

The Impact of Coal and Biomass Co-Firing on the Economy of Power Plant Carbon Capture

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Abstract: A detailed economic evaluation was carried out to determine the impact of biomass and coal co-firing on power plant carbon capture by methods of plants equipment designing factors and performance, and the sum up of the associated breakdowns of CAPEX and OPEX. Based on the assumptions of the CO₂ neutrality of biomass and likely governmental incentives to reduce CO₂ emissions, the study results show that biomass and coal co-firing would result in both lower cost of carbon avoided (carbon capture) and lower incremental cost of electricity generation when MEA solvent carbon capture is applied. Two scenarios for co-firing with carbon capture, 30% biomass blending and 90% or 60% CO₂ capture from stack, indicate different preference depending on lower or higher incentives.

Keywords: Coal and biomass co-firing; Carbon capture; Renewable energy; Economic evaluation; Cost of CO₂ avoided.

1. Introduction

After decades of investigation, mitigating climate changing is regarded as a worldwide priority [1,2]. For stationary emission sources of carbon dioxide (CO₂), several efforts are being pursued, in which exploration of renewable energy utilization and carbon capture stand out as the most probable strategies to achieve the long term goal of worldwide sustainable development [3-6].

Biomass is a widely available renewable energy resource. Plants undergo a natural growth and decay cycle. Carbon dioxide (CO₂) in the atmosphere is fixed into the body of biomass in the growth period, and then released back to the atmosphere while decaying. When sustainable biomass is harvested and consumed as an energy resource, the fixed carbon in the biomass body is converted back to CO₂ and released to the atmosphere, without incurring a net increase in the atmosphere [7]. Therefore, biomass is regarded as a carbon neutral energy resource. There are potential ways to utilize biomass, however, some require the development of new combustion technologies [6,8]. A simple and economic way is to adopt coal and biomass co-firing in existing power plants, which has been practiced for decades, as it can be technologically viable for existing power plants [6]. It is anticipated that more and more power plants will adopt the co-firing strategy in the near future. As for carbon mitigation strategies, post combustion capture is the most probable strategy compared to integrated gasification combined cycle (IGCC) and oxy-fuel combustion in terms of technology readiness [9,10]. If a post combustion carbon capture technology is applied to a biomass (or partial biomass) fired boiler, a scenario of negative carbon emission could be created, i.e., the CO₂ is removed out of the atmosphere into the ground via biomass harvest, combustion, carbon capture and sequestration. This could be the most preferable scenario in limiting global warming [1,3,11].

Carbon tax and trading schemes have been proposed for years and now they are being practiced in Europe and some North American jurisdictions [12,16]. This is to provide an economic penalty for status-quo, and also a financial incentive to encourage using more renewable energy or carbon capture technologies. The Government of Canada recently introduced a Pan-Canadian Framework on Clean Growth and Climate Change that will allow individual provinces to select their own pricing system, with minimum requirements for incremental carbon price increases over time (rising from a minimum of CAD\$10/tonne in 2018 to CAD\$50/tonne in 2022) [17].

Although it is planned to phase out coal power generation down the road, there are still 26 coal-fired power plants in operation in Canada as of 2020, will remain more or less steady until 2030 [18]. On the other hand, shale-gas production in the United States is reaching peak now or in the first half of 2020s [19]. Worldwide, coal reserves will last for hundreds of years, whereas, natural gas will only last for decades [20]. How coal-fired power generations will be evolving remains to be seen. As recent publications on coal and biomass co-firing show continuing activities, it is still necessary for studies like this to continue.

In this paper, a detailed economic evaluation of carbon capture for coal and biomass co-firing in a power plant is presented. The impact of co-firing on power plant de-rating, carbon capture equipment sizing, and the related cost increase are investigated. The level of carbon incentive is a major factor affecting the carbon capture cost as well as the resultant incremental cost of electricity generation. The results show that, under several scenarios, by co-firing biomass with coal, both carbon capture and incremental costs of power generation could be lowered. This study is intended to provide some economic impacts of biomass-coal co-firing to the Canadian power industry for considering and planning to adopt technologies of biomass utilization and carbon capture with existing boilers when CO₂ emission regulations come into play in the near future.

2. Methodology

A common approach for the economic evaluation of post combustion carbon capture has been applied in this study [21-23]. Most of the coal fired power plants in Canada were designed and constructed over 30 years ago. A typical Canadian 150 MW_e subcritical boiler tangentially firing high volatile Colombian bituminous coal was chosen as a base case (reference case).

A 30 wt% monoethanolamine (MEA) solution was chosen as the CO₂ capture solvent. A process flow diagram of an existing power plant with an add-on carbon capture plant is illustrated in Fig. 1. A post combustion carbon capture process is shown in Fig. 2.

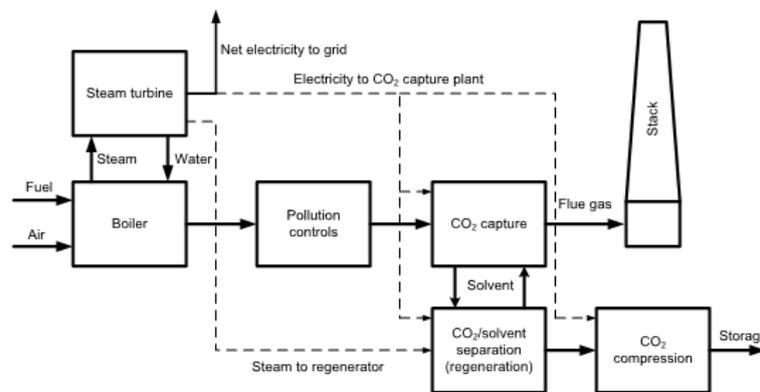


Figure 1. A typical power plant with an added CO₂ capture process

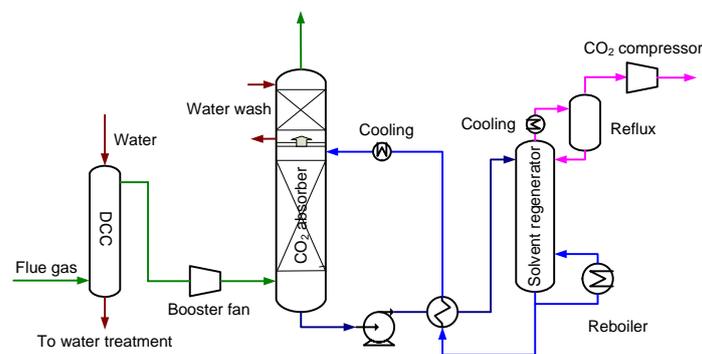


Figure 2. Post combustion CO₂ capture process (DCC: direct contact cooling)

The electricity and steam needed for the carbon capture process are extracted from the existing power plant as shown with the dashed lines in Fig. 1. Thus the power plant will experience a de-rating [24]. The performance influence of extracting steam for the post combustion capture (PCC) re-boiler from the low pressure (LP) turbine is assumed nil other than de-rating.

Three cases were evaluated;

- 1) Baseline case: coal fired case achieving 90% capture of CO₂ through PCC
- 2) Case 1: co-firing 30% biomass (by heat input) to achieve 90% CO₂ capture by PCC
- 3) Case 2: co-firing 30% biomass (by heat input) to achieve 60% CO₂ capture by PCC

The baseline case is a coal fired operation with 90% CO₂ capture. It is assumed that a future regulation would require 90% CO₂ capture for coal fired power plants, because capturing the last 10% of CO₂ is not cost effective.

The Colombian bituminous coal (which is being fired in a Canadian 150 MW_e power plant) and biomass (a Canadian commercial wood chip) analyses are shown in Table 1. The moisture of the air-dried Canadian wood chips is in the range of reported values [25,26]. The flue gas compositions of the coal case and the co-firing case are summarized in Table 2, derived by combustion calculation from the fuels. The influence of the co-firing ratio on CO₂ emissions is shown in Table 3. Biomass is considered carbon neutral and therefore the reduction of CO₂ emission in the co-firing case is the same as the co-firing ratio, i.e., 30% co-firing is equivalent to a 30% CO₂ emission reduction. In Table 3, the real CO₂ emission (from coal or biomass or both of them) amounts are the sum of the CO₂ generated from both coal and biomass. At the moment, the biomass co-firing ratio is typically from 3 to 15% [1,27]. A higher co-firing ratio in the future is anticipated, and has already been demonstrated in a full-scale power plant [26]. It can be seen from Table 3 that when co-firing 30% biomass with coal, the total fuel feeding volume would be more than doubled. This is one of the restrictions for biomass co-firing at higher ratios in existing power plants; the existing coal feeding system would not be able to handle such high volumetric throughput. Other restrictions may relate to slagging, fouling, corrosion, ash control.

Table 1. Fuel analyses

	Colombian coal	Canadian wood chips
Proximate analysis	As received (wt%)	As received (wt%)
Moisture	10.7	13.0
Ash	9.6	0.58
Volatile matter	32.5	72.16
Fixed carbon	47.1	14.26
Total	100.0	100
Ultimate analysis (dry ash free)		
C	81.09	50.16
H	5.47	6.16
N	1.67	0.13
S	1.26	0.05
O	10.52	43.51
Total	100.00	100.00
Heating value (BTU/lb)	12430	8125
(kJ/kg)	29154	19057

Table 2. Flue gas compositions in mole% and the total flue gas amounts

Gaseous component	Coal only	Coal and 30% biomass co-firing ^a
N ₂	74.62	73.15
CO ₂	14.73	14.82
H ₂ O	7.48	8.89
O ₂	2.97	2.97
NO	0.01	0.01
SO ₂	0.03	0.03
CO	0.00	0.00
Total	100	100
Fuel amount (t/h ^b)	56.65	65.65
Air amount required (t/h)	626.52	618.29
Flue gas amount (t/h)	683.14	683.94

a: by higher heating value; b: metric tonne

Table 3. Co-firing performance with various biomass ratios

Co-firing ratio (HHV%)	5	10	15	20	25	30
Biomass ratio (wt%)	7.45	14.53	21.26	27.26	33.77	39.6
Additional mass input (wt%)	2.65	5.3	7.95	10.6	13.25	15.9
Fuel volume increase (%)	22.47	44.36	66.26	88.16	110.06	113.95
Reduction in CO ₂ emission (%) ^a	5	10	15	20	25	30
Real CO ₂ emission (%) ^b	100.12	100.24	100.36	100.48	100.61	100.73

a: reduction in fossil fuel CO₂ emission

b: fossil fuel CO₂ plus biogenic CO₂

In Europe, it is being practiced under the Green Certificate or ETS Mechanism that governmental incentives or subsidies are given to power plant for biomass firing and adoption of lower carbon emission measures [5,6,28]. At some point in the future, other judiciaries may follow suit. The evaluated case matrix is shown in Table 4. In Case 1, 90% of the total CO₂ is to be captured, in which 30% is from biomass. This means that 30% more CO₂ is captured than required by the assumed future regulation. For this part, the power plant would get credit (30% negative emission). The 60% capture in Case 2 is equivalent to the 90% capture in the Base Case. There would be no carbon credit.

FLUOR Corporation has conducted a detailed study of engineering design of an amine CO₂ capture plant for existing Canadian power plants [29]. Some of the items in the present study are referenced to the results of the FLUOR report.

Table 4. Cases evaluated in the study

	Base Case	Case 1	Case 2
Fuel	100 % Bituminous coal	70 % Bituminous coal and 30% wood chips	70 % Bituminous coal and 30% wood chips
CO ₂ Capture Rate	90 %	90%	60%

2.1 General assumptions and conditions

The following conditions were used in the evaluation. The power plant energy efficiency was based on fuel (coal and biomass) higher heating values. The sensitivity to CO₂ price was also evaluated.

Boiler:	Subcritical tangentially fired
Base Plant Capacity:	150 MW _e (net before retrofitting to capture carbon)
Coal:	low sulphur high volatile Colombian bituminous
Biomass price:	the same as coal (an assumption)
Capacity Factor:	85%
CO ₂ capture solvent:	30 wt% MEA aqueous solution
CO ₂ Capture Efficiency:	90% (as required by future regulation)
CO ₂ incentive:	\$50/tonne (\$0 – 80/tonne)
Construction period:	3 years
Carbon capture plant life:	30 years
Interest rate:	10%
Cost reported in:	Constant 2017 U.S. Dollars ^[30,31]

2.2 CO₂ capture and regeneration process description

From the flue gas quantity and conditions, the sizes of the CO₂ absorber, rich solvent regenerator, blowers, pumps, and other minor items, were determined. The costs of the equipment and components were derived by engineering and economic evaluations based on available published sources as well as by contacting commercial equipment providers [21,22]. The equipment design/operation conditions are as follows, which were referenced to a detailed design report [29], based on a real Canadian power plant in operation.

1) Flue Gas Pre-Cooling

The flue gas exits the power plant particulate matter (PM) control device at 147 °C. For better absorption, the flue gas is cooled to 44°C by a direct contact cooler. The cooling water temperature is 23°C.

2) Flue Gas Booster Blower

A flue gas booster blower is positioned between the quench cooler and the absorber. The flue gas leaves the blowers at 44°C and a gauge pressure of 5.6 kPa.

3) Absorber

In the absorber tower, the aqueous amine solution is sprayed downward. The flue gas enters from the bottom of the absorber. A small amount of ammonia evolves from MEA degradation; a wash section at the top of the absorber above the packed bed section washes away the ammonia to below 50 ppmv. The ammonia rich water then trickles down a tube which is fed back into the absorber at the top of the packed bed section. The packing is CMR 3, a commercial product [29].

4) Solvent Cross Heat Exchanger

The aqueous amine solution falls down into the bottom of the absorber tower after it is reacted with the carbon dioxide in the flue gas. The solution then is pumped to a rich/lean solvent heat exchanger. Heat taken from the lean solvent stream is used to heat up the rich solvent stream in the heat exchanger. The type of heat exchanger for this process is a fixed shell and tube heat exchanger. The rich solvent enters the shell side at 42.8°C and 550 kPa gauge pressure, and leaves at 112°C. The lean stream enters the tube side at 121°C and 82 kPa gauge pressure and leaves at 52.8°C. Next, the lean solvent stream should go through a further cooling step.

5) Lean Solvent Cooling Unit

The absorber requires the lean solvent to be fed at a temperature of 38 °C. Therefore, a cooling step is required meeting the absorber inlet condition. The type of cooling unit for this step is a fixed tube and shell heat exchanger. The solvent is cooled down by cooling water with inlet and outlet temperatures of 24°C and 49°C, respectively.

6) Regenerator

In this unit operation, the rich solvent is regenerated. The condition is 120°C and 345 kPa. In order to minimize the energy consumption, the loading ratio of carbon dioxide over solvent must be high. In the Base Case and Case 1, the weight ratio of carbon dioxide over solvent is set to be 1:5, whereas the ratio of Case 2 is 1:2.5. According to a kinetics study, with 60% capture the CO₂ loading capacity would be tripled [21]. Therefore, much less solvent would be required, meaning a more efficient carbon capture.

2.3 Process description of the product recovery train (PRT)

1) Reflux Drum and Product Recovery Train

The CO₂ and water vapour mixture is sent to the reflux drum in the post-generation stage. The objective is to eliminate the suspended water droplets from the carbon dioxide gas stream by providing residence time in order to allow the droplets to precipitate. The water condensed in this step is sent back to the wash cycle in the absorber. The reflux drum is a two-phase vertical vessel. Once the vapour exits the reflux drum, it contains approximate 99.7% CO₂, and is sent to the product recovery train where it is compressed and sent off for transportation by pipeline or truck and sequestration at a geologic site. The CO₂ is delivered at 10 MPa and 30°C [32].

2) CO₂ Gas Cooling Unit

The CO₂ mixture (99.7%) leaves the regenerator at a temperature of 120°C and a pressure of 345 kPa. The mixture must be cooled down to about 32°C in order to condense the last portion of water in the mixture, and this will result in 99.9% purity of CO₂. The type of unit selected for this process is a fixed-tube and shell heat exchanger. The mixture enters the heat exchanger at 120°C. It is cooled down by counter-current flow cooling water whose inlet and outlet temperature are 23 °C and 48.9°C, respectively.

3) CO₂ Gas Compression (stage 1 and 2)

The CO₂ (99.9% CO₂) leaves the CO₂ gas a cooling unit at a temperature of 30°C. It is crucial to compress the CO₂ stream to 10 MPa to supercritical state for transportation. The compressor can handle inlet temperature ranging from 5°C to 130°C, and has a compression ratio of 9:1. For this purpose, the developed compressor can insert cooling function to cool down the CO₂ stream while compressing it [29,33]. The most economic delivery conditions for sequestration of CO₂ are determined to be about 10 MPa and 30°C [34]. If the CO₂ is compressed in one stage from 1.5 bar to 10 MPa, the temperature of the stream would reach about 300°C. This is far beyond the operating conditions most of the compressors can handle. Therefore, it is essential to use at least two stages of compression. The CO₂ enters the first stage of compression at 32°C and 327 kPa, where it is compressed to a pressure of 1.33 MPa and a temperature of 130°C with internal cooling. The compression ratio for the first stage is 9:1. It then enters a tube and shell heat exchanger where it is cooled by water to a temperature of 40°C and a pressure of 1130 kPa, assuming that the pressure drop of the CO₂ stream is 200 kPa. The stream then goes through the second stage of compression. It is compressed to a pressure of 10 MPa and a temperature of 130°C with internal cooling. The compression ratio for the second stage is 9:1. The CO₂ then enters another tube and shell heat exchanger where it is chilled by cooling water to the delivery temperature of 30°C and a pressure of 10 MPa.

4) Cooling Tower

In order to increase the efficiency of the PRT (product recovery train), it is essential to recycle the cooling water to be reused for the heat exchanger. A wet cooling tower is appropriate for cooling the water. The water goes through the cooling tower at the temperature of 42°C, and the temperature of the cooling tower outlet is 23°C. The heat released in the cooling tower can be calculated according to the specific heat capacity of water, mass flow rate of cooling water, and the temperature change between the inlet and outlet of cooling tower. The transferred heat can be converted to tonne of air condition, and the cost of the cooling tower is then determined using the commercial handbook of costing according to the tonne of air condition [35].

2.4 Cost indices and currency conversion

Fluctuations in economic conditions cause price changes of purchased equipment, labour, and financial costs. Cost indices should be utilized to update old cost data in order to account for these changes. The conversion formula is:

$$\text{Present Cost} = \text{Past Cost} \times (\text{present Index Value} / \text{Past Index Values}) \quad (1)$$

Two of the most common indices are the Marshall and Swift indices and Chemical Engineering Plant Cost Index (CEPCI). These two indices are recommended for plants costing, and they give very similar results. In this report, the CEPCI is used [22]. If a cost of a reference item was not available in US\$, it was converted to the US\$ by

currency exchange rate of the year. The resultant US\$ costs are then transformed to the present value according to the index conversion mentioned above.

2.5 Estimation of equipment costs by scaling

When the cost of a piece of equipment of a particular size is not available, the six-tenth factor rule was used [22]:

$$\text{Cost 2} = \text{Cost 1} \times (\text{Capacity 2}/\text{Capacity 1})^{0.6} \quad (2)$$

2.6 Nature of economic data

The CO₂ capture cost is composed of the items of fuel properties and cost, plant/equipment sizes, efficiency factor, financing, performance and maintenance of the CO₂ capture system, and other environmental control systems.

The total capital cost of a plant consists of direct and indirect costs. The direct costs consist of: purchased equipment; equipment installation; instrumentation and controls; piping; electrical systems; buildings; yard improvements; service facilities; land.

Indirect costs include: engineering and supervision; construction expense; legal expenses; contractor's fees; contingencies.

2.7 Costing method for capital

From the flue gas quantity and conditions, the sizes of the CO₂ absorber, rich solvent regenerator, fans, pumps, and other auxiliary equipment were determined.

The method is first to calculate the cost of all delivered equipment which marked as item 'C' in Table 5. Then, every direct and indirect cost is calculated based on the item 'C'. The only item for next step calculation is the Total Fixed Capital Investment (FCI). FCI is not only one of the four root cost components of cost of electricity in the report, but also the important input for the cost of the Annual Operation and Maintenance which will be discussed in the next subsection.

Table 5. Fixed Capital Investment Estimation Method [22]

	Component	User Value
	Direct Costs	
A	Purchased Equipment	Sum of all equipments
B	Delivery, Percent of Purchased Equipment	10% A
C	Subtotal: Delivered Equipment	A+B
D	Purchased Equipment Installation	47% C
E	Instrumentation and Controls (Installed)	36% C
F	Piping (Installed)	68% C
G	Electrical Systems (Installed)	11% C
H	Buildings (Including Services)	18% C
I	Yard Improvements	10% C
J	Service Facilities (Installed)	70% C
K	Total Direct Cost	C+D+E+F+G+H+I+J
	Indirect Costs	
L	Engineering and Supervision	33% C
M	Construction Expenses	41% C
N	Legal Expenses	4% C
P	Contractor's Fee	22% C
Q	Contingency	44% C
R	Total Indirect Cost	M+N+O+P+Q
S	Total Fixed-Capital Investment (FCI)	K+R
T	Working Capital	89% C
	Total Capital Investment	S+T

2.8 Costing method for operating and maintenance

The Annual Operating and Maintenance cost is calculated as a percentage of the FCI, Cost for Material, and Cost for Labour tabulated in Table 6. An iteration process is necessary for the final column of Table 6.

Table 6. Annual Operating and Maintenance Cost [22]

Item	Factor	Basis
Variable Cost		
Material	-	-
Operating Labour (OL)	-	-
Operating Supervision (OS)	0.15	OL
Utilities	-	-
Maintenance and Repairs (M&R)	0.06	FCI
Operating Supplies	0.15	M&R
Laboratory Charges	0.15	OL
Total Variable Costs (TVC)		
Fixed Charges		
Property Taxes	0.02	FCI
Interest Financing	0.10	FCI
Insurance	0.01	FCI
Total Fixed Charges (TFC)		
Plant Overhead		
Safety and Protection	0.05	OL,OS,M&R
General	0.60	OL,OS,M&R
Total Plant Overhead (TPO)		
General Expenses		
Administration	0.20	OL,OS,M&R
Distribution	0.05	O&M
Research and Development	0.04	O&M
Total General Expenses (TGE)		
Annual Operating and Maintenance	TVC +TFC+TPO+TGE	

2.9 Costs for materials

The cost of the absorbent is determined by the cost of amine stated on the Chemical Market Reporter [36], and the mass flow rate of amine which compensates for the amine losses due to degradation and evaporation in the system, i.e., the makeup amine.

2.10 Costs for labor

The correlation used to determine the annual cost for labor simply relates to the skilled wage, the employee hours per day, and the days of operation. The employee hours per day is based on the assumption that there are 9 operators working a combined 72 hours in a day.

$$\text{Cost for labour} = 72 \text{ (hr/day)} \times 310.25 \text{ (day/yr)} \times 33.67 \text{ (2002) USD/hr} \times 1.57 \text{ (2017 USD)/(2012 USD)} \quad (3)$$

2.11 Cost formula of CO₂ avoided

$$\frac{\text{Annualized Cost w/CO}_2 \text{ Capture} - \text{Annualized Cost w/o CO}_2 \text{ Capture}}{\text{Total Tonnes of CO}_2 \text{ Captured /150MW}} \quad (4)$$

$$\text{Cost of Power Plant Derating} = \text{Plant Net Power (w/o CO}_2 \text{ Capture)} \times \text{Plant Derating Rate} \times \text{Price of Electricity (w CO}_2 \text{ Avoided)}, \quad (5)$$

$$\text{Plant Derating Rate} = \text{Power requirement of pumps and fans/150MW} + \text{Reboiler heat duty / Plant heat requirement}, \quad (6)$$

and

$$\text{Annualized Plant Cost per Tonne CO}_2 \text{ Captured} = \frac{\text{Annualized Plant Cost for CO}_2 \text{ Capture only}}{\text{Total Tonnes of CO}_2 \text{ Captured}}, \quad (7)$$

and

$$\text{Electricity Generation Increment per Tonne CO}_2 \text{ Captured} = \frac{\text{Capital} + \text{O\&M} + \text{Purchase Cost for Derating Power} - \text{CO}_2 \text{ Credit}}{\text{Total Tonnes of CO}_2 \text{ Captured}}, \quad (8)$$

3. Findings and discussions

The major capital costs of the evaluated three cases are shown in Table 7. It can be seen from Table 2 that both the flue gas quantities and composition of the coal fired and the 30% biomass coal co-fired cases are very close. Therefore, the capital costs of the Base Case and Case 1 are almost the same, whereas for Case 2, only 60% of the CO₂ in the flue gas needs to be captured. This results in size reduction of the equipment of the CO₂ capture plant. Therefore, the capital costs of the equipment of the carbon capture plant are lower. In this study, the regenerator and product recovery train are listed separately, whereas, other studies may report them as a “regeneration unit” [37].

Table 7. Major capital costs of CO₂ capture equipment

Purchase cost (US\$)	Base case	Case 1	Case 2
Cooling towers / heat exchangers	3,999,563	3,999,563	2,738,283
Absorber	7,589,518	7,589,518	5,649,049
Regenerator	2,098,408	2,098,408	1,316,644
Product recover train	9,407,291	9,407,291	4,968,788

The major energy consuming operations of the CO₂ capture plants for the three cases are shown in Table 8. For the Base Case and Case 1, the same amount of flue gas is processed and the same percentage of CO₂ is to be captured (in Case 1, CO₂ from biomass is also captured). Thus the energy consumptions by the CO₂ capture plants are the same. Less CO₂ is to be captured in Case 2, therefore less energy is consumed by the CO₂ capture plant.

Table 8. Energy consumption by the carbon capture plant (MW)

	Base case	Case 1	Case 2
Regeneration steam	68.9	68.9	45.9
Compression	11.2	11.2	7.6
Fan / pump	3.8	3.8	3

The electricity and steam required by the CO₂ capture plant are extracted from the power plant. This would result in de-rating for the power plant. As shown in Figure 3, the Base Case and Case 1 have the same de-rating. The de-rating of Case 2 is lower because, capturing less CO₂ consumes less energy (i.e., less electricity and steam). De-rating results of studies by others (the year of the studies are shown in brackets) are also plotted in Figure 3 for comparison [21].

The costs of the CO₂ avoided and the electricity generation increment of both the co-firing cases are lower than the Base Case (Fig. 4). For Case 1, the cost reduction is due to the CO₂ credit, i.e., capturing 90% is equivalent to capturing 120% (negative emission). The power plant in Case 1 gets credits for capturing 30% more CO₂ than required by the regulation (one of the assumptions in this study). For Case 2, 60% CO₂ capture is equivalent to 90% capture of the Base Case required by the regulation. So, the power plant in Case 2 would not get any credit. Its cost reduction of CO₂ avoided and electricity generation increment is due to the smaller size of the equipment and the related lower capital, O&M costs and lower de-rating.

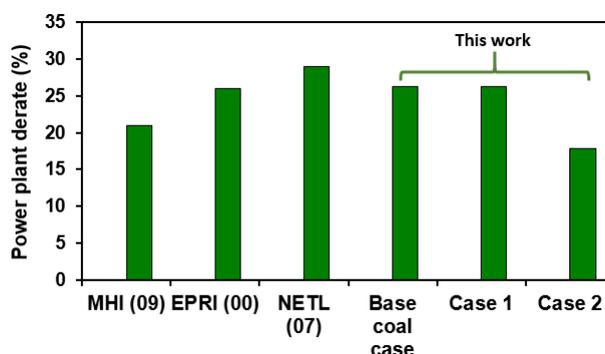


Figure 3. Derating by installing CO₂ capture plant (the number is the year the report was published [21])

At the moment, the trading price of CO₂ in Europe and California is in a range of US\$10 – 30 per tonne [38]. The Canadian federal carbon tax is set to start at C\$10/tonne sometime in 2018. As of early 2018, the province of Alberta already charges carbon tax for C\$30 a tonne [39]. A study predicted a CO₂ price of \$70 in 2030 and \$180

in 2050 [17,40]. The influence of the CO₂ incentive on the power plant performance with biomass co-firing and CO₂ capture is depicted in Figure 5. As discussed above, the CO₂ incentive would only impact on Case 1, but not Case 2. At lower CO₂ incentive values, Case 2 is preferable. At higher CO₂ incentive values, Case 1 performs better.

To compare our study results with others, the dollar numbers look higher (Figure 4) [37,41,42]. This is because our study is aimed at a 150 MW_e power plant and most of the published studies are for larger sizes, e.g., at about 500 MW_e range. If our results are converted to 500 MW_e by using equation (2), the costs would be at the same level with other published results (Fi. 6) [37,41-43] at a level of US\$32-35/tonne CO₂. This shows that the results from this study are reasonable.

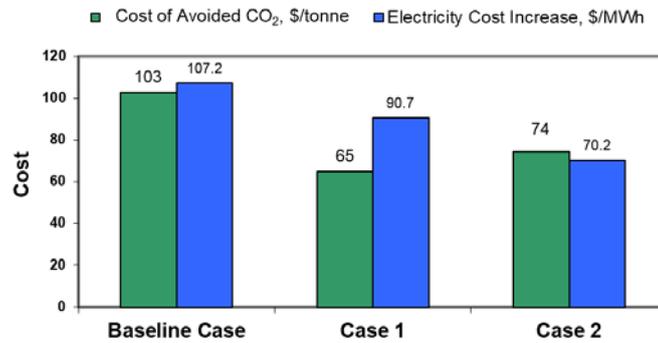


Figure 4. Costs of CO₂ avoided and the electricity generation increment

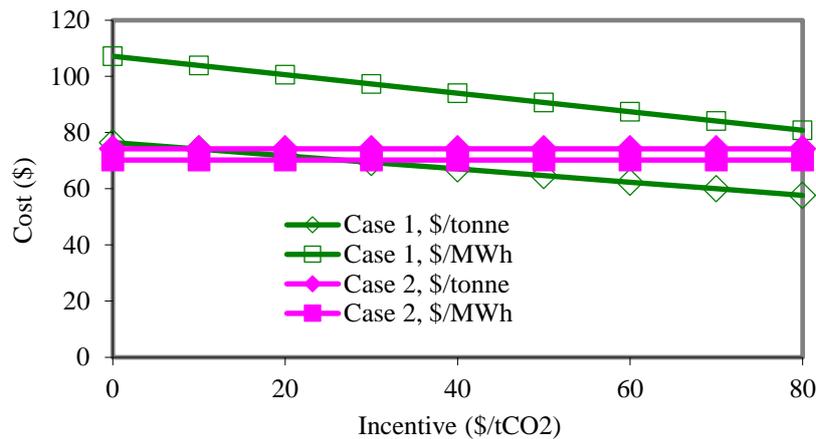


Figure 5. Costs of CO₂ avoided and electricity generation increment versus CO₂ incentive for Cases 1 and 2

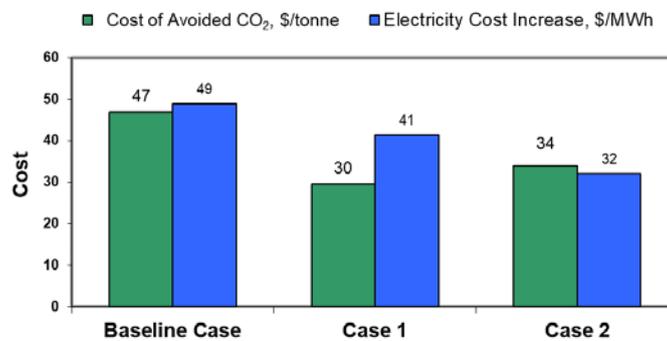


Figure 6. Costs of CO₂ avoided and the electricity generation increment converted to 500 MW_e

4. Conclusion

The impacts of the biomass cofiring are to reduce carbon capture cost of a power plant firing coal only to meet the same level of CO₂ emission reduction. For low or high incentive scenarios, a power plant can select Case 1 or Case 2 accordingly.

Currently, the cost of CO₂ avoided for coal power generation plants is still high because of the enormous equipment capital and operating/maintenance costs for all the three options in this study.

Two emerging factors have significant influence on the economics of carbon dioxide capture from electric power plants. First, government incentives for CO₂ capture could offset part of the capture cost for coal and biomass co-firing cases. The cost of electricity of coal and biomass co-firing with 90% CO₂ avoided is 35% less than that of the coal-fired case at the same CO₂ capture level with an assumed CO₂ price of \$50 per tonne.

Second, the cost per tonne of CO₂ avoided will drop dramatically if the biomass such as wood chips is co-fired with coal because of the neutral factor of biomass on CO₂ emission, and the negative emissions realized in the cases studied (Figure 4).

The most significant research finding of this study is that Case 2 (co-firing with 60% CO₂ capture) has cost advantage over Case 1 (co-firing with 90% CO₂ capture) for electricity production. However, this cost advantage will diminish when the price of CO₂ credit approaches \$80 per tonne.

The reason of Case 2's superiority over Case 1 is as follow: Case 2 requires less MEA than Case 1, which results in smaller equipment including the cooling tower, solvent pumps, and compressors. For example, the cooling tower operating cost is 32 % lower in Case 2 than in Case 1. In addition, the size and the suitable throughput of this equipment results in a lower de-rating factor for Case 2.

The de-rating rate drops to 18% for Case 2 from 26% for both Case 1 and the Base Case. The small de-rating factor of Case 2 is due to smaller heat duty of the re-boiler, as well as lower electricity power consumption by pumps and smaller compressor motors.

The study is based on some future governmental carbon incentive scenarios. It should be pointed out that there are uncertainties in the whole carbon capture and renewable technology development path in this study, as well as in the literatures. Further studies and development are necessary to lead to eventual implementation of biomass cofiring and carbon capture in power plants.

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