Integrated Techno-economic and Environmental Assessments of Sixty Scenarios for Co-firing Biomass with Coal and Natural Gas

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Abstract

Displacement of fossil fuel-based power through biomass co-firing could reduce the greenhouse gas (GHG) emissions from fossil fuels. In this study, data-intensive techno-economic models were developed to evaluate different co-firing technologies as well as the configurations of these technologies. The models were developed to study 60 different scenarios involving various biomass feedstocks (wood chips, wheat straw, and forest residues) co-fired either with coal in a 500 MW subcritical pulverized coal (PC) plant or with natural gas in a 500 MW natural gas combined cycle (NGCC) plant to determine their technical potential and costs, as well as to determine environmental benefits. The results obtained reveal that the fully paid-off coal-fired power plant co-fired with forest residues is the most attractive option, having levelized costs of electricity (LCOE) of \$53.12 to \$54.50/MWh and CO_2 abatement costs of \$27.41 to \$31.15/tCO_2. When whole forest chips are co-fired with coal in a fully paid-off plant, the LCOE and CO_2 abatement costs range from \$54.68 to \$56.41/MWh and \$35.60 to \$41.78/tCO_2, respectively. The LCOE and CO_2 abatement costs for straw range from \$54.62 to \$57.35/MWh and \$35.07 to \$38.48/tCO_2, respectively.

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1. Introduction

Increased energy use has resulted in heavy reliance on fossil fuels like coal, oil, and natural gas and led to a significant increase in greenhouse gas (GHG) emissions, which are considered to be the root cause of the rising global temperatures [1, 2]. In 2010, the generation of electricity and heat, a major form of energy use, produced about 41% (close to 10,000 MtCO2 per year) of global GHG emissions through the combustion of fossil fuels [1]. It is even more noteworthy that in Canada, where 16% of the electricity comes from coal power plants, coal power plants account for about 77% of the overall GHG emissions associated with the nation's entire electricity sector [3, 4].

Several environmental policies exist around the world to encourage large industrial emitters, including utility companies, to reduce their overall GHG emissions. For example, in Canada the federal government mandated emissions-intensity levels of 0.42 tCO_2/MWh for new thermal power plants and 1.1 tCO_2/MWh for old plants [3, 4], as well as a carbon levy in other jurisdictions [4-6]. The quest to reduce GHG emission levels has led to interest in biomass use. Biomass, a "nearly" carbon neutral-based energy, can be used effectively to mitigate GHG emissions [7-10]. Biomass can also be used in several ways to produce power and heat [11-15]. One of these is biomass co-firing.

Biomass co-firing, with either coal or natural gas (NG) in existing power plants, is considered an option to reduce the life cycle GHG emissions associated with the use of fossil fuel to produce electricity, as well as mitigate their impacts on the environment [16]. It also offers utility owners a reduced incremental investment cost (i.e., the cost required to retrofit an existing plant) and fuel supply flexibility [6, 9, 10, 17-19]. Biomass co-firing involves the simultaneous blending and combustion of biomass feedstock along with coal or natural gas (NG) to produce electricity mostly in existing power plants.

Coal/biomass co-firing occurs either in direct or parallel co-firing. In direct co-firing, the biomass feedstock is either fed directly into the boiler with the coal where it is milled and burned together with the coal or it is milled externally before being fed separately into the boiler to be burned with the coal [20, 21]. Parallel co-firing is similar to direct co-firing except for the installation of a completely separate external biomass-fired boiler. Biomass feedstock is processed and fed separately into a dedicated boiler where it is burned to produce steam used to generate electricity in the power plant [9].

Biomass co-firing with natural gas, on the other hand, uses indirect co-firing technology. Here the biomass feedstock is first gasified to produce syngas, which is then co-fired with natural gas in a gas turbine. NG/biomass co-firing offers a higher co-firing rate than coal/biomass co-firing, enabling the substitution of up to 40% of the base fuel with biomass in the system [17, 22, 23]. Compared to coal/biomass co-firing, NG/biomass co-firing is rarely used, partly because it is still in a development form but also due to the much higher capital costs associated with the gasification process [17, 24]. The most notable commercial operation of NG/biomass co-firing is found in Lahti, Finland, where several biomass fuels such as sawdust, straws, wood wastes, and other waste-derived fuels are gasified in fluidized bed gasifiers and then co-fired with natural gas in a turbine [24]. An overview of the different co-firing technologies is provided by Agbor et al. [23] and the technical challenges associated with co-firing are highlighted by Li et al. [25].

There are several studies published techno-economic assessments and feasibility studies of co-firing processes [7, 21, 26-30]. The economics of different coal/biomass co-firing options was studied by Basu et al. [21]. Their results show that the direct co-firing approach is the least expensive of all the co-firing options; however, their work does not include an environmental assessment of different co-firing options in terms of abatement costs. Al-Mansour and Zuwala [26] reviewed the best practices of biomass co-firing in Europe. They concluded that while direct co-firing is the most straightforward and least expensive option for co-firing biomass with coal, indirect co-firing can best handle higher biomass co-firing rates. A study by Malmgren et al. [31] shows that while parallel co-firing has significantly higher biomass use rate, it is more expensive than direct co-firing due to higher plant modification costs. Rodrigues et al. [30] investigated the feasibility of mixing syngas from biomass with natural gas and also analyzed the cost and efficiency benefits associated with the process. Their results show that co-firing substantially increases the efficiency of electricity production from biomass and becomes more competitive than biomass firing only due to economies of scale, but their studies did not include an environmental assessment of the process [30].

Few techno-economic assessment and feasibility studies on co-firing include an environmental assessment along with the techno-economic analysis. At present, government and industry are interested in understanding the trade-offs of these two aspects of sustainability. Very little literature exists that could help them in their decision making, particularly in western Canada. In studies on biomass co-firing, comparative analyses of the coal/biomass and NG/biomass are scarcely discussed and this needs to be addressed due to the increase in natural gas-fired plants. Another important knowledge gap addressed in this study is the age of the power plant used for the co-firing plants. Existing literature on co-firing focusses mainly on old coal plants, while relatively new plants (plants less than 15 years old) have not been considered for co-firing. In studies by the Canadian Clean Power Coalition and Basu et al. [20, 21], only paid-off plants were considered for biomass co-firing and currently, no study exists on new plants that are less than 15 years old. Studying the effect of co-firing biomass in relatively new coal or natural gas plants on electricity and GHG abatement costs will be of major interest, especially in jurisdictions where there are new plants that could be affected by an increase in carbon tax. This is key gap that this study addresses.

In light of the stated gaps in the literature, this study developed a data-intensive techno-economic model to comparatively evaluate the costs of co-firing three biomass feedstocks with coal and natural gas in both a fully paid-off modified plant and partially paid-off plant. This study also conducted an environmental assessment of co-firing biomass with coal and natural gas in western Canada, work that has not been done in detail until now.

The overall objective of this research is to perform an integrated techno-economic and environmental assessment for different biomass co-firing scenarios. The specific objectives are:

- To develop a techno-economic model to determine power generation costs ($/MWh) for the co-firing of biomass with coal for different power plant configurations.
- To develop a techno-economic model to determine power generation costs ($/MWh) for the co-firing of biomass with natural gas for different power plant configurations.
- To develop biomass harvesting and transportation models to estimate transportation and feedstock costs ($/tonnes) for three biomass feedstocks, namely whole forest (i.e., wood chips), agricultural resides (i.e., wheat straw), and forest residues.
- To develop GHG abatement costs ($/tonne of CO_2) for the co-firing of biomass with coal and natural gas in western Canada.
- To develop electricity generation and GHG abatement costs for the different co-firing scenarios.

- To perform a series of sensitivity and uncertainty analyses to determine the impact of various input parameters on the attractiveness of co-firing technology.
- To conduct a case study for western Canada.

2. Methodology and assumptions

The technical and economic parameters considered in this study include all aspects of the upstream and downstream processes required to generate electricity in co-fired plants including the technical description of each co-fired plant, capital cost required to modify the plants, harvesting, processing, and transportation costs for each biomass feedstock, the cost of acquiring either coal or NG, operation and maintenance costs, plant administrative cost, ash disposal costs when necessary, and site reclamation costs. This research is a follow-up of an earlier study by the authors that included a review of the present state of biomass co-firing technology, especially with respect to North America, as well as the unique physical and chemical properties and the availability, feasibility, and costs of the each biomass considered for co-firing (whole forest, wheat straw, and forest residues), as well as coal and NG [23].

Whole forest biomass includes any live or dead tree that is not generally considered to be merchantable, especially for pulp and timber production; forest residues include the limbs and tops of the trees that are left on the roadside to rot after logging operations by pulp and timber companies; and agricultural residues are straw obtained as the by-product of threshing crops such as wheat, barley and flax, etc. [11, 20].

The methodological approach taken in this study involves the following key steps:

1. The development and collection of technical data on all operational units required to co-fire various biomass feedstocks with both coal and NG to generate electricity in a modified power plant.
2. The development and collection of financial data on all operational units required to co-fire various biomass feedstocks with coal or NG to generate electricity in a modified power plant.
3. The development of a data-intensive techno-economic model for the creation of various cost curves to show the technical, economic, and the environmental costs of the biomass co-firing scenarios.
4. The use of a Monte Carlo simulation to understand uncertainties in the input parameters and results.

Data were developed through first principles and wherever required collected from market sources and published literature, as well as through consultations with other researchers. All cost figures in this study are adjusted to the year 2014 and given in Canadian dollars (CAD $), unless specified otherwise, with an assumed inflation rate of 2%.

Data-intensive, discounted techno-economic models were developed once credible economic and technical parameters were identified for co-firing biomass feedstock with coal or NG in order to generate electricity. Using a period of 25 years and assuming an internal rate of return (IRR) of 10%, full-time life cycle costing models were developed. These models included the technical and cost characteristics for different co-firing scenarios as well as the chemical and cost characteristics of coal, natural gas, and the biomass feedstock considered. The models' outputs, such as the costs of delivering the biomass feedstock to the power plant, the incremental cost of co-firing, the levelized cost of electricity (LCOE), and the carbon abatement cost of the power plant, were thoroughly analyzed to assess the potential for generating electricity by co-firing biomass feedstock with coal or NG in western Canada.

3. Inputs description

3.1 Technical description

Two power plant configurations were evaluated in this study with different amounts of biomass at co-firing levels of 5%, 10%, 15%, 20%, and 25% to determine the output power as well as the financial and carbon abatement costs associated with each. The first configuration was based on a 500 MWe subcritical pulverized coal (PC) plant and the second on a 500 MWe natural gas combined cycle (NGCC) plant. Generally, the amount of biomass feedstock that can be co-fired with a base fuel in a boiler is referred to as the system's co-firing level [9, 23, 32]. While it is desirable to substitute as much of the base fuel as possible with biomass to reduce the GHG emissions from the plants, the design co-firing level depends largely on technological, economic, and logistical factors such as the plant set-up, boiler type and efficiency, the nature and cost of the plant modifications needed, the nature, quality, cost and supply chain of the biomass used, as well as the ability to control the deposition and corrosion issues associated with the by-products of the combustion process [17, 32, 33]. Different co-firing technologies, as summarized by Agbor et al. [23], including direct co-firing, indirect co-firing, and parallel co-firing, were considered. In this study, both direct and parallel co-firing technologies have direct applications in coal/biomass co-firing, while indirect co-firing is applicable to NG/biomass co-firing.

3.1.1 Coal/biomass co-firing

The required amount of biomass feedstock is introduced alongside coal and ambient air into the PC boiler where they are combined and burned to generate steam. The steam is fed into a high pressure steam turbine where it is converted to mechanical energy in the form of a circular motion on the turbine blade. The used steam is sent back to the boiler for reheating to raise its temperature before it is fed into the intermediate pressure turbine and then to the low pressure turbine [2]. The boiler is operated at a slight negative pressure to reduce air leakage out of the boiler. Before the flue gas that remains after these operations is discharged into the atmosphere, it is used to generate preheated air streams, thereby enhancing the overall efficiency of the plant [6, 19, 34]. An illustration of the process flow of the modified PC used in this study is shown in Fig. 1.

Fig. 1

For co-firing levels between 1 and 5%, a direct co-firing system is proposed wherein the biomass feedstock is either fed directly into the boiler with the coal, where both are milled and burnt together, and for co-firing levels between 5 and 10%, a direct co-firing system is proposed wherein the biomass is milled externally before being fed separately into the boiler to be burned together with the coal [9, 23, 32]. While direct co-firing has the lowest modification costs compared to other co-firing configurations, it offers the least amount of biomass that can be milled or burned with coal without reducing the plant's operational efficiency, and there are significant level of deposit formation issues associated with it as well [9, 32]. To overcome these limitations, a parallel co-firing configuration was employed for co-firing levels over 10%

wherein the biomass feedstock is processed and fed separately into a dedicated boiler to be burned to produce steam used to generate electricity in the power plant [9]. Here, the installation of a completely separate, external biomass-fired boiler allows higher percentages of biomass fuels to be used in the boiler because the biomass is fired independently from the coal. With this design, the plant's operational risk is reduced and it is more reliable, due to fewer deposition formation issues like fouling and slagging, as well as corrosion, since the biomass flue gas is prevented from reaching the boiler heating surfaces [9, 23, 32]. However, this technology is more capital intensive than direct co-firing due to the dedicated boiler system [31]. Table 1 outlines the characteristics of the coal plant as well as the assumptions considered in this study [20, 34-38].

Table 1

3.1.2 Natural gas/biomass co-firing

Two design configurations of the modified NGCC plant were originally proposed to study the various proportions of NG/biomass co-firing. Both plants were based on a 2x250 MWe NGCC power plant modified for indirect co-firing technology to fire biomass-derived syngas alongside natural gas [34]. The original NGCC design is a multi-shaft 2x2x1 configuration consisting of two advanced F-Class CTGs, two HRSGs, and one STG, along with a recirculating wet cooling tower for cycle heat rejection. The HRSG is constructed with HP, IP, and LP steam systems, including drum, superheater, reheater, and economizer sections. Ambient air and NG are fed in and mixed at the designed pressure and temperature in a dry low NOx burner (LNB) combustion system and then fed through variable inlet guide vanes into the two-axial flow, constant-speed CTGs at a design temperature of 1371 °C. The exhaust gas leaves the turbine at 629 °C and is fed into the HRSG, where it generates both the main steam and reheat steam for the conventional steam turbine for power generation. Finally, the exhaust gas from the HRSG is passed to the plant stack at a temperature of 106 °C [34].

Two modification options were considered to co-fire NG with the biomass-derived syngas in the original NGCC plant. The eventual design configuration used was chosen based on efficiency and performance [39].

Figure 2a illustrates the process flow of the first design configuration of the modified NGCC plant considered. Here, the biomass is gasified to produce LCV syngas and then cleaned to enhance its quality. The LCV syngas is fed together with NG into each CTG at the design pressure and temperature. The rest of the process is similar to that of the original NGCC plant. Due to the lower calorific value of the biomass-derived syngas, there is a significant drop in the power generated by the plant. To prevent this power loss, the amount of syngas fed with the NG is increased so that it is equivalent to the desired plant power. However, this may lead to an increased flow rate beyond the designed limit. To overcome this challenge, it will be necessary to install a dedicated CTG to fire only the syngas, as well as a burner combustion system, HRSG, and a STG, along with a gasifier and a syngas cleanup unit. These will lead to very high modification capital costs [39].

Fig. 2

The process flow of the second design of the modified NGCC plant is shown in Fig. 2b. Here, the system installations required to achieve this configuration are a gasifier, a syngas cleanup unit, a burner combustion system, a boiler, and a higher capacity STG. The process flow of this design option is very similar to the original design except that the system enables the LCV syngas to be fired alone in a dedicated burner combustion system, and the heat fed into a dedicated turbine and then the steam generated are fed into a dedicated STG. It is noteworthy that the configuration ensures that there is no power loss since the flow rate of the LCV syngas can be increased till the design power is achieved [18, 39-42].

Out of the two co-firing configurations considered, the second design option is preferred and chosen given that plant performance is not compromised and its modification cost is lower. Therefore, the NG/biomass co-firing considered in this study is based on this modified NGCC plant (as shown in Fig. 2b). Table 1 presents a summary of the performance data and characteristics of the modified NGCC plant as well as an outline of the assumptions used [18, 34-38, 41].

3.2 Key cost components

3.2.1 Capital costs

The capital costs of co-firing any amount of biomass feedstock with either coal or NG in a power plant consist of the modification cost, which is the cost required to retrofit the original plant to enable it to process and fire the biomass feedstock, and the book value (i.e. the remainder of the capital cost) of the original plant, termed the "initial capital cost" in this paper. These data were used to calculate the LCOE and incremental cost of co-firing coal with these biomass feedstocks. The co-firing scenarios are based on existing PC or NGCC plants whose initial capital costs have either been paid off entirely or are partially paid off. The modification costs of each system considered were estimated based on Eq. 1:

$$\text{Cost}_2 = \text{Cost}_1 \text{ x } (\text{Capacity}_2/\text{Capacity}_1)^{\text{scale factor}} \quad (1)$$

Table 2

Tables 2a and 2b present the cost-list of all the equipment involved in retrofitting the existing power plants for each co-firing scenario [43-45]. The capital costs were considered to be very similar at each co-firing level for all the biomass feedstocks investigated in this study [46].

Fig. 3 shows a graphical representation of the capital costs per unit output for each of the co-firing scenarios considered in this study. It reveals that for both coal/biomass and NG/biomass co-firing scenarios, there was a gradual decrease in the capital costs per unit output as the co-firing levels increased. This is noteworthy because although the capital costs typically tend to increase with increasing co-firing levels due to the need to retrofit the power plants to accommodate larger amounts of biomass, the rate at which this increase occurs is less than the increase in the power output at each co-firing level due to economies of scale.

Fig. 3

3.2.2 Biomass delivery cost

The information required to estimate feedstock costs includes all the expenses to grow and harvest the trees or agricultural crops, the costs for transporting, processing, and storing the feedstock, and the cost to provide necessary infrastructure [37]. The cost of using biomass feedstocks in a co-fired plant, also referred to as the biomass delivery cost, includes all the costs required to deliver the biomass feedstock from the point before it is harvested at the forest or farm to its eventual use at the power plant. This cost is divided into the point of origin cost and the transportation cost, both measured in $/dry tonne. Depending on the feedstock considered, the point of origin cost may include some or all of the following: harvesting cost, biomass field cost (also referred to as the premium above the cost of fuel or royalty that is paid to the land owner as an incentive to collect and sell the biomass), road construction cost, nutrient replacement cost, and silviculture cost. The transportation cost is comprised of the cost of loading and unloading the biomass feedstock, as well as the cost of transporting it from the forest or field to the co-fired plant. This study assumes a typical harvesting field to be sustainable for a 25-year period to meet the fuel requirements of the co-fired plant. Thus,

1. For whole forest biomass, this study assumed boreal forests in Alberta and other parts of western Canada are predominantly spruce and mixed hardwood. Although most of these resources are reserved for timber and pulp operations, significant amounts exist, enough to support several co-firing operations for a long time [11, 12]. The trees are cut and skidded to a 50/48 Morbark chipper, chipped, and transported by chip van to a power plant. A selective clear-cut logging method was adopted throughout the dedicated forest plot to ensure a constant transportation distance to the power plants [11]. Other costs involved are the silviculture costs associated with replanting the trees, logging road construction costs, and the royalty fee paid to the land owners as an additional market premium to gain timber cutting rights [11, 13, 14]. This study did not consider nutrient replacement costs, as did Kumar et al. [11]. A summary of the cost characteristics of whole forest biomass is shown in Table 3.

2. Forest residues: These residues constitute 15-25% of the total biomass in the forest, depending on the type of harvesting operation or activity employed [11, 13, 14]. The assumption in this study is based on a system where after logging operation, forest residues are piled in the forest using a forwarder, chipped, and transported by B-train chip vans [11, 13, 14]. No cost is accrued for road construction since the residues are transported on existing roads built by whole tree harvesting companies for the harvesting and transporting of tree stems [11, 13, 14]. A summary of the costs of forest residues considered is shown in Table 3.

3. Agricultural residues: Both Kumar et al. and Sultana et al. [11, 47] report that there is great potential in Alberta to use straw from wheat, barley, and flax to generate electricity in co-fired systems. Our study focuses on wheat straw, with the assumption of an average

straw production density/yield of 0.416 dry tonnes of dry straw per gross hectare [13, 14]. The straw is harvested by the crop owners and baled in the field before being transported using a 19 tonnes/load capacity, flat-bed trailer to the co-fired power plant, where it will be chopped by an electric-driven straw shredder. The feedstock cost includes harvesting, bale collection, bale wrapping and storage, and loading, transporting, and unloading [11, 13, 14, 47]. Other components of the feedstock cost are the market premium fee paid to the farm owner as an incentive and the nutrient replacement cost, which is the money paid to the farmers to purchase fertilizer applied to their fields in order to replenish the nutrients initially taken up by the straw. A summary of the cost characteristics of forest residues considered is given in Table 3.

Table 3

Figures 4a and 4b illustrate in detail the transportation and delivery costs of the biomass feedstock considered in this study. Both the point of origin costs and the transportation costs change as the plant's fuel requirements change, but the transportation cost changes are greater because feedstock is transported farther. Biomass delivery costs will increase with an increase in transportation cost.

Fig. 4

3.2.3 Operational costs

Co-firing plant operating costs include the direct operating labor cost, the administrative cost, and the maintenance cost. The cost estimates are based on a previous study done by Ortiz et al. [46] on biomass power generation; however, the present operating conditions of an existing power plant were also taken into consideration. The remuneration to cover salary plus benefits of the power plant's operating and administrative staff is estimated at $36/h [11-14]. The total number of employees for a co-fired plant is thus:

i. Direct operating labor: In both the coal and NG scenarios, the operating staff level at the co-fired power plant is assumed to be 12. Further details are provided in Table 3.
ii. Administration costs: It is assumed that the co-fired power plant will have 26 administrative staff for both the coal and natural gas base case scenarios.
iii. The maintenance cost of the co-fired plant is assumed to be 3% of the initial capital cost of the plant for both the coal and natural gas base case scenarios.

A detailed illustration of the operating costs for both the coal and NG co-fired plants considered in this study is given in Table 4.

Table 4

3.2.4 Other cost parameters

3.2.4.1 Ash disposal costs

The ash collected as a by-product of coal combustion exists in two forms, fly ash and bottom ash. The prevalent practice adopted at most coal-fired power plants in Alberta and other western Canadian provinces is to sell the fly ash produced either to road construction companies for use as a gravel substitute or to the cement industry to manufacture Portland cement, and to store the bottom ash in nearby coal landfills [48]. However, the fly ash from a biomass/coal-fired plant may not satisfy the material specifications required in road construction or cement manufacturing due to the presence of biomass. It is assumed in this study, therefore, that fly ash recovered from the biomass/coal-fired plants is collected and stored along with the bottom ash in nearby landfills. This is the current situation in North America, despite ongoing research to improve the usefulness of the ash, as, under the current scenario, the plants not only suffer from likely loss in revenues from ash sales but also pay for the cost of hauling and landfilling the ash. The hauling cost is \$0.21/dry tonnes/km and the landfill tipping cost is \$52.52/dry tonnes [11-14, 49].

In the case of natural gas/biomass co-fired plants, the only source of ash is from the biomass feedstock. This ash can be used by local farmers and foresters as a soil supplement [11-14]. However, since it will take some time to develop this demand, we adopted a conservative approach wherein it is the responsibility of the utility companies to haul the ash and spread it in the fields. An average haul distance of 50 km and hauling and spreading costs similar to those of the biomass-coal-firing scenarios are assumed [11-14].

3.2.4.2 Avoided fuel costs

Avoided fuel costs are the amount of money saved from substituting the base fuel (i.e., coal or natural gas) with any of the three biomass feedstocks, i.e., the cost that would have been spent to acquire the replaced base fuel [50]. This cost is crucial in determining the actual cost of biomass co-firing in terms of LCOE, incremental cost of biomass co-firing, and the avoided CO_2 cost. It is calculated by multiplying the original amount of the base fuel required for a non-biomass operation by the eventual co-firing level in a biomass co-fired operation.

3.2.4.3 Life cycle CO_2 emissions

As mentioned earlier, biomass is often considered to be nearly carbon-neutral due to the almost insignificant amount of CO_2 emissions released to the atmosphere during its use. Most of these emissions are released when the biomass is harvested either in the fields or forests, during the processing phase to bring it to the desired state before use, and when the biomass is being transported to the plant. The carbon emission intensity of the three biomass feedstocks considered as well as of coal and NG are presented in Table 5. The emission intensity is based on the amount of emissions from coal- and NG-only plants, as well as the emissions from the equivalent biomass plants [34].

Table 5

3.2.4.4 Avoided CO_2 cost

The avoided CO_2 cost of generating electricity from a co-firing plant, also referred to as the carbon abatement cost for co-firing, is the cost of reducing CO_2 emissions released to the atmosphere while producing the same amount of electricity as a reference plant. The carbon abatement cost allows a way to compare the cost of mitigating CO_2 emissions between a co-fired plant and an associated reference plant. The cost is measured in $/tonne of CO_2 not emitted with respect to a reference plant [51, 52]. It is among the main outputs of this study and is of significant relevance, considering that one of the key objectives of biomass co-firing is to consolidate GHG mitigation efforts in western Canada. For each co-firing scenario, the avoided CO_2 cost is calculated by dividing the incremental cost of the co-fired plant for a one-year period by the difference in the amount of CO_2 emissions avoided by the co-fired plant compared to a reference plant, and then multiplying this figure by the MWh produced in the different co-firing scenarios [52, 53]. The denominator is the volume of CO_2 avoided through the use of biomass less the volume of CO_2 emitted by the reference systems [37, 53]. An equation of the avoided CO_2 cost of co-firing biomass is shown in Eq. 2:

$$Avoided\ CO_2\ costs = \frac{(Incremental\ cost\ of\ co{-}firing)}{(GHG\ Intensity_{ref} - GHG\ Intensity_{co-firing})}$$

$$Avoided\ CO_2\ costs = \frac{(Incremental\ cost\ of\ co{-}firing)}{(GHG\ Intensity_{ref} - GHG\ Intensity_{co-firing})} \quad (2)$$

where:

$Incremental\ cost\ of\ co-firing\ Incremental\ cost\ of\ co-firing$
$Incremental\ cost\ of\ co-firingIncremental\ cost\ of\ co-firing$ = *LCOE of co-fired plant* –

LCOE of a reference plant without co-firing, CAD $/MWh

$GHG\ Intensity_{ref}\ GHG\ Intensity_{ref}$ = *GHG emission intensity of an existing coal/NG plant without biomass co-firing,* tCO_2/MWh

$GHG\ Intensity_{co-firing}GHG\ Intensity_{co-firing}$ = *GHG emission intensity of the coal/biomass co-fired plant,* tCO_2/MWh.

Note: In both the coal/biomass co-firing and the NG/biomass co-firing aspects of this study, the reference plants are 25-year-old coal- and NG-fired power plants.

4. Results and discussion

4.1 Costs of electricity

Power costs for the biomass co-firing scenarios considered in this study are measured in two forms, incremental cost and levelized cost of electricity (LCOE). The incremental cost of co-firing different biomass feedstocks with either coal or natural gas in an existing power plant is the amount by which the selling price of power generated from such a plant is increased in order that the plant breaks even. This cost is the increase in the overall cost of generating electricity from the existing plant due to the co-firing process. This increase is derived by adding the capital recovery costs, biomass feedstock costs for a given year, and avoided coal or natural gas costs, and dividing this figure by the total electrical output (in MWh) of the plant [37, 54]. The LCOE of generating electricity from co-firing different biomass feedstocks with either coal or natural gas provides an overall summary of the competiveness of different biomass co-firing technologies by measuring the per-kilowatt-hour cost of retrofitting and operating an existing coal plant over an assumed financial life and duty cycle [55]. The key input parameters used to calculate LCOE are fuel costs, capital costs, plant operational costs, etc., as well as an assumed capacity factor for each plant type [37, 54, 56]. Both the LCOE and the incremental cost of co-firing are measured in this study in $/MWh.

4.1.1 The incremental cost of co-firing

Figure 5 shows the incremental costs of generating power from both the modified coal and natural gas plants for the 60 scenarios of biomass co-firing in western Canada considered in this study. These costs represent some of the output of the detailed discounted cash flow analyses from the techno-economic assessment models developed using the input parameters mentioned in Section 3. The results indicate, first, that there is a steady rise in the incremental costs of co-firing as co-firing levels increase for each biomass feedstock as well as within each co-firing technology and for different plant ages for both the coal and the natural gas scenarios. This rise is influenced by the steady rise in the costs of acquiring each biomass feedstock (both field and transportation costs) especially as the co-firing level increases. Second, straw has the highest incremental costs across all the co-firing levels as well as plant ages, followed by wood chips, with forest residues having the lowest incremental costs of co-firing. These results can be attributed to the cost of acquiring agricultural residues (i.e., straw) compared to the other feedstocks. Last, the LCOEs were generally lower for a 25-year-old plant (for those scenarios, the assumption is that the plants have been fully paid off) than a 15-year-old plant (those scenarios in which the plants are partially paid off). This trend is due to the effect of the age of the original plant on the overall capital costs of the modified co-fired plant, which has a direct effect on incremental cost in each biomass co-firing scenario.

Fig. 5

4.1.2 The levelized cost of electricity (LCOE)

The LCOE for the 60 biomass co-firing scenarios with both coal and natural gas in western Canada considered in this study is given in Fig. 6. The results reveal the following:

- There is a steady rise in the LCOE as co-firing levels increase for each biomass feedstock for each plant age considered (i.e., power plants modified for co-firing after 15 years and those modified after 25 years) as well as for the co-firing technology for both the coal and natural gas scenarios. This rise in LCOE is influenced by the steady rise in the incremental costs of substituting each of these base fuels with biomass feedstock, especially as the level of co-firing increases.
- Straw has the highest LCOE across all the co-firing levels and plant ages, followed by wood chips, with forest residues recording the lowest LCOE. This can be attributed to the cost of obtaining or delivering each feedstock.
- The LCOEs were generally lower at the 25-year plant age (those scenarios in which the plants were assumed to have been fully paid off) compared to the 15-year plant age (those scenarios in which the plants are partially paid off). This trend is due to the effect of the original plant's age on the overall capital costs of the modified co-fired plant, which has a direct effect on the incremental cost of each biomass co-firing scenario.

The following observations were made when we compared the LCOE values for coal/biomass co-firing with those of the NG/biomass co-firing:

- For the partially paid-off plants scenarios, the LCOE values are significantly higher for coal/biomass co-firing than for NG/biomass co-firing. This disparity can be attributed to differences in the original capital costs of both plants—evidently, the original capital costs of constructing a coal power plant are much higher than those of an NGCC plant.

- For the fully paid-off plant scenarios, the LCOE values are significantly lower for coal/biomass co-firing than for NG/biomass co-firing. This is because the cost of retrofitting the coal power plant to co-fire biomass is significantly lower than the cost of retrofitting an NGCC plant to co-fire biomass.

Fig. 6

Figure 7 shows the LCOE breakdown for all the feedstocks considered at a 25% co-firing level for both the coal and NG scenarios. The 5%, 10%, 15%, and 20% co-firing levels followed a similar trend. The major cost components of the LCOE of the coal/biomass co-firing are capital costs, maintenance costs, biomass feedstock costs to plants (the sum of all the cost components involved in acquiring and delivering biomass feedstock), and the costs of acquiring coal. The major cost components of the LCOE of the NG/biomass co-firing are biomass feedstock costs and the costs of acquiring natural gas.

The LCOE values in this study are slightly higher than the 2014 average electricity pool price ($49.42/MWh) in Alberta, as reported by the Alberta Electricity System Operator (AESO) [57]. Compared with the ten-year average reported pool price of electricity from 2005-2014 ($67.69/MWh), the LCOE values in this study especially for the coal/biomass co-firing are much lower. It can be inferred that the LCOE values reported in this study are feasible for Alberta consumers. Furthermore, the LCOE values in this study are much lower than those obtained from the three scenarios considered by Richardson and Harvey [58] for replacing conventional fuel use in Ontario, Canada. In their study, they reported LCOE values of $83.6/MWh, $88.8/MWh and \$109.8/MWh for the displacement of fossil fuel generation, planned retirement of existing nuclear reactors, and electrification of fleet vehicles, respectively in Ontario [58].

Fig. 7

4.2 Avoided CO_2 cost

The costs of avoiding one tonne of CO_2 by co-firing each of the biomass feedstocks with coal or natural gas in western Canada in the 60 scenarios considered in this study are presented in Fig. 8. The figure shows that there is a gradual decrease in the avoided CO_2 costs of biomass co-firing as co-firing levels increase for each biomass feedstock and plant age considered for both the coal and the natural gas scenarios. This trend is influenced significantly by the effects of economy of scale on the systems' capital costs as the co-firing level increases for both the coal and the natural gas scenarios. Another observation is that, comparatively, straw recorded the highest avoided CO_2 costs in co-firing relative to the other feedstocks based on both co-firing levels and the plant age. This trend is followed by wood chips and then forest residues. This trend was a result of the outcome of the biomass feedstock costs and consequently the incremental co-firing costs. It underlines the relationship between carbon abatement costs and incremental costs. An analysis based on the plant ages for the avoided CO_2 in the 60 co-firing scenarios reveals that the abatement cost is significantly higher in the partially paid-off scenarios than the fully paid-off ones. However, a closer look at each sub-group shows higher avoided CO_2 costs for the fully paid-off NG plant scenarios than the fully paid-off coal plant scenarios, as well as higher CO_2 costs for the partially paid-off coal plant scenarios than the partially paid-off NG scenarios. These outcomes are attributed to the effects of the age of the original plant on the overall capital costs of the modified co-fired plant, which directly influence both the incremental and abatement costs of the co-firing scenarios.

Fig. 8

4.3 Sensitivity analysis

The sensitivity analyses of co-firing each of the biomass feedstocks considered with coal and NG at a 25% co-firing level in a fully paid-off plant are shown in Figs. 9 and 10, respectively. This sample is representative of similar trends associated with all 60 scenarios studied. It shows that the overall size of the power plant is the most sensitive parameter inversely affecting the LCOE. Also, the efficiency of the co-fired plant is nearly as sensitive to the LCOE as the overall plant size. Therefore, the LCOE is higher at lower plant efficiencies and lower at higher plant efficiencies. Therefore, it will be ideal to choose a plant with considerably high efficiency to achieve a favorable (i.e., low) LCOE.

A few other parameters such as the quantity of biomass co-fired and the costs of feedstock transportation and base fuel were significantly sensitive to the LCOE, especially in a positive direction. For each scenario, the LCOE remains almost unchanged with changes in both feedstock harvesting costs and co-fired plant staffing costs.

The concept of power derating was investigated to determine the robustness of the co-fired plant. Power derating occurs when the power rating of the co-fired plant(s) is lowered due to substantial deterioration in the energy conversion efficiency of the plant. Here, a derate factor of 0.03 was assumed while the other parameters were varied within the established boundary to test how sensitive a co-fired plant could be to power loss. This study revealed that the power derate factor does not have a substantial impact on the plant's LCOE.

The results in this study show that biomass co-firing is an effective option for reducing GHG emissions from old power plants, especially coal-fired ones. An economical way of extending the life of existing coal plants is to use them to co-fire biomass feedstock with coal. This may be particularly true if these plants will not be operated long enough to recover the costs associated with other more capital-intensive carbon mitigation technologies. However, biomass co-firing with natural gas does not offer the same economic and environmental advantages as its coal counterparts. Furthermore, due to the higher delivery costs of biomass feedstock, the most economical approach is to operate the co-fired plants mostly during peak power consumption periods when the operating cost is most justifiable.

Fig. 9

Fig. 10

4.4 Uncertainty analysis

Though a robust approach was used to achieve the best research outcome, one major limitation of this cost analysis is imperfect data. Some degree of uncertainty was assumed in the estimation of all the cost parameters used in this study due to direct interaction with actual production processes associated with the power generation cycle as well as the present market conditions. The authors used a combination of previous technical experience and sound data judgment as well as detailed thinking to assume the "best guess" point values used in all the analyses in this study. This approach was enhanced through the use of probabilistic simulation techniques to ensure that the likely range of values for model input and output parameter aligns with industry trends. The uncertainty values assumed in this study, taken largely from a study by Dassanayake and Kumar [59], are thus:

- Farming and Harvesting, Collecting and Transportation – 5%.
- Plant Operations and Construction, Maintenance and Decommissioning – 10%.

Using Monte Carlo simulation techniques, uniformly distributed cost numbers ranging from \$61.92 to \$84.66 are generated representing the fractile of the random variables of each sample. This method enables the representation of model uncertainty by repetitive runs to obtain a set of sample values. ModelRisk, an Excel-based software, was used to carry out the Monte Carlo simulation [60]. 10,000 iterations were run to identify the total uncertainty of the system. The graphical representation of the Monte Carlo analysis results for direct combustion is presented in Fig. 11. The results show that the LCOE ranges for coal/wood chips are \$56.42 ± \$2.691/MWh, for coal/straws are \$57.35 ± \$2.54/MWh, and for coal/forest residues are \$54.50 ± \$2.744/MWh at a 95% confidence level. Table 6 shows the rest of the Monte Carlo simulation results for the co-firing of both coal and NG with 25% of each biomass feedstock considered. It is important to note that both Fig. 11 and Table 6 are only sample representations of the rest of the study.

Fig. 11

Table 6

5. Conclusion

From the detailed techno-economic and environmental assessment carried out in this study, a set of useful conclusions has been reached. First, most biomass feedstocks have higher delivery costs than either coal or natural gas. Second, the total capital costs per unit output (in \$/kW) required to modify a plant to co-fire biomass decrease as the co-firing level increases for both the coal and the natural gas scenarios. In terms of the plant age, the total capital cost is significantly less for a fully paid-off plant than a partially paid-off one. Third, the high costs for both the biomass feedstock and plant capital actively contribute to the typically higher cost of generating electricity from a co-fired plant compared to either a coal- or a natural gas-fired plant.

Fourth, while the LCOE of generating electricity from a co-fired plant increases as the level of co-firing increases, the avoided CO_2 costs decrease due to the rising incremental costs associated with these changes as well as the effects of economy of scale on the capital costs at each co-firing level. Fifth, a fully paid-off coal plant offered the best economic and environmental benefits to support biomass co-firing due to favorable plant modification costs, incremental costs, LCOEs, and avoided CO_2 costs. Lastly, forest residues emerged as the cheapest biomass feedstock to co-fire with coal in a fully paid-off modified plant with incremental costs ranging from $1.72/MWh to $7.90/MWh, LCOE ranging from $53.12/MWh to $54.50/MWh, and CO_2 abatement costs ranging from $31.15/t$CO_2$ to $27.41/t$CO_2$, respectively. Forest residues are closely followed by wood chips; wheat straw is the most expensive.

This outcome of this study is proof that biomass co-firing is a useful option toward a low-carbon power sector in Alberta, especially considering the proposed increase of the carbon tax to about $30/tCO2 by 2017, since it is able to mitigate life cycle GHG emissions associated with the use of fossil fuels in the power generation industry at reduced incremental investment costs.

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TABLES
Table 1

Techno-economic modeling input data

Power Plant Parameters	Coal	NG	Source/Remarks
Plant capacity (MW)	500	2x250	[34]
Plant type	Subcritical pulverized coal (PC) boiler	Natural gas combined cycle (NGCC)	[34]
Capacity factor (%)	85	85	[11, 34]
Plant life (years)	25	25	Initial capital cost of power plant has been fully paid out.
	15	15	Initial capital cost of power plant has been partially paid out.
Scale factor	0.79	0.71	[11]
Number of scenarios	30	30	The first set of 30 scenarios was based on biomass-coal co-firing and the other set of 30 scenarios was based on biomass-natural gas co-firing.
Cost of coal ($/tonne)	22	--	Coal is supplied from a mine-mouth source [11, 20]
Cost of natural gas ($/GJ)	--	3.47	[36]
Coal or NG replaced			This is measured in megatonnes/year for the coal/biomass co-firing scenarios. However, for the NG/biomass co-firing scenarios, it is measured in cubic metres/year.
5% co-firing rate	0.13	5,855.86	
10% co-firing rate	0.26	11,711.11	
15% co-firing rate	0.39	17,567.57	
20% co-firing rate	0.52	23,423.42	
25% co-firing rate	0.65	29,279.28	
Cost base year	2014	2014	
Internal rate of return (IRR)	0.1	0.1	This was used for the discounted flow sheet [11].
Inflation	0.02	0.02	This was used for the discounted

			flow sheet [38].
Exchange rate: CAD/USD	1.115	1.115	This was used for the discounted flow sheet [35].

Table 2

Plant modification equipment costs

a. Coal/biomass co-fired plant

Parameter	**Comments**	**Cost/unit Output (2014 CAD $/kW)**	**Sources**
Truck tipper	Cost for one tipper	13.62	[43]
Bale loaders, receipt	Cost in $/annual dry tonne[a]	13.62	[45]
Bale loaders, transfer to the line	Cost in $/annual dry tonne[a]	8.30	[45]
Bale merge conveyer	For 10 tonne/hour line	6.79	[44]
Bale infeed conveyer	For 10 tonne/hour line	9.09	[44]
Moisture meter	For 10 tonne/hour line	0.91	[44]
Bale rejector	For 10 tonne/hour line	0.75	[44]
Destringer	For 10 tonne/hour line	3.58	[44]
Debaler	For 10 tonne/hour line	13.10	[44]
Debaler outfeed conveyer	For 10 tonne/hour line	3.42	[44]
Magnet	For 10 tonne/hour line	1.71	[44]
Fine hammer mill	For 10 tonne/hour line	16.04	[44]
Baghouse fan	For 10 tonne/hour line	0.37	[44]
Baghouse	For 10 tonne/hour line	3.53	[44]
Surge bin	For 10 tonne/hour line	4.92	[44]
Rotary airlocks and feeders	For 10 tonne/hour line	3.74	[44]
Pneumatic transport system	For 10 tonne/hour line	36.96	[44]

Total cost	**207.37**

[a]The modification costs presented above are for a 25% co-firing level only and will vary accordingly to the different levels considered.

b. NG/biomass co-fired plant [34]

Parameter	**Description**	**Cost/unit Output (2014 CAD $/kW)**[b]
Biomass preparation & feeding	Magnetic separator	0.09
	Screen and hammer-mill	0.67
	Bag house dust collection	2.83
	Auxiliaries	0.48
Gasifier & accessories	Gasifier (High pressure directly heated fluidized bed)	234.63
	Compressors for gasifier air	6.60
	Gasifier gas cooling	0.17
Gas cleanup & piping	Syngas clean-up	30.21
	Gasification system installation cost	265.01
Boiler & accessories	Boiler & Accessories	405.06
Steam turbine generator	Steam Turbine Generator & accessories	71.43
	Condenser & auxiliaries	12.34
	Steam piping	12.12
Project contingency	15% of equipment and general plant facilities	116.50
Total cost		**1,158.14**

[b]The modification costs presented above are for a 25% co-firing level only and will vary accordingly with the different levels considered.

Table 3

Cost characteristics of the biomass feedstock

Items	Values/Formulas	Sources/Comments
Royal/premium fee ($/dry tonnes)	5.41	[11-14].
Ash disposal cost:		[11-14].
Hauling cost ($/dry tonnes/km)	0.21	
Disposal cost ($/dry tonnes/km)	28.97	
Whole forest		
Biomass yield (dry tonnes/ha)	84	[11, 12]
Harvesting cost:		[11, 12]
Felling ($/dry tonnes)	19.67	
Skidding ($/dry tonnes)	16.65	
Chipping cost ($/dry tonnes)	16.88	[11, 12].
Log loading, unloading, and transport cost ($/dry tonnes)	2.91+0.0326D	A circular harvesting area is assumed where D = 2*Average radius required to collect the biomass feedstock[c]. D represents the round-trip road distance from the forest to the receiving plant [11, 12].
Cost of road construction and infrastructure ($/ha)	[1.27 + (635.5/VT)] × average gross yield	VT is assumed to be 185.64 m^3/ha for the boreal forest [11, 12].
Silviculture cost (2014 $/ha)	254.19	[11, 12].
Forest Residues		
Biomass yield (dry tonnes/ha)	0.247	[11, 13, 14].
Harvesting cost ($/dry tonne)	16.41	[11, 13, 14].
Chipping cost ($/dry tonne)	16.10	[11, 13, 14].
Log loading, unloading, and transport cost ($/green tonne)	2.91+0.0326D	[11, 13, 14].
Wheat Straw		
Biomass yield (dry tonnes/ha)	0.333	[11, 13].
Harvesting cost:		

Shredding ($/dry tonne)	4.22	[47]
Raking ($/dry tonne)	2.65	[47]
Baling ($/dry tonne)	4.19	[47]
Bale wrapping—twine ($/dry tonne)	0.56	[47]
Bale collection:		
Bale picker ($/dry tonne)	0.77	[47]
Tractor ($/dry tonne)	4.11	[47]
Bale storage:		
On-field storage ($/dry tonne)	2.07	[47]
Storage premium ($/dry tonne)	0.11	[47]
Log loading, unloading, & transport cost ($/dry tonne)	6.7+0.1843D	[47]
Nutrient replacement cost ($/dry tonne)	25.72	[47]

[c]D is dependent on the density, calorific value, and the energy requirement of the biomass feedstock. It will vary with each of the feedstocks and co-firing levels.

Table 4

Base case of the operating costs of the co-firing scenarios

Operating Labor Cost	Value	Comments/Sources
Average annual labor rate (including benefits) for both administrative and operating staff	46.15	[11]
Annual staffing input (hours/shift position/year)	10,400	A five-shift rotation of 10,400 hours per shift position per year is assumed with the inclusion of vacations & training [11].
No. of shifts	5	[11]
Operating labor requirements per shift (coal)	Staffing level	12 workers are required in the coal/biomass co-firing plant [11].
Fuel receiver	1	
Fuel handlers	3	
Control room staff	2	
Ash handling plant staff	2	
Other power plant tasks	4	
Operating labor requirements per shift (NG)	Staffing level	12 workers are required in the NG/biomass co-firing plant [34].
Skilled operator	1	
Operator	3	
Foreman	2	
Lab tech's, etc.	2	
Administrative staff	26	[11]
Maintenance cost (% of initial capital cost of coal power plant)	3	[11, 13, 14].

Table 5

GHG (carbon) emission intensity of both the coal and NG plants

Parameters	Emissions (g/kWh)	Source/Comments
Coal	1065.6	The emission intensity level is calculated based on characteristics of Alberta's coal and the new 500 MW coal power plant [11].
NG	355.2	The emission intensity of NG plant is roughly one-third of that of the coal plant [34].
Whole forest	46.4[c]	[11]
Forest residues	75.5[c]	[11]
Straw	48.9[c]	[11]

[c]This includes the emissions from harvesting, processing, and transporting the biomass from the field/forest to the plant, as well as from retrofitting the old power plant to co-fire biomass.

Table 6

Monte Carlo results for the co-firing of both coal and NG with 25% of each biomass feedstock considered

Co-firing Types	Biomass Feedstock	Power Cost Range	Confidence Level
Coal-biomass co-firing	Wood chips	\$56.41 ± \$2.691/MWh	95%
	Straw	\$57.35 ± \$2.54/MWh	95%
	Forest residues	\$54.50 ± \$2.744/MWh	95%
NG-biomass co-firing	Wood chips	\$67.24 ± \$2.54/MWh	95%
	Straw	\$68.45 ± \$2.65/MWh	95%
	Forest residues	\$63.75 ± \$2.529/MWh	95%

FIGURES

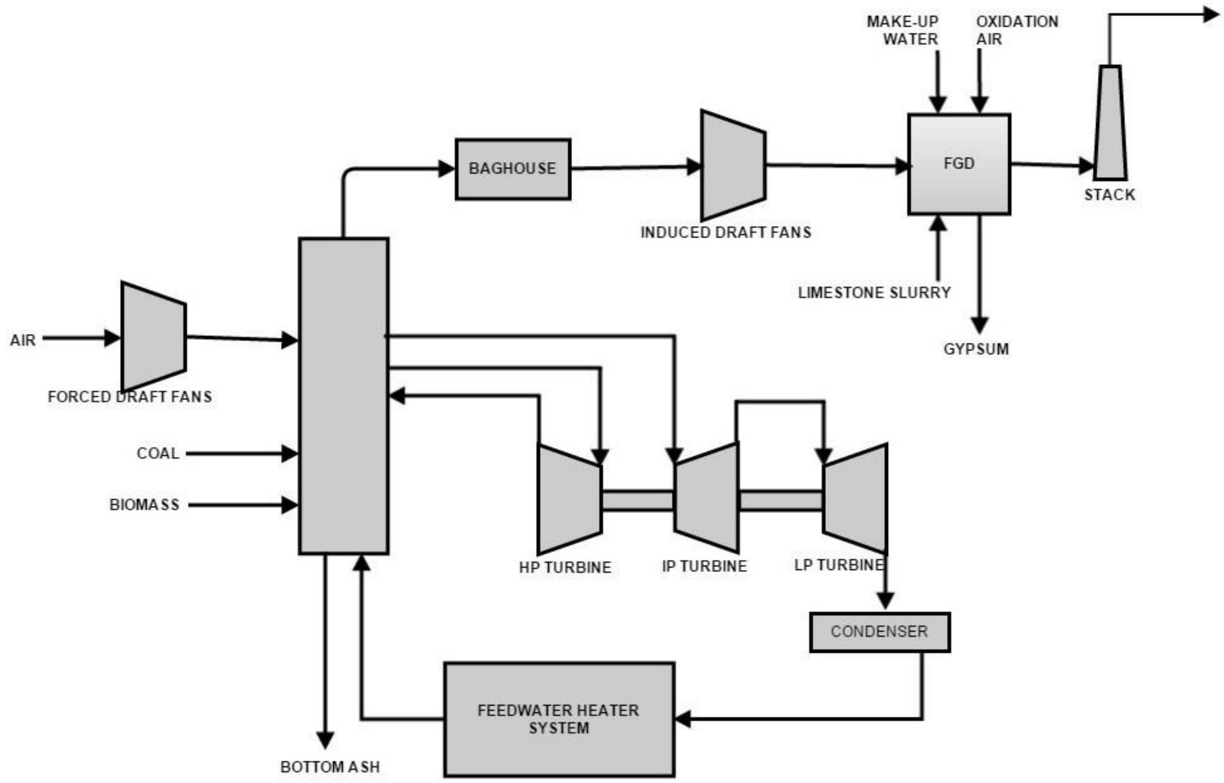
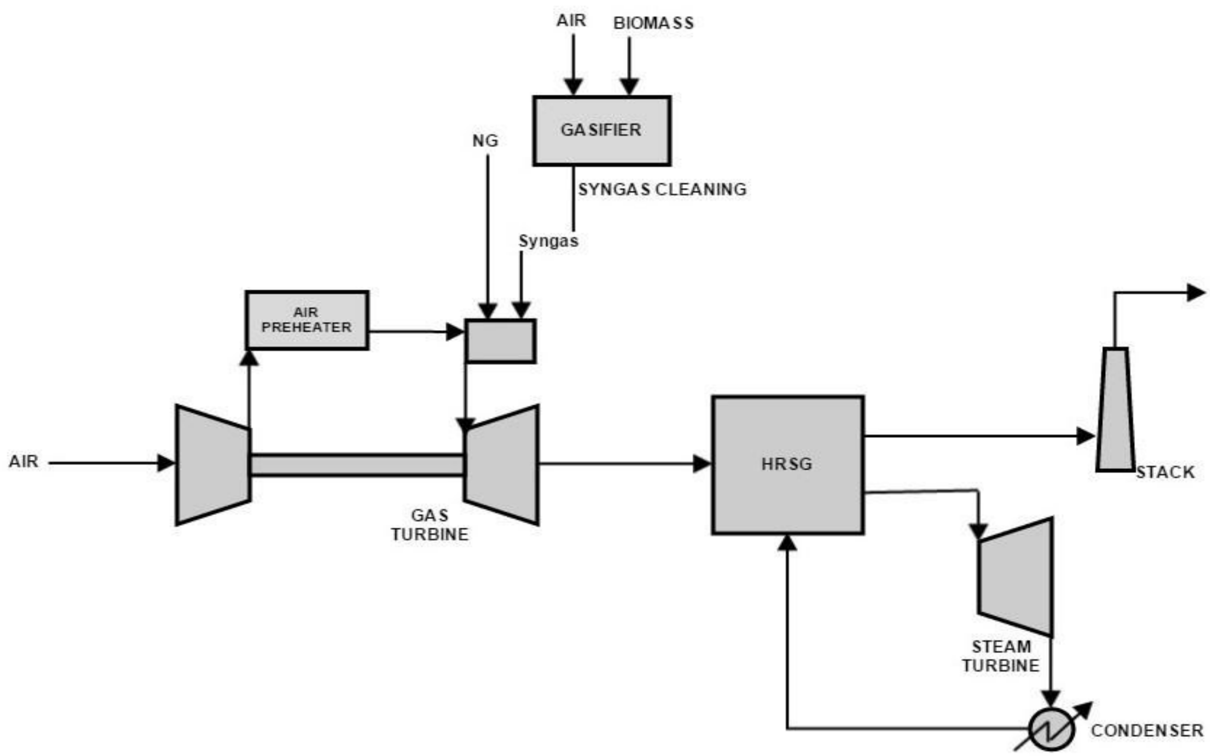


Fig. 1. Flow diagram of a modified subcritical PC plant

a. Design configuration I



b. Design configuration II

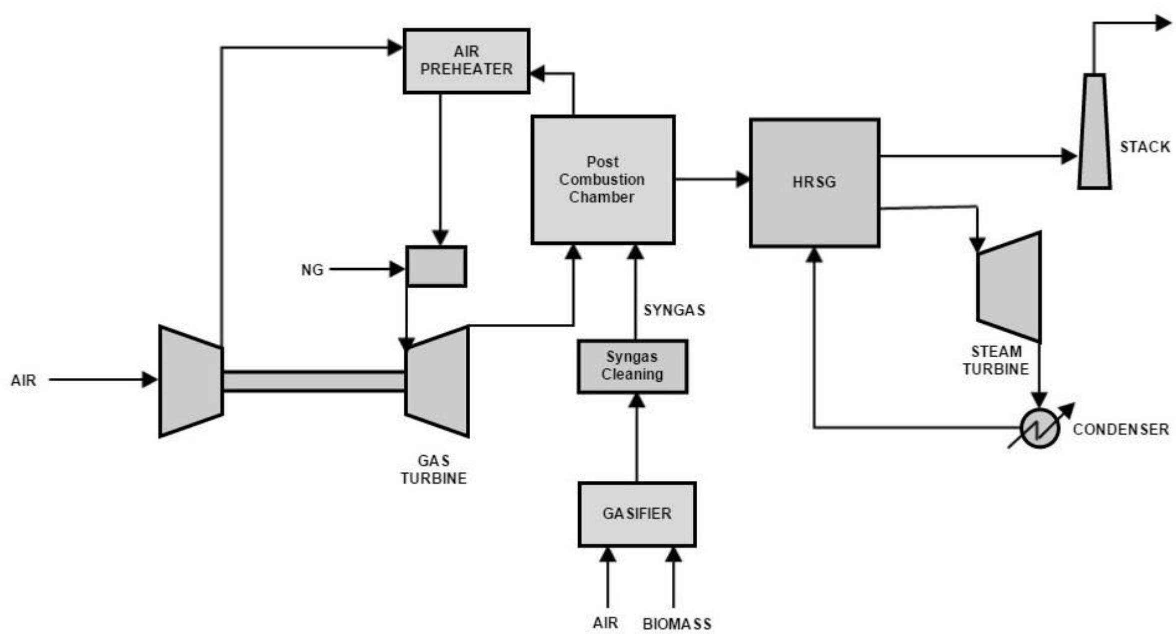


Fig. 2. Flow diagrams of modified NGCC plants.

Fig. 3. A distribution of the modification costs per unit output for each co-firing scenario.

a.

b.

Fig. 4. Transportation costs (a) and biomass delivery costs (b) at different co-firing levels for different biomass feedstocks.

a.

b.

Fig. 5. Increase in power costs at different co-firing levels and different years of plant modification after (a) 15 years, (b) 25 years.

a.

b.

Fig. 6. Levelized costs of electricity (LCOE) at different co-firing levels for different biomass feedstocks modified after (a) 15 years, (b) 25 years.

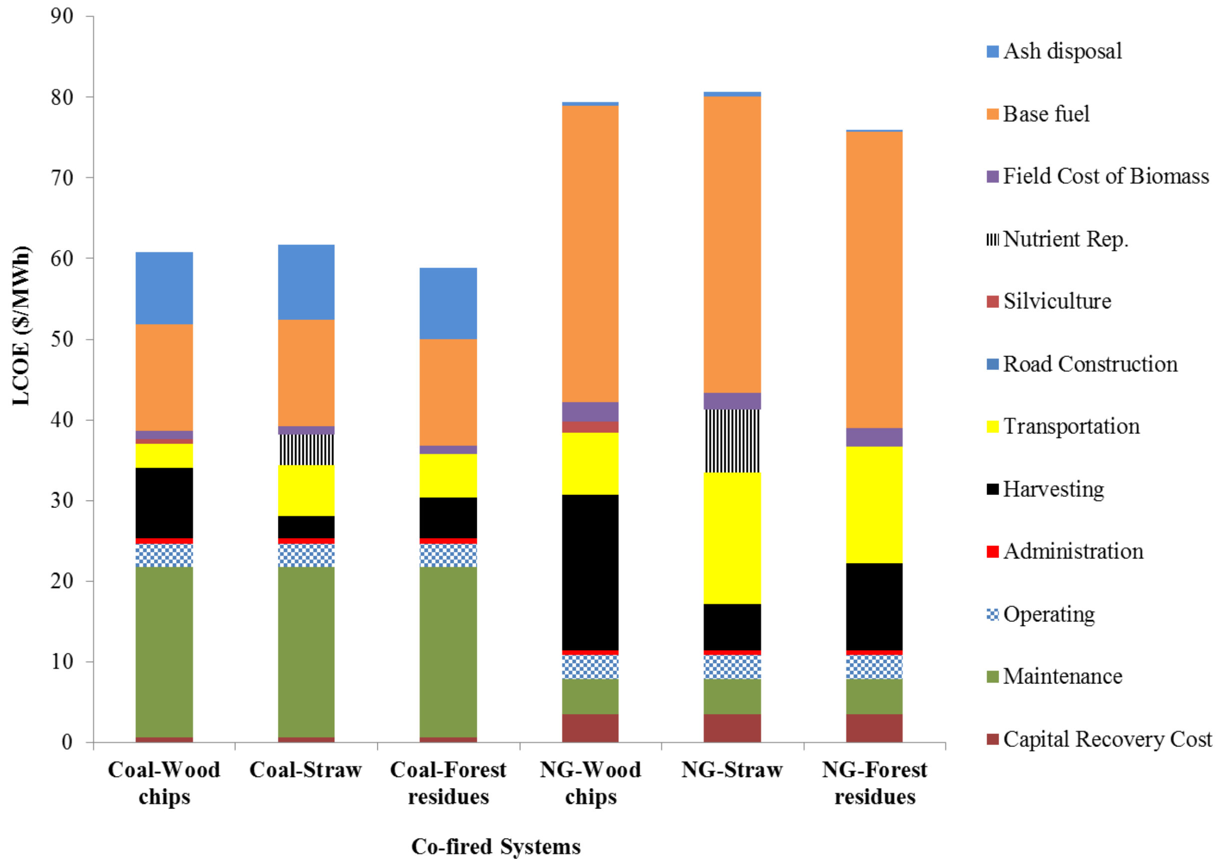


Fig. 7. Make-up of the LCOE for different biomass feedstocks at 25% co-firing levels at fully paid-off coal and NG plants.

a.

b.

Fig. 8. Avoided CO_2 costs at different co-firing levels for different biomass feedstocks modified after (a) 15 years, (b) 25 years.

a. Wood Chips

b. Straw

c. Forest Residues

Fig. 9. Sensitivity analyses for the coal/biomass co-firing scenarios at a 25% co-firing level

a. Wood Chips

b. Straw

c. Forest Residues

Fig. 10. Sensitivity analyses for the NG/biomass co-firing scenarios at a 25% co-firing level

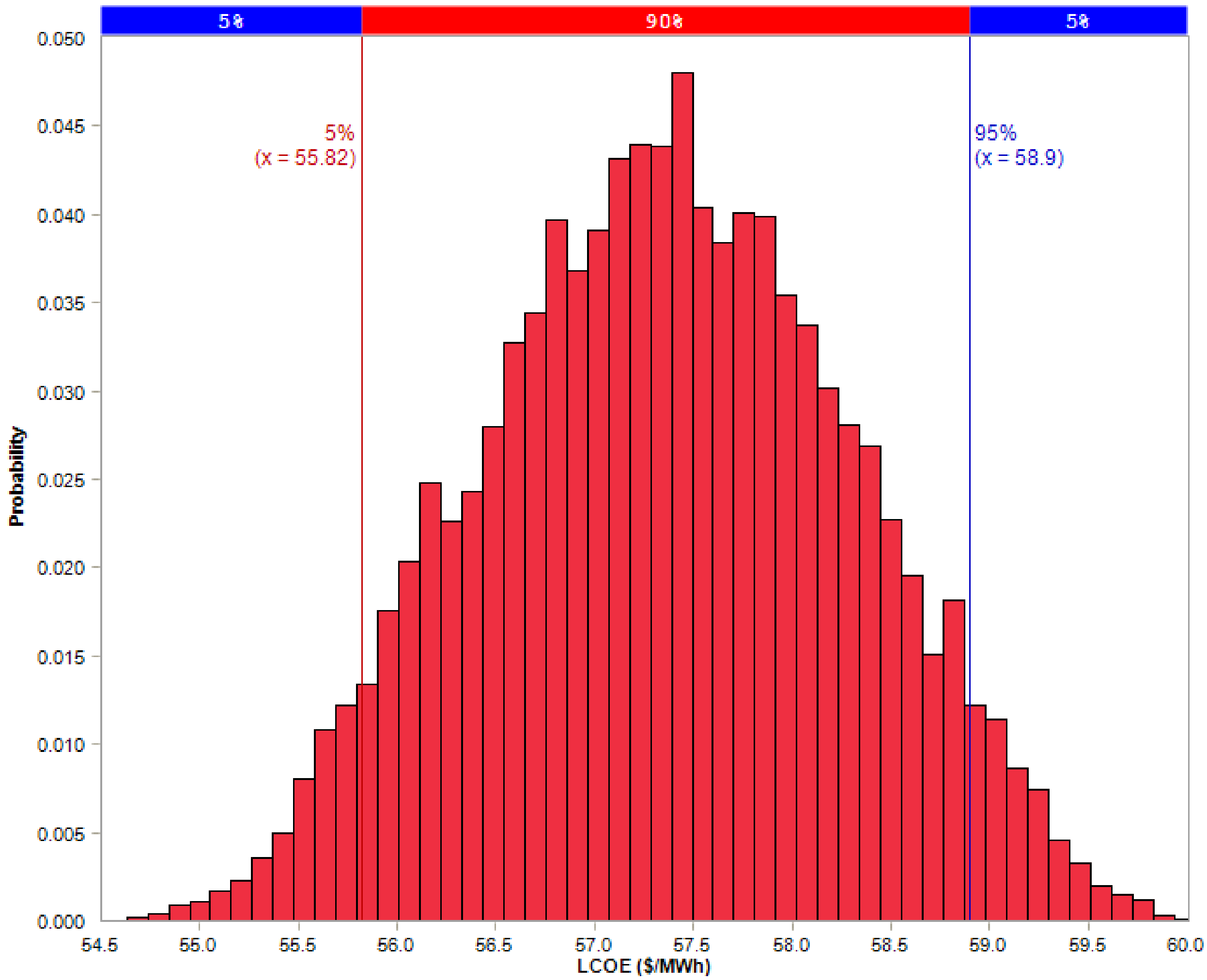


Fig. 11. Graphical representation of the Monte Carlo results for the parallel co-firing of coal with 25% wheat straw.

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