Spotlight

GREENHOUSE GASES SCIENCE AND TECHNOLOGY

Implementing a second generation CCS facility on a coal fired power station – results of a feasibility study to retrofit SaskPower's Shand power station with CCS

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Abstract: In 2018, the International CCS Knowledge Centre (CCS Knowledge Centre) conducted a feasibility study with SaskPower to determine if a business case could be made for a postcombustion, carbon capture retrofit of SaskPower's Shand Power station, a 305-MW, single-unit, lignite coal-fired power station located near Estevan, Saskatchewan. Specifically, Mitsubishi heavy industries' KM CDR technology was evaluated for this study. While no decision has been made, should SaskPower decide to proceed, the Shand carbon capture and storage (CCS) project would produce the second, full-scale capture facility in Saskatchewan with a nominal capacity of 2 million tonnes of CO_2 (Mt) per year. This paper summarizes the key technical and economic findings of this study. Notably this study found that the capital costs of the potential Shand CCS facility are decreased by 67% on a per tonne of CO_2 captured basis when compared to the CCS retrofit of Unit 3 at the Boundary Dam Power Station (the world's first industrial scale CCS installation on a coal fired power station). The proposed capture facility would also have a load following operational profile, reduction in parasitic loses by employing heat integration strategies, and need no additional water draw to provide the required increase in cooling duty. © 2020 The Authors. *Greenhouse Gases: Science and Technology* published by Society of Chemical Industry and John Wiley & Sons, Ltd.

Keywords: CO_2 capture; CCS feasibility studies; CCS retrofits; energy penalty minimization; heat integration; levelized cost of capture

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Introduction and motivation for the Shand CCS feasibility study

A coal phase out is underway in Canada. Certain provinces continue to produce much of their electricity from coal; Saskatchewan is one of them. Saskatchewan's provincial electrical utility provider, SaskPower, operates three coal fired power stations supplying 30% of the province's electrical needs. Previously, SaskPower had retrofit Unit 3 of the Boundary Dam Power Station (BD3) with post combustion carbon capture and storage (CCS) technology. As the world's first industrial scale CCS application on a coal fired power plant, this project was a major milestone for CCS technology. The facility has been operational since October 2014 and was completed proactively as the Canadian federal CO_2 emission regulations had not yet materialized. Boundary Dam's Unit 3 integrated carbon capture and storage (BD3 ICCS) facility was designed to capture up to 90% of the CO_2 in the flue gas and operate as low as 120–140 t GWh^{-1} – cleaner than any existing fossil-fuel power station.

The reduction of carbon dioxide emissions from coal-fired generation of electricity regulations came into effect on July 1, 2015, and has been amended and regionalized such that all coal fired power plants in Canada must reach a performance standard fixed at 420 tonnes of carbon dioxide per gigawatt hour (t GWh^{-1}) to allow continued operation while emissions exceeding 370 t GWh^{-1} would be subject to a carbon tax which would increase to $50 per tonne by 2022 (see Table 1). The aim of these regulations is to implement a permanent shift to lower or nonemitting types of generation. The flat topography of Saskatchewan limits additional hydro generation to provide the much-needed baseload electricity currently provided by the coal plants. Low natural gas pricing in the region enabled the replacement of conventional coal fired generation with new natural gas combined cycle (NGCC) facilities effectively prompting the 'dash to gas'; however, future tightening of emissions regulations was widely anticipated to discourage this. In June 2019, the federal government introduced new regulations that specifically targeted any new natural gas fired power generation. New NGCC facilities beginning operations after 2021 would be required to meet an emissions limit of 0 t GWh^{-1} by 2030 to avoid the carbon pricing (see Table 1). Reducing the associated CO_2 emissions from these NGCC facilities, either by lowering the dispatch of the facility or through additional investment to retrofit these NGCC facilities with CCS, could be required in the future.

CCS is the only method by which coal-fired power generation plants (old and new) can achieve these emission targets. The Shand power station, commissioned in 1992, is SaskPower's newest coal unit and was intended to operate until 2042. Shand is key in providing reliable and affordable base-load power in Saskatchewan. Unless retrofitted with CCS Shand would be required to cease operations by 2030. This early retirement of Shand would render Shand a stranded asset and represent an economic loss to the province. These regulations provided the motivation for the Shand CCS feasibility study, which evaluated the option of retrofitting SaskPower's Shand power station with post combustion CO_2 capture technology.

Identifying the parameters of the Shand CCS feasibility study

The Shand CCS feasibility study evaluated whether a business case can be made to retrofit the Shand power station with CCS technology. Mitsubishi heavy industries' (MHI) proprietary Kansai Mitsubishi carbon dioxide removal process (KM CDR) process, which was successfully implemented as part of the Petra Nova Project,[2] was evaluated for Shand. The study was divided into two major groups of work: work specific to MHI and Mitsubishi Hitachi power systems (MHPS) and work specific to the CCS Knowledge Centre and their contracted consultant engineering firm. Division of the scope of work is summarized in Table 2. A battery limit at the inlet to the SO_2 capture system (a wet limestone FGD) was established to separate the responsibilities between MHI/MHPS and the CCS Knowledge Centre (see Fig. 1). Shand's steam cycle, cooling capacity, and site layout were evaluated during the study. It was determined that modifications to the turbine and feed heating plant were required, while additional cooling capacity would need to be established.

Power plant and capture island design parameters

A 3D model of the proposed carbon capture facility for the Shand power station is depicted in Fig. 1. Table 3 summarizes Shand's current operating performance which was used as the basis of design for this study.

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Table 1. Summary of carbon pricing in Canada.

Year	Carbon tax (CAD$/t)	Emission intensity limit for coal (t GWh $^{-1}$)	Emissions intensity limit for *current* natural gas (t GWh $^{-1}$)	Emissions intensity limit for *new* NGCC beginning operations after 2021 (t GWh $^{-1}$)
2020	30	650	370	370
2021	40	622	370	370
2022	50	594	370	329
2023	50	566	370	288
2024	50	538	370	247
2025	50	510	370	206
2026	50	482	370	165
2027	50	454	370	124
2028	50	426	370	83
2029	50	398	370	42
2030	50	370	370	0

Table 2. Summary of division of labor by scope of work.

MHI/MHPS Scope	CCS knowledge centre scope
• SO_2 Capture system	• Steam supply to battery limit
• CO_2 Capture system	• Feed-heating modifications
• CO_2 Compressor	• Condensate preheating
• Turbine modifications	• Deaerator replacement
	• Flue gas supply
	• Flue gas cooler
	• Hybrid heat rejection system
	• Waste disposal

Site conditions influence the design of a power plant and its capture island. Parameters such as air temperature and humidity are critical in designing for the cooling duty requirements of the capture facility as they dictate the quantity and annual variance in cooling availability. Table 4 summarizes the design conditions used for the Shand CCS feasibility study.

Well-understood flue gas composition is essential in planning amine health maintenance as flue gas impurities can induce amine degradation. Flue gas composition can vary due to changes in coal composition and varying power plant load. For this study, flue gas composition was determined at 100 and 75% power plant loading. This data is summarized in Table 5. Using this information, MHI and MHPS predicted the capture efficiency of the potential CO_2 capture facility and turbine performance of the Shand power plant in order to verify performance continuity of the capture process at the various power plant loads.

Performance criteria, design considerations, and key technical findings

Learnings from the building, commissioning, and operating of the BD3 CCS guided key performance criteria and design considerations of the Shand CCS feasibility study. These provisions are discussed in this section.

Thermal integration and minimizing the output penalty

Energy, usually supplied by steam, is required for amine regeneration when utilizing a solvent-based post combustion CO_2 capture system. Steam can be sourced by integrating directly with the power station's steam cycle (as was done with the BD3 project) or by constructing a purpose-built auxiliary steam generator (as was done with the Petra Nova project). Option one induces a parasitic loss in generation output for the power station during CCS operations while option two produces additional CO_2 emissions (which hinders overall CO_2 emissions reduction) while also requiring adequate natural gas infrastructure to support such a facility. The integrated design was chosen for Shand (see Fig. 2). Heat integration strategies to reduce the parasitic loses would include:

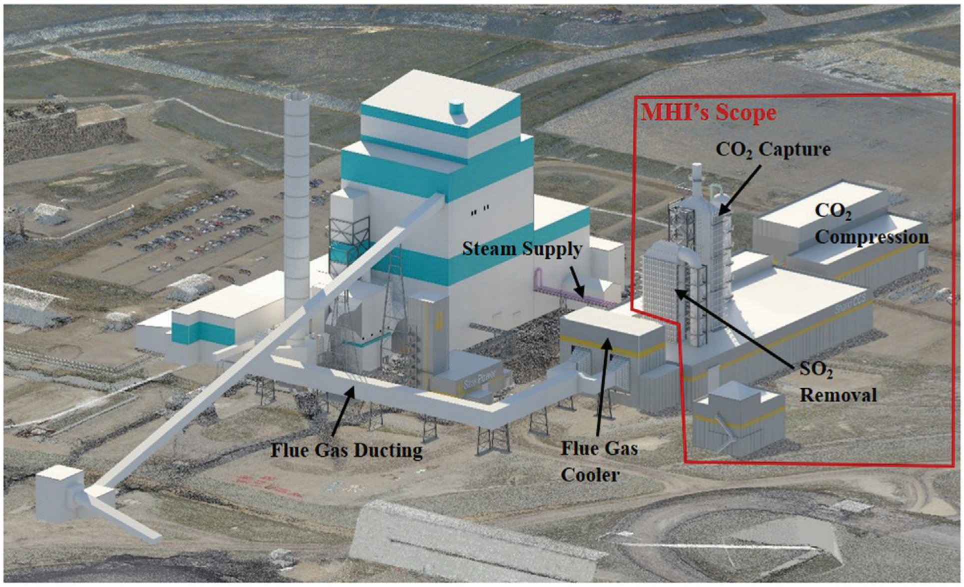

Figure 1. 3D model of the proposed CO_2 capture facility for the Shand power station.

Table 3. Shand's current operating performance.

Operating Parameter	Value
Gross Output (MW)	305
Auxiliary Load (MW)	26.5
Net Output (MW)	278.5
Fuel Input (GJ hr $^{-1}$)	3,230
Gross Unit Heat Rate (kJ kWh $^{-1}$)	10,590
Net Unit Heat Rate (kJ kWh $^{-1}$)	11,598

Table 4. Design conditions at Shand power station.

Parameter	Value
Site Elevation (metres above sea level)	558
Atmospheric Pressure (kPaa)	99.5
Design Dry Bulb Temperature (°C)	18*
Design Wet Bulb Temperature (°C)	13.7*

*85th percentile.

- Utilizing flue gas waste heat for low pressure condensate preheating by means of a flue gas cooler and condensate preheater and,
- Utilizing energy in the condensate returning from the capture facility for feed water preheating.
- Replacing the DEA to facilitate a higher pressure steam bleed therefore maximizing the use of rejected flue gas heat and energy in the returning condensate for LP condensate preheating and,

Table 5. Flue gas properties at Shand up to the FGD inlet with varying load.

	100% Load (measured data)	75% Load (calculated data)
Fuel Flow (kg hr $^{-1}$)	218,013	159,900
Flue Gas Mass Flow (kg hr $^{-1}$)	1,737,398	1,290,926
Temperature (°C)	85	75
Pressure (kPag)	–1	–1
Flue Gas Composition		
CO_2 (% Vol wet)	11.4	11.3
H_2O (% Vol wet)	12.6	12.4
O_2 (% Vol wet)	6.1	6.3
N2+Ar (% Vol wet)	69.4	69.9
SO_2 (ppmv dry)	600	*
SO_3 (ppmv dry)	<1	*
NO (ppmv dry)	198	*
NO_2 (ppmv dry)	2	*
HCl (ppmv dry)	6.7	*
HF (ppmv dry)	0.14	*

*Contaminant concentrations not confirmed for reduced load operation.

- Adding bypass drains to remove FWH4 from service during CCS operations rather than incurring costs associated with replacing a costly high pressure FWH, as the increased operating pressure and

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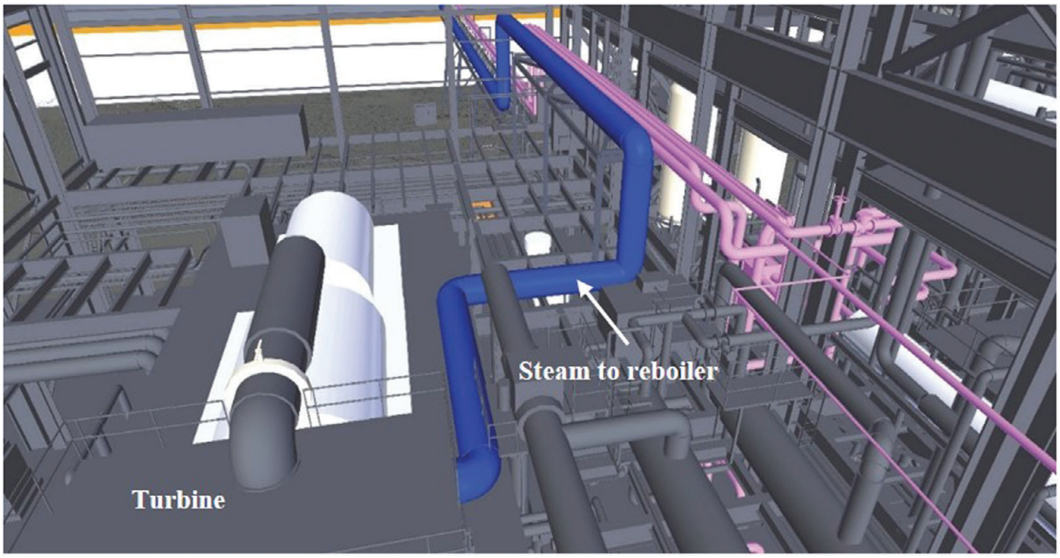

Figure 2. Proposed design and location of the process steam extraction line to the reboiler.

temperature of the new DEA would exceed the current operating pressure and temperature of FWH4.

These integration strategies would maximize waste heat utilization while reducing the parasitic load, which was determined to be 22.2% with these strategies. Modifications to the steam cycle are depicted in Fig. 3. A detailed analysis of this work can be found in our previous work.[3]

Maintaining capture operations at reduced power plant load

As more variable renewable energy (VRE) sources, such as wind and solar energy, are added to the grid, 'load following' capabilities will be demanded of larger thermal power stations. This would have larger thermal generators reduce their output to accommodate increased periods of VRE generation and supplement electricity demand when VRE are insufficient or unavailable. Any proposed CO_2 capture facility would have to mirror this operational variability. The fully integrated steam extraction design (as was applied to BD3) encounters limitations. As the power plant load decreases, the quantity of steam flowing through the turbine also decreases. The corresponding pressure drop at the intermediate pressure–low pressure (IP-LP) crossover reduces the steam's energy density. The reduction in the desired duty to the reboiler, however, is disproportional to the reduction in power plant load, resulting in a greater percentage of the steam consumed for capture operations. Eventually the required steam properties to the reboilers cannot be maintained and amine regeneration is hindered. This limiting factor prevents continued capture operations at reduced loads. To ensure seamless and continuous capture operation at 90% capture during decreased power plant output a butterfly valve would be inserted in the IP-LP crossover between the steam extraction point and the inlet to the LP turbine. Throttling the steam at reduced loads (only), via the butterfly valve, would maintain enough flow and energy density to the reboiler for continued capture operations.

The butterfly valve would also enable over-capture (beyond the 90% capture design parameter) at reduced loads by increasing extraction steam pressure. MHI and MHPS investigated the capture performance at reduced loads using the reduced-load flue gas compositions and flowrates. Results from these investigations, summarized in Fig. 4, showed the percent of CO_2 captured could be increased well above the "traditional 90%." Continuity in CO_2 capture operations at reduced loads is vital. Larger thermal units run less efficiently at reduced loads yielding an increased CO2 emission intensity profile. Using thermal power stations to backup VRE without CCS somewhat mutes the emissions reduction afforded by the VREs. From an emissions-mitigation point of view, a CCS equipped coal-fired power station could be made responsive to VRE generation and would emit

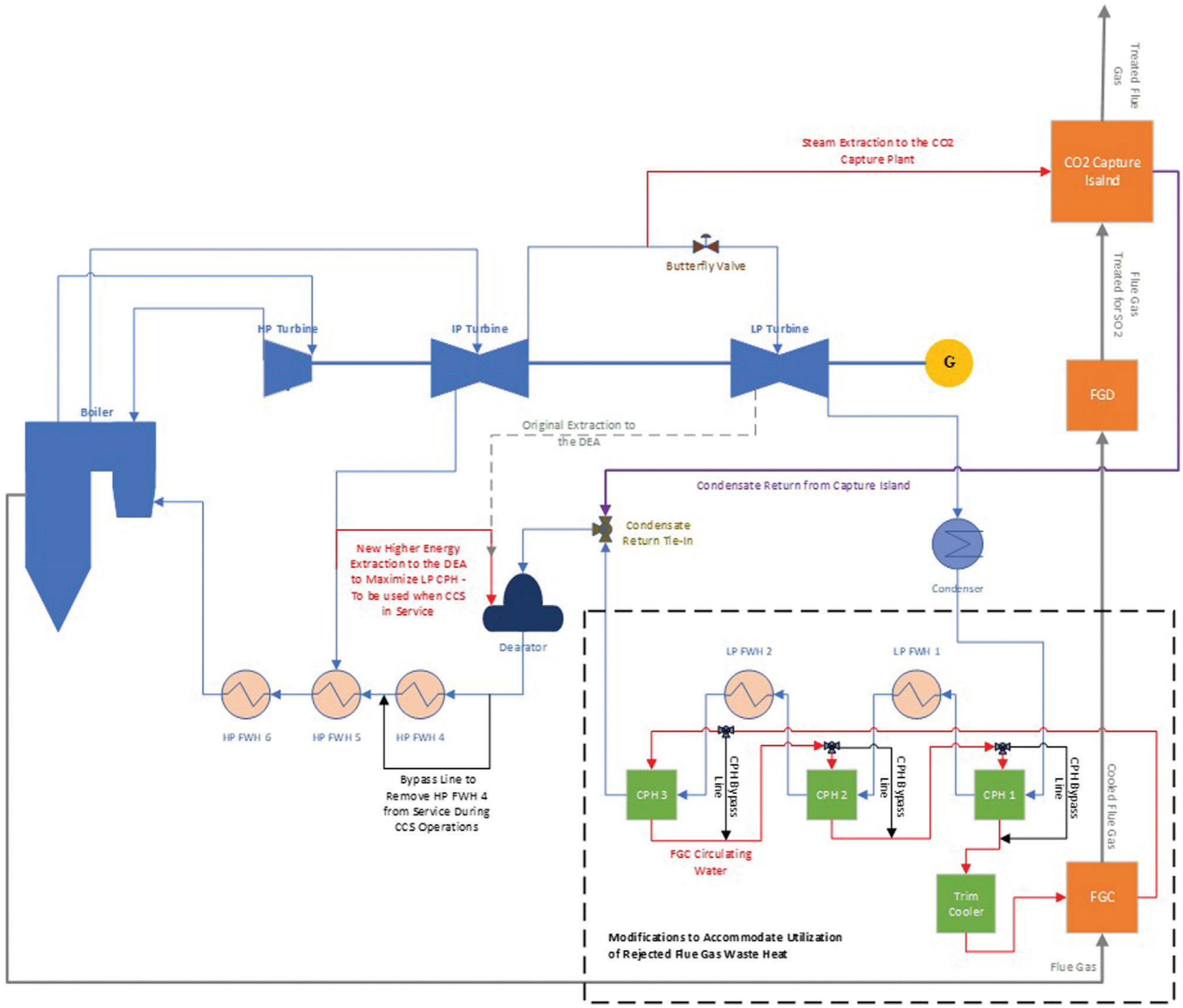

Figure 3. Modifications to the steam cycle to facilitate CCS integration.

less CO_2 per MWh, effectively magnifying the emissions reduction contribution of the VREs.

Maintaining water neutrality while increasing heat rejection capacity with CCS

Availability of cooling capacity is generally one of the first design concerns for siting a new facility, and can limit further expansion at a given site. Adding CCS to a coal fired power plant increases heat rejection capacity requirement by 50%. In the case of Shand, the CCS facility would add 339MWth of cooling duty. For Shand, there is limited water in the area, and additional water use permit is not probable for increasing cooling duty. Geographical challenges also exist as ambient temperatures in Western Canada can range from +40°C to −40°C which increases complexity in selecting the design temperature of the cooling system. Designing for the extreme ends of the temperature spectrum would provide adequate cooling capacity throughout the year; although desirable from a process perspective, the economics may be constrained as additional capital costs will be needed to size the heat rejection for the entire cooling capacity. Rather than sizing the new heat rejection system with this excess capacity, which would (comparatively speaking) have minimal annual usage, reduced design margins were considered. Derating the CCS facility at high ambient temperatures in favor of lower CO_2 capture with increased power output during times of excessive temperatures was found to be a practical solution.

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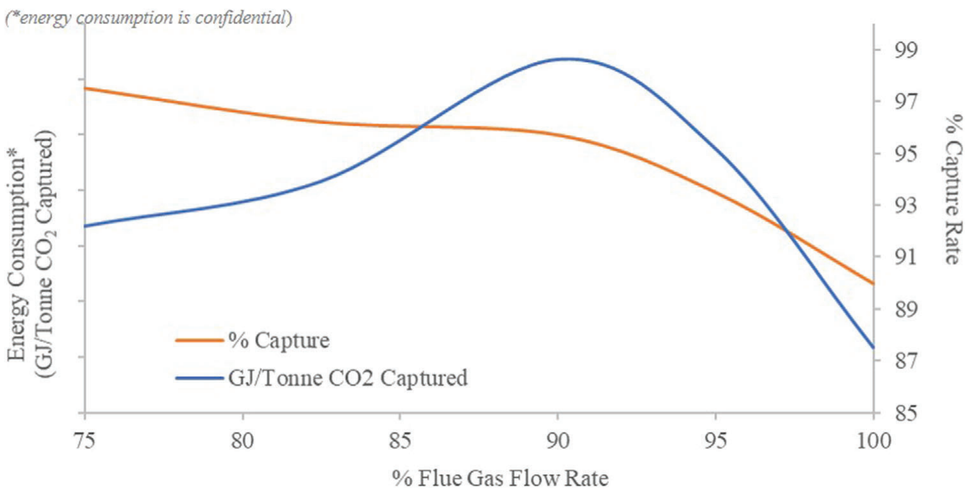

Figure 4. Relationship between energy requirements and capture rate at reduced power plant loads.

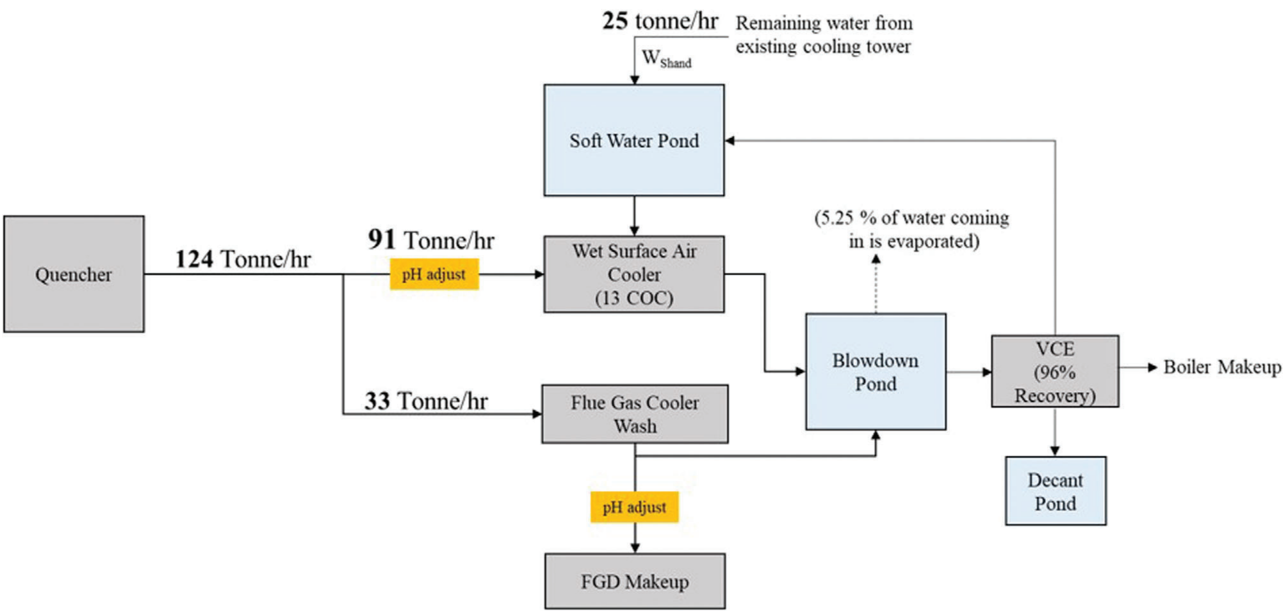

Figure 5. Block diagram of water usage and integration flows for the hybrid cooling system.

CCS application would also generate three new liquid water discharge streams. Shand operates on a zero liquid discharge (ZLD) license which would have to be maintained. The option to treat the additional waste streams in the existing wastewater facilities is limited. To maintain Shand's ZLD status, the process design entailed integrating these new streams into the cooling system (see Fig. 5). This strategy effectively would consume excess water, provide cooling, and maintain the plant water balance. To this end, a hybrid heat rejection system was designed for the 85th percentile — providing reduced margins in favor of cost savings (see Fig. 6). The only new water used in the system would be flue gas condensate. The design of new hybrid heat rejection system would consist of 26 air-cooled heat exchangers and four wet surface air coolers connected in series. The series configuration chosen for the design of the hybrid cooling system maximizes the use of dry cooling by approaching the dry bulb temperature before moving onto wet cooling where the wet bulb temperature is approached. This design minimizes both the surface area of the dry cooler and the volume of water used by the wet cooler. Details on this can be found in our previous works.[4]

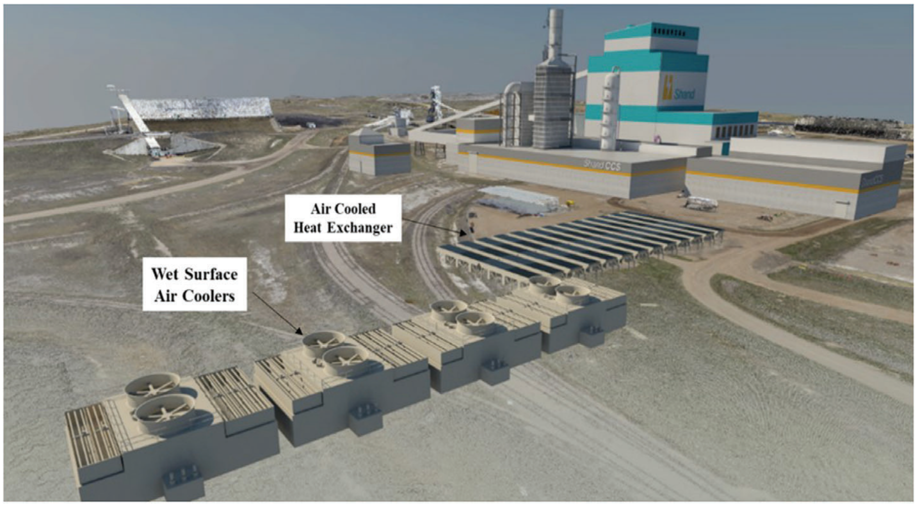

Figure 6. Proposed Shand hybrid cooling system.

Table 6. Summary of Shand's performance at full load following a CCS retrofit.

Case Description	1 Current operation	2 Operation following turbine upgrade, CCS not in service	3 Operation, CCS in service	4 Operation, CCS & reclaimer in service
Gross output (MW)	305.0	307.8	*	*
Recovery of 3% turbine degradation (MW)	N/A	9.2	*	*
Corrected gross output (MW)	305.0	317.0	*	*
Flue gas flow (kg h^{-1})	1,737,398	1,737,398	1,737,398	1,737,398
CO_2 capture efficiency (%)	0	0	90	90
Power island auxiliary load (MW)	26.5	26.5	26.5	26.5
Capture island auxiliary load (MW)	0	0	*	*
Fuel input (MJ hr^{-1})	3,230	3,230	3,230	3,230
Net output (MW)	278.5	290.5	216.75	215.3
Overall net output change (%)	Base Case	+4.3	-22.2	-22.7

*Confidential.

Evaluating Shand's performance with a CCS retrofit

Power plant performance with CCS at full load

The fully integrated design chosen for this study would yield parasitic losses in generation. Quantifying this loss is vital in establishing the business case for a CCS retrofit of this design. A turbine vendor, MHPS, was consulted during this investigation. Shand's net output performance was evaluated at full load for the following four cases:

Case 1: Current operation (Case 1, or the 'base case')
Case 2: Operation following turbine upgrade, CCS not in Service (Case 2)
Case 3: Operation with CCS in service (Case 3)
Case 4: Operation with CCS and reclaimer in service (Case 4)

MHI provided thermal energy requirements for the amine regeneration and reclamation processes, while MHPS provided turbine heat balances to support the evaluation of Cases 2 through 4. Upgraded turbine technology was included in Cases 2–4 which would

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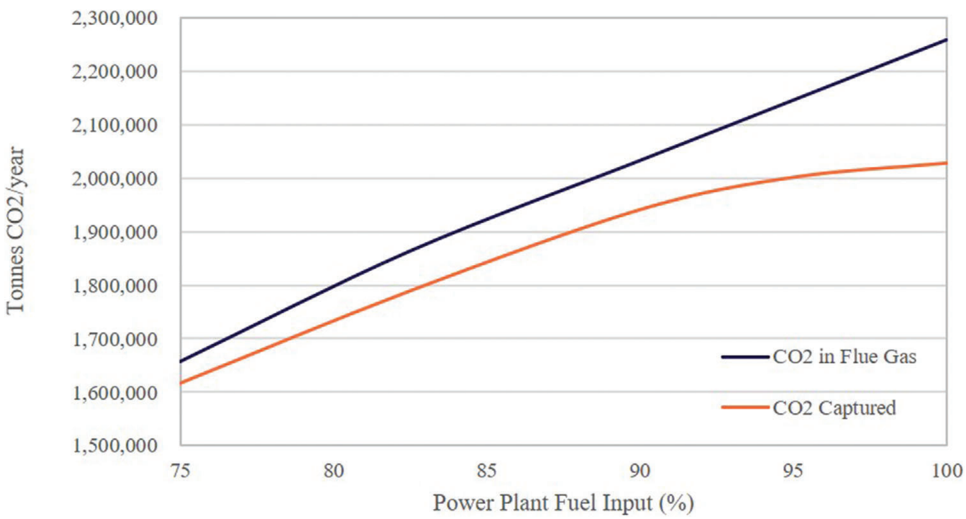

Figure 7. Relationships between CO_2 produced and CO_2 captured with load.

result in improved electrical output. The estimated performance of Shand in each case is shown in Table 6. The proposed turbine upgrades necessary to facilitate steam extraction to supply the CCS facility would also correct degrading performance associated with the age of the original turbine. Consequently, an additional 3% gross power output would be realized, which was included in the estimation of performance for Cases 2, 3, and 4.

Emission performance of Shand power station with CCS

The emissions profile of the proposed Shand CCS retrofit was calculated at various loads. Emission rates were observed to decrease at decreased loads due to the ability of the power plant to increase capture rate at reduced load rather than simply maintaining it. The relationships between the produced CO_2, captured CO_2, and overall capture rate are depicted in Fig. 7. Using Shand's historical loading profile and a predicted capture rate of 90%, an average emission intensity was calculated at 106 t GWh^{-1} (see Table 7). This value is significantly lower than proposed Canadian federal regulations.

Economic analysis of a Shand CCS retrofit

Capital and operating costs for a Shand CCS retrofit

The costs of a Shand CCS facility were determined and compared to that of the BD3 project (see Fig. 8).

Table 7. Average annual performance for Shand CCS with 90% design capture at full load.

Item	Value
Net electricity production (MWh)	1,539,815
CO_2 Emissions (Tonnes)	163,521
CO_2 Emission intensity (kg MWh^{-1})	106.2

Table 8. Summary of total costs of a Shand CCS retrofit.

Item	Cost ($M)
Total cost of CCS retrofit + life extension	986.4
Direct costs	786.4
Owner's costs	200.0

Overall the capital cost of capture was decreased by 67% on a per tonne of CO_2 captured basis. Factors such as scale, process simplifications, selection of a newer facility requiring only bolt in modifications to the turbine and minimal modifications to the feed heating plant, a modularized construction philosophy, and general lessons learned contributed directly to these cost reductions. High-level summaries of capital and operating costs for a Shand CCS retrofit are provided in Tables 8 through 10.

Capital costs per tonne of CO_2 captured comparison between BD3 and Shand CCS

The estimated costs of a CCS retrofit of Shand were compared to CCS related costs of the BD3 ICCS project. Capital costs of the Shand CCS retrofit were

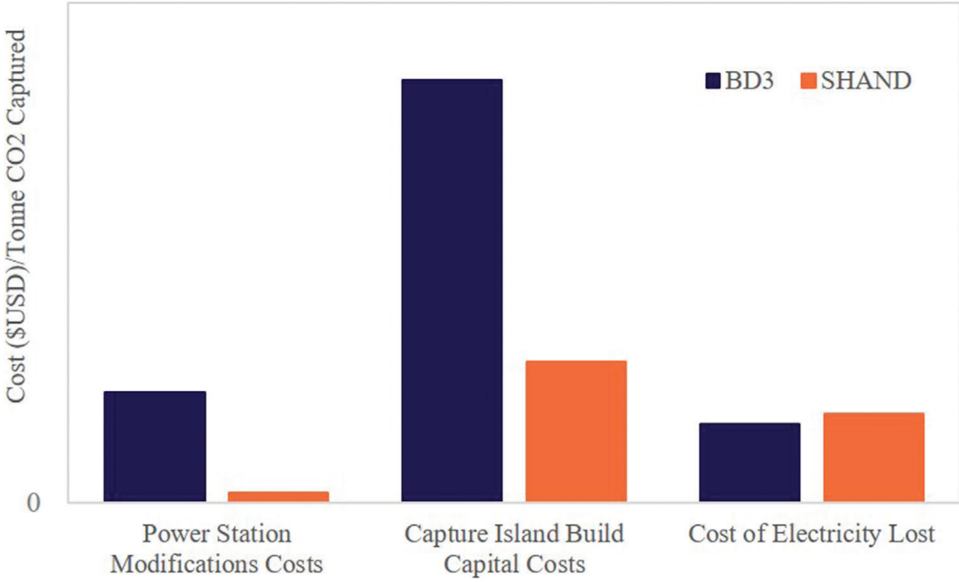

Figure 8. Cost reduction of the Shand second-generation CCS facility compared with the BD3 project.

Table 9. Summary of owner's costs for Shand CCS.

Owners Costs	$M (CAD)	Est Type
Insurance OCIP	4	Scaled
Project management, permitting and engineering	23	Scaled
Construction, critical spares and commissioning services	17	Scaled
Training, simulator and transition to operations	6	Estimate
Contingency	100	Estimate/Calculated
IDC	50	Calculated

Table 10. OM&A costs summary (all costs are in 2020 CAD dollars).

Capture island costs	Value
Fixed costs	
Labour ($M/year)	2.46
Maintenance ($M/year)	1.64
Variable costs (Assumes 0.85 CF)	
Consumables ($M/year)	11.48
Waste disposal ($M/year)	0.82
Total OM&A per year ($M/year)	16.41

based on the cost estimation methodology that was in place at the time of the original approval for the BD3 project and included interest charges during construction, contingency, owner-controlled insurance program, and project and site management, as well as transition to operations activities. Capital costs for the CCS portion of the BD3 project were determined independent of the life-extension work that were also undertaken at the power plant. The modification costs of the power plant that were necessary to support the BD3 capture facility rather than life extension costs were estimated based on a review of the expense items in the final project budget. It was determined that CCS related costs represented approximately 40% of the capital costs expended at the BD3 power island. Local taxes and permits were removed from both project cost estimates for the purpose of global relevance. The capital cost differential was adjusted to account for 10 years at an escalation rate of 2% per year for BD3. The loss in power generated, or the power production penalty due to capture operation was accounted for and converted to a cost value by forcing the project to "purchase" this power loss using a nonescalated estimate of the LCOC from an NGCC plant.

Determining the levelized cost of capture

The net present value (NPV) methodology was used to calculate the LCOC (Equation 1). Construction of the capture island was given a start date of 2020, while it

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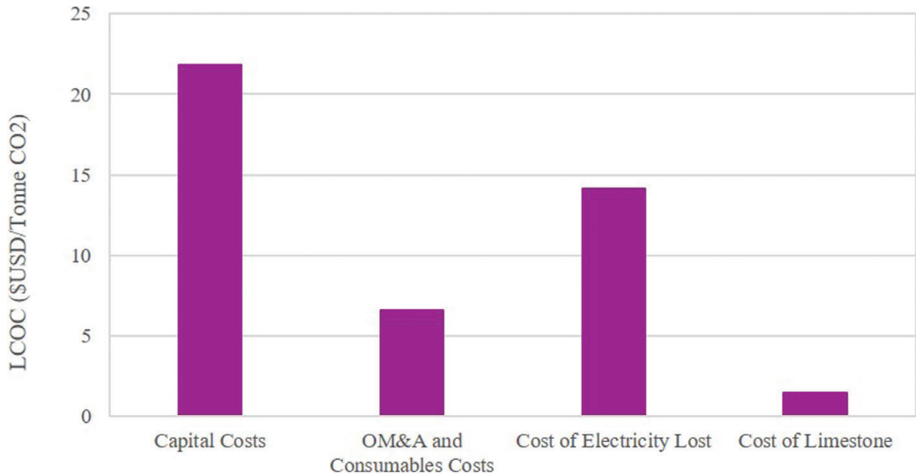

Figure 9. Break down of LCOC for Shand CCS.

Table 11. Data used to calculate the levelized cost of capture.

Parameter	Value
Discount rate (%)	5.5
Escalation rate (%)	2.0
Replacement electricity ($/MWh)	65
Net output prior to CCS (MW)	278.5
Net output with CCS (MW)	216.75
CO_2 produced (tonnes per day)	6540

was assumed that commissioning would be completed by the end of 2023. CO_2 capture operation was to commence at the beginning of 2024. A 30-year life span was assumed for the project.

$$\text{Levelized Cost of Capture} = \frac{\text{PV Costs}}{\text{PV CO}_2\text{ Captured}} \quad (1)$$

where the present value (PV) was calculated using:

$$\text{PV} = \frac{\text{Cash Flow}_{\text{period}}}{(1 + \text{Rate of Return})^{\text{number of periods}}} \quad (2)$$

Table 11 summarizes the input data used in the calculations.

The overall cost for Shand CCS was determined to be approximately $45 USD/tonne of CO_2. Costs have been attributed to four major cost categories (see Fig. 9): capture facility capital costs, OM&A and consumable costs, cost of electricity lost, and cost of limestone. Note that this value does not consider a CO_2 sale.

Conclusions and recommendations

The opportunity exists to retrofit the Shand power station with CCS. The Shand CCS facility would be the second industrial scale CCS facility on a coal fired power plant in Canada and the third in the world. The comparative cost savings and design considerations of a Shand CCS retrofit point to a project that can play a key role in reducing CO_2 emissions from power generation while preserving the value of the industries that rely on this type of generation within the province. Alternatives to CCS retrofitted coal in the province of Saskatchewan include a build out of NGCC plants (which would still be subjected to carbon pricing), increasing VRE capacity (which would still require a backup energy source) or importing hydro energy from neighboring provinces (which could create an economic imbalance and a loss of revenue to the province associated with generating its own electricity). The decision to ultimately retrofit the Shand power station will require additional investigation and a FEED study.

Disclaimer

The Shand CCS Feasibility Study and its associated documents reflect the findings and opinions of the International CCS Knowledge Centre. SaskPower has many factors that will determine if or when CCS will be deployed on units beyond BD3.

Nomenclature

BD3	SaskPower's Boundary Dam Power Station unit 3
BD3 ICCS	Boundary Dam's unit 3 integrated carbon capture and storage

CCS	Carbon capture and storage
DEA	Deaerator
FGD	Flue gas desulphurization
FWH	Feed water heater
IP	Intermediate pressure
LCOC	Levelized cost of capture
LP	Low pressure
MHI	Mitsubishi Heavy Industries
MHPS	Mitsubishi Hitachi Power Systems
NGCC	Natural gas combined cycle
VRE	Variable renewable energy
ZLD	Zero liquid discharge

Stavroula Giannaris

Stavroula Giannaris holds a Bachelor of Science degree in Chemistry, a Bachelor of Applied Science degree in Petroleum Engineering, and a Master in Process Systems Engineering with a focus of carbon capture technology – all from University of Regina. In January 2017, she started working with the International CCS Knowledge Centre as a researcher and in July 2017 began working as an Engineer in Training. Stavroula's interests include heat integration strategies, systems modelling and process optimization. Stavroula also enjoys project management and technical report writing. She is currently working towards her Professional Engineering designation.

Corwyn Bruce

Corwyn Bruce holds a Mechanical Engineering degree from the University of Saskatchewan, and is registered as a Professional Engineer. Corwyn has been working on the Boundary Dam 3 CCS project since 2009. During this time, he served as both an engineer and a project manager focusing on building the original business case, scope definition and delivery of the power plant upgrades and capture plant integration, as well as spending three years as the engineering manager leading the post start-up effort to resolve deficiency and operational issues at the facility. Prior to joining the clean coal initiative, Corwyn spent five years with SaskPower leading the control system replacement projects at Poplar River Power Station in 2006 and again in 2008. Previously, he spent 10 years with ABB / Bailey Controls, designing, commissioning and tuning control system upgrades on thermal power plant and industrial facilities. Corwyn joined the International CCS Knowledge Centre in August 2017, and currently he is Vice-President, Project Development and Advisory Services.

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