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Maximization of Net Output for Boundary Dam Unit 3 Carbon Dioxide Capture Demonstration Project

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Abstract

This paper presents the historical data during the design process of Boundary Dam Unit 3 Carbon Dioxide Capture Demonstration Project (BD3 ICCS) focusing net output improvement. BD3 ICCS is known as the first commercial CO_2 capture and storage facility integrated to a coal-fired power plant. Without CO_2 capture, pre-upgraded BD3 produced a 150 MW gross output and a net output of 139 MW. Initial models incorporating CCS calculated a net power output of 80.95 MW which indicated a reduction in net output of approximately 42% - an unfavorable value. This paper recounts the optimizing, retrofitting and upgrading options that were investigated in order to maximize the net output during the design process of BD3 ICCS. Several factors were taken into consideration including technology for CO_2 compression, turbine refurbishment, steam extraction and optimization, flue gas cooler (FGC) installation for heat recovery, main steam temperature, boiler refurbishment and others.

The final integrated model produced a net output of 110.88 MW – a 29.93 MW increase when compared to the initial cases. Selecting optimum technology for CO_2 compression accounted for 24% of the 29.93 MW improvement. Turbine refurbishment and corrected turbine degradation was responsible for 20 % of the net output increase. Recovering heat via flue gas cooling and condensate preheating increased the net output by another 13 %. Furthermore, boiler refurbishments and increases to the main steam temperature increased the net output by 5% and 7% respectively. This paper presents the analysis of each aspect in detail; including the design criteria and decision making steps during the engineering design process. However, it should be noted that the data presented here was design data and might be slightly different from the current operation.

Keywords: Post-combustion CO_2 capture; heat integration; heat recovery

1. Introduction

Boundary Dam Power Station, located by Estevan, Saskatchewan, is one of three coal-fired power plants in the province. Boundary Dam consisted of six units, commissioned between 1959 and 1978 and had a total capacity of 882 MW. In the early 2010's, new environmental regulations prompted SaskPower to assess the remaining life span of the plant. It was concluded that the older units in the plant were approaching their end of life marker. Subsequently units 1 and 2 were retired in 2013 and 2014 respectfully. Upgrades along with studies for a retrofit of carbon capture technology were considered for Boundary Dam Unit 3 (BD3). Among carbon capture technologies considered for BD3, post-combustion capture was the most promising. Decisions were made for turbine upgrades and installation of a post-combustion carbon capture facility to the unit. The first CO_2 was delivered to the pipeline in the fall of 2014.

Upgrades extended the life of BD3, installed emissions control (SOx and NOx) equipment, and saw the commissioning of the world's first fully Integrated Carbon Capture and Storage (ICCS) facility on a utility plant with a capture capacity of up to one million tonnes per year. The captured CO_2 was to be used for enhanced oil recovery (EOR) in a nearby oil field. EOR CO_2 injection continues today. Overall the BD3 ICCS Demonstration Project transformed Unit 3 at Boundary Dam Power Station into a long-term producer of more than 110 megawatts (MW) of clean, base-load electricity, while demonstrating EOR potential for a fully integrated process [1,2].

Nomenclature

BD3	Boundary Dam 3
BD3 ICCS	Boundary Dam Unit 3 Carbon Dioxide Capture Demonstration Project
CCS	Carbon Capture and Storage
ICCS	Integrated Carbon Capture and Storage
EOR	Enhanced Oil Recovery
FD	Forced Draft
FGC	Flue Gas Cooler
FGD	Flue Gas Desulfurization
PA	Primary Air
PMV	Pressure Maintaining Valve
HP	High Pressure
IP	Intermediate Pressure
LP	Low Pressure
HHV	High Heating Value

Chemical

SOx	Sulfur oxides
NOx	Nitrogen oxides
CO_2	Carbon dioxide

2. Fundamental knowledge

2.1. Coal-fired power plant

A coal-fired power plant is a thermal power plant that mainly consists of a steam generator, turbines, a generator, a condenser and feed water systems. A coal-fired power plant generates steam using energy from coal combustion in the boilers. The coal is burned in the boiler's furnace which generates a hot flue gas. The hot flue gas exchanges thermal energy to the feed water to generate superheated steam. The superheated steam at high pressure and temperature is fed to a turbine which usually includes high (HP), intermediate (IP), and low pressure (LP) sections. Once the steam enters the turbines, it expands. The high pressure and kinetic energy of the steam act on the turbine blades and turn the turbine shaft which is converted to electricity in the generator. The low pressure exhaust steam exiting the LP turbine flows to a condenser where it is condensed back into water. The water passes through the feed water system which includes a condensate pump, a low pressure preheater train, a deaerator, a boiler feed pump, and a high pressure feed preheater train respectively before reentering the boiler [3].

2.2. Integration of CO_2 capture process to a coal-fired power plant

Fully integrating a coal-fired power plant with carbon capture technology involves extracting the required steam quantity for solvent regeneration from within the power plant. This contributes the largest energy penalty to the overall output of the power plant. A large volume of steam is required, as such its point of extraction must be physically accessible. Options for sourcing this extraction include the main steam, the cold reheat steam, the hot reheat steam, and from the IP-LP crossover of the turbine. The steam at the IP-LP has already produced power in the HP and IP sections of the turbine, resulting in the lowest thermal energy density and so becomes the preferred extraction source [4]. The amount of steam going to solvent regeneration can be controlled by a valve if there is too much steam, and if there is too little steam, a valve at the inlet to the LP turbine can force more steam to the capture plant, at the expense of output and efficiency of the LP turbine. Control of steam flow is required to prevent thermal degradation of the solvent [5]. Losses in gross output due to the steam extraction are unavoidable. However, to minimize these losses, thermal energy can be recovered from other sources within the power plant and capture facility; for example the flue gas cooler, stripper overhead condenser, and the CO_2 compression train. Each source will vary in terms of thermal quality and quantity. Heat integration analysis for these sources must be done to determine their feasibility from a technical and economic standpoint.

3. Engineering design process

Selecting a Post-combustion capture process required a process integration study. SaskPower, with a mandate to provide affordable electricity to the province of Saskatchewan, was interested in a process thermal integration strategy that maximized the power plant's net output. Without CO_2 capture, BD3 produced a gross output of 150 MW with 11 MW auxiliary load. This resulted in a net output of 139 MW. Integration of a CO_2 capture process entailed losses of both gross turbine output due to the steam extraction for solvent regeneration, and net output of electricity for the CO_2 compression process and other additional auxiliary loads.

Various cases were evaluated in the design process for BD3. Using an iterative process, the net output was maximized while losses were minimized. Electricity outputs for each model are depicted in Fig. 1. The improvements in gross output, auxiliary load losses, and net output from the initial model to the final model are also compared. Initial models incorporating CCS produced a 124.13 MW gross output and a net power output of 85.95 MW with losses attributed to steam extraction. However, it was noted that for this initial model some auxiliary loads had not been considered (such as electricity for service and maintenance). Consideration of these inputs further reduced the net output to 80.95 MW. The resulting energy penalty, approximately 42%, was most concerning when considering the business case for BD3. Improvements were made through subsequent models. This included steam cycle components, such as the boiler and turbines, and decreasing auxiliary loads, such as compression power. Power production increased; the final integrated model produced a net output of 110.88 MW – a 29.93 MW increase when compared to the initial cases. The optimizations that led to this 29.93 MW gain are explained below.

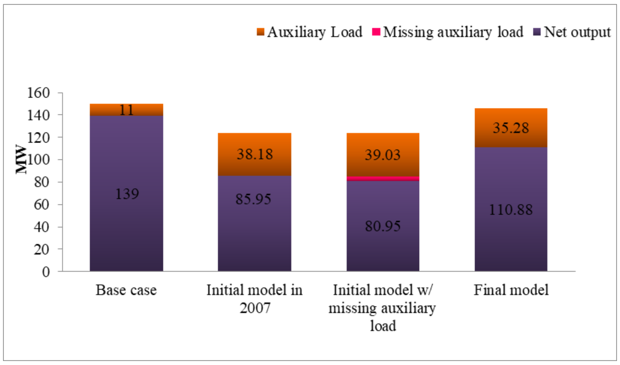

Fig. 1. Improvement of net output during the ICCS design process

3.1. Heat recovery from flue gas cooler

Flue gas preconditioning is required for CCS integration. This includes particulate removal, SO_2 removal and flue gas cooling. Particulate removal is required to prevent equipment fouling. Decreasing the SO_2 concentration in the flue gas prior to capture operations reduces amine degradation. The flue gas temperature must be reduced before entering the absorber column to favor reaction kinetics between the CO_2 and amine molecules. Flue gas exiting the boiler has a high quality and quantity of thermal energy that is available for recovery. Recycling this heat back to the steam generation process helps to improve heat rate. Based on flue gas temperature ranges, two options were considered for applying this recycled waste heat; air preheating and condensate preheating.

Utilizing low grade heat in air preheating requires the installation of air preheaters downstream of the primary air (PA) and forced draft (FD) fans and upstream of the existing unit air heaters (tubular primary, rotary secondary). The waste heat could preheat the combustion air from a standard 27 ºC up to 121 ºC. This would offload the existing air preheaters and allow for lower economizer exit temperatures, assuming a constant boiler air heater/back end flue gas temperature. The shift of heat from combustion air heating to the boiler convective pass results in the potential for additional steam generation. Although air preheating represented a potential efficiency improvement for the project and use for low grade heat recovery, it was not selected for implementation due to the cost and complexities of the retrofit requirement.

Condensate preheating was ultimately evaluated and selected for BD3 ICCS. A closed loop of circulating water was installed between the flue gas cooler, and the condensate preheater. The condensate preheater was integrated into the LP feed heating train. The flue gas exiting the boiler passes through precipitators and ID fans before being introduced into the flue gas cooler (FGC). The cool circulating water entering the FGC cools the flue gas while transferring the thermal energy from the flue gas through a gas to liquid energy exchange process. Then the circulation water (now hot) is circulated to the condensate preheater where it pre-heats the boiler feedwater via a heat exchanger. Both low pressure feed water heater (LP FWH 1 and 2) would be completely bypassed during capture mode as the feedwater is completely preheated using waste heat in the condensate preheater.

3.2. Steam extraction and optimization

Two main criteria must be considered when sourcing the steam extraction:

1) Adequate steam quality for use in solvent regeneration.
   - The extracted steam should be at a pressure that results in a saturated steam temperature that exceeds the amine regeneration temperature by enough to result in a reasonable sized heat exchanger. Therefore, the regeneration temperature is the main factor to determine where the steam should be withdrawn.
2) Minimizing the accompanying power generation reduction.
   - The regeneration temperature determines the pressure that the CO_2 is recovered at, and the amount of energy required to compress the CO_2 increases when it is delivered at lower pressures. Determining the optimum regeneration temperature is a complex matter which includes relative efficiencies of the steam turbine generator, and the CO_2 compressor, the relative cost of equipment on both the gas and liquid side of the process, and the solvents stability which is a function of among other things, the temperature.

Four scenarios were investigated as steam extraction locations. As mentioned above, the controlled extraction by incorporating a Pressure Maintaining Valve (PMV) at the IP-LP crossover between the extraction point and the LP turbine inlet will lead to the loss in power generation. Therefore, all scenarios assumed the use of an uncontrolled extraction.

To investigate the effect of steam extraction on the gross output of the plant based on the four different scenarios, GateCycle™ was used. GateCycle™ is a powerful and flexible engineering software tool that allows user to model steady state design and off design performance of a thermal process. The design model of BD3's steam cycle was built in GateCycle™ using BD3's heat balance. The design model (built in design mode) allows GateCycle™ to size all components of the steam cycle specifying the performance of each, especially the steam turbines. After the design model was built, the model was switched into off design mode and steam was extracted from the steam cycle for solvent regeneration. Running the model in off design mode allows predictions on how the power plant will perform when the process conditions have been changed without changing properties of the steam cycle components themselves. Since, at this time a wet limestone flue gas desulfurization (FGD) system was assumed for SO_2 removal there was no requirement of steam for the SO_2 capture process. Four steam extraction positions for solvent regeneration were investigated in this study as follows:

Scenario 1: Hot reheat / backpressure turbine

This scenario entailed withdrawing high energy steam from the hot reheat and feeding it to a backpressure turbine prior to use in the capture facility. The GateCycle^{TM} model of this scenario is shown in Fig. 2. The backpressure turbine was modelled with an isentropic efficiency of 80%. The use of a backpressure turbine generates additional electricity before sending the steam to the capture process; this can help to minimize losses in gross output for the power plant, but with additional complexity. An advantage of using the hot reheat steam is that its steam flow is proportional to the main steam flow. The hot reheat steam extraction will result in a similar reduction in load on IP and LP turbines. Disadvantages include changes in thrust loading and pressure ratios in the turbine. Moreover, sourcing the steam extraction from this point might result in changes to the cold reheat temperature, which could require adjusting the relative distribution of heat transfer surface in the boiler.

Scenario 2: IP-LP crossover

This scenario investigated sourcing the steam extraction from the IP-LP crossover as shown in Fig. 3. This option is the most reasonable as this steam is low quality and is easily accessible. The extraction from this location has no impact on LP operation other than reducing the flow; similar to reducing load condition, thanks to its balanced double flow design. However, the pressure at the extraction point cannot be controlled, and therefore, additional allowances are required. The turbine can only be optimized for one condition, and other operating conditions may require alternate or less efficient sources of extraction steam. Moreover, the changes due to extraction flows result in changes to pressure ratios and outlet temperatures for the IP turbine.

Scenario 3: Cold reheat and IP-LP crossover

The steam was withdrawn from two positions including cold reheat and the IP-LP crossover as shown in Fig. 4. As adding a single large extraction flow can have impacts on pressure ratios, thrust loads, and stresses in the steam turbine sections upstream of the extraction point, this scenario investigates the impact of splitting the extraction flow into two smaller extraction flows. Taking steam from the cold reheat also reduced the steam flow through the reheater, required changes to reheater surface area.

Scenario 4: IP and IP-LP crossover

Instead of withdrawing steam with higher thermal energy, such as from the cold reheat, Scenario 4 (as illustrated in Fig. 5) extracted steam with a lower pressure from IP and mixed it with steam extracted from the IP-LP crossover. This scenario also mitigated the change in reheater flow as noted in the previous scenario.

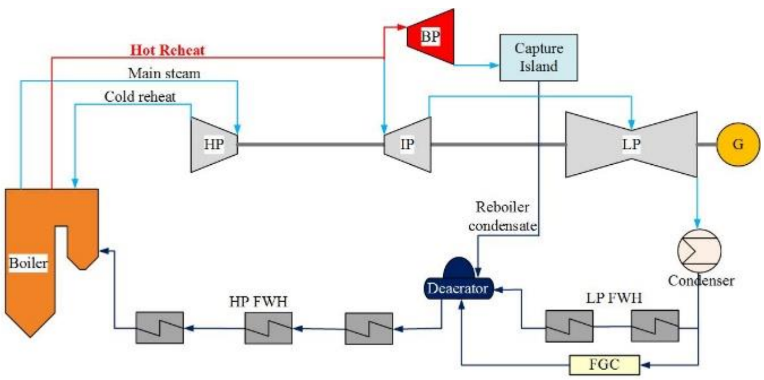

Fig. 2. Simplified diagram for steam extraction from Hot reheat/ backpressure turbine

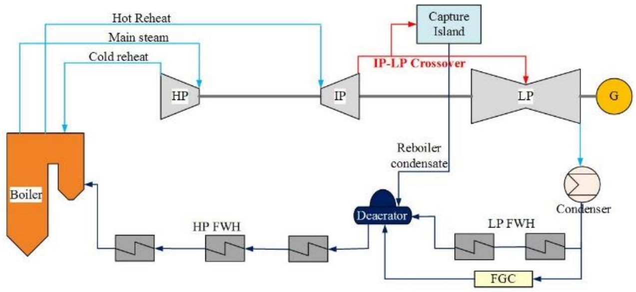

Fig. 3. Simplified diagram for steam extraction from IP-LP crossover

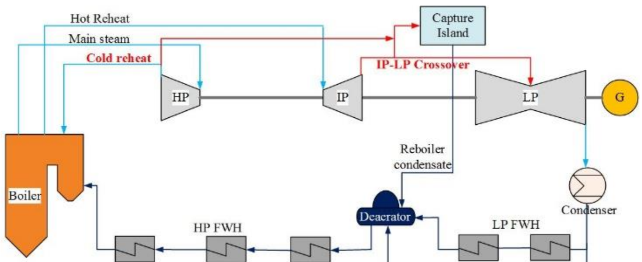

Fig. 4. Simplified diagram for steam extraction from Mixed cold reheat and IP-LP crossover

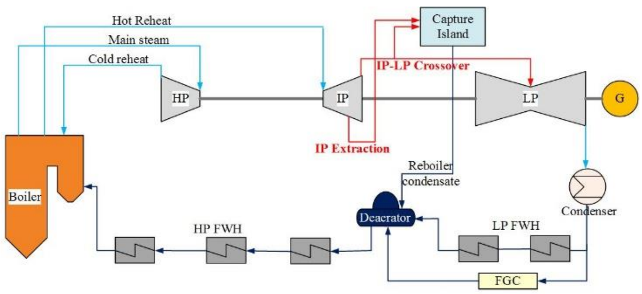

Fig. 5. Simplified diagram for steam extraction from Mixed IP and IP-LP crossover

After completing all simulations in GateCycle™, the gross outputs from each scenario were compared. One parameter that can be used to quantify the impact of the steam extraction on the process is the cost of steam. This metric is presented in the unit of MW electricity loss per MW thermal withdrawn from the cycle. The cost of steam can be calculated using Equation 3.1.

$$\text{Cost of Steam} = \frac{\text{Electricity productionloss from the steam cycle (MW)}}{\text{Thermal energy withdrawn from the steam cycle (MWth)}} \qquad 3.1$$

3.3. Turbine Customization

An advantage when integrating CCS to a power plant requiring modifications is the potential to customize these modifications. After investigating several locations for sourcing the amine regeneration extraction steam, the option of replacing the steam turbine was investigated. Four scenarios involving turbine customization were investigated. Once again, a series of GateCycle™ modes were used to predict the losses in generation resulting from a range of IP-

LP crossover steam extraction flows rates. Steam extraction flow rates investigated included 12.11, 24.21. 36.32 and 48.42 kg/s.

Scenario 1: Original turbines

This scenario was used to predict the performance of the cycle using the original turbine design performance as represented in the original BD3 heat balances. This case was used for comparison purposes.

Scenario 2: Customized LP

This scenario involved keeping the HIP turbine with its original design parameter; as per GE design with the IP turbine exhaust pressure of 491 kPa abs. Properties of the LP turbine were optimized to minimize the amount of throttling required by the valve on the IP-LP crossover.

Scenario 3: Customized IP/LP

This scenario involved customizing both the IP and LP turbines. The IP turbine exhaust pressure was reduced to 374 kPa abs.

Scenario 4: Customized IP/Original LP

This scenario customized the IP turbine while keeping the LP turbine at its original design parameters. The IP customization increased efficiency of the IP turbine while keeping its exhaust pressure constant.

3.4. CO_2 compression

Once CO_2 is captured, compression is the next necessary step. Several options and equipment vendors were investigated for the compression process. The first option explored using a Ramgen CO_2 compressor. A Ramgen compressor is a two stage compressor configuration that provides a high-pressure ratio. A Ramgen compressor had the added benefits of low cost and simplicity. Moreover, it generated heat during the compression process, providing an opportunity for heat recovery [6]. Based on the initial design, the compressor consumed up to 20.79 MW. This compression power seemed high but could be compensated for through the heat recovery application for additional capital costs. However, it was decided not to continue further with heat recovery from the compressor. Instead, a compressor with lower energy consumption but with higher equipment cost was selected.

Besides compressor type, other factors in the compression process needed to be considered. The pressure of the CO_2 entering the compressor processes plays a key role in lowering power consumption. Inlet CO_2 pressure must be optimized. A data set of the required CO_2 compression power as a function of pressure was generated. The suction pressure range at the inlet of the 1st stage wet compressor was varied from 101.3 to 3000 kPa with the inlet temperature 45 °C. The CO_2 would be compressed to a supercritical stage with the outlet pressure of 17,244 kPa. The detail assumptions of this analysis are listed in Table 1.

Table 1 Parameters used in modelling of CO_2 compression process

Condition	Assumed Value
Inlet temperature to 1st stage compressor	45 °C
Suction pressure range at inlet of 1st stage wet compressor	101.3 – 3000 kPa
Pressure leaving the wet compressor	4482 kPa
Wet stages polytropic efficiency	80%
Pressure at inlet of dehydration unit	4454 kPa
Temperature at inlet of dehydration unit	21.1 °C
Cooling water inlet temperature	16.1 °C
Cooling water return temperature	42.2 °C
Pressure at inlet of 1st stage dry compressor	4330 kPa
Dry stages polytropic efficiencies	65-85%
Dry stages compression ratio	2

Temperature at inlet of 1st stage dry compressor	21.28 ºC
Outlet pressure of supercritical CO2 from last stage (at pipeline)	17244 kPa
Pressure drop in the intercoolers, knock-out drum and associated piping	28 kPa

3.5. Steam Temperature and Boiler Refurbishment

Due to BD3 being at the end of its useful life, boiler maintenance and upgrades were necessary to improve the overall boiler performance. BD3 is considered a small coal-fired power plant with a drum type boiler as shown in Fig. 6. The original BD3 boiler was designed and supplied by Combustion Engineering Superheater Company in the late 1960's and was refurbished by Babcock and Wilcox Canada between 1993 and 1997. The boiler is equipped with tilting, tangentially fired burners, six pulverizers, two tubular primary air heaters, two regenerative Ljungstrom secondary air heaters, an external economizer, and internal superheater/reheater.

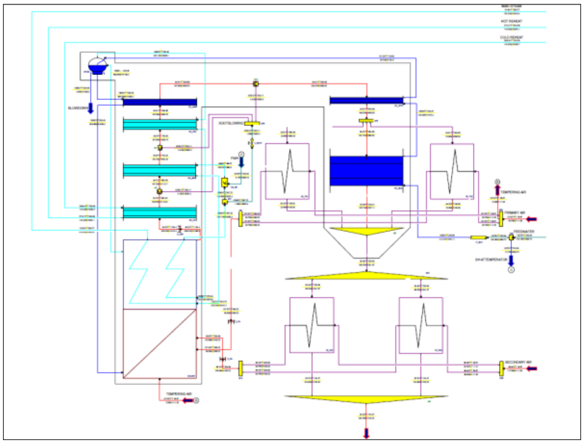

Fig. 6. Simplified schematic diagram for BD3 boiler

SaskPower cooperated with Babcock and Wilcox Canada to investigate the effect of increasing steam temperature and eight different refurbishment scenarios for the BD3 boiler. Main steam conditions for BD3 were 12,411 kPa and 538 ˚C. Current technology allows for higher steam pressure and temperature. The increasing of the boiler outlet steam temperature from 538 ˚C to 566 ˚C to supply to the steam turbine was investigated. The study for boiler refurbishment was performed by investigating the increase of heat transfer surface area of different boiler compartments including the secondary air heater, the superheater, the primary air heater, and the economizer. Other modifications that were investigated included adding pendant superheater above the economizer, the use of low grade heat recovery for air preheating, and installing a new primary air heater and secondary air heater. The replacement which upgraded the secondary air heater baskets is a minor modification with significant efficiency improvements. The superheater and preheater heating surfaces were increased to the point where the reduction in gas temperature entering the existing primary air heater causes primary air temperature to drop to the recommended minimum value. The surface area of primary air heater was increased to recover some of the heat. Low grade heat exchangers were considered as a black box heat source supplying preheated combustion air to the air heaters. The summary of the boiler refurbishment modification (Mx) options, and their combinations are shown in Table 2.

Table 2 The summary of the boiler refurbishment options

	Base	M1	M2	M3	M4	M5	M6	M7	M8
Secondary air heater surface addition	X	X	X	X	X	X	X	X	X
Superheater surface addition		X	X	X	X	X	X	X	X
Primary air heater surface addition			X	X	X	X	X	X	X
Economizer surface addition				X	X	X	X	X	X
Add Pendant superheater above economizer					X	X	X	X	X
Low Grade heat recovery							X	X	X
New regenerative primary air heaters								X	X
New regenerative secondary air heaters									X

4. Results and discussions

The overall net output of the BD3 ICCS at the final design is 110.88 MW – a 29.93 MW increase from the initial design. Table 3 shows the contribution of each aspect to the overall net output. The main contribution was obtained from the selection of the proper CO_2 compression technology and the turbine refurbishments.

Table 3. Net output improvement by improving integration process in each aspect

	MW
CO_2 compression	7.05
Turbine refurbishment	6
Steam extraction and optimization	5.29
Flue gas cooler (FGC)	4
Steam temperature	2
Boiler refurbishment	1.6
Others	3.99

4.1. Compression power

The effects of the CO_2 suction pressure from the capture plant on the compression power per mass flow of CO_2 is illustrated in Fig. 7. It can be noted that increased pressure of the incoming stream equates to lower energy requirements by the compressor. However, the higher suction pressure indicates higher steam extraction quality/quantity requirements. Suction pressure must be optimized to compensate between thermal energy supply to the capture process and the electricity supply to the compression process. The final model resulted in the compression power of 13.74 MW.

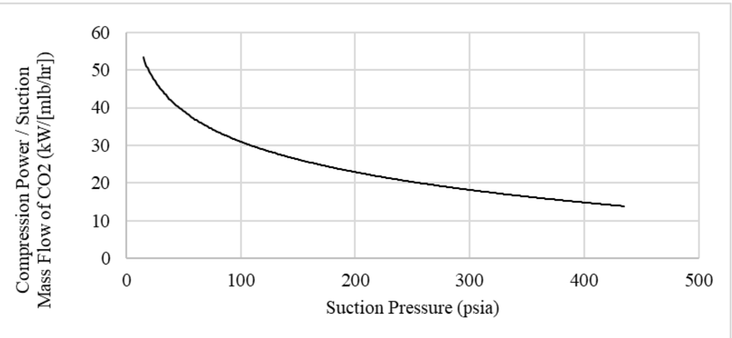

Fig. 7. The effect of suction pressure on compression power

4.2. Effects of steam extraction on the gross output

The effect of steam extraction position and pressure were investigated. Table 4 shows simulation results corresponding to varying the position of the steam extraction point within the steam cycle. Four scenarios were investigated. Comparison between the four scenarios indicate that the highest net output can be obtained by sourcing the extraction from IP-LP crossover (136.60 MW) followed by the hot reheat/backpressure turbine scenario (133.51 MW), the IP/IP-LP crossover scenario (120.66 MW) and the cold reheat/IP-LP crossover scenario (118.58 MW). It should be noted that the extraction from IP-LP crossover and hot reheat/backpressure turbine (which are single point steam extractions) resulted in higher net output compare to the extraction from IP/IP-LP crossover and cold reheat/IP-LP crossover (which are dual point extractions). Not only do dual extractions result in decreased performance they are also impractical. The dual extraction configuration can lead to complicated construction and can be difficult to operate; increased piping and controls would be required compared to the single extraction configuration.

Table 4 Results from the simulation by different steam extraction locations

Scenario	1	2	3	4
Description	Hot Reheat/BP	IP-LP Crossover	Cold Reheat/ IP-LP Crossover	IP/ IP-LP Crossover
Gross Power Output (MW)	133.51	136.60	118.58	120.66
Main turbines (MW)	117.06	136.60	118.58	120.66
Backpressure turbine (MW)	16.45	-	-	-
Gross HHV Eff. (%)	29.67	30.34	26.33	26.80
Gross HHV heat rate (kJ/kW-h)	12134.08	11866.79	13671.04	13434.70

The electricity loss per thermal energy withdrawn from the steam cycle (MWe/MWth) is depicted in Fig. 8. Factors influencing the cost of steam included steam pressure and enthalpy at the extraction point. Cost of steam and net output generation usually display an inverse correlation. As expected, the lowest cost of steam was obtained from situating the extraction point at the IP-LP crossover.

For comparison sake, a fifth case is displayed in Fig. 8; the cost of steam corresponding to sourcing the steam extraction from the hot reheat and attemperating it to suitable reboiler conditions instead of installing a backpressure turbine, was included. Without the backpressure turbine the cost of steam can be as high as 0.278 MWe/MWth. Using a backpressure turbine reduces the cost 0.168 MWe/MWth. Although a significant reduction, this is still 13.5% higher than the cost of steam extracted from IP-LP crossover which is 0.148 MWe/MWth. Thematically, these two cases should have similar costs of steam as the condition of the steam leaving the steam cycle in the two scenarios are comparable. Turbine efficiency plays a large role in the observed differences. For this study the backpressure turbine was assumed to have an efficiency of 80%. This value was based on small industrial backpressure turbines available in the market which usually have lower efficiencies than thermal power plant steam turbines.

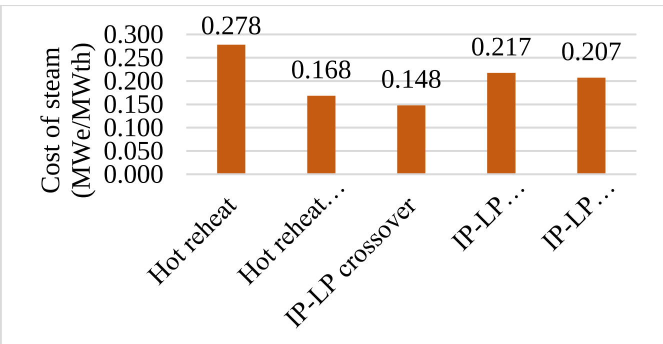

Fig. 8. Cost of Steam at Different Steam Extraction Location

The pressure of the steam extraction also affects the cost of steam. Low grade steam would be ideal for the extraction as it would minimize the output penalty, however, in most cases, this is impractical as the quality of steam must be sufficient for solvent regeneration. The turbine island with the extraction positioned at the IP-LP crossover was simulated. For each model, the IP-LP crossover pressure was varied to achieve a desired crossover pressure during full CO_2 capture operations at ranged between 241 to 621 kPa. Each model incorporated a 75 kPa line loss between the crossover and the reboiler (crossover valve installed produces a dP = 2 %). Cost of steam results are summarized in Fig. 9. Results indicate that extraction steam pressure has a significant effect on the cost of steam.

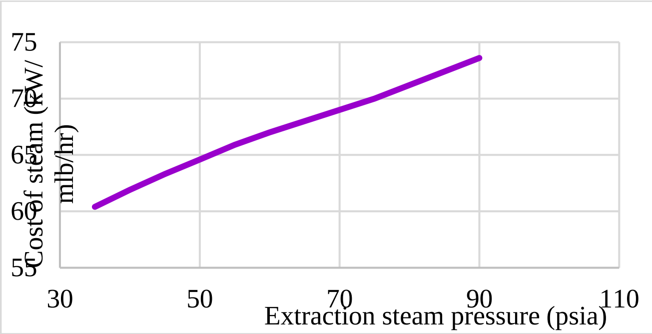

Fig. 9. Cost of Steam with Extraction Pressure (Steam extraction from IP-LP Crossover)

4.3. Effects of turbine optimization

Effects of the steam extraction flow rate were also investigated as part of turbine optimization. Fig. 10. shows the electricity loss in MW associated with varying steam extraction flow rate at different turbine conditions. Higher steam extraction flow rates lead to higher losses of gross output. The model associated with the original turbine design gave the highest loss due to the requirement for throttling and the installation of a backpressure valve to provide steam to the capture process at the suitable pressure. Strategies to help recover this loss include customizing the turbine so that it is able to provide steam at the suitable pressure for capture operations. Higher MW recovery due to turbine customization became increasingly significant at the higher steam extraction flow rates.

The combined results from the optimizing steam extraction location, turbine design, and heat recovery through flue gas cooling paired with condensate preheating are illustrated in Fig.11. To reiterate, steam extraction from the IP-LP crossover not only yields the highest gross output (136.6 MW) but also provides increased steam accessibility. Paired with the customized LP turbine, the net output can be increased to 138.8 MW - a significant 2.2 MW gain.

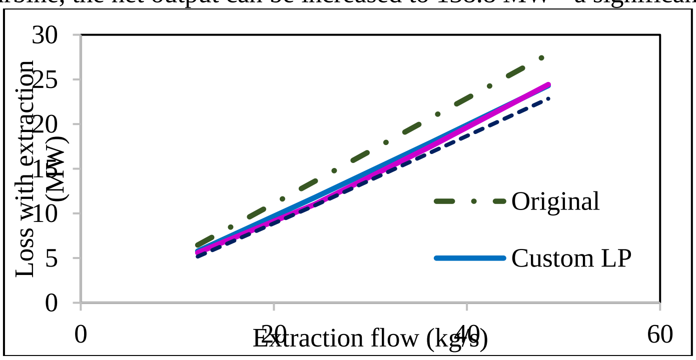

Fig. 10. Evaluation of Turbine Optimization (Extraction from IP-LP Crossover with Valve for Crossover Pressure Control No Condensate Preheating with Flue Gas)

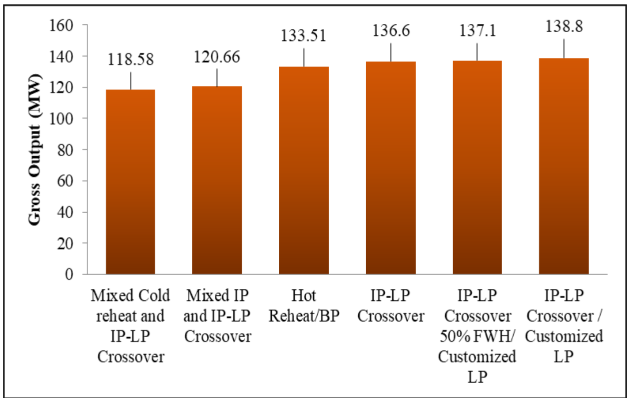

Fig. 11. The results from the effect of steam extraction location and the turbine optimization

4.4. Gross output improvement by heat recovery from flue gas cooler

Flue gas cooling offers the opportunity to improve plant heat rate through low grade waste heat recovery for condensate preheating. Recovering this heat back to the process through condensate preheating facilitates a net output increase up to 4 MW. Choosing between bypassing the high pressure (HP) feed water heaters and the low pressure (LP) feed water heaters was based on the quality of waste heat. Completely bypassing LP FWH 1 and 2 reduced the steam extraction from the turbine for condensate preheating resulting in increased power generation. Furthermore, the use of an FGC provides the potential to reduce water consumption used for flue gas cooling and clean up.

4.5. The effect of boiler refurbishment

The improved steam cycle performance resulting from increasing main steam temperature is presented in Fig. 12, a plot between the relative heat rate improvement and HP turbine inlet pressure at the different main steam and reheat steam temperatures. Three sets of main and reheat steam temperatures are shown in the figure including the temperature of original BD3 boiler (538/538 ºC), the temperature of intended boiler upgrade (566/566 ºC), and the temperature of a state of the art boiler in a super critical plant (presented here for a comparison). If the BD3 boiler could be upgraded to a supercritical plant with a main steam temperature and pressure of 566 ºC and 29,647 kPa, the heat rate would have been improved by 7.6%. The increase of the main steam pressure would significantly improve the heat rate. By increasing the main steam and reheat steam temperatures from 538 ºC to 566 ºC without increasing the main steam pressure, the heat rate could be improved by 1.7% (approximately 2 MW output increase). Increasing the steam temperature required installation of a new steam turbine and high pressure steam piping, and new heat transfer surfaces in superheater and re-heater, which were already slated for replacement due to condition/life assessment issues. Incremental cost to upgrade materials for 566 ºC were minor, the higher turbine inlet steam temperature significantly increases the unit heat rate. Fig. 13. shows relative improvements in boiler efficiency and the cost of boiler upgrades for the different boiler upgrade options. Increased upgrades lead to higher relative improvement of boiler efficiency. However, the costs of the refurbishment are also increased through equipment and labor requirements.

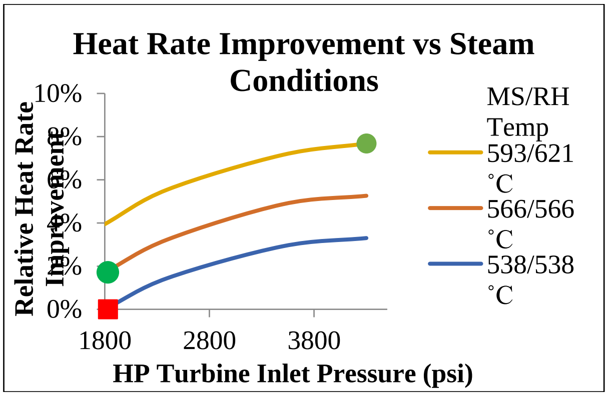

Fig. 12. The effect of increasing steam temperature on relative heat rate improvement

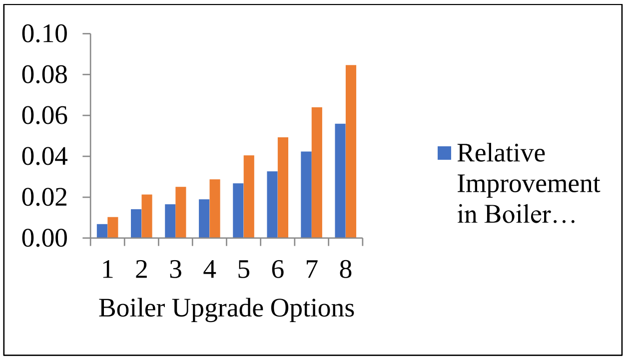

Fig. 13. Relative improvement in boiler efficiency and cost of boiler upgrade at the different boiler upgrade options

5. Conclusions

Rigorous modelling and investigations improved the net output production of BD3 when integrated with CCS technology. The 29.93 MW net output increase from the initial process integration model was significant. The main contributors in the net output improvement were: selection of CO_2 compression technology (contributing to 24 % of the net output improvement), turbine refurbishment (contributing a 20 % improvement) due the elimination of turbine leakage and turbine degradation, and heat recovery and integration via flue gas cooling and condensate preheating (contributing a 13% improvement). Furthermore, increasing main steam temperature and the boiler efficiency as part of the refurbishment increased the net output 7% and 5% respectively.

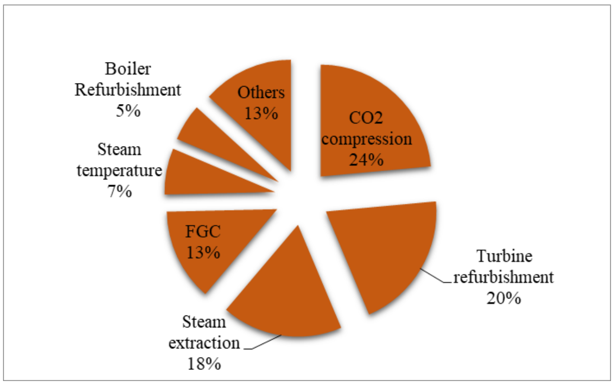

Fig. 14. Net output percent increase corresponding to studied aspects

Currently, operating conditions at BD3 may differ from those described in this paper. Learnings from operational experience may have changed the way in which the capture island is run. The BD3 ICCS project continues to lead the evolution of CCS technology. The trail blazing nature of this “first of a kind” mega project has inspired the next generation of industrial scale carbon capture projects.

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