Biomass Co-firing with Coal and Natural Gas

by

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Abstract

Biomass fuels have long been accepted as useful renewable energy sources, especially in mitigating greenhouse gases (GHG) emissions. Fossil fuel-based power plants make up over 30% of the GHG emissions in Alberta, Canada. Displacement of fossil fuel-based power through biomass co-firing has been proposed as a near-term option to reduce these emissions. In this research, co-firing of three biomass feedstocks (i.e., whole forest, agricultural residues and forest residues) at varying proportions with coal as well as with natural gas in existing plants was studied to investigate different co-firing technologies. Whole forest biomass refers to live or dead trees (spruce and mixed hardwood) not considered merchantable for pulp and timber production; agricultural residues are straws obtained as the by-product of threshing crops such as wheat, barley, and flax; and forest residues refer to the limbs and tops of the trees left on the roadside to rot after logging operations by pulp and timber companies. Data-intensive models were developed to carry out detailed techno-economic and environmental assessments to comparatively evaluate sixty co-firing scenarios involving different levels of the biomass feedstock co-fired with coal in existing 500 MW subcritical pulverized coal (PC) plants and with natural gas in existing 500 MW natural gas combined cycle (NGCC) plants. Minimum electricity production costs were determined for the co-fired plants for the same three biomass feedstocks and base fuels. Environmental assessments, from the point of harvesting to delivering electricity to the customers, was evaluated and compared to the various co-fired configurations to determine the most economically viable and environmental friendly options of biomass co-firing configuration for western Canada.

The results obtained from these analyses shows that the fully paid-off coal-fired power plant co-fired with forest residues is the most attractive option and has levelized cost of electricity (LCOE) ranging from \$53.12 to \$54.50/MWh; and CO_2 abatement costs ranging from \$27.41 to \$31.15/tCO_2. Similarly, the LCOE and CO_2 abatement costs for whole forest chips range from

$54.68 to $56.41/MWh and $35.60 to $41.78/$tCO_2$ respectively. When straw is co-fired with coal in a fully paid-off plant, the LCOE and CO_2 abatement costs range from $54.62 to $57.35/MWh and $35.07 to $38.48/$tCO_2$ respectively. This is of high interest considering the likely increase of the carbon levy to about $30/$tCO_2$ in the Province of Alberta by 2017.

Preface

Chapter 2 of this thesis has been published as*: Agbor, E., Zhang, X., Kumar A. 2014. A review of biomass co-firing in North America. Renewable and Sustainable Energy Reviews, 40: 930–943*. I was responsible for the data collection and analysis as well as the manuscript development and composition. X. Zhang assisted with the data collection. A. Kumar was the supervisory author and was also involved with the concept formation, analysis and manuscript composition.

Chapter 3 of this thesis has been submitted as: *Agbor, E., Oyedun A.O., Zhang, X., Kumar A., "Integrated techno-economic and environmental assessments of co-firing biomass with coal and natural gas in western Canada."* to the *"Energy"* journal. I was responsible for the concept formulation, data collection and analysis, and manuscript composition. A. O. Oyedun and X. Zhang contributed in data collection and by reviewing the results and provided useful inputs. A. Kumar was the supervisory author and was also involved with the concept formation, analysis and manuscript composition.

Dedication

This thesis is dedicated to my wife—**Jane Ezinwa-Agbor**, daughter—**Uchechi Nnenna Agbor**, dad—**Mr. Cornelius Idekwuli Agbor**, mom—**Mrs. Julianah Uchechi Agbor**, and brothers—**Ositadinma Agbor** and **Ogbonnaya Agbor**.

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List of Abbreviations

CCS	Carbon capture and sequestration
CO_2	Carbon dioxide
CTG	Combustion turbine generator
GHG	Greenhouse gas
HHV	Higher heating value
HP	High pressure
HRSG	Heat recovery steam generator
IP	Intermediate pressure
LBN	Low NOx burner
LCV	Low calorific value
LCOE	Levelized cost of electricity
LP	Low pressure
MMBtu	Million British thermal units
MWh	Megawatt-hour
NG	Natural gas
NOx	Oxides of nitrogen
NPV	Net present value
O&M	Operation and maintenance
OPG	Ontario Power Generation
PC	Pulverized coal
SOx	Oxides of sulfur
STG	Steam turbine generator
$/kW	Dollar per kilowatt

\$/tonne	Dollar per metric ton
RE	Renewable energy
tCO_2	Metric ton of carbon dioxide
Tonne	Metric ton (1000 kg)

Chapter 1: Introduction

1.1 Background

Energy can be described as one of the cornerstones of modern civilization, especially in terms of driving economic growth and social progress [1, 2]. We use different energy sources to do work, and these sources are typically classified into two main groups — non-renewables and renewables. Non-renewable energy sources are those that are usually not replenished at all or are replenished slowly by natural processes and usually produce greenhouse gases (GHGs) that can potentially harm our environment. Non-renewables include fossil fuels such as coal, petroleum, natural gas and uranium. Renewable energy sources (RES), on the other hand, are sources of energy that are replenished naturally and are mostly considered environmentally-friendly because they do not produce GHGs. Renewables include hydropower, solar energy, wind energy, biomass energy or biofuels, geothermal energy, ocean energy, etc. [1-4] .

Though RES presently make up less than 20% of global energy consumption, it is predicted that this will change significantly, and is expected to increase in the near future [2]. This change is motivated by the need to mitigate environmental issues such as global warming, acid rain, and urban smog, which have become prevalent due to the continuous emissions of GHGs from the use of fossil fuels. A report published by the Intergovernmental Panel on Climate Change (IPCC) projects that the earth's temperature will likely rise between 1.4^{o}C and 5.8^{o}C from 1990 to 2100 given the persistent emissions from the use of fossil fuels [5]. The likely change in energy consumption is also supported by the anticipated depletion of most fossil fuels, which are the prime energy sources at the moment, in the near future. According to Oka [6], the energy crisis of the early 1970s led to a severe shortage in the supply of liquid and gaseous fuels in most parts of the world. This energy shortage, along with the growing concerns of the effects of GHG emissions, prompted governments in most developed countries, including Canada and the United States, to reconsider their energy policies [6].

Biomass is a form of renewable energy that is derived from processing organic matter such as agricultural residues, wood resources from forests, seaweeds, biodegradable wastes, etc. It is classified as a renewable energy source because of its limitless supply. For instance, used trees and crops can be grown back easily, and wastes will always occur as a result of human activities and natural processes [3, 4]. However, of more interest is the fact that biomass is carbon-neutral (i.e., it has a zero net carbon contribution to the atmosphere), given that the amount of CO_2 generated when this fuel is burnt is equivalent to that which is removed from the atmosphere during the growth phase of new plants and all biomass materials ultimately trace their origin from plants. A report published by the World Energy Council states that RES such as biomass will provide 60% of global electricity supplies and 30% of direct fuel use by 2025, providing suitable policy initiatives are implemented in most parts of the world, since RES have the potential to reduce overall GHG emissions [7].

Biomass is used to generate electricity, primarily through a dedicated biomass power plant. Although this technology offers significant environmental benefits, it is faced with several challenges, such as high operational costs and unpredictable feedstock supply due to the seasonal nature of biomass resources and poorly established supply infrastructure in many parts of the world [4, 8]. Another constraint of plants that generate power solely from biomass is the high transportation cost of the biomass feedstock due to its low heating value and low bulk density. The high cost results from to the need to transport large units of the fuel.

A sustainable way of overcoming these challenges is to combine biomass with other fuels like coal or natural gas for power generation in a process called biomass co-firing. In situations where there is insufficient biomass feedstock supply, the other fuel can buffer the system until the biomass supply improves [3]. In addition, the cost of retrofitting an existing power plant to co-fire biomass with either coal or natural gas is usually significantly lower than the cost of building a new dedicated biomass power plant [1, 9, 10].

1.2 Research motivation

The interest in this research was born out of the need to aid electric utility companies to develop and incorporate a specific percentage of renewable energy in their overall electricity generation portfolio. This is backed by a growing socio-political drive and legislations in many parts of the world, including western Canada, to reduce the environmental impacts and financial costs associated with fossil fuel exploration, production, and use. An initial investigation revealed that little work has been done previously to determine the aspects of biomass co-firing with different fossil fuel that have an impact on GHG emissions mitigation especially with a focus on western Canada.

1.3 Research objectives

The main purpose of this research is to carry out detailed assessment of the generation of electricity by co-firing biomass with coal and natural gas in existing coal-fired power plants as well as natural gas-fired power plants in western Canada. Following are the specific objectives of this study:

i. Identify the challenges that hinder the successful adoption of biomass co-firing by utility companies.
ii. Develop a framework for selecting the most favorable biomass co-firing technology and fuel for utility companies in western Canada based on the lowest financial cost and highest GHG reduction.
iii. Identify and assess the properties of different biomass-based fuels that can be effectively used in biomass co-firing configurations in western Canada. Along with the two base fuels considered in the study (coal and natural gas), three supplemental

(biomass) fuels were considered: whole forest (wood chips), forest residues, and agricultural residues (wheat straw).

iv. Develop data-intensive techno-economic models for determining the levelized cost of electricity (LCOE), incremental costs, and avoided cost of CO_2 for each of the considered scenarios.

v. Evaluate 60 co-firing scenarios employing different proportions of biomass and base fuels, technical configurations and co-firing levels to determine the levelized cost of electricity (LCOE), incremental costs, and avoided cost of CO_2 for each of these scenarios.

vi. Determine the most appropriate biomass co-firing configuration for western Canada in terms of technical, economic, and environmental factors, as well as the fuels used.

1.4 Research approach

To achieve the objectives listed in Section 1.3 the following approach was adopted for this thesis. It was designed to provide a thorough and transparent mechanism for selecting the most favorable biomass co-firing technology along with fuels for utility companies in western Canada that minimizes financial cost and maximizes GHG reduction in the form of a low carbon credit. Firstly, biomass co-firing was studied thoroughly to gain a full understanding of the technologies involved. This was crucial when collecting technical data of all the operational units required to co-fire the biomass feedstocks considered with either coal or NG. Section 1.4.1 presents the technological approach and assumptions employed in this study. Secondly, detailed financial data of all operational units required to co-fire various biomass feedstocks with both coal and NG were collected to from reliable sources for economic assessment of the biomass co-firing systems. Section 1.4.2 presents a clear description of the approach and assumptions employed in the economic assessment of biomass co-firing in western Canada.

1.4.1 Biomass co-firing technologies

Biomass co-firing can be a useful GHG emissions reduction tool in the power generation industry since it can enable utility companies to reduce overall GHG emissions significantly by substituting significant portions of their base fuels with carbon-neutral biomass-based fuels [10]. Biomass co-firing also creates an opportunity in industries such as forestry, agriculture, construction, manufacturing, food processing, and transportation to better manage large quantities of combustible agricultural and wood wastes [4]. Presently, there are over 150 biomass co-firing installations in the world, with Europe accounting for roughly two-thirds of them. The rest are based mostly in North America and Australia. Incentives and favorable environmental policies and regulations are the major factors encouraging the recent interest in power generation and co-generation from biomass energy sources, especially in Europe. However, several challenges and issues presently hinder the effective adoption of this technology by utility companies [3, 4, 9, 10].

Generally, the amount of biomass feedstock that can be co-fired with a base fuel in a boiler is referred to as the co-firing level of the system. Several technological, logistical, and economic factors such as the plant set-up, boiler type and efficiency, biomass type, quality and supply chain, etc., influence the amount of base fuel that can be substituted with the biomass feedstock [1, 9, 10]. When co-firing biomass with another fuel type, it is necessary to gain a sufficient understanding of the properties of the fuels involved since biomass varies significantly from one type and category to another and from the base fuels [15]. This research focused on three biomass co-firing technologies (discussed further in Chapter 2 of this thesis), with scenarios involving two base fuels (coal and natural gas), and three supplemental biomass feedstocks (whole forest [wood chips], agricultural residues [wheat straw], and forest residues), and five co-firing levels (5%, 10%, 15%, 20%, and 25%).

1.4.2 Economic Analysis

According to earlier studies [13, 14], the cost to use any biomass feedstock is based on three factors: the end product, the conversion technology, and the scale. This study focused on the last two factors, conversion and scale. Once credible economic and technical parameters were identified, two detailed techno-economic models were developed in this research for each for the base fuels on a spreadsheet. These models were built by collecting detailed relevant data on the characteristics of coal, natural gas, and the biomass feedstock considered, the capital costs of the power plants, including the modification capital costs to retrofit existing plants to fire biomass feedstock, and all forms of plant operating and maintenance costs associated with different scenarios of the co-fired systems. Where necessary, the data were based on full life cycle costing, using an appropriate discount factor over a period of 25 years [13, 15]. All costs are given in Canadian dollars (CAD) and adjusted to the year 2014 [16]. A 2% inflation rate and a 12% rate of return on total installed capital cost were assumed. When there were differences in capacities from multiple data sources, cost estimations were adjusted based on equation 1.1:

$$cost_2 = cost_1 \times (capacity_2/capacity_1)^{\text{scale factor}} \qquad (1.1)$$

A scale factor of 0.75 was used to determine a best fit [13].

From these data, the following model outputs were determined: feedstock costs, including both the field costs and transportation costs to deliver the feedstock to the power plant, the incremental cost of co-firing, the levelized cost of electricity (LCOE), and the avoided cost of CO_2 to the power plant. The final results were thoroughly analyzed to assess the potential to generate electricity by co-firing biomass feedstock with coal or natural gas. The full details of the modeling and analysis are described in Chapter 3 of this thesis. These results were validated by the outputs from similar research works from different organizations. It is believed that is this modeling and analytical method is comparable to investment screening techniques used in the energy industry.

1.5 Organization of thesis

This thesis is organized into four sections, as follows:

- *Chapter 1: Introduction*

  This chapter outlines the need and motivation for the thesis, as well as the methodology used to carry out the research.

- *Chapter 2: A review of biomass co-firing in North America*

  This chapter presents a detailed technical description of various aspects of biomass co-firing in North America. It identifies several biomass fuels that are most relevant for co-firing in western Canada and assesses their physical characteristics and availability. It also explores the benefits of biomass co-firing, such as the reduction of GHG emissions and its implications. This chapter is based entirely on one of my recent publications, "A review of biomass co-firing in North America," published in the journal, *Renewable and Sustainable Energy Reviews*.

- *Chapter 3: Integrated techno-economic and environmental assessments of co-firing biomass with coal and natural gas in western Canada.*

  A techno-economic assessment of sixty biomass co-firing configurations was carried out to investigate the operating consequences of these co-firing configurations. The assessment also determined the power costs associated with co-firing the fuels. Sensitivity analyses were performed to determine the effect of different values of each of model parameters on the power costs under the given model assumptions.. This chapter is based entirely on one of my recent publications: "Techno-economic modeling of biomass co-firing in Western Canada," submitted for publication in the journal: ---------

- Chapter 4*: Conclusions and Future Research*

  Conclusions regarding technology, costs, and carbon emissions are made, and opportunities for future research are discussed.

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Chapter 2: A review of biomass co-firing in North America[1]

2.1 Introduction

Biomass is a renewable energy source that has the potential benefits of decreasing pollutant generation. One of the oldest sources of energy known to man, biomass is derived from organic matter such as agricultural crops, forest harvest residues, seaweed, herbaceous materials, and organic wastes [1-4]. Compared to other sources of energy, biomass offers some unique advantages with respect to the environment since it is “carbon neutral.” Although the combustion of biomass generates as much carbon dioxide as fossil fuels do, the carbon dioxide released is removed when a new plant grows. This means the biomass expels the carbon (usually in the form of carbon dioxide) that it had originally taken in from the atmosphere, thereby reducing net carbon emissions significantly [5, 6].

Biomass co-firing is regarded as one of the attractive short-term options for biomass use in the power generation industry. It is defined as the simultaneous blending and combustion of biomass with other fuels such as coal or natural gas in a boiler in order to generate electricity [7-10]. Solid biomass co-firing is the combustion of solid biomass fuels like wood chips and pellets in coal-fired power plants [10]. Gas biomass co-firing is the simultaneous firing of gasified biomass with natural gas or pulverized coal in gas power plants in a technique usually referred to as indirect co-firing [11, 12]. In both situations, whenever there is insufficient biomass feedstock, the primary fuel buffers the system until the biomass supply improves.

Co-firing biomass with fossil fuels like coal and natural gas offers several opportunities, especially to utility companies and customers, to protect the environment by lowering GHGs [5]. It also creates opportunities in industries such as forestry, agriculture, construction,

[1] This chapter has been published in the Journal of Renewable and Sustainable Energy Reviews. Agbor E., Zhang X. and Kumar, A. A review of biomass co-firing in North America. ***Renewable and Sustainable Energy Reviews*** 2014: 40: 930–943.

manufacturing, food processing, and transportation to better manage large quantities of combustible agricultural and wood wastes [1]. In addition, the cost of adapting an existing coal power plant to co-fire biomass is significantly lower than the cost of building new systems dedicated only to biomass power [13, 14]. Even though a dedicated biomass plant offers significant environmental benefits. However, relying solely on biomass is risky due to unpredictable feedstock supply because of the seasonal nature of biomass resources as well as poorly established supply infrastructure in many parts of the world [1, 5]. Other constraints of generating power solely from biomass are the low heating values and the fuel's low bulk densities, which create the need transport large units of biomass [7]. Biomass co-firing for power generation provides an effective way to overcome these challenges.

This chapter reviews biomass co-firing with a focus on western Canada. The specific objectives include:

i. A review of different biomass co-firing technologies.
ii. A review of biomass co-firing in western Canada.
iii. A review of possible approaches to improve biomass co-firing.
iv. A comparative assessment of co-firing in western Canada and around the world.
v. A discussion on opportunities and the future of co-firing in western Canada due to policies.

2.2 Existing co-firing technologies

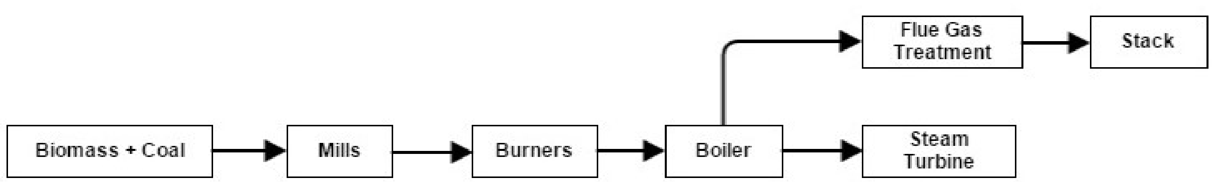
Biomass feedstock can be mixed with the base fuel outside the boiler or it can be added to the boiler separately. Co-firing technologies are usually implemented in existing coal-fired or NG-fired power plants. The most common type of co-firing facility is a large, coal-fired or NG-fired power plant, though related coal-burning facilities, like cement kilns, coal-fired heating plants, and industrial boilers can be used [9, 15].

Al-Mansour and Zuwala [16] lists three technological approaches to co-fire biomass with coal or natural gas in a power plant: direct co-firing, indirect co-firing, and parallel co-firing. The approaches differ in terms of the boiler system design as well as the percentage of biomass to be co-fired.

2.2.1 Direct co-firing

Direct co-firing is a simple approach and the most common and least expensive method of co-firing biomass with coal in a boiler, usually a pulverized coal (PC) boiler. As shown in Figure 1, in direct co-firing technology, biomass is fed directly into the furnace after either being milled with the base fuel (Figure 2.1a) or being milled separately (Figure 2.1b) [17]. The fuel mixture is then burned in the burner. The co-firing rate is usually in the range of 3-5%. This rate may rise to 20% when cyclone boilers are used, although the best results are achieved with PC boilers [18, 19].

a.



b.

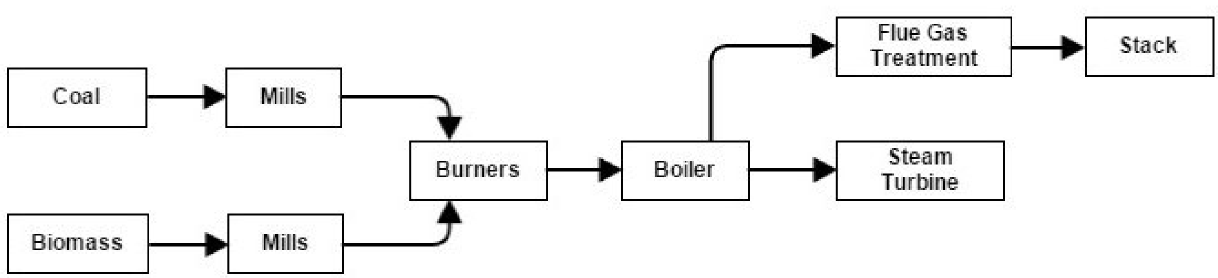


Figure 2.1: Direct biomass co-firing technologies: a) Mixing biomass with coal. b) Separate biomass feeding arrangement.

Maciejewska et al. [15] note that most direct co-firing issues are a result of high co-firing levels, poor biomass quality, and lack of dedicated infrastructure. Studies carried out by the Tennessee Valley Authority (TVA) show that blending biomass fuels like wood waste (for example, sawdust) directly with coal in a PC boiler tend to have an unfavorable effect on the pulverizer and lead to unacceptable sieve analyses results as the co-firing percentages of the system starts to exceed 5% on a mass basis [20]. Depending on the type of biomass feedstock used, some challenges may be encountered when biomass is directly blended on the coal pile. For example, straws and switchgrass can plug the bunkers if they are milled to 25-50 mm (1-2 in) in length. Also, bark may affect milling operations since it can be very stringy. When pulverizers are not used, cyclone boilers are recommended, although the coal should be crushed to a particle size of 6 mm x 0 mm (1/4 in x 0 in). However, there is a capacity limit that hinders the quantity of biomass that may be fired when cyclone boilers are used. This is based on the higher heating value of biomass feedstocks, which exceeds the design limits of most cyclone boilers (they would usually have a heating value of about 20 MJ/kg). Also, even though some experts specify an ash concentration level of approximately 5%, the ash concentration of different types of biomass fuels varies significantly, from 0.44% in white pine to 7.63% in switchgrass, as shown in Table 2.2. The inherently high ash concentration levels of some biomass fuels like those from herbaceous materials might be a challenge in the boilers since there is a higher tendency of ash deposition problems like slagging and fouling as well as the corrosion of the boiler heat transfer surfaces [7, 20, 21].

2.2.2 Indirect co-firing

Indirect co-firing technology allows biomass to be co-fired in an oil- or gas-fired system. It exists in two forms, gasification-based co-firing and pyrolyzation-based co-firing. In gasification-based co-firing, the biomass feedstock is fed into a gasifier in the early stages of the process to produce syngas, which is rich in CO, CO_2 H_2, H_2O, N_2, CH_4, and some light hydrocarbons. This syngas is then fired together with either natural gas in a dedicated gas burner. The net heating value of the syngas produced from the gasification process has an inverse relationship with the moisture content of the feedstock [20, 22, 23], which, for the biomass fuels in this paper, ranges from 8% in corn stover to 38% in white pine (as shown in Table 2.2). The negative impact of moisture content is mainly because: 1. Higher moisture content consumes more energy for drying, which reduces the energy converted into syngas; 2. Higher moisture content in the feedstock leads to higher vapor content in the syngas, which reduces the percentage of the combustible gases (CO, H_2) in the syngas.

The other kind of indirect co-firing is based on pyrolysis, where the biomass fuel undergoes a destructive distillation process to produce a liquid fuel like bio-oil as well as solid char, and then the bio-oil is co-fired with a base fuel such as natural gas in a power station [24]. It is worth mentioning at this stage that this technology has yet to record any commercial success given that it is still in a development and demonstration phase. An illustration of indirect biomass co-firing is shown in Figure 2.2.

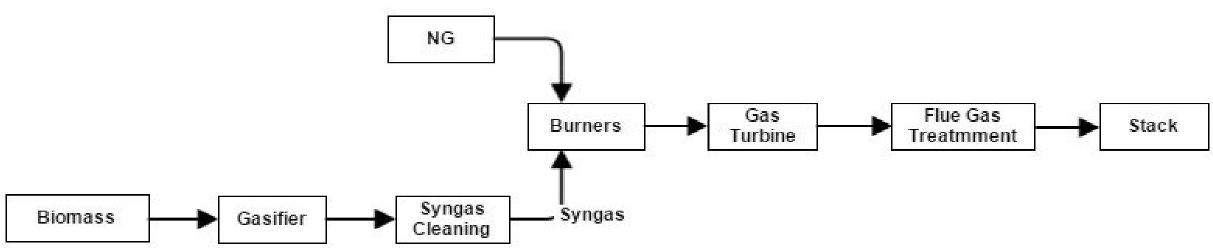


Figure 2.2: Indirect biomass co-firing technologies.

Gasification-based co-firing in PC boilers has been successfully demonstrated in Lahti, Finland with a wide range of biomass fuels such as sawdust, straws, wood wastes, and other waste-derived fuels [25]. Its commercial acceptance has increased significantly through the aid of the recent successful commercial operation of a fluidized bed gasifier. Evidence shows that the most suitable gasification technology for indirect co-firing is fluidized bed gasification, whether in the form of bubbling fluidized bed gasification or circulating fluidized bed gasification, since it permits the use of a wide range of biomass fuels. The gasification-based co-firing technology in the demonstration plant in Finland addresses several co-firing issues when compared with conventional co-firing technologies, such as: 1. This technology prevents biomass material from being fed into the boiler in a solid form, which in turn reduces boiler slagging and prevents the alteration of the ash characteristics; 2. Gasification can accomplish complete combustion in the furnace with a very short gas residence time [26]; 3. Gasification-based co-firing can potentially substitute higher percentages of biomass gas in the system, although its effect on combustion efficiency, boiler efficiency, and emissions from pollutants is yet to be determined [26]; 4. Gasification offers a unique advantage in that it is fuel-flexible in terms of the base fuel used since it can accommodate coal, oil, and natural gas [20]. However, the major concerns associated with this technology, especially in the large-scale application, are in achieving and maintaining a very high level product gas purity and its high capital costs. These issues make indirect co-firing the least successful commercial co-firing technology [25].

2.2.3 Parallel co-firing

In parallel biomass co-firing technology, as shown in Figure 2.3, biomass pre-processing, feeding, and combustion activities are carried out in separate, dedicated biomass burners. Parallel co-firing involves the installation of a completely separate external biomass-fired boiler in order to produce steam used to generate electricity in the power plant [27]. Instead of using high pressure steam from the main boiler, the low pressure steam generated in the biomass boiler is used to meet the process demands of the coal-fired power plant [27].

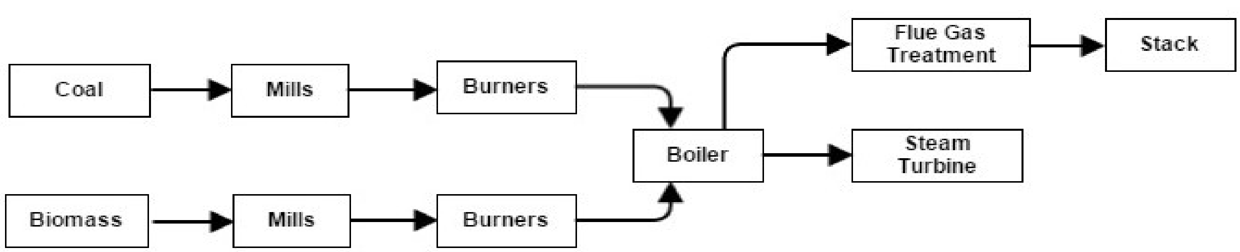


Figure 2.3: Parallel biomass co-firing technologies.

Parallel co-firing offers more opportunity for higher percentages of biomass fuels to be used in the boiler [27]. This technology also offers lower operational risk and greater reliability due to the availability of separate and dedicated biomass burners running parallel to the existing boiler unit. There is a reduced tendency for deposition formation issues like fouling and slagging, as well as corrosion, since the system design prevents biomass flue gas from contacting the boiler heating surfaces and the combustion process is better optimized. However, this technology is more capital intensive than direct co-firing due to the dedicated boiler system [28]. Its application is commonplace in industrial pulp and paper facilities where it makes use of by-products from paper production like bark and waste wood.

2.3 Levels of co-firing

Generally, there is a large possibility that biomass co-firing can reduce CO_2 emissions given that a significant amount of biomass can be co-fired with a base fuel like coal or natural gas in a boiler. The amount of biomass fuel that is co-fired is called the co-firing level or the rate of co-firing. Although it is believed that biomass can potentially be substituted for more than 50% of the coal used in a co-firing configuration, at present the actual co-firing level achieved in most commercial applications is 5-10% [10]. This significant shortfall is largely caused by the current inability to effectively manipulate several logistical, technical, and economic factors such as the origin and quality of the biomass used as well as its supply chain, plant set-up in terms of boiler type and efficiency, environmental issues including emissions from sulfur and nitrogen oxides, the overall quality of the by-products (e.g., fly ash, bottom ash, and gypsum), deposition and corrosion formation, and the deterioration of downstream gas cleaning systems [10]. Table 2.3 shows the range of co-firing levels for different boiler types as well as a technical comparison of the boilers.

Higher biomass co-firing levels are generally achieved with fluidized bed boilers and cyclone boilers rather than with pulverized coal-fired or grate-fired boilers, though pulverized boilers are more commonly used [29, 30]. This is because PC boilers and grate-fired boilers are limited by the particle size of the biomass fuel; they are only able to grind (pulverize) the biomass fuel to a fine powder of less than 10-20mm, though they can grind coal particles to 75-300μm. This disparity leads to serious challenges as the co-firing level increases. While this challenge is eliminated through both the fluidized bed boiler and cyclone boiler, the boilers offer other advantages such as increasing the choice and nature of biomass fuel that can be used as well as the possibility of reducing NOx and SOx emissions [9]. Table 3 shows the range of the co-firing levels that can be achieved by these boiler technologies [16, 31, 32]). Usually, the boiler types used for biomass co-firing record little or no loss in total boiler efficiency after adjusting combustion output for the new fuel mixture. Therefore, the efficiency of biomass feedstock combustion to electricity may range from 33-37% when biomass feedstock is co-fired with coal. However, a high percentage of biomass co-firing generally results in a drop in the efficiency and power output of the system. It is estimated that about 150 GW of power (i.e., up to 2.5 times more than the current globally installed biomass power capacity) can be generated if the current installed coal-fired electricity capacity is co-fired with biomass at a rate of 10% [7, 10].

The net electric efficiency of a typical biomass co-firing plant usually ranges from 35-44%. Evidence shows that direct co-firing is usually slightly more efficient (roughly 2% more) than other co-firing technologies due to the conversion losses that occur in the biomass gasifiers and boilers [10]. However, the efficiency of direct co-firing plants decreases when biomass co-firing rates or levels increase due to fouling and slagging and associated corrosion that may occur in the boiler. This is more commonplace in grate-fired (stoker) boilers. Moreover, modern, large, and highly efficient power plants achieve significantly higher biomass conversion efficiency compared to small (less than 10-50 MW) dedicated biomass power plants. The economy of scale of such large power plants contributes to lower energy costs per unit of biomass fuel used [1, 10, 33].

2.4 Technical and logistical issues

To reduce GHG emissions significantly, more biomass should be used. However, there are technical issues related to the unstable supply of biomass [2]. Large amounts of quality biomass can be achieved when co-firing plants are located close to abundant sources of desirable biomass fuel types; when more expensive but reliable, dedicated energy crops are used or there is international biomass trade in cases where the local infrastructure will not support sufficient biomass supply; and when biomass pre-treatment technologies like pelletization, briquetting, and torrefaction are applied to enhance biomass handling and transportation [34].

Biomass co-firing may be affected by the following technical and logistical issues:

1. Fuel, including fuel type, availability, and quality; fuel logistics, required fuel handling and transportation, pre-processing (drying, milling), and storage capacity; the price of the biomass feedstock, compared to the relatively low cost of coal; the size of the biomass particles for suspension burning in pulverized coal boilers, and the possibilities for injecting biomass into the boiler.
2. Boiler, including boiler/combustor capacity and performance, net power output, burner configuration, flame location and different combustion behaviors, and existing boiler limitations; deposition formation (slagging and fouling effects), corrosion and/or erosion and consequently changes in the life-time of equipment, agglomeration, and sintering.
3. Flue gas cleaning operation and performance.
4. Reduction in ash landfill costs and/or income from ash applications.

   [1, 8, 13, 28, 35].

The rest of Section 2.4 will provide a detailed analysis of each of these technical and logistical issues.

2.4.1 Fuel

2.4.1.1 Fuel type

Biomass is a combustible material usually burned to produce heat that can be used to generate motion in vehicles and electricity in power plants [5]. According to Parry et al. [36], biomass is an organic material or a by-product of an organic material. When co-firing biomass with another fuel type, it is necessary to gain sufficient understanding of the fuel properties. The sub-properties of each group of fuel types must be considered as well. Biomass varies drastically from one type and category to another and that properties of coal differ significantly across ranks as well [7].

Generally, biomass can be classified based on its origin and its properties. Based on its origin, biomass can be classified into: a) Primary residues: These include biomass such as wood, straw, cereals, maize, etc., obtained from the by-products of forest products and food crops. b) Secondary residues: These include biomass such as saw and paper mills, food and beverage industries, apricot seed, etc., derived from processing biomass material for industrial and food production. c) Tertiary residues: These include waste and demolition wood, etc., that are derived from other used biomass materials. d) Energy crops [3]. In addition, biomass fuels can also be classified into the following based on their properties: woody biomass; herbaceous biomass; wastes and derivates; and aquatic biomass (kelp, etc.) [37-39]. The major solid biomass materials when considering both origin classification and properties classification are shown in Figure 2.4.

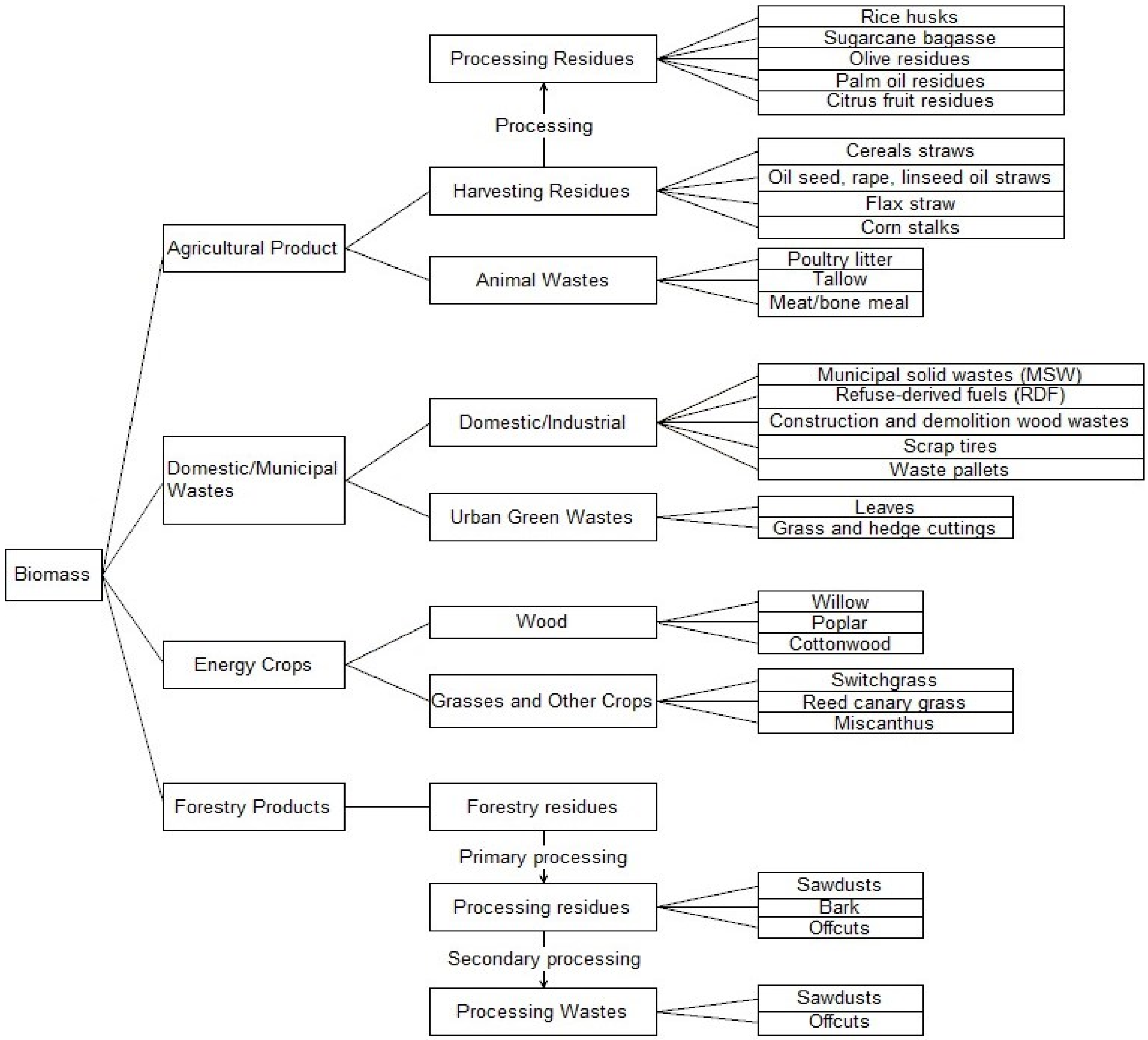


Figure 2.4: Major solid biomass materials of industrial interest on a global scale (adapted from [40]).

Woody biomass is considered to be the most convenient option for co-firing activities. Woody biomass is regarded as a premium biomass fuel because it is naturally low in ash, sulfur, and nitrogen, all of which are highly reactive and volatile entities. Therefore, woody biomass fuels such as forest residues and mill residues like sawdust are the most favorable biomass feedstocks [8]. Both forest and mill residues have been successfully co-fired with coal in many installations in both North America and Europe [19]. Other biomass feedstocks that have been co-fired are agricultural products like straw, switchgrass, corn stover, rice hulls, and olive pits [28]. This review focusses majorly on woody and herbaceous fuels since they meet the central goal of the co-firing technologies discussed here in terms of fuel properties, co-firing technology, and geographical location.

2.4.1.2 Fuel properties

The properties of biomass feedstocks vary widely due to their diverse nature, and biomass fuels differ significantly from both coal and natural gas in terms of physical and chemical properties as well as composition and energy content [41]. For example, coal and natural gas (and other fossil fuels) are not considered biomass although they trace their origins to the remains of dead plant and animal materials. The reason for this is that the carbon on which fossil fuels are based has not been in the established carbon cycle for millions of years. Therefore, the carbon they eventually release during their combustion disrupts the carbon cycle. Some typical elemental compositions of different forms of biomass and coal are shown in Table 2.1, and a comparison of the typical composition of several biomass fuels and coal based on proximate and ultimate analyses is shown in Table 2.2. When compared to these fossil fuels, most biomass fuels contain less carbon, sulfur, and nitrogen and more hydrogen, oxygen, and volatile material; and they have less heating value and lower bulk density [42, 43].

Table 2.1: Typical elemental compositions (%) of different forms of biomass and coal fuels [8]

Fuel	C	H	O	N	S	Si	K	Ca	Cl
Anthracite coal	91-94	2-4	2-5	0.6-1.2	0.6-1.2	2-6	0.1-0.5	0.03-0.2	0.01-0.2
Bituminous coal	83-89	4-6	3-8	1.4-1.6	1.4-1.7	2-3	0.1-0.2	0.1-0.3	0.01-0.13
Wood (clean & dry)	50	6.1	43	0.2	-	0.05	0.1	0.04	-
Switchgrass	48	5.5	43	0.2	-	1.4	0.4	0.2	-

Note: C = Carbon; H = Hydrogen; O = Oxygen; N =Nitrogen; S = Sulfur; Si = Silicon; K = Potassium; Ca = Calcium; Cl = Chlorine.

Table 2.2: Properties of typical biomass fuels compared with coal (adapted from [7, 20, 44]).

	Typical Biomass					Coal	
	Sawdust	Urban wood waste	Switchgrass	Corn stover	White pine	lignite	peat
Proximate Analysis (wt %)							
Fixed carbon	9.34	12.5	12.18	15.36	15.1	23.9	29.4
Volatile matter	55.03	52.56	65.19	69.74	84.5	54.0	68.6
Ash	0.69	4.08	7.63	6.90	0.44	22.0	2.0
Moisture	34.93	30.78	15.00	8.00	38	30	35.8
Ultimate Analysis (wt %)							
Carbon	32.06	33.22	39.68	42.00	52.5	58.8	56.1
Hydrogen	3.86	3.84	4.95	5.06	6.32	4.17	5.67
Oxygen	28.19	27.04	31.93	36.52	40.6	13.6	35.2
Nitrogen	0.26	1.00	0.65	0.83	0.10	0.91	0.81
Sulfur	0.01	0.07	0.16	0.09	<0.05	0.50	0.23
Ash	0.69	3.99	7.63	6.90	0.44	22.0	2.0
Moisture	34.93	30.84	15.00	8.00	38	30	35.8
HHV—as received (Btu/lb)	5431	5788	6601	7000	8856	9372	9200
Volatile/fixed carbon ratio	5.89	4.20	5.35	4.54	5.60	2.26	2.33

Biomass fuels tend to behave similarly to peat, a low-rank coal, and lignite. They have much less carbon and a higher fraction of hydrogen and oxygen compared to both peat and lignite. This leaves them with much less energy density compared to what both peat and lignite possess. A typical biomass has only about one-tenth of the overall fuel density of coal [5]. Therefore, a 10% biomass co-firing level will be very favorable in terms of magnitude since the volume of the coal involved will be comparable to the flow rate of the biomass [9]. However, an examination of the co-firing relationship shows that logistics and technologies associated with the shipping, storage, and handling of biomass will be complex compared to firing only these fossil fuels in a boiler due to the low heat contribution of biomass. More deposit formation occurs with biomass combustion than with either coal or natural gas combustion. Such deposits may be hard to remove, even requiring additional cleaning efforts. The emissions of particulate matter that occur during biomass combustion are much higher than those of natural gas or gasified coal [9, 34].

Both coal and biomass have similar ignition processes, although biomass fuels may experience more homogenous and flaming combustion due to higher volatile materials (VM). The presence of higher VM in the biomass fuels may affect the optimum sizing and design of the combustion chamber and other properties like the ideal flow rate and location of combustion air. Coal combustion equipment can handle solid biomass feedstock quite easily; the same applies to natural gas equipment and gaseous biomass, although these fuels have different chemical compositions [8, 9, 34].

While agricultural and herbaceous products (e.g., corn stover and switchgrass) have high ash and volatile contents, the same is not true for woody biomass (e.g., sawdust and urban wood waste) (see Table 2.2). Also, the heating values of woody biomass and switchgrass are substantially higher than those of agricultural residues such as rice hulls, cotton gin trash, vineyard prunings, etc. On the other hand, the moisture concentration of woody biomass depends jointly on the living and growing processes and on the manufacturing process imposed on the wood. The moisture content in sawdust is usually a result of the machinery used during processing. Compared to most other biomass, the moisture content in herbaceous fuels such as switchgrass is generally lower. However, straw has a significantly high level of volatile matter such as chlorine, and alkaline, but ecological factors such as soil types and weather conditions influence the ash and nitrogen content of the fuel [7].

The heating value of biomass is compromised by its high proportion of oxygen and hydrogen to carbon atoms. This is because breaking the C–H and C–O bonds of biomass releases less energy compared to the predominately C=C bonds found in coal. Also, biomass has a much higher reactivity than coal due to its higher oxygen content, and this usually results in a lower activation energy barrier to devolatilization and oxidation [16, 45].

Several other issues associated with combusting biomass in a coal-fired boiler, such as low bulk density, high moisture content, ash deposition and fouling problems on hot surfaces, hydrophilic nature, etc., can be mitigated by blending higher ratios of torrefied biomass with fossil coal than with raw biomass. However, torrefied biomass has coal-like characteristics that may lead to drops in energy efficiency and fluctuations in boiler load [46, 47].

2.4.1.3 Fuel cost

The price of biomass is strongly dependent on the following: a) the feedstock's origin, type, and composition; b) the cost of handling, preparing, and transporting the feedstock; and c) the plant's geographic location [48].

The transportation cost over long distances is influenced strongly by the energy density or the heating value of the biomass feedstock. Biomass pre-treatment technologies such as pelletization, briquetting, and torrefaction can be effectively used to increase the heat value per volume of biomass, thereby reducing the overall transportation costs. However, such technologies have extra costs, and the cost of operating a large-scale biomass co-firing plant could exceed the cost of operating an equivalent coal-fired plant, depending on the cost of coal. However, a favorable CO_2 emission allowance price can take care of this price differential [8, 9].

2.4.1.4 Feedstock size and nature

The size and nature of the biomass feedstock should be taken into consideration when designing a co-firing operation. This is because the amount of biomass that can be milled with coal prior to co-firing is heavily dependent on the physical nature and grindability of the biomass feedstock. For example, the fibrous nature of some biomass prevents it from being processed in a pulverizer boiler-based direct co-firing system. This challenge may be overcome by milling and delivering the biomass to the boiler through an independent line [1, 34].

2.4.2 Boiler type

Most biomass co-firing projects usually use existing coal- or gas-fired combustion technologies since they do not necessarily require a new, dedicated technology to function. With minimal modifications, a coal- or NG-designed power plant can be suitable for blending biomass feedstock with either coal or NG. For example, typical coal combustion technologies that can easily be effectively used for biomass co-firing include a fluidized bed combustion boiler (FBC), a pulverized coal combustion boiler (PCC), a packed-bed combustion boiler, and a cyclone boiler [7, 28, 49]. A comparison of biomass-coal co-firing in different combustion systems is shown in Table 2.3.

Table 2.3: Typical features of common coal combustion technologies in biomass co-firing systems (adapted from [16, 31, 32]).

Co-combustion system	Operation requirements	Co-firing percentage (% heat)	Technical features
Pulverized combustion	Fuel type: coal, sawdust, and fine shavings; particle size: <10-20mm; moisture content: <20wt%	1-40%	Can decrease NOx significantly; limited by biomass particle size and moisture content.
Fluidized-bed combustion	Fuel type: various fuels, better suited for woody biomass than for herbaceous biomaterial; particle size: <80 mm (BFB), < 40 mm (CFB); temperature: <900°C	CFB: 60-95.3% BFB: 80%	The fluidized bed combustion system is the most suitable boiler for biomass co-firing. The soot formation is problematic, especially in CFB.
Packed-bed combustion	Fuel type: wide range of fuels, including coal, peat, straw and woody residues; particle size: fairly large pieces < 30mm)	3-70%	Not suitable for direct co-firing, although can be used for parallel or in-direct co-firing.
Cyclone combustion	Ash content: > 6%; volatiles: >15%; except in a dried form, moisture content: > 20%.	10–15% by heat input or 20-30% by mass	Suitable for co-firing since minimal modifications are needed for feeding and mixing the biomass and the coal

A pulverized coal combustion boiler (PCC) is a popular technology used in converting energy from coal and some other fossil fuels to heat energy, usually in a controlled amount of air, for subsequent use in a boiler. The fuel is finely ground before it enters the combustor. When a PCC reactor is used for a co-firing system, some studies showed that it can reduce NOx emissions significantly. However, this technology requires high fuel quality since the maximum fuel particle size should be 10-20 mm, and the moisture content should be no more than 20 wt%. This lowers the application of this combustion system in co-firing projects [9, 31].

Pulverized boilers are not affected by deposition formation problems like slagging, fouling, and corrosion from high concentrations of potassium and chlorine in biomass compared to fluidized or grate-fired boilers. The risk of slagging, fouling, erosion, and corrosion occurring in biomass co-firing can be countered by choosing the right co-firing technologies and feedstock. Also, washing and leaching biomass feedstock in acid, water, or ammonia reduces the feedstock's alkali and ash contents, thereby reducing the possibility of deposition formation and corrosion. This is more important in herbaceous biomass since it is richer in alkali compounds. Washing and leaching biomass, which reduce the amount of alkali compounds in the biomass fuel, can reduce plant maintenance costs [10].

The fluidized bed combustion (FBC) is designed to operate at very high temperatures ranging from 800–900°C, which lowers the NOx and SOx emissions compared to other combustion technologies [14]. A fluidized bed combustor is the most suitable reactor for co-firing. The fuel types that can be used in the FBC boiler system are low-grade fuels like peat, woody biomass like forest residues, wood wastes, industrial wastes like sawdust, and municipal solid wastes (MSW) [50]. A fluidized bed boiler operating on direct co-firing technology is less sensitive to any changes in the overall efficiency as the biomass level increases, although this may require a more sophisticated boiler and fuel handling control system. Fluidized bed boilers are also more capable of handling biomass with higher moisture content (10-50% instead of <25%) and larger particle sizes (<72 mm instead of <6 mm) than pulverized boilers [10].

The fuel-particle mix is suspended by an upward flow of combustion air within the bed, which acquires more fluid-like properties as velocities increase. While the bubble fluidized bed combustion boilers (BFBC) usually operate at a lower air velocity when compared to the transport velocity of the fuel particles, the circulating fluidized combustion boilers (CFBC) are designed to have a significantly high gas velocity that entrains the fuel and bed particles in the gas flow exiting the combustion chamber, from where these particles will be separated in a beam separator or cyclone and then recirculated back to the system [49, 50].

The packed-bed combustion system uses a stoker or grate combustion boiler and is designed to allow the fuel to be fed onto a moving grate while a controlled amount of air is steadily blown onto the fuel. During operation, the fuel particles are steadily moved to the front of the boiler from the back as the larger particles are burned directly on the grate, while the smaller fuel particles burn in the air adjoining the grate. The system can fire different types fuels, such as peat, coal, or biomass feedstocks like straw and woody residues in several sizes (up to 3 cm), which makes it suitable for biomass co-firing. Some researchers have paid attention to the direct co-firing in a packed-bed combustion system [51]. However, the system has a few technical flaws such as lower thermal efficiencies, the tendency of ash to sinter on the furnace, the need to feed the fuel into the combustor in a high rank, coarse particle form, and the cost of cleaning out ash particles from the flue gas, all of which make it less desirable for co-firing biomass with coal [3, 28, 51]. Moreover, one big technical difficulty of the packed-bed combustion system is that it is not suitable for direct co-firing, although it can be applied in parallel or in-direct co-firing technologies. Finally, although the packed-bed combustion boiler produces high electrical power, and its operational and maintenance costs are low, its low thermal efficiency compared with the FBC and PCC limits the extensive application of this system.

The cyclone boiler system is designed with large, water-cooled burners that are placed in a horizontal position, and its external furnace can reach combustion temperatures in the range of 1650°C and 2000°C. The boiler allows the fuel's mineral matter to form a slag capturing the over-sized particles and to combust the fine and volatile fuel particles in suspension. The intense heat that radiates from this design burns up the layer of slag formed [49]. The fuels that can be burned in a cyclone boiler include a variety of coal and biomass feedstocks, and they are best when crushed. This technology is suitable for biomass co-firing, though a few modifications may be necessary to enhance the feeding and mixing of the biomass and the coal. For optimum performance, certain requirements are specified for the fuels that can be fired on a cyclone boiler. Based on these specifications, the ash content must exceed 6%, volatiles are expected to be greater than 15% of the fuel, and, except in a dried form, the moisture content of the fuel must not be less than 20%. These requirements may be a bit challenging for some pure biomass types [28, 32].

Except with direct co-firing in existing combustion systems as discussed before, the gasification technology is meant to be used in an indirect co-firing system. Fixed bed gasifiers are generally used in small-scale applications involving fuels with specific physical characteristics. Generally, their applications are limited to less than 10-15 MWe power capacity. The fluidized bed gasification has been identified as the most effective gasification technology for indirect biomass co-firing. The technology uses a wide variety of biomass fuels as well as waste-derived fuels that differ in terms of their heating value, density, and other characteristics. Both bubbling fluidized bed (BFB) gasification and circulating fluidized bed (CFB) gasification can be applied. One major example of commercial biomass gasification systems is in the Kymijärvi power plant in Lahti, Finland. The arrangement is illustrated in Figure 2.5. The system is based on a CFB gasifier and uses coal and natural gas, as well as biomass and waste-derived fuel. The burners are equipped with flue gas circulation and staged combustion to control NOx emissions. However, since the sulfur content of the coal is relatively small (0.3 to 0.4 %), the system does not have a sulfur removal system [10, 24].

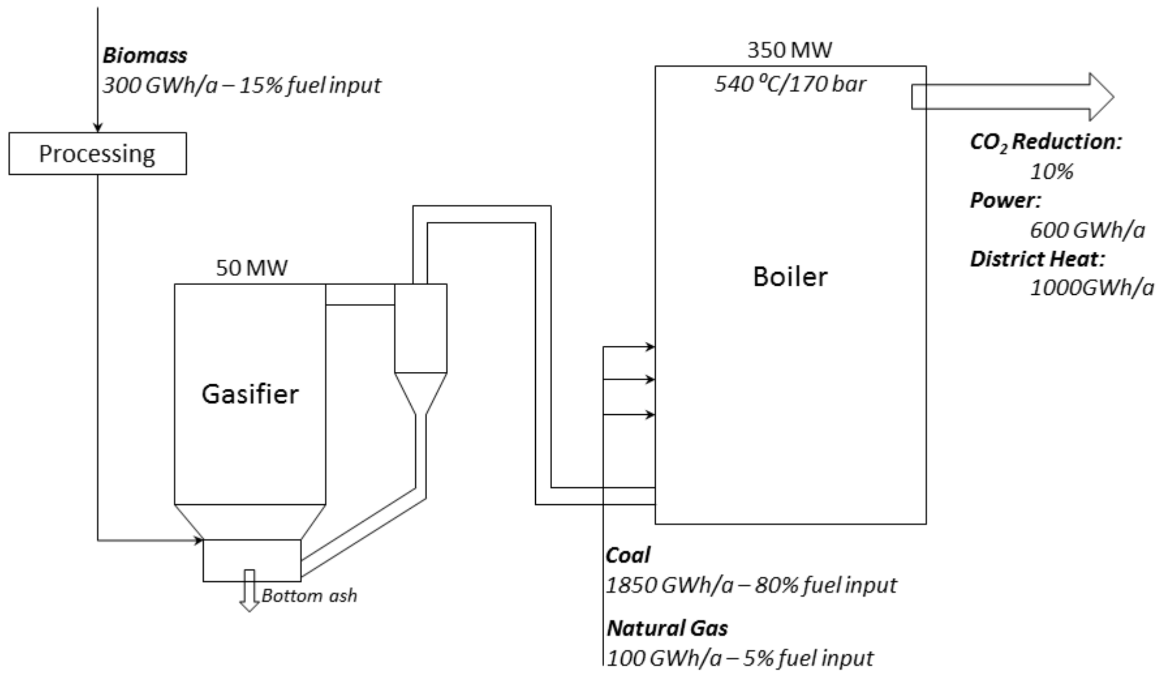


Figure 2.5: Biomass gasification systems used for indirect co-firing in Kymijärvi power plant, Finland (adapted from [24]).

Other major issues in biomass co-firing are the corrosion of boiler surfaces and deposition formations due to the reaction of chlorine with alkali metals such as potassium and sodium. This is commonplace when herbaceous biomass is used since it is rich in chlorine and alkali. Tillman et al. [41] write that woody biomass is less likely to contribute to corrosion and deposition since it is lower in alkaline and chlorine.

2.5 Regulatory and environmental considerations

Since the properties of biomass fuels vary significantly with those of both coal and natural gas, blending biomass with any of these fuels offers many environmental and economic benefits [1]. According to Tillman et al. [7], biomass co-firing was originally put forward as a useful tool for utility companies to meet the following environmental goals: (1) help reduce carbon dioxide emissions from fossil fuels in line with the voluntary global climate challenge program; (2) help reduce other airborne emissions like SOx, NOx, and trace metals.

Biomass co-firing can contribute significantly to the reduction of SOx and NOx emissions given that most biomass contains less sulfur and nitrogen than coal [14, 41]. However, the net reduction of CO_2 emissions and other pollutants is strongly influenced by the origin and supply chain of the biomass feedstock [10].

2.5.1 CO_2 emissions

Compared to conventional power generation (i.e., solely coal- or gas-fired plants), biomass co-firing has a huge potential to reduce GHG emissions and to produce power at a relatively low initial cost. Very few net GHG emissions are released from co-fired power plants because the net CO_2 from the combustion of biomass is reduced to almost zero when the effects of photosynthesis are taken into account. Biomass co-firing can further yield negative GHG emissions (i.e., net removal of CO_2 from the atmosphere) if used in combination with carbon capture and storage (CCS) technologies such as biogenic carbon sequestration. This technology is more financially attractive than building dedicated biomass-fired plants since the incremental investment costs for retrofitting or building new co-fired power plants are much lower than building a dedicated biomass-fired plant. However, co-firing biomass is generally more expensive than generating electricity solely through coal or natural gas. Since current market prices of natural gas and coal are relatively lower than those of biomass, utility companies may be reluctant to favor biomass co-firing over the other power generation options [9].

2.5.2 NOx and SOx emissions

Coal-fired power plants emit flue gases that contain much more SOx and NOx than are found in the gases emitted from a co-fired plant. This is because coal contains more sulfur and nitrogen than biomass does. When SOx and NOx are released into the atmosphere, depending on their scale, they may create air pollution such as acid rain or deplete the ozone. Biomass co-firing could reduce the level of SOx and NOx emissions, thereby significantly decreasing air pollutants [5, 52].

However, the use of biomass fuels may pose some operational challenges. For example, the way the biomass is handled and transported differs from how the main fuel is handled, and dealing with slagging, corrosion, and fouling associated with the ash content from the biomass may lead to higher costs of maintaining and replacing the plant equipment and parts.

Compared to the biomass derived from agricultural residues, biomass fuels derived from forest residues tend to produce less NOx, Sox, and particulate emissions during combustion, because they contain less nitrogen, sulfur, and ash. With respect to coal, lignite offers some environmental advantages, such as relatively low sulfur content, although it is not comparable to biomass. Some of the SOx produced during the combustion in the lignite power plant can be absorbed by the higher ash contents of CaO and MgO before it is emitted, forming $CaSO_4$ and $MgSO_4$ [44, 53].

Generally, NOx is formed during combustion in one of three different reactions, thermal NOx, prompt NOx, and fuel NOx. Thermal NOx is formed from nitrogen in the air at high temperatures, while prompt NOx is formed in the presence of hydrocarbons. Lastly, fuel NOx forms as a result of nitrogen-containing fuels. In a biomass co-firing operation, the main sources of NOx are thermal NO and fuel NO from coal while NOx originating from biomass fuel has little effect. The thermal NOx is usually formed on the highest level of coal burners in the boiler while low NOx is formed in the lower levels. The level of NOx emissions reduces steadily as the percentage of wood chips co-fired with coal increases [44, 54].

Badour and Gilbert et al. [44] studied the emissions content from co-firing a Canadian lignite coal with a Canadian peat and a woody biomass in a BFBC boiler. The NOx and SO_2 emissions per energy input obtained when peat pellets or pine pellets are blended and fired together with lignite at 0%, 20%, 50%, 80%, and 100% on a thermal basis are shown in Figure 2.6. Co-firing lignite and white pine pellets decreases both NOx and SO_2 emissions. As with the influence of biomass fuels on NOx emissions, SOx emission levels reduce gradually as the amount of biomass fuel co-fired with coal increases [55].

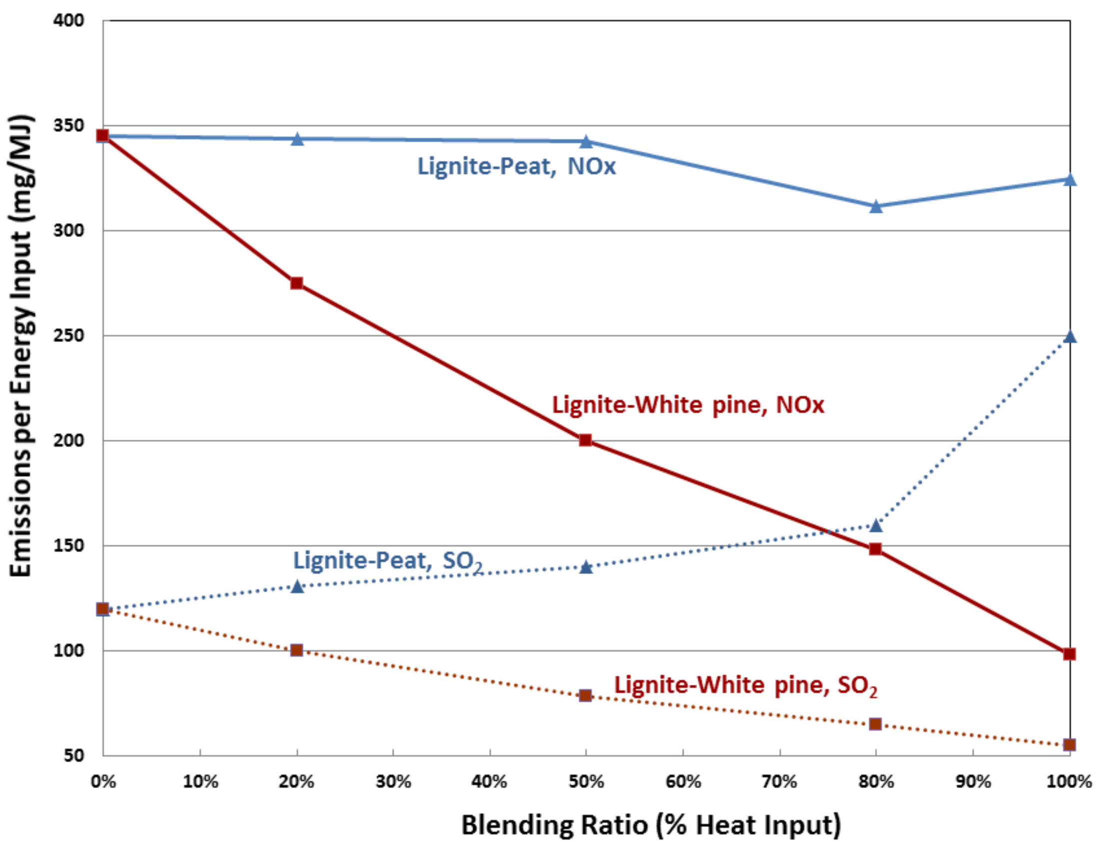


Figure 2.6: The effects of lignite-peat co-firing and lignite-white pine co-firing on NOx and SO2 emissions (adapted from [44]).

2.5.3 Ash

One of the issues associated with biomass co-firing is how to deal with the ash left over after the combustion of the fuels. This is because using the ash produced from combustion may be necessary for environmental reasons as well as for the plant performance [8]. Generally, the co-firing technology employed determines the nature of the ash left at the end of the combustion process. For example, a mixture of biomass and coal ash is obtained from a direct biomass/coal co-firing operation, while separate biomass and coal ashes can be obtained after an indirect or parallel biomass co-firing operation. Also, the ash contents of different biomass and coal feedstocks differ significantly in composition (see Table 2.2). For example, herbaceous feedstocks have higher ash contents than woody biomass feedstocks since they take in more nutrients during growth, while the bark content of woody biomass feedstocks have a higher ash content and level of mineral impurities (such as sand and soil) than the rest of the wood [9].

In many parts of the world, these ashes are sold to target buyers who use them for different purposes. For example, fly ash obtained from the combustion of biomass is used as raw material in the production of concrete used in the construction industry. The ash can also be used for fertilizer production since it is rich in Mg and Ca, though this use may be hindered by the lack of nitrogen and soluble phosphorous in the ash. Also, fly ash from the gasification of biomass in the fluidized bed can be reused as fuel for power generation since it has a high energy content rich in unburned carbon. Research shows that this is the most favorable choice economically. Furthermore, different forms of coal ash like boiler slag, fly ash, and bottom ash are used in the construction industry and in underground mining, as well as the restoration of open cast mines, pits, and quarries [1].

2.6 Opportunities for North America

The carbon tax, also known as the carbon abatement cost, is a form of pricing on GHG emissions that requires individual emitters such as energy companies and other consumers to pay a specified fee, charge, or tax for every tonne of GHG that they release into the atmosphere [68].The logic behind this policy is that mandating emitters to pay the carbon tax motivates them to weigh the cost of emissions control against the cost of emitting and paying the tax. Eventually emitters will likely adopt cheaper emissions-reductions programs rather than pay the tax, while the programs that are more expensive the emitters may not implement. Those who favor this cost-effective approach will help equalize the marginal cost of abatement [69, 70].

In order to achieve greater success, especially with respect to the overall emissions limit, it is necessary that the carbon taxes are uniform and sensitive to changes in the system. This means that the emission tax level should be adjusted to: (1) meet the emissions standard that has been jointly approved by most countries in the world; and (2) continually correspond to changing external factors like inflation, technological progress, and new emissions sources [33, 56].

Generally, carbon taxes place a direct price on the tonne of GHG emitted through man-made activities such as the production and use of energy especially from hydrocarbons. For example, there are up to 150 taxes levied on energy products and 125 taxes on motor vehicles, as well as some direct taxation of CO_2 emissions across some OECD (Organization for Economic Co-operation and Development) countries such as Australia and New Zealand and the Nordic countries [29]. There is no existing federal emission tax levied in either Canada or the United States of America. However, the tax is found in various forms in several provinces and states. For example, the Government of Alberta presently levies a tax of $15 per tonne of CO_2 in Alberta. Different forms of carbon taxes are also found in Quebec, Maryland, California, and Colorado [72, 73].

As mentioned above, carbon taxes offer a potentially cost-effective tool for reducing overall GHG emissions. A carbon tax gives energy companies a real incentive to reduce a significant portion of their overall GHG emissions. Biomass co-firing can be viewed as a useful emissions reduction tool in the power generation industry since it can enable utility companies that generate electricity from coal/NG to reduce their overall GHG emissions significantly by substituting a portion of their base fuel, if it is coal or natural gas, with a "carbon-free" fuel such as biomass [11].

2.7 Possibility of increasing the scale of biomass co-firing

Co-firing biomass with coal/NG is advantageous especially to utility companies and customers not only because of cost savings but also because this technology protects the environment by reducing GHGs [5]. Co-firing also creates an opportunity in industries such as forestry, agriculture, construction, manufacturing, food processing, and transportation to better manage large quantities of combustible agricultural and wood wastes [1]. However, several technical barriers associated with co-firing biomass and fossil fuels have been identified, such as the availability of quality biomass fuels, limits to the percentage of biomass that can be fired under given configurations, and issues associated with boiler performance, deposition formation, corrosion, etc. [10]. Several solutions have been developed to address these challenges, including pretreating the biomass fuels in order to reduce their high moisture content, thereby improving their transportation and storage, and government policies in some countries that require utility companies to sell fly ash (a product of the combustion process) as an active raw material in the making of Portland cement and concrete. It is believed that the second requirement may encourage more utility companies to adopt co-firing since they will be able to sell the ash [34].

2.7.1 Technical issues

2.7.1.1 Pretreatment

Several issues associated with the handling and combusting of biomass in a boiler can be improved significantly through pretreatment methods such as pelletization or torrefaction. Biomass pretreatment reduces the overall cost of handling, storage, and transportation and improves transport and storage characteristics. Since these technologies enhance homogeneity in terms of fuel use, they minimize the investment of plant infrastructure and also reduce the overall operation and maintenance costs [57].

According to IEA-ETSAP and IRENA [10], pelletization is a technique that improves the energy density of fuel. The compact cylindrical shape of a biomass pellet enables it to repel moisture, thereby solving the low bulk density problems of most biomass as well as the corresponding logistics and storage issues associated with it. Both woody and herbaceous biomass can be pelletized, and evidence shows that pellets are the most suitable biomass-derived feedstock for biomass co-firing operations [9, 14].

Torrefaction is the thermo-chemical treatment of biomass in the absence of oxygen at very high temperatures of up to 200-300°C for nearly an hour. The result is the partial decomposition of the biomass, thus creating a charcoal-like, high-energy dense substance with a lower moisture content and smaller particle size [8]. Bergman [58] described torrefaction as a pre-treatment technology that positively increases the possibility of using biomass in co-firing, thereby enabling biomass to compete directly with fossil fuels and provide an option for direct co-firing with a significant amount of torrefied biomass with minimal operating challenges. The co-firing system with torrefaction is shown in Figure 2.7. Torrefied biomass has properties that are reasonably similar to coal, thereby making it more favorable for combustion and gasification purposes [58, 59].

Pelletization and torrefaction complement each other in enhancing biomass co-firing [60]. These pretreatment technologies can contribute actively in controlling several issues associated with biomass co-firing such as the storage and feeding characteristics of the biomass and achieving a desirable handling size. Since torrefaction makes biomass properties more compatible with those of coal, it increases the possibility of substituting more coal with biomass in the combustor [61]. However, torrefied biomass has a low volumetric energy density, which may limit its use. It is recommended that biomass be pelletized in order to improve the fuel's volumetric energy density. Also, the torrefaction technology involves significant investment, which may increase the overall cost of generating electricity through biomass co-firing. Torrefaction also requires a large amount of biomass feedstock to compensate for the huge investment. Pyrolysis of biomass fuels can be carried out within a temperature range of 300-650^{o}C compared to 200-300^{o}C for torrefaction.

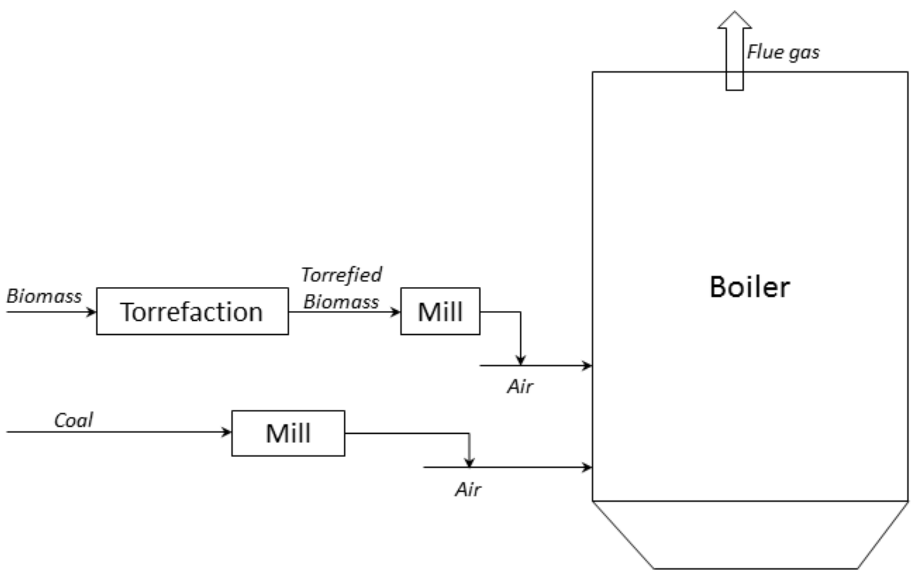


Figure 2.7: Co-firing systems with torrefaction (adapted from [62]).

2.7.1.2 Advanced combustion technology

Except for biomass pretreatment, some advanced combustion technologies such as the volumetric combustion of biomass can enlarge the fuel diversity during combustion followed by enlarging biomass co-firing substitution ratios. The volumetric combustion concept is an air staging technique that leads to the thorough mixing of the gas species within the combustion chamber of the boiler based on the internal flue gas recirculation. The technology enables the secondary air to increase (by over 30%) without leading to instability or incomplete combustion problems [47]. A large amount of secondary air is injected downward with an angle of inclination, delivering some of the flue gases to the primary combustion zone right from the secondary combustion zone. Due to the level of thoroughness of the internal recirculation of the flue gases, there is a uniform distribution of gas species and temperature inside the furnace that eventually results in combustion reactions through the whole furnace chamber with a low maximum flame temperature [47]. Accordingly, volumetric combustion can be characterized as a stable biomass combustion technology, one that improves the chance of biomass co-firing in coal-fired power plants and that leads to significant reductions of both the thermal NOx and fuel NOx.

2.7.2 Policies

Biomass co-firing is usually more expensive than exclusively coal-firing because coal costs less than biomass. Different levels of government in both Canada and the U.S., as well as in several other countries, presently have various policy incentives and obligatory regulations aimed at increasing the overall contribution of renewable energy to their electricity sectors. It is important to note that the existence of such policies enhance the competitiveness of biomass co-firing projects. For example, by making coal-based energy more expensive through measures like carbon pricing in the form of carbon taxation or emission cap-and-trade schemes, governments make biomass co-firing more attractive to utility companies [10].

Other measures that may significantly favor the development and adoption of biomass co-firing are different forms of government support and aid aimed at further developing the existing biomass supply infrastructure, the removal of subsidies associated with fossil fuels like coal, and the provision of sufficient funding for biomass co-firing research and development projects. Establishing mandatory quota obligation schemes for biomass in co-firing operations, as found in the Renewable Energy Portfolio Standards in a number of the United States, can also enhance co-firing technology and improve its attractiveness to utilities [10, 34].

Below is a summary of regulatory and environmental policies and measures that can enhance biomass co-firing:

i. Carbon dioxide emission-reduction targets and tax incentives
ii. Environmental taxes and credits and renewable energy certificates (RECs)
iii. Permit requirements and specific site restrictions.
iv. Benefits from reduced sulfur dioxide and nitrogen oxides emissions
v. Policies favoring the disposal of biomass wastes
vi. Policies favoring the use of the ash
vii. Removal of fossil fuel subsidies
viii. Dedicated R&D funding for co-firing and support to biomass supply and co-firing infrastructure
ix. Establishing the mandatory use of biomass co-firing through quota obligation schemes [34].

2.8 Co-firing experience in North America

2.8.1 Biomass status in North America

North and Central America have an estimated forest area of 549 (10^6) ha representing nearly 26% of their land areas. Cultivated plantations occupy less than 1% of these forest resources, while the remaining forests represent the abundant natural forest of the subcontinent. Based on the data represented in Table 2.4, the average area of forest and wooded land per inhabitant (i.e., the forest area per capita) of 1.1ha indicates the potential contribution of wood to the energy supply of the countries involved. This is particularly substantial in some sub-regions such as the northwest part of North America (including Washington State and British Columbia) that have abundant forest resources. Generally, the possibilities of producing fuels derived from forest biomass vary significantly between regions across the continent [63-65].

The total above-ground biomass in forests in both North and Central America is 52 (10^9) tonnes, while its average above-ground woody biomass is 95 tonnes/ha [63, 65]. This is a representation of the total above-ground wood volume (m^3) and woody biomass (tonnes) in forest within the continent.

Table 2.4: Forest resources, area (ha), above-ground biomass volume, and biomass (m^3 and tonne) (adapted from [63]).

	Land area (ha) (10^6)	**Forest area (ha) (10^6)**	**Ratio of forest area (%)**	**Plantations (ha) (10^6)**	**Forest area per capita (ha)**	**Volume (m^3/ha)**	**Volume (m^3) (10^9)**	**Woody biomass (tonne/ha)**	**Woody biomass (tonne) (10^9)**
Africa	2978	649	21.8	8	0.8	72	46	109	70
Asia	3084	547	17.8	115	0.2	63	34	82	44
Europe	2259	1039	46.0	32	1.4	112	116	59	61
North and Central America	2136	549	25.7	2	1.1	123	67	95	52
Oceania	849	197	23.3	3	6.6	55	10	64	12
South America	1754	885	50.5	10	2.6	125	110	203	179
World	13063	3869	29.6	171	0.6	100	386	109	421

2.8.2 Existing co-firing plants in North America

Although there are many biomass co-firing operations in the United States, many are still at demonstration levels with different boiler types. Utility companies in the U.S. are still reluctant to adopt co-firing at a commercial level, in part due to a lack of favourable incentives. However, due to new environmental policies and regulations, there is a recent interest in power generation and co-generation from biomass, waste, and recovered fuels within the power sector [17].

In Canada, biomass co-firing technology has developed quickly during the last ten years through efforts to increase biomass use in the country's electric utility sector. During this time various biomass fuel and coal co-firing projects have been evaluated and demonstrated successfully, especially in Ontario. IEA Bioenergy Task 32 [66] lists that as of early 2013, 47 biomass co-firing installations had been established in North America at either demonstration or commercial levels. So far, only 7 of these are in Canada (see Table 2.5). They are all based in Ontario and are owned and operated by the Ontario Power Generation (OPG). However, none of these 7 facilities is operating yet as they are being transformed to either solely natural gas-fired or biomass-fired plants [67].

Table 2.5: Defunct biomass co-firing installations in Canada (adapted from [66]).

Location	Plant name	Owner	Co-firing type	Boiler	Burner configuration	Output (MWe)	Primary fuel	Co-fired fuel(s)
Ontario	Atikokan	OPG	Direct	PF	Front wall	227	Lignite	Wood pellets
Ontario	Lambton 1	OPG	Direct	PF	Tangential	500	Pulverized coal	Dry distillers and grain
Ontario	Nanticoke 4	OPG	Direct	PF	Opposed wall	500	Blended coal	Agricultural residues
Ontario	Nanticoke 6	OPG	Direct	PF	Opposed wall	500	Blended coal	Agricultural residues and wood pellets
Ontario	Nanticoke X	OPG	Direct	PF	Opposed wall	500	Blended coal	Wood pellets
Ontario	Thunder Bay 2	OPG	Blended on coal pile	PF	Tangential	155	Lignite	Wood pellets
Ontario	Thunder Bay 3	OPG	Direct	PF	Tangential	155	Lignite	Grain screenings

Since 2003, coal-fired power generation capacity in Ontario has been reduced by 40% as part of the province’s drive to reduce the air pollution that results from this process as well as the negative perception of coal firing. It is expected that changes will lead to the reduction of nearly 30 megatonnes of carbon dioxide emissions in Ontario, which is equivalent to taking almost 7 million cars off the roads. The utility company directly involved, Ontario Power Generation, is aggressively seeking to add more renewable energy sources such as biomass and wind power, as well as natural gas-fired plants. Similar policies have been sought in some other provinces, such as Nova Scotia, but that province’s Renewable Electricity Plan, established in 2010, is being hindered by the need to protect the sustainability of the province's forests [67, 68].

Recently many utility companies in the United States and Canada have indicated their intentions to begin biomass co-firing, especially with coal, using different biomass fuel types, co-firing technologies, and levels (see Table 2.6). The goal is to achieve higher levels of co-firing in an existing co-firing system or to repower an entire coal plant to run on biomass [64]. The co-firing options used by these utility companies are to: a) co-fire at low biomass rates with little equipment modification; b) co-fire at higher biomass rates with equipment upgrades; c) convert/repower individual coal burners to be fired with biomass; d) convert/repower entire coal plants to be fired with biomass; and e) co-fire with torrefied wood [69].

Table 2.6: Summary of recent co-firing activities (coal plant conversions and repowering) in North America (adapted from [70]).

Location	Plant name	Owner	Co-fired fuel(s)	Description
Bakersfield, California	Mount Poso Cogeneration Plant	Red Hawk Energy	Agricultural and residential waste	Expected conversion date is September 2010
Boardman, Oregon	Boardman Plant	Portland General Electric	Torrefied wood or other biomass	Plan to operate coal plant until 2020, then close.
Portsmouth, New Hampshire	Schiller Station	Public Service Co. of NH	Wood	In operation since December 2006; burns approx. 400,000 tons/year in fluidized bed boiler
Cassville, Wisconsin	E.J. Stoneman	DTE Energy	Wood	Plan to convert a 50 MW-coal plant entirely to wood
Hawaii	Hu Honua Station	Hu Honua Bioenergy, LLC	Agricultural residues	24-MW facility burning local wood and agricultural wastes
Ashland, Wisconsin	Bay Front Station	Xcel Energy	Wood waste from forest harvesting	After repowering, will burn biomass in all three boilers
Charter St. Heating Plant	Madison, Wisconsin	University of Wisconsin	Various biomass fuels	Refire coal boilers with biomass or natural gas; install a new boiler to burn 100% biomass
Mitchell Steam Generating Plant	Albany	Southern Company	Woody biomass	Plan to convert 163 MW coal plant to biomass
Shadyside, Ohio	R.E. Burger Plant	First Energy Corp. (Ohio Edison)	Variety of biomass fuels	Plan to repower two coal units to biomass (up to 312 MW of total biomass energy)
Ontario, Canada	Lambton Station	OPG	Agricultural residues and wood pellets	Though the plant is no longer operational, some units will be operated by biomass in the future
Ontario, Canada	Nanticoke Station	OPG	Agricultural residues and wood pellets	Though the plant is no longer operational, some units will be operated by biomass in the future
Ontario, Canada	Atikokan Station	OPG	Agricultural residues and wood pellets	100% biomass-fired since 2014

2.8.3 Comparative assessment of co-firing in North America and around the world

As mentioned earlier, significant biomass co-firing projects have been established in many parts of the world, both at demonstration and commercial levels, especially in the past decade. Presently, there are over 150 biomass co-firing installations in the world, with roughly two-thirds of them in Europe. The rest are based mostly in North America and Australia [66]. More progress in terms of use and results has been recorded among European utility companies, especially in countries like the Netherlands, Denmark, Finland, and the United Kingdom, than in North America. For example, biomass and coal have been co-fired in many boiler types in the Netherlands for the past ten years [8]. Incentives and favorable environmental policies and regulations are the major factors encouraging the recent interest in power generation and co-generation from biomass energy sources especially in most European countries [8]. Despite the remarkable commercial success of biomass co-firing in many European countries, most of the biomass co-firing in North America is still limited to demonstration levels. Based on the research carried out, the authors attribute this slow progress to the absence of appropriate incentives and regulatory policies to make the technology better able to compete adequately with conventional power generation technologies. At present, coal, natural gas, and nuclear power generation systems are viewed by most stakeholders in the North American power generation industry to offer better economic, environmental, and technological benefits than biomass co-firing. Moreover, the slow adoption is believed to be influenced by the challenges associated with guaranteeing a stable and cheap supply of biomass to ensure the continuous operation of the co-firing system. Therefore, an improved and optimized biomass delivery system can contribute to improving the co-firing efficiency significantly.

2.9 The future of biomass co-firing

Biomass is considered to be an unreliable energy source due to the challenges posed by its unstable supply [33]. In recent years, many efforts have been made in different continents to cultivate biomass crops for energy purposes in order to improve the reliability of this source of energy. Such efforts are backed up by advanced research carried out in many parts of the world to develop more efficient biomass conversion technologies [34].

The investment required to adapt or retrofit an existing power plant to co-fire a biomass feedstock is generally low compared to the cost of building a new one or building a dedicated biomass power plant. Biomass co-firing even offers higher overall environmental and economic value when used to produce useful heat in addition to power in combined heat and power plants (CHP) in industrial facilities or for district heating networks [71, 72].

In addition to reducing GHG emissions, biomass co-firing enables highly efficient power generation in modern, large power plants. This is because the total energy efficiency achieved in co-fired plants is usually much higher than that of dedicated biomass power plants. This may be further improved if biomass co-firing takes place in combined heat and power (CHP) plants [7, 20].

A sustainable biomass co-firing project is highly dependent on a stable and cheap flow of biomass. In other words, the economic feasibility of co-firing biomass with either coal or natural gas is determined by the costs of biomass acquisition and transportation. Many factors affect the acquisition costs of a biomass feedstock such as local availability of large quantities of cheap biomass as well as possible competition with other biomass energy and non-energy uses. If these biomass materials are locally available in large quantities and at low prices, then biomass co-firing is economically attractive. However, high energy-dense, pre-treated biomass feedstocks such as wood pellets may be used when local sources are insufficient since such feedstocks are better suited for long-distance transportation than ordinary biomass feed stocks [10].

Based on the work done by the OPG in biomass co-firing, any successful commercial biomass co-firing project in North America must develop a sustainable supply of the biomass fuel(s) and effective fuel transportation and must also complete any plant modifications needed to achieve successful operations. All of this requires contributions from many groups including government, utility companies, forestry, agriculture, academic and research institutions, and communities. The use of biomass as a power generation fuel will create new market opportunities for the agricultural and forestry industries and for communities in many parts of the country, especially in Western Canada, which is very rich in forest resources. The use of biomass will also enable old coal power plants to continue to be used even after coal is phased out in the near future [67].

In order to encourage the use of biomass fuels, national and regional governments should devise favorable regulatory and environmental policies to help utility companies adopt biomass co-firing technologies and make fossil fuel-based energy more expensive. A recent European Union Emissions Trading System (EU ETS) policy aimed at increasing co-firing competitiveness and the use of pellets in power plants in Europe enables major coal-power plant owners to auction their CO_2 allowances. Also, another European Union policy mandates its member states to achieve an expected level of renewable energy use by 2020. Similar policies and measures exist in several states in the United States of America. The lack of specific incentives is seen as the main reason behind the slow growth in the implementation of co-firing technology in Canada and Australia compared to European countries. Policies designed to enhance the efficient use of biomass, such as encouraging co-firing in CHP plants where district heating systems and connections with industrial facilities are available, should be adopted [10, 48].

2.10 Chapter summary

Successful projects both at demonstration and commercial levels, especially in Europe and North America, have shown that co-firing biomass fuels with fossil fuels can be a transitional option towards completely carbon-free power.

Biomass co-firing can be done through direct co-firing, indirect co-firing, and parallel co-firing. Most of these pathways are mature technologies, although there are a few innovations and developments. Generally, biomass co-firing levels are still within 5-10% on a continuous operational basis in most commercial operations.

The presence of biomass in the combustor can reduce overall GHG emissions as well as NOx and SOx from existing coal-fired and gas-fired power plants. Several other advantages, such as a reduction in biomass waste and soil and water pollution and in the overall cost of the base fuel, may benefit the utility companies and the environment. In addition, co-firing has lower initial capital costs since it uses existing facilities. However, the plant's operational and maintenance costs may eventually be higher than those of a dedicated coal-fired power generation plant.

Biomass co-firing may further reduce GHG emissions in North America because many regions are rich in biomass resources that can ensure a sustainable supply base. However, in order to effectively exploit the potential offered by co-firing, urgent measures and policies are needed to address several technical and logistical issues. First, a harmonized system between all the relevant stakeholders is needed to ensure the long-term sustainability of high-quality biomass fuels. Second, there have to be favourable policies, preferably in the form of subsidies and tax exemptions, as well as a regulatory framework mandating GHG reductions.

Finally, there should be sustained research and development programs with a focus on resolving the issues and challenges that have been identified in this chapter. The future of biomass co-firing in North America, especially in Canada, depends on the ability to address these issues, along with policy incentives and mandatory regulations that enable power utility companies to take advantage of the opportunities in this sector.

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Chapter 3: Integrated Techno-economic and Environmental Assessments of Co-firing Biomass with Coal and Natural Gas in Western Canada[2].

3.1 Introduction

Global energy consumption has grown rapidly since the last century largely due to the need to support the increasing socio-economic development both in the developing and developed worlds. The increase in energy use has resulted in the heavy reliance on fossil fuels like coal, oil, and natural gas and led to a significant increase in GHG emissions, which are considered to be the root cause of the rising global temperatures [1, 2]. In 2010, electricity and heat generation, both major forms of energy use, produced about 41% of global GHG emissions through the combustion of fossil fuels, representing close to 10,000 $MtCO_2$ per year [3-5]. It is even more noteworthy that in Canada, while 16% of its total electricity comes from coal power plants, these plants currently account for about 77% of the overall GHG emissions associated with the nation's entire electricity sector [6, 7]. To protect its environment, the Government of Canada has made a commitment to reduce present GHG emissions levels by 17% by 2020 through stricter regulatory policies such as an emission intensity level of 0.42 tCO_2/MWh for new thermal power plants and 1.1 tCO_2/MWh for old plants [7, 8]. In addition, different forms of emission regulatory policies exist at the provincial level, such as carbon taxes in Alberta and British Columbia and feed-in tariffs (FITs) in Ontario and Quebec, designed to encourage large industrial emitters such as utility companies to reduce their overall GHG emissions [8-10].

Many alternatives such as renewable energy (RE) technologies, carbon capture and sequestration (CCS), energy conservation and efficiency technologies, etc., are being explored with the aim to lower the GHG emissions from energy systems while still satisfying

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corresponding energy demands [2, 11, 12]. Biomass use for energy and heat can help in lowering the GHG emissions. Biomass is a renewable energy source derived from organic matter such as agricultural crops, woody and herbaceous materials, seaweed, and organic wastes [2, 13-16]. Compared to other sources of energy, biomass offers some unique advantages with respect to the environment since it is "carbon neutral." The term "carbon-neutral" refers to the ability to produce energy without any net increase in overall life-cycle GHG emissions since the amount of CO_2 emitted during the energy production cycle is absorbed when a new plant grows [17-20]. There are several ways in which biomass could be used for producing power and heat [21-24]. One such option is biomass co-firing.

Biomass co-firing, either coal or natural gas (NG) in existing power plants, has been considered as an option to reduce the life-cycle GHG emissions associated with the use of fossil fossils to produce electricity, as well as mitigate their impacts on the environment. It also offers utility owners a reduced incremental investment cost (i.e., the cost required to retrofit existing plant) and fuel supply flexibility [10, 19, 20, 25-27].

Biomass co-firing with coal can be described as the simultaneous blending and combustion of solid biomass with coal in existing coal-fired power plants to generate electricity. Here, an existing plant is retrofitted to enable the co-firing operation. Coal/biomass co-firing occurs either in the form of direct co-firing or parallel co-firing. In direct co-firing, the biomass feedstock is either fed directly into the boiler with the coal where they are then milled and burnt together or it is milled externally before being fed separately into the boiler to be burnt together with the coal. It is the most simple and least expensive form of biomass co-firing, tend to have the lowest co-firing rate compared to the other technologies, usually ranging from 1-10% [28, 29]. Parallel co-firing is similar to the direct co-firing except for the installation of a completely separate external biomass-fired boiler. Firstly, the 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 [19]. Compared to direct co-firing, more biomass can be fired although at higher plant modification costs [30]. Further details on these co-firing technologies can be found in our preceding publication [31]

Biomass co-firing with natural gas is a form of indirect co-firing technology. Here, the biomass feedstock is first gasified to produce syngas which is then co-fired with either natural gas or coal gas in a gas turbine. NG/biomass co-firing offers a higher co-firing rate compare to coal/biomass co-firing, enabling the substitution of up to 40% of the base fuel with biomass in the system [25, 32, 33]. However, it remains the least adopted co-firing technology partly because it is still in a development form, but also due to the much higher capital costs associated with the gasification process [25, 34]. The most notable commercial operation of NG/biomass co-firing is found in Lahti, Finland where diverse biomass fuels such as sawdust, straws, wood wastes, and other waste-derived fuels have been gasified in fluidized bed gasifiers and then co-fired with natural gas in the turbine [34]. Detailed information on this co-firing technology can be found in Agbor et al. [31].

Presently, biomass co-firing is receiving a favorable attention especially from recent research and development activities in Europe and the U.S. aimed at resolving several technological and logistical issues that had previous hindered its adoption [25, 31, 35]. The increase in biomass energy use in co-fired systems is crucial to significantly reduce overall GHG emissions [25]. In western Canada, large amounts of biomass that could be harvested for energy production are left to rot in forests and agricultural fields [21]. For example, although a significant amount of the whole forest in Alberta is currently allocated to pulp and timber production companies, this province still has an annual capacity of approximately 3.19 million dry tonnes/year of agricultural residues and 3.29 million dry tonnes/year of forest residues available for RE technologies such as biomass co-firing [21].

This overall objective of this chapter is to perform an integrated techno-economic and environmental assessment for different biomass co-firing scenarios in western Canada. The specific objectives of the chapter are:

- To study the different configurations of co-firing biomass feedstocks with coal and NG in western Canada.
- To develop techno-economic models specific to western Canada.
- To evaluate 60 co-firing scenarios employing different proportions of the biomass & base fuels, and technical configurations.
- To develop the electricity costs (in $/MWh) for the 60 scenarios.
- To develop the GHG mitigation costs (in $\$/tCO_2$) for the 60 scenarios.
- To carry out sensitivity & uncertainty analyses on the model results to determine the impact of various input parameters on the attractiveness of co-firing technologies.
- To develop a framework for selecting the most favorable biomass co-firing technology for western Canada.

3.2 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, the 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 [31].

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 [21, 28].

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

1. The development 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 both coal and 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. Use of Monte Carlo simulation for understanding the uncertainty of in the input parameter and results.

Data were developed through first principle 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 returns (IRR) of 12%, 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 both coal and NG in western Canada.

3.3 Inputs description

3.3.1 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 [19, 31, 36]. 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 [25, 36, 37]. Different co-firing technologies, as summarized in Agbor et al. [31], 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.

3.3.1.1 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. They are fed into a high pressure steam turbine where they are 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 enhance air leakage into 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 [10, 27, 38]. An illustration of the process flow of the modified PC used in this study is shown in Figure 3.1.

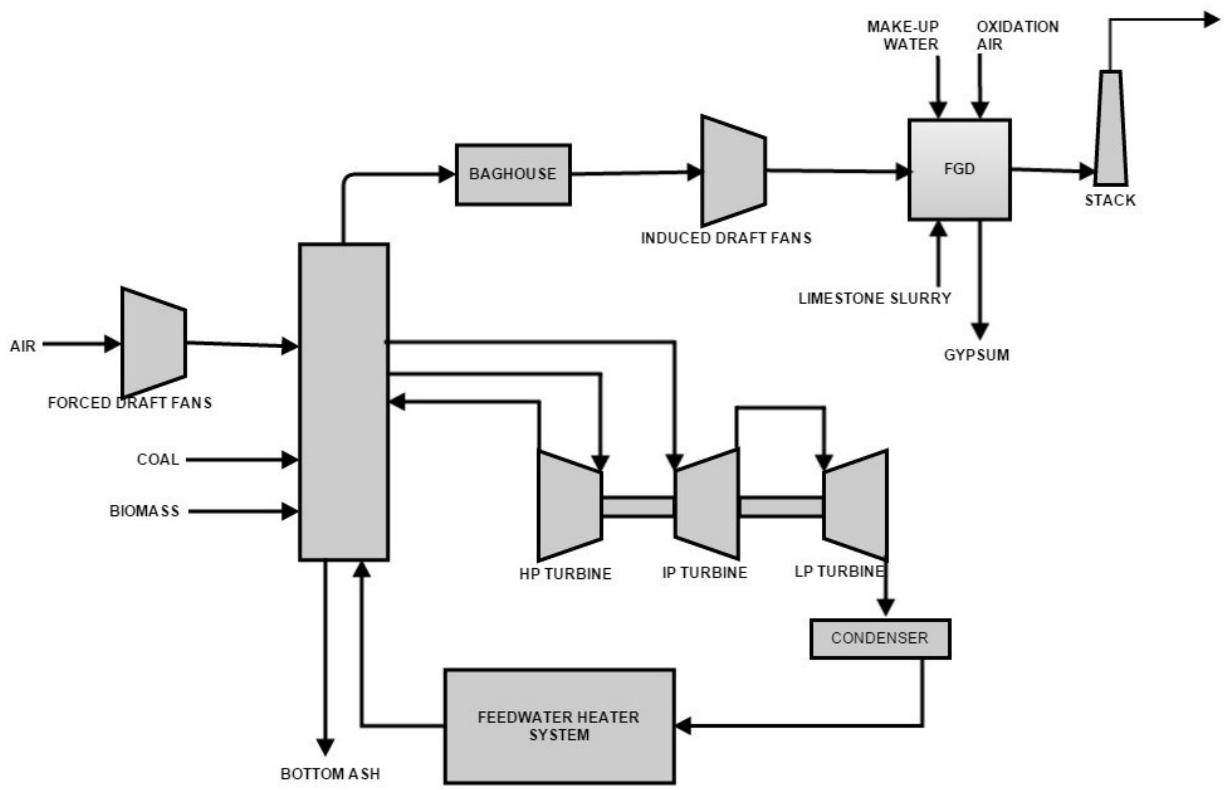


Figure 3.1: Flow diagram of the modified subcritical PC plant

For co-firing levels between 1-5%, a direct co-firing system is designed 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 5-10%, a direct co-firing system is designed wherein the biomass is milled externally before being fed separately into the boiler to be burned together with the coal [19, 31, 36]. 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 [19, 36]. 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 [19]. 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 minimal deposition formation issues like fouling and slagging, as well as corrosion, since the biomass flue gas is prevented from reaching the boiler heating surfaces [19, 31, 36]. However, this technology is more capital intensive than direct co-firing due to the dedicated boiler system [30]. Table 3.1 outlines the characteristics of the coal plant as well as the assumptions considered in this study [28, 35, 38-41].

Table 3.1: Techno-economic modeling input data

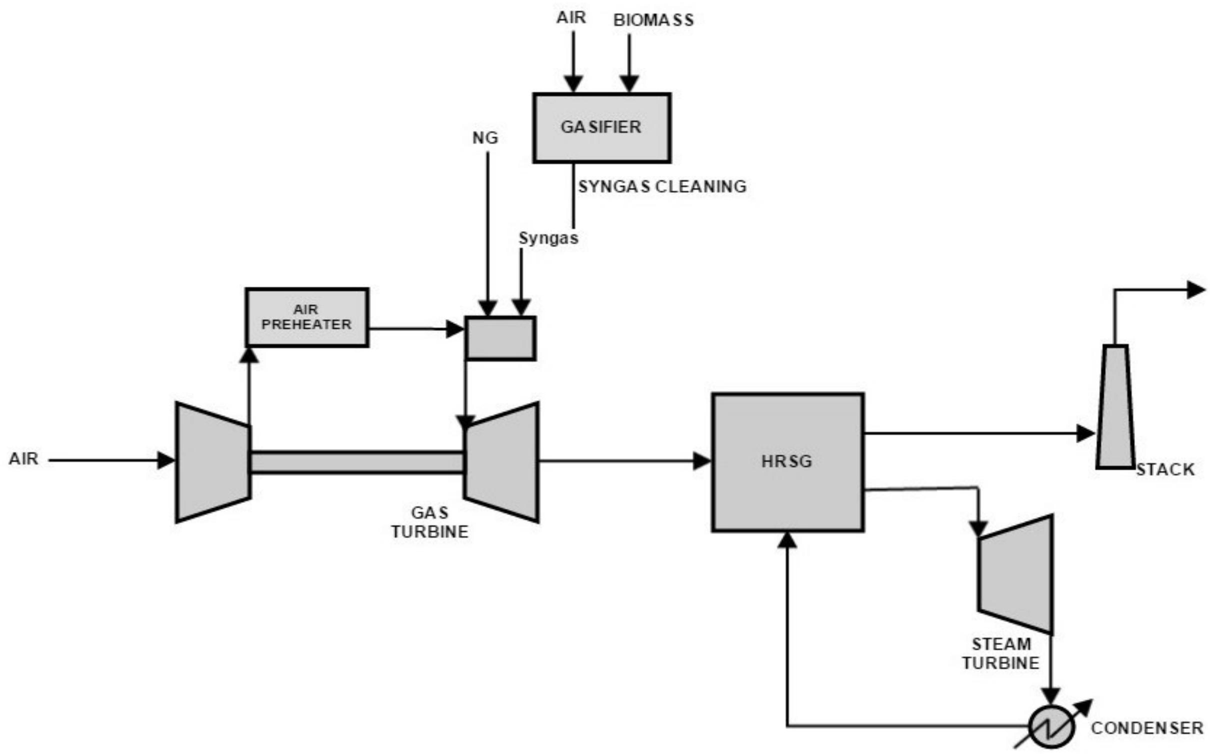
Power Plant Parameters	Coal	NG	Source/Remarks
Plant capacity (MW)	500	2x250	[28]
Plant type	Subcritical pulverized coal (PC) boiler	Natural gas combined cycle (NGCC)	[28]
Capacity factor (%)	85	85	[21, 28]
Plant life (years)	25	25	Initial capital cost of power plant has been fully paid out.
	15	15	Initial capital cost of power plant has been partially paid out.
Scale factor	0.79	0.71	[38, 46]
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 ($/tonne)	22	--	Coal is supplied from a mine-mouth source [21, 29]
Cost of natural gas ($/GJ)	--	3.47	[30]
Coal or NG replaced			This is measured in (megatonne/year for the coal/biomass co-firing scenarios. However, for the NG/biomass co-firing scenarios, it is measured in cubic metre per 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	[21]
Inflation	0.02	0.02	[31]
Exchange rate: CAD/USD	1.115	1.115	[32]

3.3.1.2 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 the indirect co-firing technology to fire biomass-derived syngas alongside natural gas [38]. 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 to 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 [38].

A few modification options were considered to co-fire NG with the biomass-derived syngas in the NGCC plant. The eventual design configuration used was chosen based on the achieved efficiency and performance of the co-fired plant [42]. In the initial design considered, biomass is gasified to produce low calorific value (LCV) syngas and then cleaned to enhance its quality. The LCV syngas is fed together with NG into each combustion turbine generator (CTG) at the design pressure and temperature. The rest of the process is similar to that of the NGCC plant. Figure 3.2a illustrates the process flow of the initial design of the modified NGCC plant. However, due to the lower calorific value of the biomass-derived syngas, there is a significant drop in the power generated by the plant. A way to prevent this power loss is to increase the amount of syngas fed with the NG 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 [42].

a. Design configuration I



b. Design configuration II

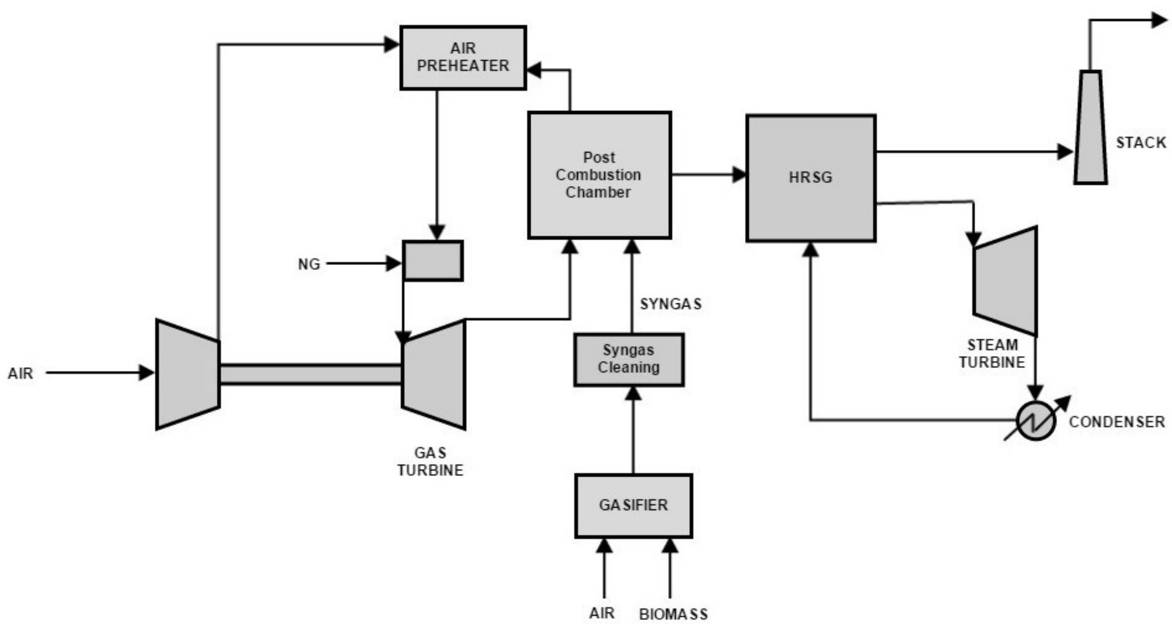


Figure 3.2: Flow diagrams of the modified NGCC plant.

The process flow of the second design option is also similar to the initial design except that the system is enables the LCV syngas to be fired alone in a dedicated burner combustion system, and the heat fed into a dedicated boiler and then the steam generated is fed into a dedicated STG. Here, 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. 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 [26, 42-45]. The process flow of the second design of the modified NGCC plant is represented in Figure 2.b.

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 Figure 3). 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 [26, 35, 38-41, 44].

3.3.2 Key cost components

3.3.2.1 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. (3.1):

$$Cost_2 = Cost_1 \times (Capacity_2/Capacity_1)^{scale\ factor} \qquad (3.1)$$

Table 3.2: 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	[10]
Bale loaders, receipt	Cost in $/annual dry tonne	13.62	[10]
Bale loaders, transfer to the line	Cost in $/annual dry tonne	8.30	[8]
Bale merge conveyer	For 10 tonne/hour line	6.79	[9]
Bale infeed conveyer	For 10 tonne/hour line	9.09	[9]
Moisture meter	For 10 tonne/hour line	0.91	[9]
Bale rejector	For 10 tonne/hour line	0.75	[9]
Destringer	For 10 tonne/hour line	3.58	[9]
Debaler	For 10 tonne/hour line	13.10	[9]
Debaler outfeed conveyer	For 10 tonne/hour line	3.42	[9]
Magnet	For 10 tonne/hour line	1.71	[9]
Fine hammer mill	For 10 tonne/hour line	16.04	[9]
Baghouse fan	For 10 tonne/hour line	0.37	[9]
Baghouse	For 10 tonne/hour line	3.53	[9]
Surge bin	For 10 tonne/hour line	4.92	[9]
Rotary airlocks and feeders	For 10 tonne/hour line	3.74	[9]
Pneumatic transport system	For 10 tonne/hour line	36.96	[9]
Total cost		**207.37**	

b. NG/biomass co-fired plant

Parameter	Description	Cost/unit Output (2014 CAD $/kW)	Comments/Sources
Biomass Preparation & Feeding	Magnetic separator	0.09	[13]
	Screen and hammer-mill	0.67	[13]
	Bag house dust collection	2.83	[13]
	Auxiliaries	0.48	[13]
Gasifier & Accessories	Gasifier (High pressure directly heated fluidized bed)	234.63	[11]
	Compressors for gasifier air	6.60	[11]
	Gasifier gas cooling	0.17	[11]
Gas Cleanup & Piping	Syngas clean-up	30.21	[11]
	Gasification system installation cost	265.01	[13]
Boiler & Accessories	Boiler & Accessories	405.06	[13]
Steam Turbine Generator	Steam Turbine Generator & accessories	71.43	[13]
	Condenser & auxiliaries	12.34	[13]
	Steam piping	12.12	[13]
Project contingency	15% of equipment and general plant facilities	116.50	[13]
Total cost		1,158.14	

Tables 3.2a and 3.2b presents the cost-list of all the equipment involved in retrofitting the existing power plants were retrofitted for all the co-firing scenarios. The capital costs were considered to be very similar at each co-firing level for all the biomass feedstocks investigated in this study [46]. Figure 3.3 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, however the rate at which this increase occurs is less than increase in the power output at each co-firing level due to the economy of scale.

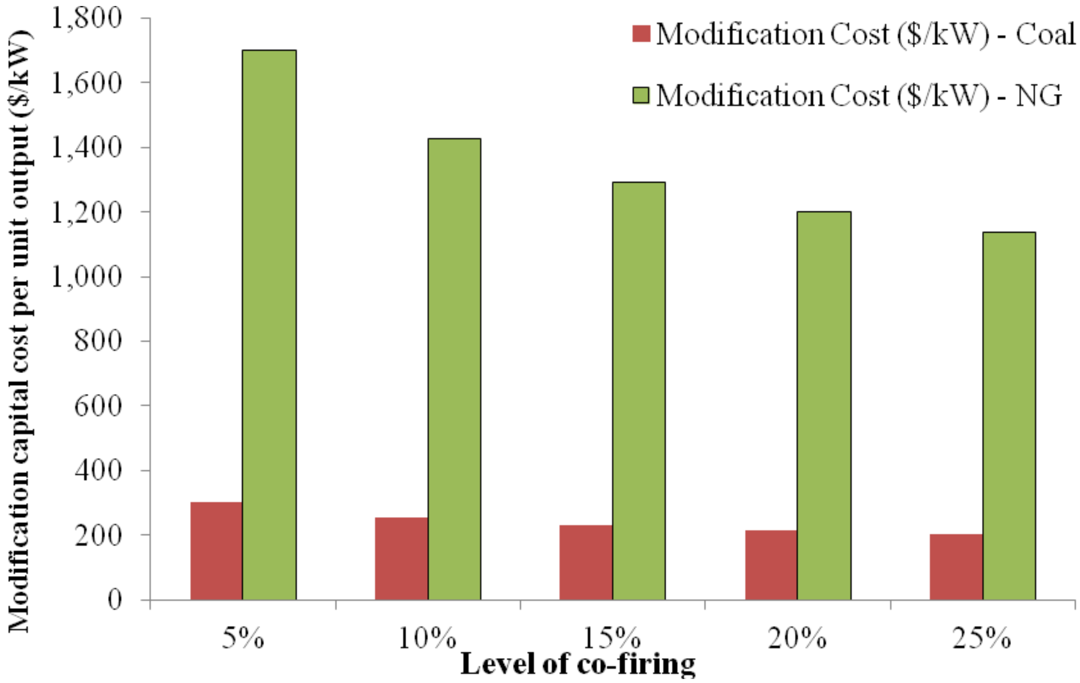


Figure 3.3: A distribution of the modification costs per unit output for each of co-firing scenario

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 [35]. 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 characterized by 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 [21, 24]. 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 [21]. 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 [21-23]. This study did not consider the costs for nutrient replacement, as did Kumar et al. [21]. A summary of the cost characteristics of whole forest biomass is shown in Table 3.3.

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 [21-23]. 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 [21-23]. No cost is accrued on road construction since the residues are transported on existing roads built by whole tree harvesting companies for the harvesting

and transporting of tree stems [21-23]. A summary of the costs of forest residues considered is shown in Table 3.3.

3. Agricultural residues: Both Kumar et al. [21, 47] and Sultana et. al [47] reports that the Province of Alberta has large potential for using 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 [22, 23]. 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 [21-23, 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 shown in Table 3.3.

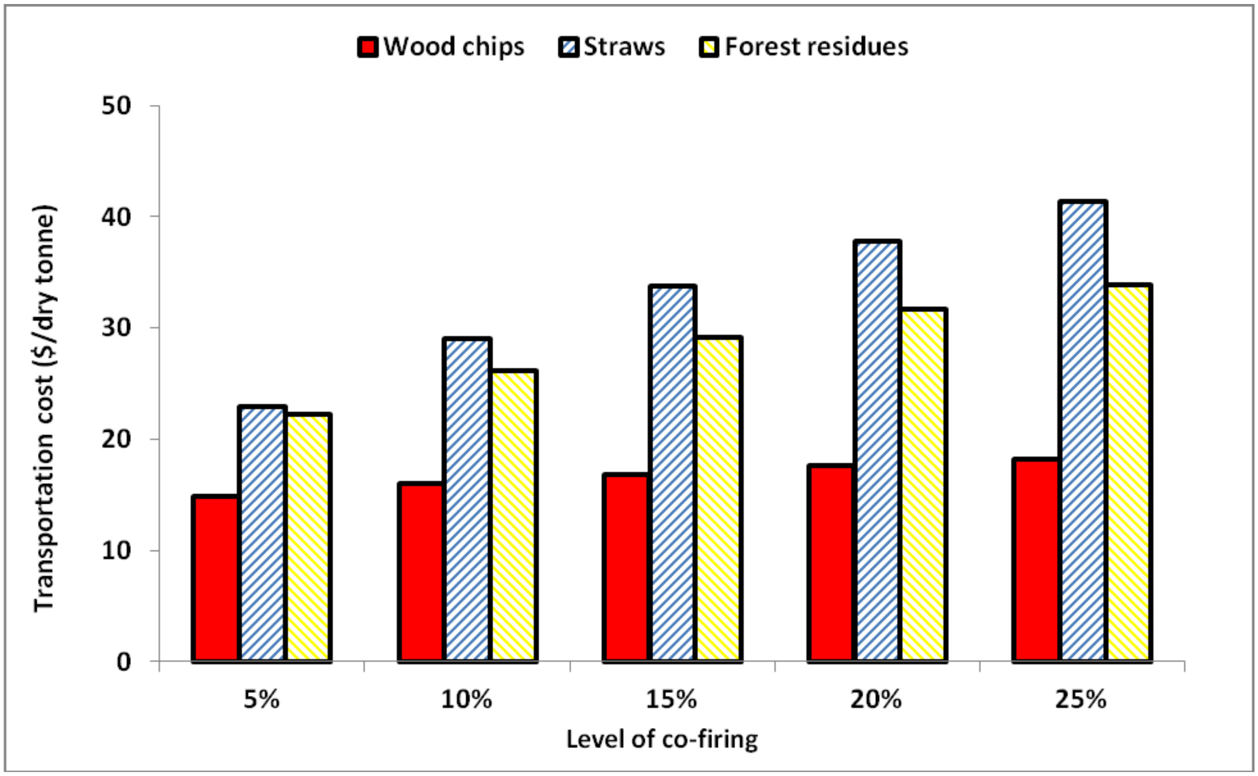
Table 3.3: Cost characteristics of the biomass feedstock

Items	Values/Formulas	Sources/Comments
Royal/premium fee ($/dry tonnes)	5.41	[21, 33-35].
Ash disposal cost:		[21, 33-35].
Hauling cost ($/dry tonnes/km)	0.21	
Disposal cost ($/dry tonnes/km)	28.97	
Whole forest		
Biomass yield (dry tonnes/ha)	84	[21, 33]
Harvesting cost:		[21, 33]
Felling ($/dry tonnes)	19.67	
Skidding ($/dry tonnes)	16.65	
Chipping cost ($/dry tonnes)	16.88	[21, 33].
Log loading, unloading, and transport cost ($/dry tonnes)	2.91+0.0326D	A circular harvesting area is assumed where D = 2*Average radius required to collect the biomass feedstock. It represents the round-trip road distance from the forest to the receiving plant [21, 33].
Cost of road construction and infrastructure ($/ha)	[1.27 + (635.5/VT)] × average gross yield	[21, 33]
Silviculture cost (2014 $/ha)	254.19	[21, 33]
Forest Residues		
Biomass yield (dry tonnes/ha)	0.247	[21, 34-35]
Harvesting cost ($/dry tonne)	16.41	[21, 34-35]
Chipping cost ($/dry tonne)	16.10	[21, 34-35]
Log loading, unloading, and transport cost ($/green tonne)	2.91+0.0326D	[21, 34-35].
Wheat Straw		
Biomass yield (dry tonnes/ha)	0.333	[21, 34]
Harvesting cost:		
Shredding ($/dry tonne)	4.22	[36]
Raking ($/dry tonne)	2.65	[36]
Baling ($/dry tonne)	4.19	[36]
Bale wrapping—twine ($/dry tonne)	0.56	[36]

Items	Values/Formulas	Sources/Comments
Bale collection:		
Bale picker ($/dry tonne)	0.77	[36]
Tractor ($/dry tonne)	4.11	[36]
Bale storage:		
On-field storage ($/dry tonne)	2.07	[36]
Storage premium ($/dry tonne)	0.11	[36]
Log loading, unloading, & transport cost ($/dry tonne)	6.7+0.1843D	[36]
Nutrient replacement cost ($/dry tonne)	25.72	[36].

Figures 3.4a and 3.4b illustrate in details 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 fuel requirements of the plant changes, the rate at which the transportation cost changes is more significant due to the need to transport the feedstock through a longer distance. Therefore, the biomass delivery cost will increase as a result of an increase in the transportation cost.

a.



b.

Figure 3.4: Transportation costs (a) and biomass delivery costs (b) at different co-firing levels for different biomass feedstocks

3.3.2.3 Operational costs

The operating costs of the co-firing plant include the direct operating labor cost, the administrative cost, and the maintenance cost. The cost estimates are based off a previous study carried out by Ortiz et al. [46] on biomass power generation however the present operating conditions of the existing power plant were also taken into consideration. The remuneration to cover salary plus benefits of the both the operating and administrative staff of the power plant is estimated at $36/h [21-24]. 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 plant as considered in this study is shown in Table 3.4.

Table 3.4: 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	[21]
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 [21].
No. of shifts	5	[21]
Operating labor requirements per shift (coal)	Staffing level	12 workers are required in the coal/biomass co-firing plant [21].
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 [28].
Skilled operator	1	
Operator	3	
Foreman	2	
Lab tech's, etc.	2	
Administrative staff	26	[21]
Maintenance cost (% of initial capital cost of coal power plant)	3	[21, 34-35]

3.3.2.4 Other cost parameters

3.3.2.4.1 Ash disposal costs

The prevalent practice adopted by most coal-fired power plants in Alberta and other western Canadian provinces is to collect the ash produced as a by-product of coal combustion and sell it either to road construction companies for use as a substitute for gravel or as fly ash to the cement industry to manufacture Portland cement, or store it in nearby coal landfills [48]. However, the 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 ash recovered from the biomass-coal-fired plants is collected and stored in nearby landfills. Thus the plants will 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 [21-24, 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 as a soil supplement by local farmers as well as foresters [21-24]. However, since this demand will require some time to develop, we adopted a conservative approach where it is the responsibility of the utility companies to haul and spread the ash 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 [21-24].

3.3.2.4.2 Avoided fuel costs

Avoided fuel costs are the amount of money saved from substituting the base fuel (i.e., either 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 has a crucial position 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.

3.3.2.4.3 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 is a way of comparing the cost of mitigating CO_2 emissions between a co-fired plant and an associated reference plant. It is measured in \$/tonne of CO_2 not emitted with respect to a reference plant [51, 52]. It is among the important outputs of this study 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 [35, 53]. An equation of the avoided CO_2 cost of co-firing biomass is shown below:

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

where: $Incremental\ cost\ of\ co-firing = LCOE\ of\ co\text{-}fired\ plant - LCOE\ of\ a\ reference\ plant$ $without\ co\text{-}firing,\ CAD\ \$/MWh$

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

$GHG\ Intensity_{co-firing}$= *GHG emission intensity of the coal/biomass co-fired plant, t CO2/MWh.*

The carbon emission intensity of both the coal and NG plant are represented in Table 3.5. 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 [38].

Table 3.5: GHG (Carbon) emission intensity of both the coal and NG plants

Parameters	Value	Source/Comments
Coal (500MWe)	1.0656	The emission intensity level is calculated based on characteristics of Alberta coal and the new 450 MW coal power plant (Kumar 2003)
NG (500MWe)	0.3552	The emission intensity of NG plant is roughly one-third of that of the coal plant (CCPC 2014)

3.4 Results and discussion

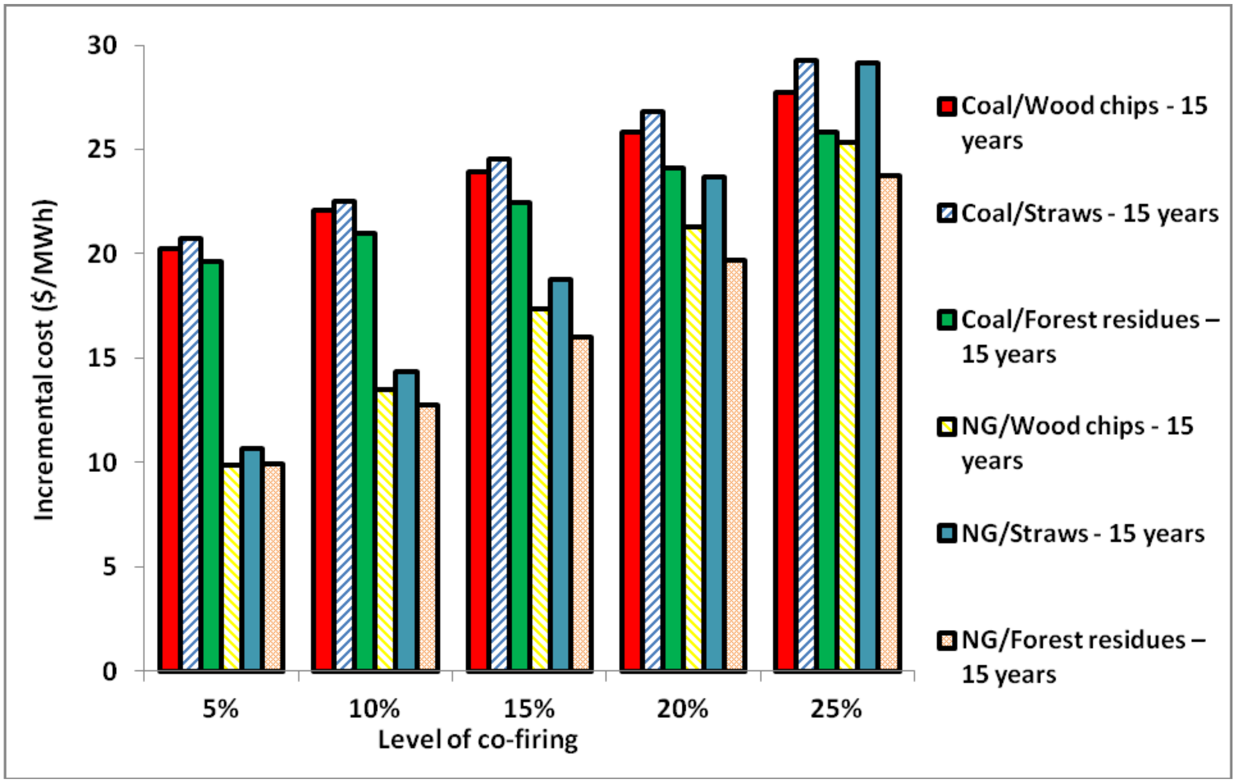
3.4.1 Costs of electricity

The power costs of the biomass co-firing scenarios considered in this study are measured in two forms, namely 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 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 by the total electrical output (in MWh) of the plant [35, 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 use rate for each plant type [35, 54, 56]. Both the LCOE and the incremental cost of co-firing is measured in this study in $/MWh.

3.4.1.1 The incremental cost of co-firing

Figure 3.5 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 analysis from the techno-economic assessment models developed using the input parameters mentioned in Section 3. Firstly, the results show 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 plant age 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. Secondly, 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 the 25-year-old plant (for those scenarios, the assumption is that the plants have been fully paid-off) compared to the 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.

a.



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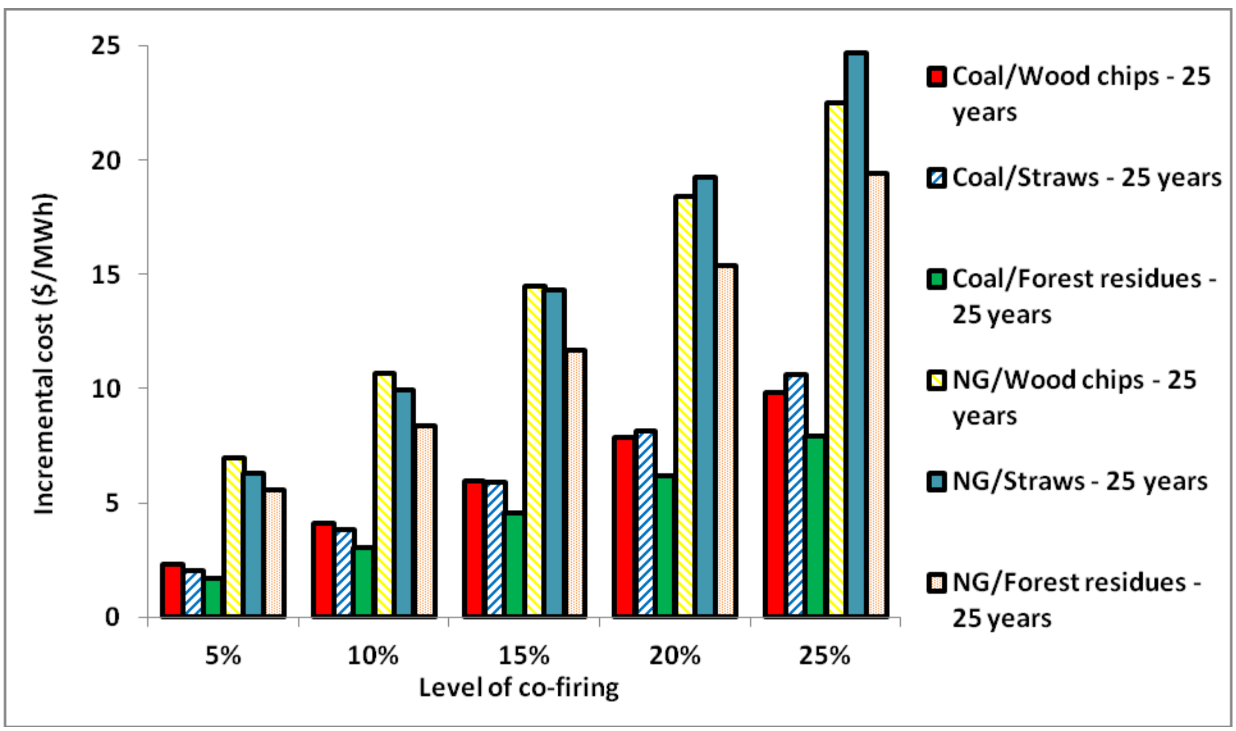


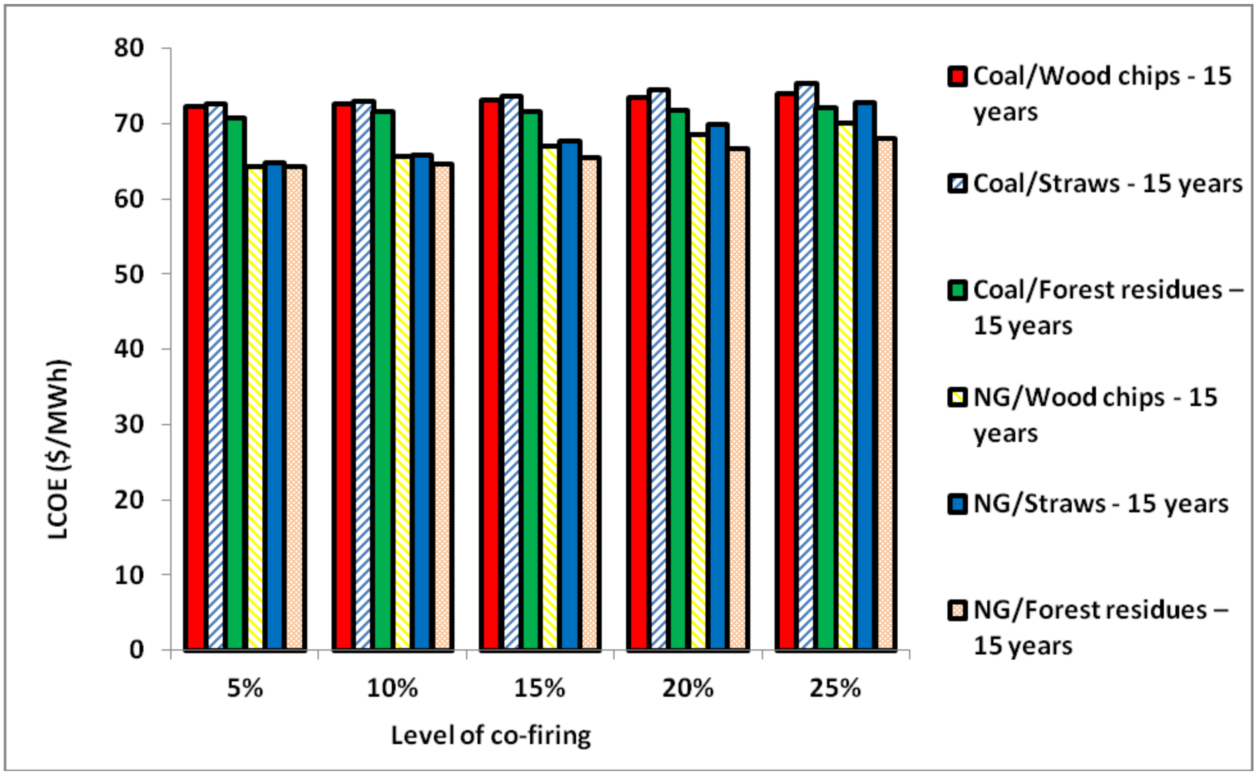
Figure 3.5: Increase in power costs at different co-firing levels and different years of plant modification after (a) 15 years, (b) 25 years.

3.4.1.2 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 presented in Figure 3.6. The results reveal the following:

- There was a steady rise in the LCOE as the 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 the co-firing technology for both the coal and natural gas scenarios. This 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-years plant age (those scenarios in which the plants were assumed to have been fully paid-off) compared to the 15-years 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.

a.



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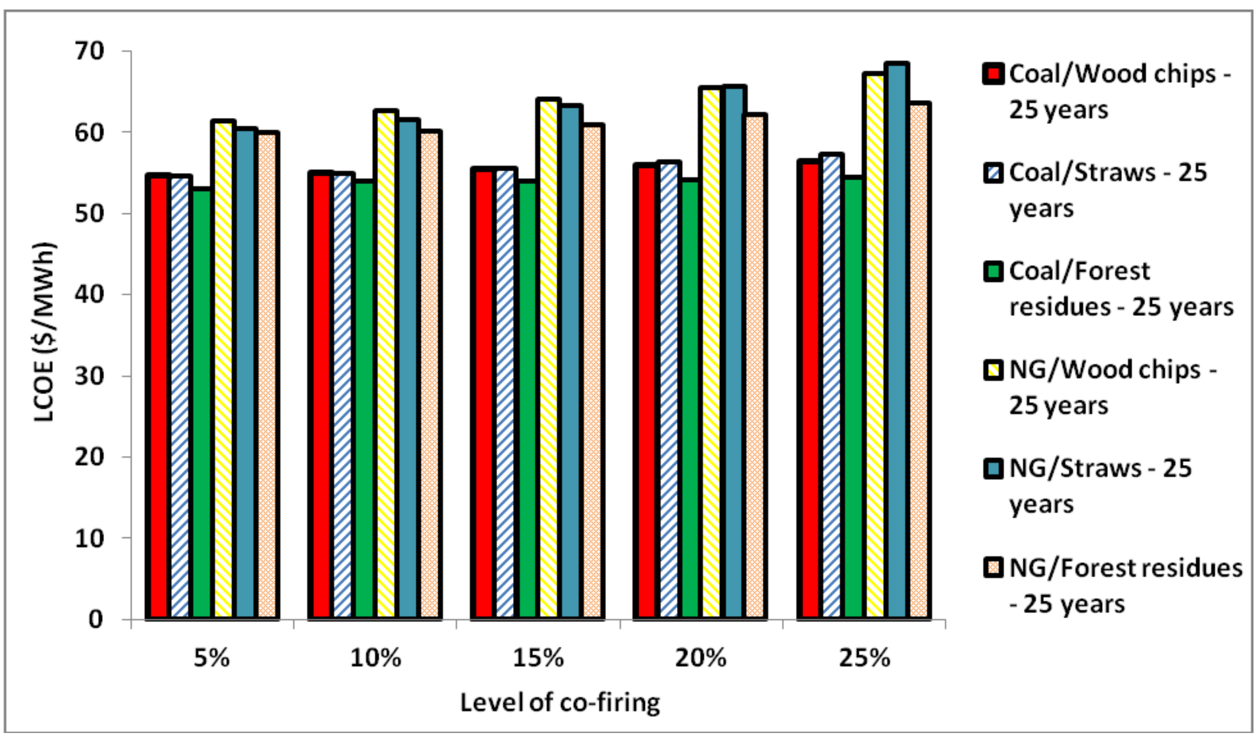


Figure 3.6: Levelized costs of electricity (LCOE) at different co-firing levels for different biomass feedstocks modified after (a) 15 years, (b) 25 years.

Figure 3.7 shows the LCOE breakdown for all the feedstocks considered at a 25% co-firing level for both the coal and NG scenarios. The values of 5%, 10%, 15%, and 20% followed a similar trend to those reported below. The major cost components of the LCOE of the coal/biomass co-firing are 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.

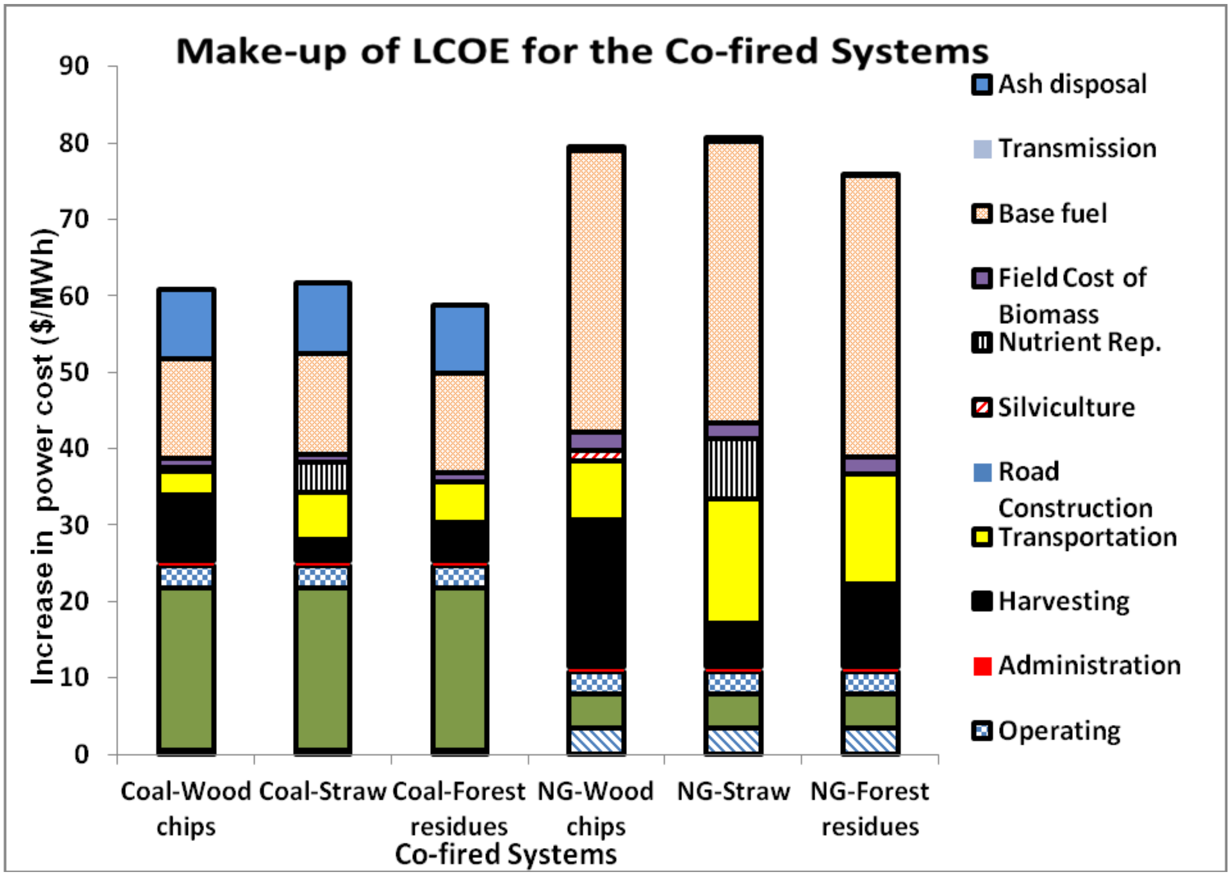
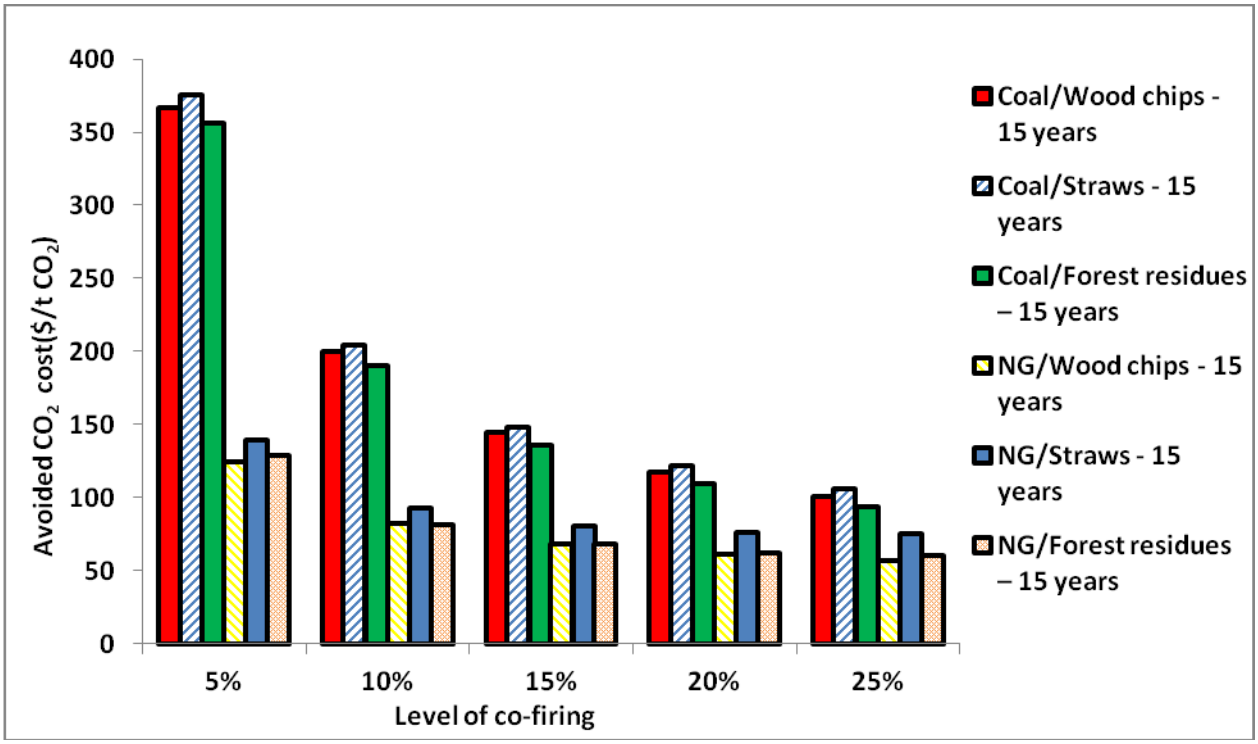


Figure 3.7: Make-up of the LCOE for different biomass feedstocks at 25% co-firing levels at fully paid-off coal and NG plants.

3.4.2 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 is presented in Figure 3.8. It shows that there is a gradual decrease in the avoided CO_2 costs of biomass co-firing as the co-firing levels increase for each biomass feedstock and plant age considered for both the coal and natural gas scenarios. This trend is influenced significantly by the impact of economy of scale on the systems' capital costs as the co-firing level increases for both the coal and 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 cost of co-firing. It underlines the relationship between carbon abatement costs and incremental costs. An analysis based on the plant ages of the avoided CO_2 in the 60 co-firing scenarios reveals that the abatement cost is significantly higher for the partially paid-off scenarios than the fully paid-off scenarios. 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 a 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.

a.



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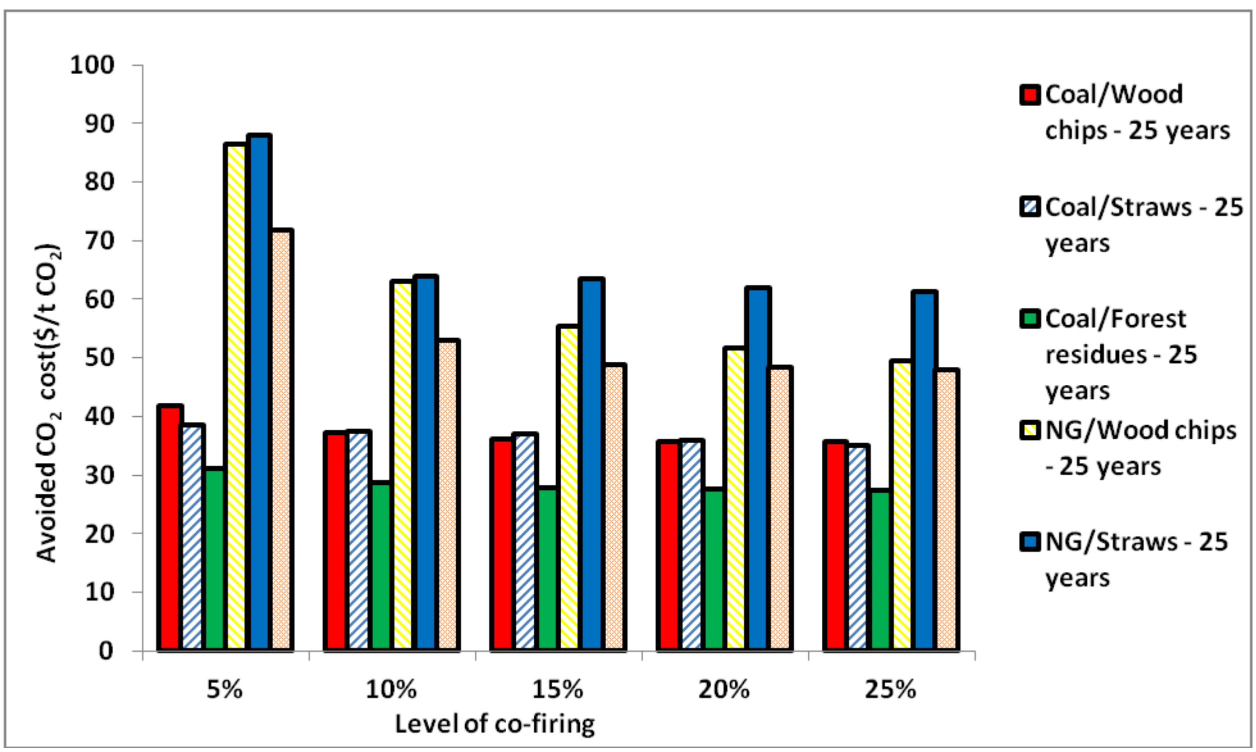


Figure 3.8: Avoided CO_2 costs at different co-firing levels for different biomass feedstocks modified after (a) 15 years, (b) 25 years.

3.4.3 Sensitivity analysis

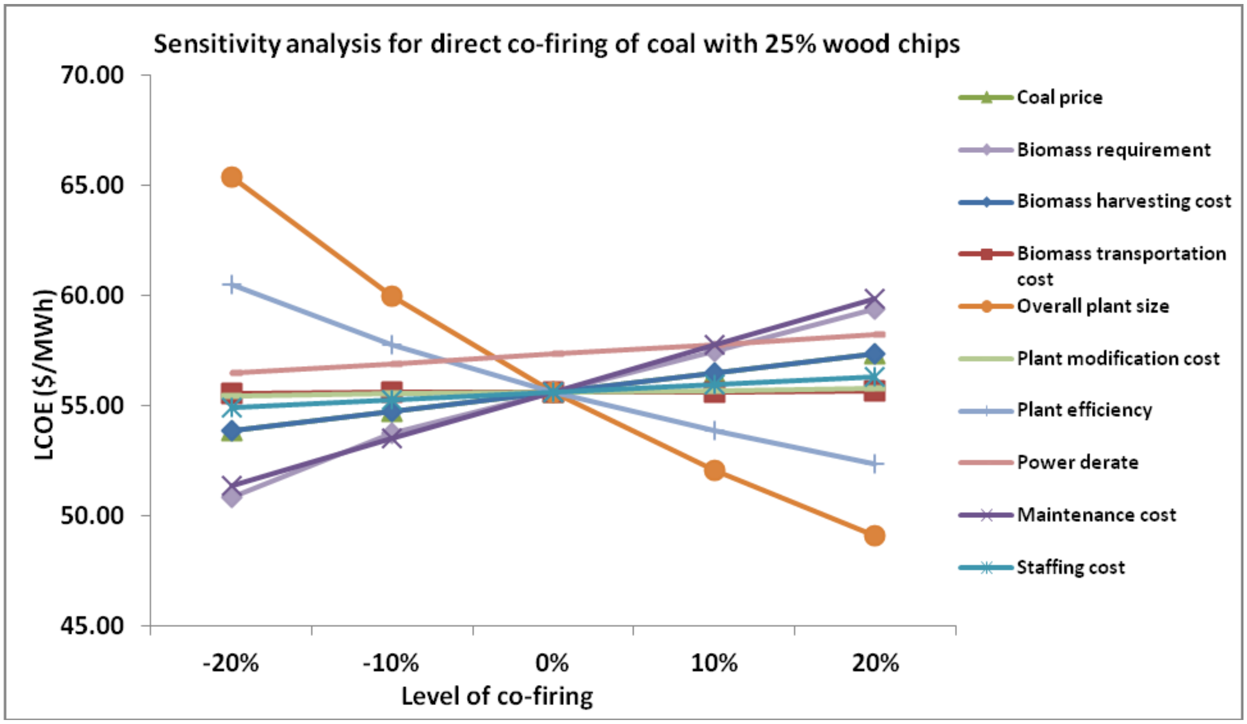
The sensitivity analyses co-firing each of the biomass feedstocks considered with coal as well as NG at a 25% co-firing level in a fully paid-off plant is presented in Figure 3.9 and Figure 3.10. This sample is representative of similar trends associated with all 60 scenarios studied. It shows that the 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 a substantially high efficiency to achieve a favorable (i.e., low) LCOE.

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

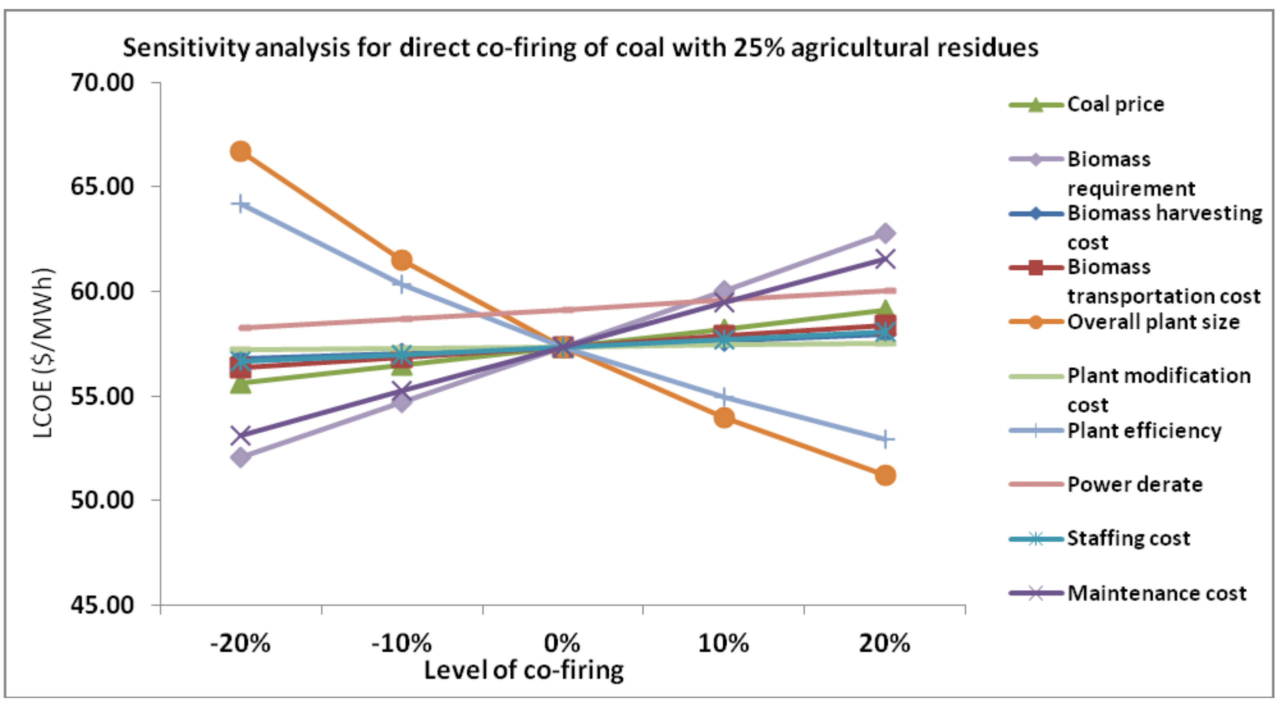
The concept of power derating was investigated to determine the robustness of the co-fired plant. Power derating occurs when the power rating of the co-fired plant(s) is lowered due to substantial deterioration in the energy conversion efficiency of the plant. Here, a derate factor of 0.03 was assumed while the other parameters are 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 LCOE of the plant.

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 of the day when the operating cost is most justifiable.

a. Wood Chips



b. Straw



c. Forest Residues

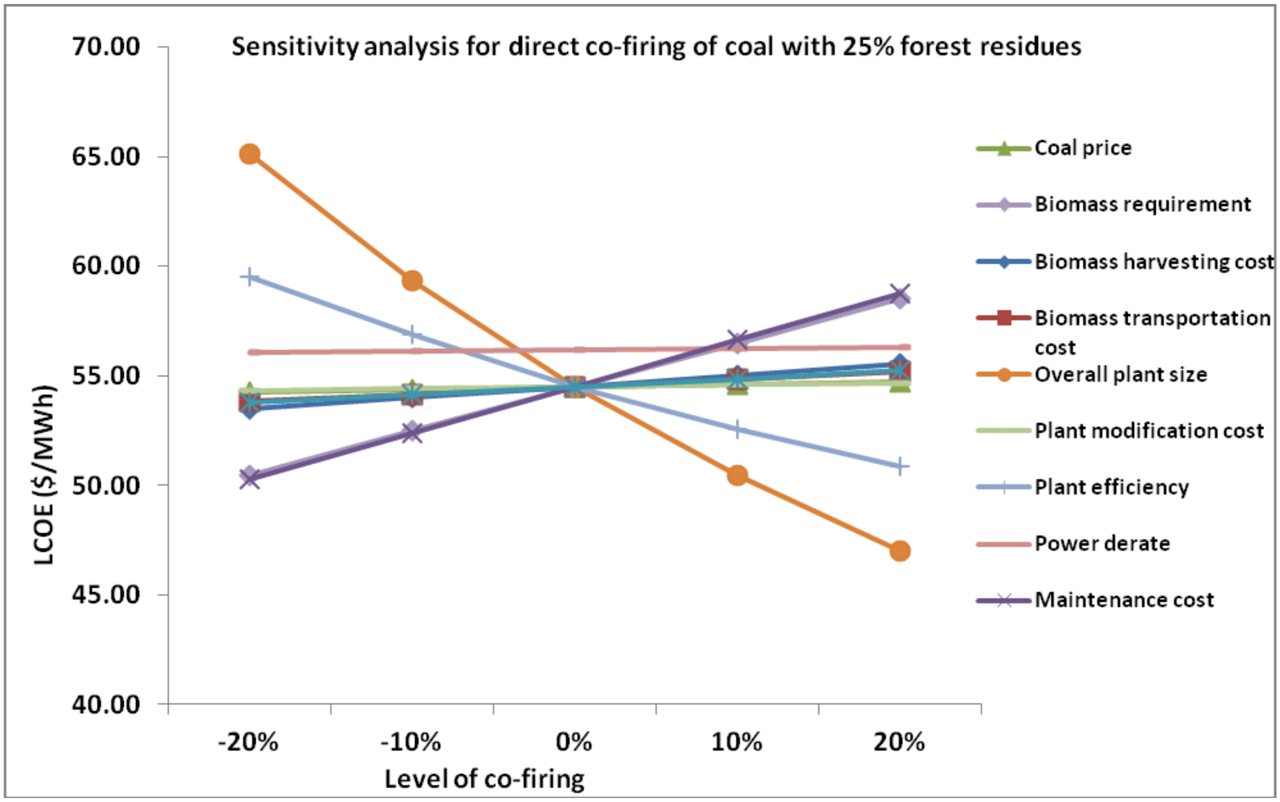
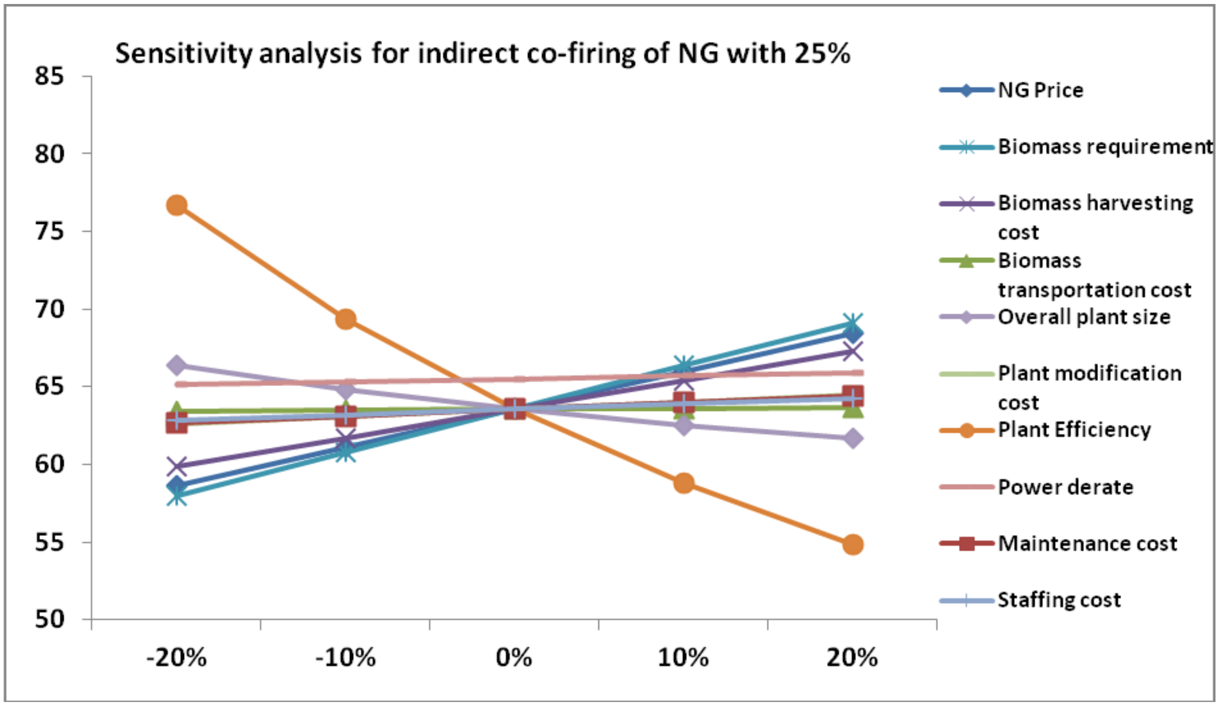
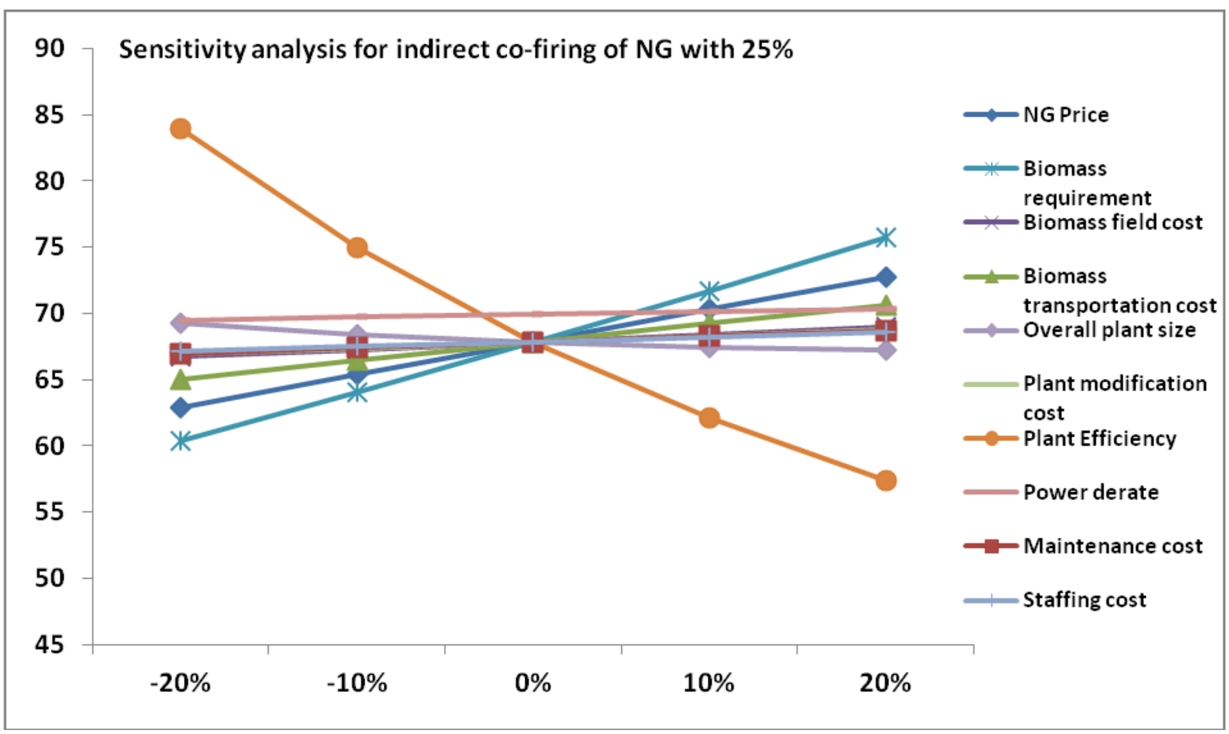


Figure 3.9: Sensitivity analyses for the coal/biomass co-firing scenarios at 25% co-firing level

a. Wood Chips



b. Straw



c. Forest Residues

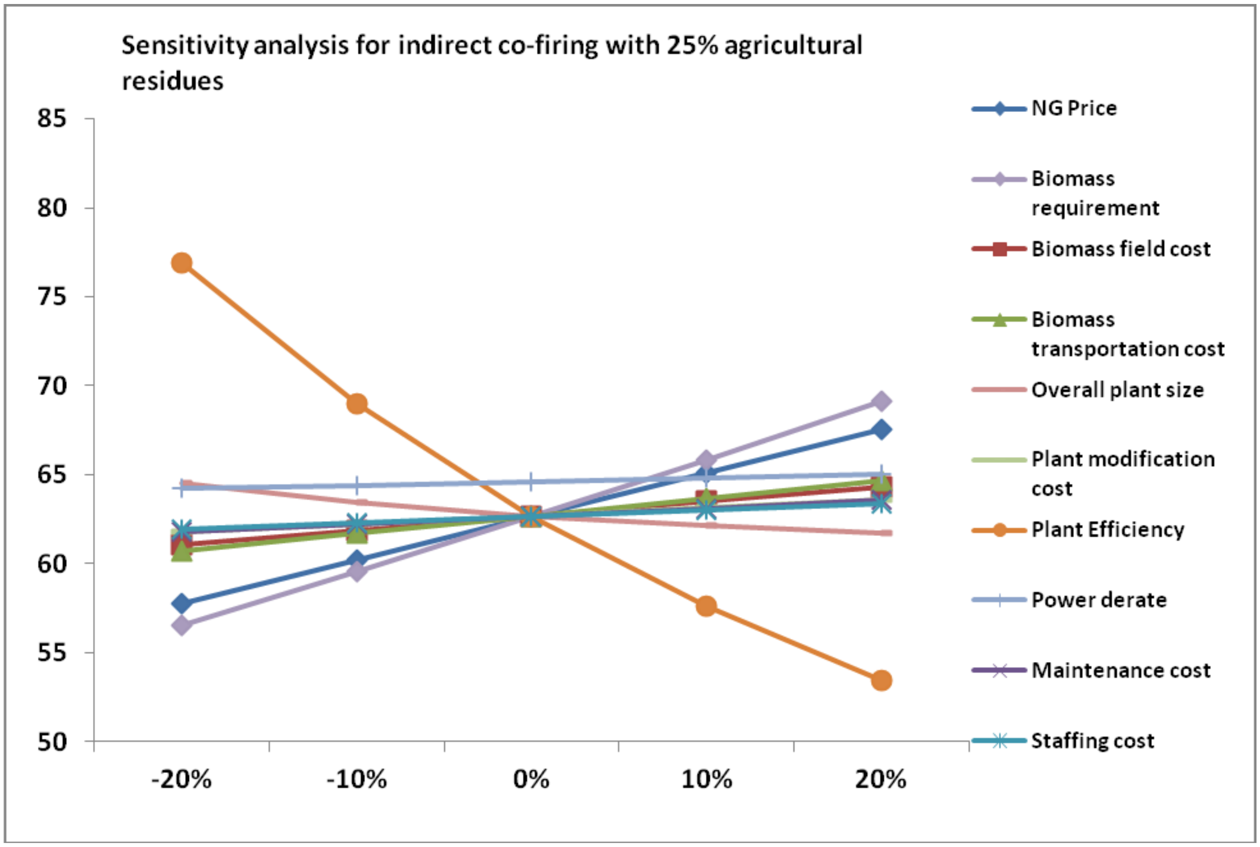


Figure 3.10: Sensitivity analyses for the NG/biomass co-firing scenarios at 25% co-firing level

3.4.4 Uncertainty analysis

Though a very robust approach was used to achieve the best research outcome, one major limitation of this cost analysis is the 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 both the likely range of values for model input and output parameters aligns with industry trends. The uncertainty values assumed in this study are thus [57]:

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

Using Monte Carlo simulation techniques, uniformly distributed 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 [58]. 10,000 iterations were run to identify the total uncertainty of the system. The graphical representation of the Monte Carlo analysis results for the direct combustion is presented in Figure 3.11. The result shows that the LCOE range for the coal/wood chips is \$56.42 ± \$2.691/MWh; coal/straws is \$57.35 ± \$2.54/MWh; and coal/forest residues is \$54.50 ± \$2.744/MWh at a 95% confidence level. Table 3.5 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 Figure 3.9 and Table 3.5 are only sample representations of the rest of the study.

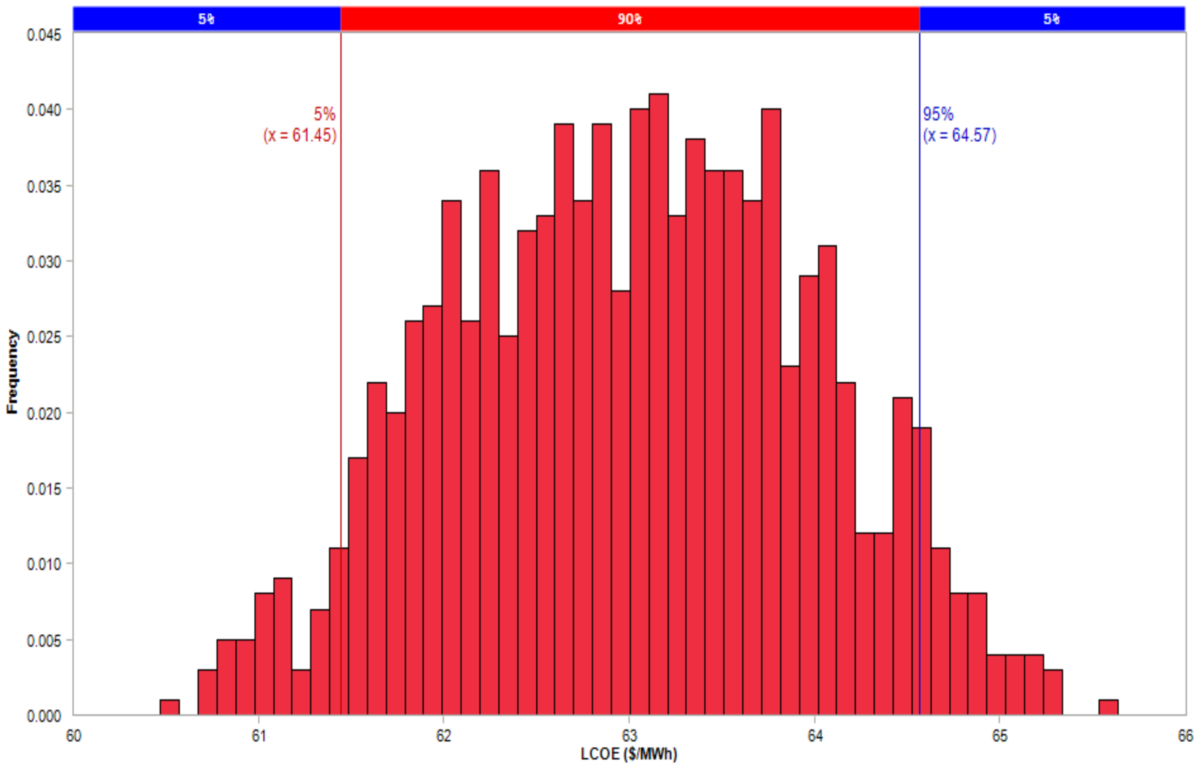


Figure 3.11 Graphical representation of the Monte Carlo results for parallel co-firing of coal with 25% wheat straw.

Table 3.6: 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	90%
	Straw	\$57.35 ± \$2.54/MWh	90%
	Forest residues	\$54.50 ± \$2.744/MWh	90%
NG-biomass co-firing	Wood chips	\$67.24 ± \$2.54/MWh	90%
	Straw	\$68.45 ± \$2.65/MWh	90%
	Forest residues	\$63.75 ± \$2.529/MWh	90%

3.5. Chapter Summary

This paper developed data-intensive techno-economic models to comparatively evaluate the costs of co-firing three biomass feedstocks (whole forest, wheat straw and forest residues) with either coal or natural gas in both a fully paid-off modified plant and a partially paid-off plant in western Canada. Detailed analyses were conducted to determine the most technically, economically, and environmentally feasible co-firing scenarios that can be adopted by power utility companies in this part of the country. The outcome of the study shows that: firstly, most biomass feedstocks have higher delivery costs compared to both coal and natural gas. Secondly, the total capital costs per unit output (in $/kW) required to modify a plant to co-fire biomass decreases 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 plant. Thirdly, 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 coal-fired or natural gas-fired plant. Fourthly, while the LCOE of generating electricity from a co-fired plant increases as the level of co-firing increases, the avoided CO_2 costs decreases 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. Fifthly, 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 $2.07/MWh to $10.62/MWh; LCOE ranging from $53.12 to $54.50/kW; 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.

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Chapter 4: Conclusions and Recommendations for Future Work

4.1 Conclusion

The overall objectives of this research were to systematically study several aspects of biomass co-firing with coal and natural gas, with particular interest in western Canada, and then carry out detailed techno-economic analyses to evaluate the technical, economic, and environmental costs of retrofitting existing coal and natural gas plants to co-fire several percentages of biomass with either coal or natural gas, again with a focus on western Canada. We identified that this technology is an option toward a low carbon power sector. This is because it is able to mitigate life cycle GHG emissions associated with the use of these fossil fuels in the power generation industry and offers utility owners reduced incremental investment costs. Also, although there is significant availability of several biomass feedstocks in western Canada, sustainable biomass co-firing is hindered by several technical, logistical, and regulatory issues such as the technical configurations of the co-fired plants, the nature, supply, costs, and amount of biomass feedstock that can be co-fired, as well as existing government policies on the environment at both the federal and provincial levels.

Based on the knowledge gained from the first stage of this study, we developed two data-intensive techno-economic models to comparatively assess the costs of co-firing three biomass feedstocks, namely whole forest, wheat straw, and forest residues, with either coal or natural gas in both a fully paid-off modified plant and a partially paid-off plant in western Canada. The main conclusions developed from this detailed study can be summarized thus:

1. Generally, biomass feedstocks tend to be more expensive than equivalent amounts of coal or natural gas. For example, at 25% co-firing rate the unit costs of the biomass feedstock are: wood chips - $81.84/dry tonne; straw - $92.55/dry tonne; and forest residues - $73.26/dry tonne; while coal is $22/tonne and $6.50/GJ (i.e. $288.09/tonne).

2. The total capital costs per unit output ($/kW) of modifying a plant to co-fire biomass decreases as the co-firing level increases for both the coal and natural gas scenarios. However, when compared based on the plant age, the total capital costs are much lower for a fully paid-off plant than for a partially paid-off plant. For example, the capital costs per unit output for the fully paid-off scenarios of coal/forest residues decreased from $303.65/kW to $5203.06/kW and the fully paid-off scenarios of NG/forest residues increased from $1,697.86/kW to $1,135.43/kW.
3. Given the factors listed above, the cost of electricity from a co-fired plant is typically higher than the cost of electricity from a dedicated coal or natural gas plant. For example, the LCOE for a fully paid-off coal/forest residues scenario co-fired at a 25% co-firing level is $54.50/MWh while an equivalent fully paid-off coal-only scenario is $33.5/MWh; and the LCOE for a fully paid-off NG/forest residues scenario co-fired at a 25% co-firing level is $63.75/MWh while an equivalent fully paid-off NGCC scenario is $59.6/MWh. However, when viewed in the longer term we believe this is lower than the cost of generating the same amount of electricity from most GHG mitigation technologies.
4. The incremental costs and LCOE of generating electricity from a co-fired system increase as the level of co-firing increases due to the increase in the incremental cost associated with this change. For example, the incremental costs for the fully paid-off scenarios of coal/forest residues increased from $1.72/MWh to $7.90/MWh and the fully paid-off scenarios of NG/forest residues increased from $5.60/MWh to $19.43/MWh; the LCOE for the fully paid-off scenarios of coal/forest residues increased from $53.12/MWh to $54.50/MWh and the fully paid-off scenarios of NG/forest residues increased from $59.99/MWh to $63.75/MWh. However, the avoided CO_2 costs have an inverse relationship with the biomass co-firing levels, mainly due to the effect of economy of scale on the capital costs at each of the co-firing levels. For example, the CO_2

abatement costs for the fully paid-off scenarios of coal/forest residues decreased from \$31.15/tCO_2 to \$27.41/tCO_2 and the fully paid-off scenarios of NG/forest residues decreased from \$73.98/tCO_2 to \$51.31/tCO_2.

5. Forest residues emerged as the cheapest biomass feedstock to co-fire with both coal and natural gas. It is closely followed by wood chips and then wheat straw. However, before a utility company can decide on the most appropriate feedstock for a co-firing project, sufficient study must be done to determine the availability of each.
6. While a fully paid-off plant offered much better economic and environmental results to support biomass co-firing, the fully paid-off coal/forest residues emerged as the most attractive option especially with CO_2 abatement costs of \$28.63/tCO_2 to \$27.41/tCO_2 for the 10% to 25% co-firing rates. This is of huge interest given the recent announcement of the Government of Alberta to increase the carbon levy to \$30/ tCO_2 from 2017.
7. Considering this likely increase of the carbon tax to about \$30/tCO_2 in Alberta by 2017, urgent measures and favorable government policies are needed to address the prevalent technical and logistical issues that hinder utility owners from effectively exploiting the full potential of biomass co-firing. Such measure and policies include:
    - The creation of a harmonized system between all the relevant stakeholders to guarantee a long-term, sustainable supply of high-quality biomass feedstock.
    - Sustained R&D activities focused on resolving the issues and challenges that have been identified in this paper.
    - The formulation of various forms of subsidies and tax exemptions for utility owners and other relevant stakeholders, as well as a regulatory framework mandating GHG reductions.

These results make a case that biomass co-firing can be effectively employed to extend the life of existing power plants in western Canada, especially coal-based ones, while achieving favorable economic and environmental outcomes. This further enhances the potential of generating commercial electricity from these fossil fuels with significant reductions in the negative impacts on the environment, thereby improving the long-term usefulness of fossil energy in Western Canada.

4.2 Recommendations for future works

- Further studies in this area of research should be focused on increasing the amount of the base fuel that can be substituted with biomass beyond 25% without compromising the efficiency of energy use.
- Another area of interest should be in the application of the co-firing technologies to other varieties of biomass feedstock available in western Canada as well as pre-treatment of the biomass feedstocks.
- The conversion of raw biomass to an intermediate such as liquid oil or biocoal for co-firing with coal should be explored.

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Appendix

Appendix A

Equation A.1: Avoided CO_2 of co-firing biomass with coal

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

Where

$Incremental\ cost\ of\ co-firing$ = *LCOE of coal/biomass co-fired plant – LCOE of a reference plant without co-firing, CAD $/MWh*

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

$GHG\ Intensity_{co-firing}$= *GHG emission intensity of the coal/biomass co-fired plant, t CO2/MWh.*

Equation A.2: Avoided CO_2 of co-firing biomass with NG

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

where

$Incremental\ cost\ of\ co-firing$ = *LCOE of NG/biomass co-fired plant – LCOE of a reference plant without co-firing, CAD $/MWh*

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

$GHG\ Intensity_{co-firing}$= *GHG emission intensity of the NG/biomass co-fired plant, t CO2/MWh.*

Appendix B

B.1. Basic equations used in the calculation of the delivery costs of whole forest.

Feller buncher cost (CAD \$/cu m) = $1.58V^{-0.5963}$

Skidding cost (CAD \$/cu m) = $1.665V^{-0.3676}$

Cost of road construction and infrastructure (CAD \$/ha) = 1.27+(635.51/VT)

Loading, unloading and transportation cost = 2.91+0.0326D

where

V = mean merchantable volume of per stem, assumed to be 0.26m3 per stem based on medium yields of hardwood and spruce in the boreal forest. Average merchantable volume is assumed to be 90% of the gross volume per stem.

VT = mean merchantable volume per hectare, assumed to be 185.4 m3 ha−1 for the boreal forest.

T = mean number of merchantable stems per hectare.

D = round-trip road distance from the forest to the receiving plant. In this study the cost has been converted to green metric tonnes.

Note: *(1)The construction cost of roads represents the tertiary road network used only during the year of the harvest (2) Infrastructure cost depends on the amount of labor and machine, and possibly the merchantable volume per hectare (3) Skidding distance is assumed to be 150m (4) D = 2*average radius of transportation.*