 loading
$m_{CO_2\ captured}$.	Mole CO_2 mole captured, mol.
m_{Amine}.	Mole of Amine used, mol.
η_{CO_2}.	CO_2 removal efficiency
V_{in}.	Flow rate of inlet flue gas, Nm^3/h
V_{out}.	Flow rate of outlet flue gas, Nm^3/h
y_{in}.	CO_2 volume ratio of inlet flue gas
y_{out}.	CO_2 volume ratio of outlet flue gas
E_{steam}.	Energy consumption through steam, GJ/ t CO_2
ΔH_{H_2O}.	Water latent heat of vaporization, kJ/kg
m_{CO_2}.	Captured CO_2 amount, tonne/hr
m_{steam}.	Steam consumption, tonne/hr

Conflict of Interest

NICE is a corporate research division of China Energy group which owns and operates Jiangyou power plant.

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