

# Material Switching in Alberta

*Opportunity and Gap Analysis for Advancing Meaningful  
Biological Greenhouse Gas Reductions*

**Prepared for Alberta Innovates – Bio Solutions**



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## Executive Summary

Biomass material switching is the substitution of fossil fuel-based products with biomass and bio-based product alternatives, with the intention of obtaining environmental, social, and/or economic benefits. This report examines the material switching opportunities available for Alberta's non-energy industries with the primary driver of reduced greenhouse gas (GHG) emissions. The project goals were to quantify the point source GHG emissions of Alberta's non-energy large industrial emitters [ $>50,000$  tonnes carbon dioxide equivalents ( $t\ CO_2\ eq$ ) per year], identify technically feasible methods of material switching, quantify the GHG emission reductions that may be possible by material switching, and provide recommendations on pursuing GHG reduction opportunities in Alberta including knowledge gaps to implementation. In total, 14 product categories were considered for material switching, with product categories Ethylene & Ethylene Derivatives, Ammonia & Fertilizers, Cement & Lime, and Hydrogen having the largest combined annual emissions. For each product category, the production process was analyzed for three different material switching opportunities: 1) Input Switching – direct substitution of raw materials used in product manufacture; 2) Fuel Switching – switching of fuels used to provide process heat in product manufacture; and 3) Product Switching – replacement of final products with biologically-based alternatives.

It was determined that material switching opportunities were available for all product categories, but not all opportunities could be pursued due to limited biomass availability. Six product switching opportunities were identified as having the greatest opportunity for realistic, large-scale GHG reductions. They are:

### **1) Intensive Wood-Use Construction**

Use of wood in construction, whether in multi-storey buildings or single-family homes, results in carbon sequestration that can last decades or centuries. Wood-intensive building construction can result in a net decrease of carbon, thereby offsetting emissions from other sectors.

### **2) Biomethane for Natural Gas Substitution**

Upgraded biogas and landfill gas can blend with, or substitute for, natural gas in pipelines and directly at large industrial consumers such as producers of ammonia, thermal carbon black, hydrogen, pulp, steel, and sugar. Similar properties of natural gas and biomethane enable blending at any percentage.

### **3) Fuel Switching in Cement and Magnesium Oxide Kilns**

With fuel handling and facility modifications, alternative fuels can be used at co-firing rates of up to 70% with coal. Alberta is currently lagging other provinces in the use of alternative fuels in cement and magnesium oxide kilns. Use of biomass such as biosolids derived from wastewater has the additional benefit of reducing methane emissions.

**4) Biomass gasification for methanol production**

Methanol can be used to produce ethylene and propylene in a methanol-to-olefins facility, resulting in significant GHG emissions reductions. This bioethylene can then be used to produce ethylene derivatives such as polyethylene or linear alpha olefins. The alternative pathway of direct conversion of cellulose to ethylene glycol requires further investigation

**5) Biomass gasification for hydrogen production**

Hydrogen is a key input for fertilizer production, oil refining, and chemical production that is typically produced from natural gas. Gasification of feedstocks such as forest harvest residue, agricultural residues, solid waste, and bioenergy crops has the potential to produce large volumes of bio-based hydrogen to reduce natural gas consumption.

**6) Wheat-based ethanol production**

Ethanol can be used to produce ETBE, a gasoline fuel oxygenate, and bioethylene. Ensuring low life cycle GHG emissions for ethanol is critical if material switching of its derivatives is to result in large GHG emissions reductions.

Given the estimates of currently available biomass in Alberta, implementation of these six recommendations has the potential to reduce life cycle GHG emissions by 4.4 Mt CO<sub>2</sub> eq. In several cases, bio-based products can be readily blended with similar or identical fossil fuel-derived products that currently dominate the marketplace. This would enable a percentage of the product to be bio-based and may be a more realistic mode of implementation than complete substitution, from both product commercialization and biomass availability perspectives.

While current industrial technical feasibility and economic viability are key metrics dictating the realism of reductions, these were not considered primary criteria for recommendations. Therefore, recommendations on commercial implementation of any material switching options will require techno-economic analyses that are beyond the scope of this report. Future work might consider quantifying the cost of reduction in each category on a per tonne CO<sub>2</sub>-equivalent basis, which would allow government to optimize economic and environmental benefits. This report should not be interpreted as a definitive assessment on which material switching opportunities *should* be pursued, but which opportunities *could* be pursued. Aggressive implementation of material switching via bioproduct blending and branding of 'Alberta Bio' content could play an important role in highlighting Alberta's environmental credentials while recognizing the current scale and economic benefits of fossil fuel-derived products.

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## Abbreviations & Chemical Formulas

AD	Anaerobic digestion	Mm <sup>3</sup>	Million cubic meters
bdt	Bone dry tonnes	MPa	Megapascal
BL	Billion litres	MSW	Municipal solid waste
CaCO <sub>3</sub>	Calcium carbonate	Mt	Megatonnes
CaO	Calcium oxide/lime	MTBE	Methyl <i>tert</i> -butyl ether
CH <sub>4</sub>	Methane	MTO	Methanol-to-olefins
CH <sub>4</sub> N <sub>2</sub> O	Urea	NH <sub>3</sub>	Ammonia
CO <sub>2</sub>	Carbon dioxide	NH <sub>4</sub> NO <sub>3</sub>	Ammonium nitrate
CO <sub>2</sub> eq	Carbon dioxide equivalent	(NH <sub>4</sub> ) <sub>3</sub> PO <sub>4</sub>	Monoammonium phosphate
ETBE	Ethyl <i>tert</i> -butyl ether	N <sub>2</sub>	Nitrogen
GHG	Greenhouse gas	N <sub>2</sub> O	Nitrous oxide
GJ	Gigajoule	OPC	Ordinary Portland cement
GWP	Global warming potential	PJ	Petajoules
H <sub>2</sub>	Hydrogen	PPM	Parts per million
kg	kilogram	P <sub>2</sub> O <sub>5</sub>	Phosphorus pentoxide
LAO	Linear alpha olefins	SMR	Steam methane reforming
LCA	Life cycle assessment	t	Tonnes (metric)
LFA	Linear fatty alcohol	tpy	Tonnes per year
MDF	Medium density fibreboard	v/v	Volume/volume
MgCO <sub>3</sub>	Magnesium carbonate	WtE	Waste-to-energy
MgO	Magnesium oxide/magnesia		
MJ	Megajoule		

## 1 Introduction

Alberta is Canada's largest emitter of greenhouse gases (GHG) in both absolute and provincial per capita terms. In 2009, Alberta's GHG emissions were 233 megatonnes carbon dioxide equivalents (Mt CO<sub>2</sub> eq), representing about 34% of Canada's total emissions [1,2]. About 117 Mt CO<sub>2</sub> eq (50% of Alberta's emissions) were from 160 large industrial emitters, which are classified as facilities producing greater than 50,000 t CO<sub>2</sub> eq annually from a single facility and are hence listed in the Canada Greenhouse Gas Inventory [1]. Alberta has 31% of all large industrial emitters in Canada (160 of 522) reported in 2009, but these facilities tend to be larger than in other provinces and produce 47% of the emissions in this category [1,2]. A large percentage of these facilities are either electricity generating stations (coal or natural gas) or energy production/extraction facilities related to the large oil and gas sector in Alberta. However, 36 of these facilities produce non-energy products and account for 11.5% of Alberta's industrial emissions or 5.8% of Alberta's total emissions [1]. The production and use of products from these 36 facilities is the emphasis of this report.

Much attention has been paid to the role biomass and biological materials can play in reducing the carbon intensity of electricity, heat, and transportation fuels. Replacement, substitution, or blending options include combustion or gasification of wood, agricultural residues, and wood pellets (in stand-alone or coal co-firing applications) for heat and electricity generation; anaerobic digestion of manure, biosolids (sewage materials), and food wastes for heat and electricity generation; and liquid biofuels, such as ethanol and biodiesel, for transportation.

Less attention has been paid to the role of biomass in reducing the carbon intensity of non-energy products. Material switching - the displacement of fossil fuel-derived products and materials with biologically-derived alternatives - could result in a reduction in emissions associated with some products, as biomass typically has lower life cycle carbon intensity than the fossil fuels coal, oil, or natural gas. Material switching is envisioned as a means of reducing Alberta's GHG emissions and the carbon intensities of the products associated with Alberta's 36 non-energy large industrial emitters. A comprehensive assessment of the role that biomass can play to reduce the carbon intensity of non-energy sector emissions in Alberta has not been completed; this report aims to fill that gap.

This report has four primary objectives:

- 1) Quantify the point source GHG emissions of Alberta's non-energy industrial emitters;
- 2) Identify technically feasible methods of material switching;
- 3) Quantify the GHG emission reductions that may be possible by material switching; and
- 4) Provide recommendations on pursuing GHG reduction opportunities in Alberta, including knowledge gaps to implementation.

The three primary material switching options considered are:

- a) **Input Switching** – direct substitution of raw materials used in product manufacture (e.g., substitution of biomethane for natural gas in hydrogen production;



- b) Fuel Switching** – switching of fuels used to provide process heat in product manufacture (e.g., replacing a portion of the coal used for process heat in cement production with forestry or agricultural residues such as straw); and
- c) Product Switching** – replacement of final products with biologically-based alternatives (e.g., utilization of wood frame construction instead of cement and steel frame construction).

The type of switching employed can have significantly different impacts on existing facilities and operations in Alberta. For example, Input and Fuel Switching would enable the continued operation of existing facilities but using biological inputs. On the other hand, Product Switching could result in a competitor product that could challenge existing operators and have a negative impact on their sales and profitability. These impacts on existing facilities and operating companies must be taken into consideration when recommending preferred material switching options.

### **Greenhouse Gas Emissions – More than CO<sub>2</sub>**

Carbon dioxide (CO<sub>2</sub>) is just one of several GHGs that cause climate change. Other important gases include methane (CH<sub>4</sub>) and nitrous oxide (N<sub>2</sub>O). These GHGs differ in their global warming potential (GWP) – their total cumulative warming impact on the climate. Since the gases remain stable in the atmosphere for differing periods of time, a standard time of 100 years for their GWP (GWP-100) is used throughout this report. The standard of CO<sub>2</sub> equivalent (CO<sub>2</sub> eq) is used as a measurement, with one tonne of CH<sub>4</sub> having a GWP of 21 tonnes CO<sub>2</sub> eq and 1 tonne of N<sub>2</sub>O having a GWP of 310 tonnes CO<sub>2</sub> eq. These are consistent with the assumptions in Canada's National Inventory Report [1].

The 36 non-energy large industrial emitters are identified in Section 2 and grouped according to product category. GHG emissions from 2009, as presented in the most recent Canada Greenhouse Gas Inventory, were used as the baseline and are presented in Section 2. Section 3 of this report is organized according to product category, with sub-sections including Product Summary, Production Facilities, Switching Options, and Scale and Greenhouse Gas benefits. This Section of the report describes the facilities, potential for switching biomass for fossil fuel-related products, and estimating potential greenhouse gas reductions. Product summaries and production facility descriptions are derived from a literature review and research into operating companies. The biomass switching options described in Section 3 are based upon a literature review of existing switching practices, emerging technologies, and experimental work. The potential GHG reductions of these switching options are estimated in the 'Scale and Greenhouse Gas Benefits' subsections of Section 3. The data and reduction estimates are quantified on a percentage reduction basis (e.g., 50% reduction) over the life cycle of the products in question. This life cycle includes raw material extraction, transportation, pre-processing, production, and product use. While the non-energy large industrial emitters were identified by point source (i.e., facility) emissions, the life cycle emission reductions are the key finding of this report. The difference between point source and life cycle emissions is described in further detail in Section 2. The fossil fuel baseline is considered to be conventional gas and oil extraction, and open pit coal mining, unless otherwise specified. Wherever possible, Alberta specific figures were utilized and these are identified in the report.

Section 4 of this report provides a summary of the potential GHG emissions reductions from material switching in Alberta for upstream (raw materials and product production) and life cycle (including product use) emissions. The biomass materials required to realize these reductions are then quantified and compared to estimates of the available biomass in Alberta. The results from Sections 2, 3, and 4 form the basis for the gap analysis and recommendations presented in Section 5.

This report is focused on biomass material switching to replace fossil fuels and is not intended to provide recommendations on the production of biomass itself. Management practices in the agricultural and forestry sectors are beyond the scope of this report. Previously completed analyses on the life cycle emissions associated with biomass production, from both the agriculture and forestry sectors, are compared to life cycle emissions associated with fossil fuel extraction and production in order to estimate the potential for GHG emissions reductions from material switching. Given the number of products analyzed, a full life cycle assessment of each product, including facility construction, is beyond the scope of this report. The estimated GHG emission reductions from material switching in this report are a comparison of the GHG profile of the Alberta products using the best available data, but should not be interpreted as definitive life cycle assessment figures. The purpose is to provide a general range of reduction opportunities, not highly detailed modelling calculations.

## 2 Major Emitters and Target Industries

To determine the potential for GHG emissions reductions via material switching in Alberta, it was necessary to specify a baseline and identify industries where GHG emissions reductions could be possible. The Environment Canada National Inventory Report of 2011, for years 1990-2009, was used as a starting point to identify major emitters – classified as facilities producing over 50,000 t CO<sub>2</sub> eq [1]. This was used to determine priority product categories for material switching to reduce GHG emissions. There are 36 non-energy large-emitter facilities that were considered in this analysis (Table 2.1) [1]. Figure 2.1 provides a map of the sites in question.

**Table 2.1 Major non-energy greenhouse gas emitters in Alberta, by product category (2009)**

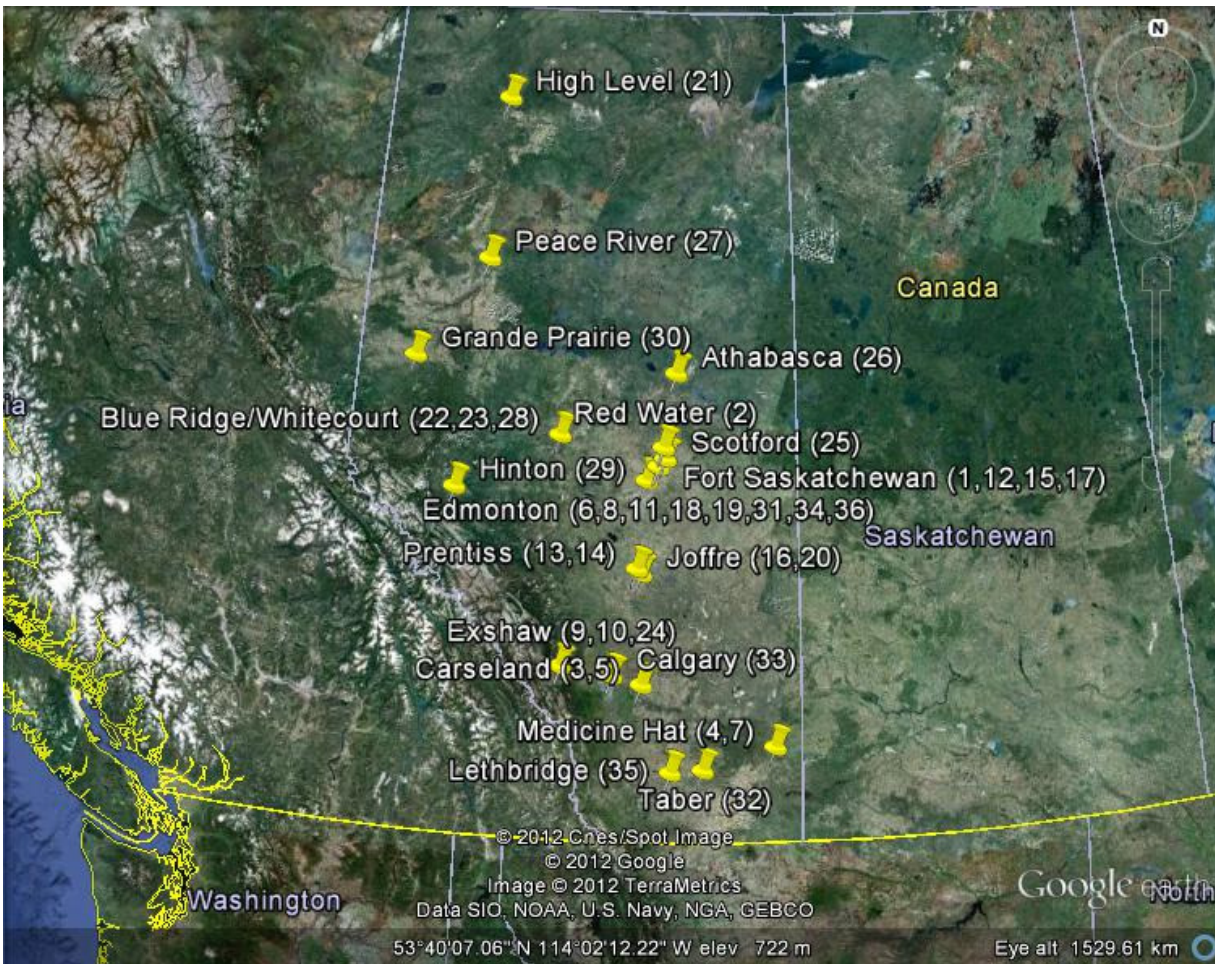
Map Number	Operator	Site	Product(s)	2004 GHG Emissions (t CO <sub>2</sub> eq)*	2009 GHG Emissions (t CO <sub>2</sub> eq)	5-year Average Annual GHG Emissions Change
<b>Ammonia &amp; Fertilizers</b>					<b>4,043,422</b>	
1	Agrium Inc.	Fort Saskatchewan	Ammonia, urea	609,871	580,218	-1.0%
2	Agrium Inc.	Red Water (N of Fort Saskatchewan)	Ammonia, urea, fertilizer solutions	1,207,689	865,019	-6.5%
3	Agrium Inc./Terra Industries Inc.	Carseland (near Calgary)	Ammonia, urea	520,749	532,861	0.5%
4	Canadian Fertilizers Limited	Medicine Hat	Ammonia, urea	1,619,815	1,417,793	-2.6%
5	Orica Canada Inc.	Carseland (near Calgary)	Ammonium nitrate	714,530	338,172	-13.9%
6	Sherritt International	Fort Saskatchewan	Ammonia, urea, ammonium sulphate, nickel, cobalt	275,580	309,359	2.3%
<b>Calcined Coke &amp; Thermal Carbon Black</b>					<b>190,657</b>	
7	Cancarb Ltd.	Medicine Hat	Thermal carbon black	127,003	95,675	-5.5%
8	Rio Tinto Alcan	Sherwood Park (Edmonton)	Calcined coke	N/I	94,982	-
<b>Cement &amp; Lime</b>					<b>1,587,603</b>	
9	Graymont Western Canada Inc.	Exshaw (near Canmore)	Lime, hydrated lime	202,749	146,305	-6.3%
10	Lafarge Canada Inc.	Exshaw (near Canmore)	Cement	1,136,616	824,088	-6.2%
11	Lehigh Cement Inc.	Edmonton	Cement	794,202	617,210	-4.9%

<b>Ethylene &amp; Ethylene Derivatives</b>					<b>4,544,571</b>	
12	Dow Chemical Canada ULC	Fort Saskatchewan	Ethylene, polyethylene, ethylene dichloride, vinyl chloride monomer, foam, chlor-alkali	1,434,027	1,440,121	0.1%
13	Dow Chemical Canada ULC	Prentiss (near Red Deer)	Polyethylene	N/I	34,325	-
14	MEGlobal Canada Inc.	Prentiss (near Red Deer)	Ethylene glycol, ethylene oxide	374,337	162,197	-15.4%
15	MEGlobal Canada Inc.	Fort Saskatchewan	Ethylene glycol, ethylene oxide	104,235	59,021	-10.8%
16	NOVA Chemicals Corporation	Joffre (near Red Deer)	Ethylene, polyethylene	3,195,293	2,615,537	-3.9%
17	Shell Chemicals Canada Ltd	Fort Saskatchewan	Ethylene glycol, diethylene glycol, triethylene glycol, styrene, fuels	280,213	233,370	-3.6%
<b>Hydrogen</b>					<b>1,069,164</b>	
18	Air Products Canada Ltd.	Edmonton	Hydrogen	N/A	1,069,164	-
<b>Isooctane</b>					<b>323,824</b>	
19	Alberta Envirofuels Inc.	Edmonton	Isooctane	348,425	323,824	-1.5%
<b>Linear Alpha Olefins (LAO)</b>					<b>112,078</b>	
20	INEOS Canada Partnership Inc.	Joffre (near Red Deer)	Linear alpha olefins (1-hexene, 1-octene and 1-decene)	109,566	112,078	0.5%
<b>Lumber &amp; Medium Density Fibreboard</b>					<b>132,081</b>	
21	Tolko Industries Ltd.	High Level	Lumber	N/I	38,917	-
22	West Fraser Mills Ltd.	Blue Ridge (NW of Edmonton)	Medium density fibreboard (MDF)	N/I	75,463	-
23	West Fraser Mills Ltd.	Blue Ridge (NW of Edmonton)	Lumber	N/I	17,701	-
<b>Magnesium Oxide</b>					<b>93,694</b>	
24	Baymag Inc.	Exshaw (near Canmore)	Magnesium oxide	N/I	93,694	-
<b>Nitrogen &amp; Oxygen Gases</b>					<b>437,984</b>	
25	Air Liquide Canada Inc.	Scotford	Oxygen, nitrogen, & carbon dioxide gases	364,289	437,984	3.8%

<b>Pulp (Kraft &amp; Mechanical)</b>					<b>535,085</b>	
26	Alberta-Pacific Forest Industries Inc.	Athabasca (50 km NE)	Kraft pulp	102,180	114,842	2.4%
27	Daishowa-Marubeni International Ltd.	Peace River (15 km N)	Kraft Pulp	84,698	98,873	3.1%
28	Millar Western Forest Products Ltd.	Whitecourt	Bleached chemi-thermo-mechanical pulp	N/I	56,460	-
29	West Fraser Mills Ltd.	Hinton (W of Edmonton)	Northern bleached softwood kraft pulp (NBSKP)	159,983	168,008	1.0%
30	Weyerhaeuser Company Ltd.	Grande Prairie	Northern bleached softwood kraft pulp (NBSKP)	127,417	96,902	-5.3%
<b>Steel</b>					<b>77,664</b>	
31	AltaSteel Ltd.	Edmonton	Steel	N/I	77,664	-
<b>Sugar (from Sugar Beet)</b>					<b>62,357</b>	
32	Lantic Inc.	Taber	Sugar beet processing	N/I	62,357	-
<b>Waste Management</b>					<b>319,159</b>	
33	City of Calgary (East Calgary Landfill)	Calgary	Waste disposal	84,364	94,324	2.3%
34	City of Edmonton (EPCOR Gold Bar Wastewater Treatment Plant)	Edmonton	Wastewater treatment	N/I	92,745	-
35	City of Lethbridge (Lethbridge Waste and Recycling Centre Disposal Site)	Lethbridge	Waste disposal	N/I	57,994	-
36	Waste Management Canada Ltd. (West Edmonton Landfill)	Edmonton	Waste disposal	N/I	74,096	-

\*N/I = Not inventoried (did not meet 2004 inventory threshold of 100,000 t CO<sub>2</sub> eq, which was higher than the 2009 threshold of 50,000 t CO<sub>2</sub> eq); N/A = Not applicable (facility did not exist in 2004)

Figure 2.1 Map of large non-energy industrial emitters in Alberta (2009)



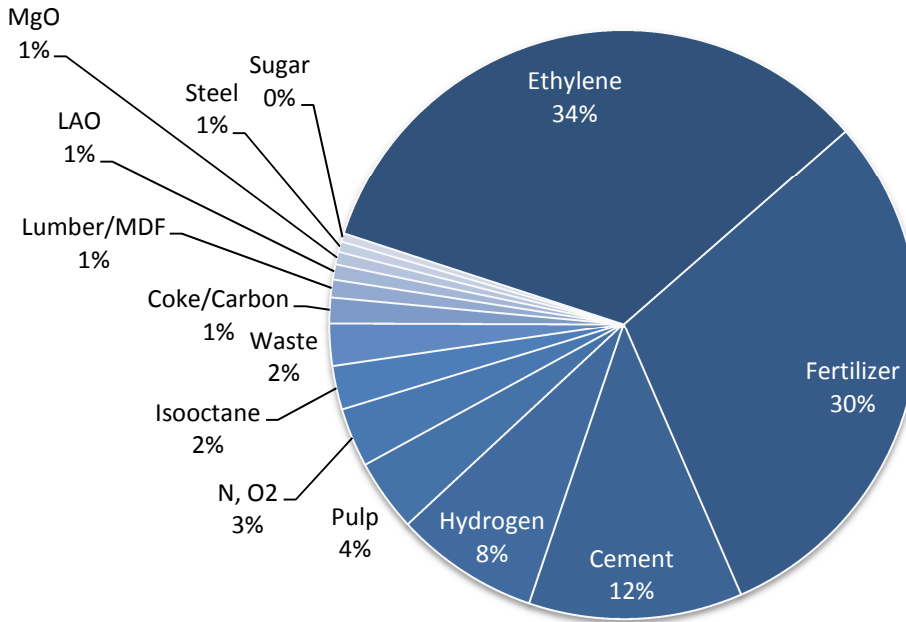
As identified in Table 2.1, the product categories with the greatest GHG emissions in 2009 were Ethylene & Ethylene Derivatives and Ammonia & Fertilizers, with over 4 Mt CO<sub>2</sub> eq each. These were followed by Cement and Lime (~1.6 Mt CO<sub>2</sub> eq) and Hydrogen (~1 Mt CO<sub>2</sub> eq). The only other product category over 500,000 t CO<sub>2</sub> eq was pulp. The proportional contribution of each product category to the non-energy industrial GHG emissions in Alberta in 2009 is presented in Figure 2.2

### Point Source vs. Life Cycle Greenhouse Gas Reductions from Material Switching

Point source emissions are those released directly by the facility listed in Table 2.1. However, most of the GHG reductions estimated in this report are on a product life cycle basis. In some cases, point source emissions from production facilities constitute less than 50% of the life cycle emissions for a product. Given material switching can result in GHG emissions reductions greater than 80% over the life cycle of a product, potential life cycle GHG reductions can exceed the total point source emissions for a study facility. Therefore, differentiation between point source and life cycle emissions reductions is a critical consideration when comparing GHG reductions from material switching.

Figure 2.2 Relative contribution of product categories to non-energy, industrial GHG emissions (2009)

Ref: [1]



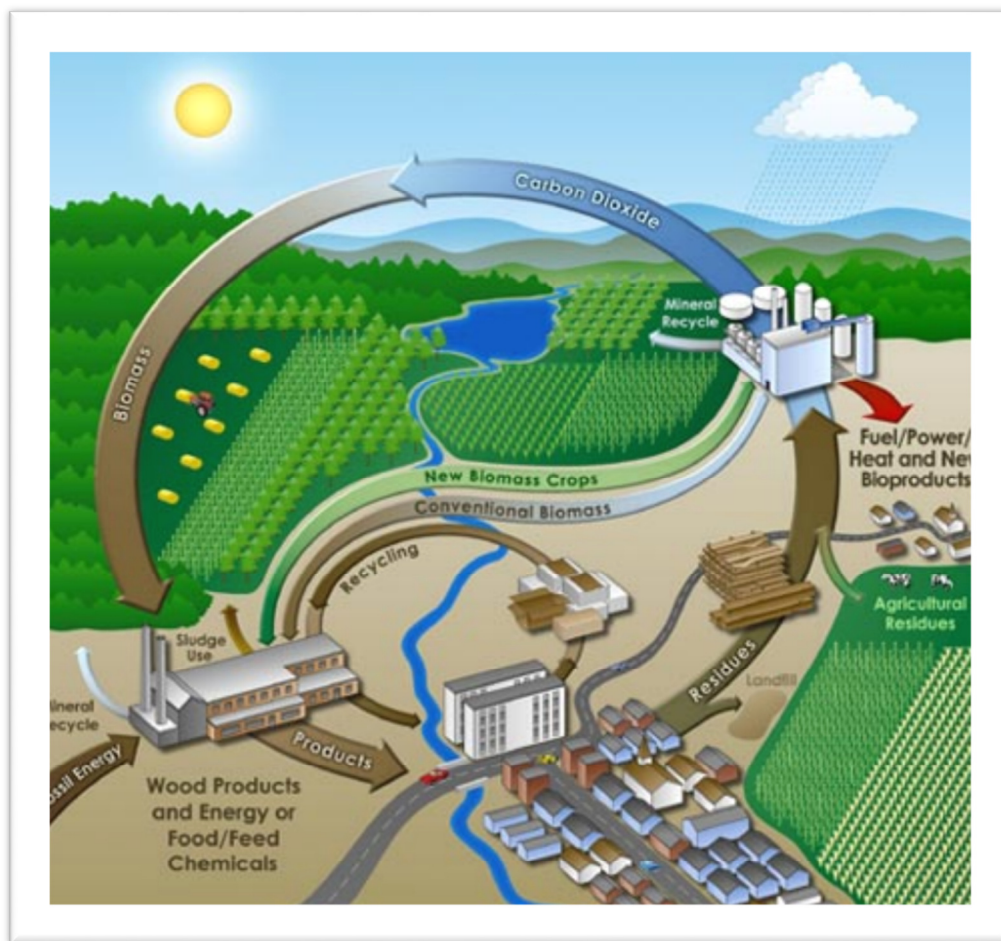
The GHG emission reduction potential from material switching requires consideration of net emissions over a product’s entire life cycle. Consideration of only point source emissions is insufficient - these emissions might be altered very little or could even increase from the use of biomass, but over the life of the product the net emissions may be reduced due to re-sequestration of carbon from the atmosphere via biomass regrowth. When biomass is used for fuel, as a raw material, or as a source of carbon for processes, it does not increase the amount of carbon in the biosphere<sup>1</sup> because it is already part of the biosphere. By comparison, when fossil fuels, such as natural gas, coal, or oil, are used for fuel, as raw materials, or as process carbon sources, the carbon they contain is added to the amount of carbon currently in the biosphere. This net increase in carbon in the atmosphere is a primary contributor to climate change. Apart from the fossil fuels used to harvest and/or process biomass, its use does not result in a net carbon contribution to the biosphere. Figure 2.3 shows a graphical representation of biomass as part of the biosphere carbon cycle and its role as a relatively carbon neutral material. The relative carbon neutrality of biomass is dependent upon sustainable management and re-growth of biomass sources, including forests and agriculture [3]. The GHG benefits from material switching, as represented by the relative GHG profile of material inputs, are estimated in the ‘Scale and Greenhouse Gas Benefits’ for each product category in Section 3.

<sup>1</sup> The biosphere consists of the ecosystems of Earth where life exists, including the air, the water, the planet surface, and the first few layers of soil

Figure 2.3 Biomass within the biosphere carbon cycle

(Image courtesy of Oak Ridge National Laboratory [4])

Figure Explanation: Plants, composed of biomass, absorb carbon dioxide (CO<sub>2</sub>) from the atmosphere to grow. The carbon taken from the atmosphere is stored in plant matter such as wood, leaves, straw, and grains. These plant materials are used to produce food, animal feed, materials, chemicals, energy, and in the case of wood, structural products. In many cases, the plant materials can be used multiple times for different purposes; an example is lumber, which is primarily used in construction, but following demolition, can be reused, turned into other products, or converted to energy such as heat and power. The residues from the production of primary products, such as lumber and food crops, often have use as energy or chemical feedstocks. Once the biomass materials are incinerated at the last stage of use, the carbon in the biomass is released back into the atmosphere for reabsorption by other plants to grow more biomass. This forms a closed carbon cycle in which net increases to the carbon in the biosphere are limited to fossil fuels required for biomass acquisition and processing.





### 3 Material Switching by Product Category

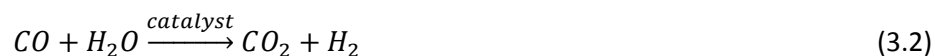
#### 3.1 Ammonia & Fertilizers

##### 3.1.1 Product Summary

Ammonia (NH<sub>3</sub>) is the primary component/input of nitrogen inorganic fertilizers, the use of which is critical to high-yield global food production systems. Combined with fuel, fertilizer accounts for approximately 16% of the operating cost for Canadian farms [5]. Although nitrogen (N<sub>2</sub>) is the dominant gas in air, it cannot be utilized by plants in its diatomic state and must be converted to a form that can be absorbed by plants. Common fertilizers include the ammonia derivatives urea (CH<sub>4</sub>N<sub>2</sub>O) and ammonium nitrate (NH<sub>4</sub>NO<sub>3</sub>) [6,7]. Ammonia is also widely used in the chemicals, pharmaceuticals, and explosives industries as a “building block” for other compounds. For Canadian ammonia producers, natural gas costs represent 70-90% of the production costs [5]. Approximately 50% of Canadian nitrogen fertilizer is exported – largely to the United States [5].

##### 3.1.2 Production Facilities

Alberta is host to a strong fertilizer industry, including North America’s largest ammonia facility – the Canadian Fertilizers Limited facility in Medicine Hat. The attraction of ammonia production in Alberta is the abundance of low-cost natural gas, which is used in the Haber-Bosch process to convert diatomic atmospheric nitrogen into ammonia. The first two stages of production involve production of hydrogen gas from methane and steam using steam methane reforming (SMR) (Equation 3.1) and the water gas shift reaction (Equation 3.2). These are followed by the actual Haber-Bosch process, which synthesizes ammonia from hydrogen and nitrogen gases (Equation 3.3). This process requires a pressure of 10-25 mega-Pascal (MPa), a temperature between 350 and 550°C, and an iron catalyst promoted with potassium (K<sup>+</sup>) cations [6,8,9].



There are seven large fertilizer facilities producing ammonia and ammonia derivatives in Alberta (Table 3.1). Several of the facilities convert a large proportion of their ammonia to urea, one facility also produces solutions, and others focus on ammonium nitrate and ammonium sulphate production. The facilities have a combined net ammonia output (subtracting that used to make derivatives internally) of 2.0 Mt, a urea output of 2.6 Mt, an ammonium nitrate output of 0.5 Mt, an ammonium sulphate output of 0.2 Mt, and a solutions output of 0.2 Mt. The Agrium facility in Red Water also has a capacity of 660,000 t monoammonium phosphate ((NH<sub>4</sub>)<sub>3</sub>PO<sub>4</sub>, the salt of ammonia and phosphoric acid) and 345,000 t phosphorus pentoxide (P<sub>4</sub>O<sub>10</sub>, with an empirical formula of P<sub>2</sub>O<sub>5</sub>) [10]. The large ammonia and fertilizer facilities in Alberta produced approximately 4 Mt CO<sub>2</sub> eq in 2009.

**Table 3.1 Alberta's large fertilizer facilities (2009)**

Ref: [1,10,11,12,13]

Company	Facility Location	Fertilizer and GHG Emissions Output (kt per year)					
		Ammonia (net)	Urea	Ammonium nitrate	Ammonium sulphate	Solutions	CO <sub>2</sub> eq
Agrium	Fort Saskatchewan	170	430	-	-	-	580
Agrium	Joffre	480	-	-	-	-	N/l <sup>a</sup>
Agrium	Red Water	250	720	-	-	180	865
Agrium/Terra Industries	Carseland	135	680	-	-	-	533
Canadian Fertilizers	Medicine Hat	784	735	-	-	-	1,418
Orica Canada	Carseland	-	-	500 <sup>b</sup>	-	-	338
Sherritt International	Fort Saskatchewan	155	105	-	200	-	309 (includes metal smelting)

<sup>a</sup>The Joffre facility uses a by-product hydrogen stream for ammonia production and does not consume natural gas directly

<sup>b</sup>End-use of ammonium nitrate dominated by explosives, not fertilizer

### 3.1.3 Switching Options

Fertilizer switching options can be broken down into two primary categories: those that provide a biological source of hydrogen for inorganic fertilizer production (Input Switching) and those that substitute organic fertilizer for inorganic options (Product Switching).

- a) Inorganic – The potential for biological sources of methane, which can be converted into hydrogen for ammonia production using SMR and the water gas shift reaction, is examined in Section 3.5.3. This discussion will focus on biological sources of hydrogen for ammonia production that do not entail SMR of biomethane, the principal option being the hydrogen component of biomass-derived syngas. Syngas, which is composed largely of CO, H<sub>2</sub>, small amounts of CH<sub>4</sub> and CO<sub>2</sub>, and traces of other gases, is produced from the gasification of biomass. Instead of the carbon in biomass being fully oxidized to CO<sub>2</sub> (as is the case in biomass combustion), the carbon is only partially oxidized and results in the production of CO [14,15]. When air, instead of pure oxygen, is used as the oxygen source in gasification, the resulting gas is called producer gas and has a nitrogen (N<sub>2</sub>) content of approximately 50%. H<sub>2</sub> and CO ratios depend largely upon the C:H ratio in the gasification feedstock. As per the water gas shift reaction used as the second step in natural gas-based ammonia production, the CO in the syngas can be used to increase the production of H<sub>2</sub>. Due to the large variety of technologies and feedstocks, and hence large variety in performance and efficiency, that could be considered for biomass gasification for hydrogen production, there is a significant range in the GHG emissions reduction potential. In addition, technical challenges, such as cost-effective syngas cleanup and tar removal, have yet to be proven commercially over an extended operating period [14,15].

- b) Organic – Organic fertilizers are naturally-occurring sources of the primary macronutrients nitrogen, phosphorus, and potassium. Organic fertilizers can be grouped into biological sources such as manure, crop residues, compost, guano, human biosolids, anaerobic digestion solids, and worm castings, while non-biological sources are typically mineral deposits that are mined. As non-biological material, the latter will not be dealt with here. Organic, biological fertilizers are classified as slow-release fertilizers due to the length of time required for macro- and micro-nutrients from the fertilizer to be absorbed and utilized by the plant. Organic fertilizers increase organic matter in the soil, and in doing so, increase soil microbiological diversity and increase soil humus and carbon stocks [16,17,18,19]. However, organic fertilizers present challenges in use due to the slow release of nutrients, variable nutrient content and reduced control of nutrient dispersal, bulkiness (which increases transportation and storage cost), and, in the case of manure, guano, and biosolids, the potential for disease transmission and food contamination [7,17,20,21].

### **3.1.4 Scale and Greenhouse Gas Benefits**

The quantity of H<sub>2</sub> produced from the gasification of biomass is dependent upon the H:C:O ratio of feedstock in question and also the gasification technology, with ratios of H<sub>2</sub>:CO ranging from 1:6 to 1:1 [22], although the water gas shift reaction can be used to produce increased volumes of H<sub>2</sub> using CO and water. In an investigation of the potential for NH<sub>3</sub> production from forest resources in western Canada using gasification technology, Sarkar et al. (2011) estimated an NH<sub>3</sub> conversion of 84% of the H<sub>2</sub> gas flow over the course of several passes [23]. Typical conversion is 25-35% for a single pass of H<sub>2</sub> and N<sub>2</sub> [24,25]. In a life cycle comparative assessment of ammonium nitrate (NH<sub>4</sub>NO<sub>3</sub>) fertilizer production by biomass gasification relative to traditional natural gas production, the life cycle GHG emissions from Salix (willow) and straw feedstocks were reduced by 70% and 78% relative to natural gas baseline, respectively [25]. This was based upon an H<sub>2</sub> yield of 0.56 megajoule (MJ) H<sub>2</sub> per MJ dry biomass (approximately 7% on a mass basis), which is confirmed by previous studies [26]. Should nitric acid production, as required for ammonium nitrate production regardless of ammonia source, be removed from the life cycle and a pure focus on ammonia, the GHG reduction would be significantly larger on a percentage basis – 85-90%. Since ammonia-based inorganic fertilizer will perform identically regardless of hydrogen source (biological or natural gas), the key metric for determining GHG reductions from material switching is the GHG emissions associated with hydrogen production. As discussed in Section 3.1.3, a large variety of biomass gasification technologies and feedstocks with differing performance and efficiency result in a large range for potential GHG emissions reductions. Life cycle analyses on hydrogen production via steam reforming have found a GWP of 11.9 kg CO<sub>2</sub> eq kg<sup>-1</sup> H<sub>2</sub> [27]. Previous estimates have found life cycle GHG emissions for H<sub>2</sub> production from biomass to be approximately 1 kg CO<sub>2</sub> eq kg<sup>-1</sup> H<sub>2</sub> [28], which is a greater than 90% reduction relative to natural gas baseline. Assuming an 80% life cycle GHG emissions reduction for fertilizer production due to biomass gasification-derived hydrogen Input Switching, including an 18% upstream emissions allowance (calculated from [29] relative to Canadian Fertilizers Inc. emission rates) and accounting for production process beyond hydrogen production, the annual life GHG emissions reduction would be 3.8 Mt CO<sub>2</sub> eq.

The GHG impact of Product Switching to organic fertilizer from inorganic synthetic fertilizer is highly variable and depends upon a combination of many factors including organic fertilizer properties, soil type and properties, crop and cropping system, weather conditions, and harvest (e.g., till vs. no-till) practices [30]. For example, nitrous oxide (N<sub>2</sub>O), which has a 100-year global warming potential 310 times that of CO<sub>2</sub>, is a major contributor to the life cycle GHG emissions of agricultural systems. Its production is strongly influenced by fertilizer properties and application practices. For some life cycle assessments, the emissions factor for direct N<sub>2</sub>O emissions has been generalized as 1.25% of nitrogen (N) applied [31]. The Intergovernmental Panel on Climate Change (IPCC) uses a general emission factor of 1% for applied N, regardless of inorganic or organic fertilizer source, with a range of 0-3% [32]. This has been used as a default value for many life cycle assessment (LCA) studies (e.g., [33]). However, site-specific assessments would be needed to accurately determine the GHG impact in Alberta.

Although the GHG emissions performance of organic and inorganic fertilizer during use is estimated to be similar on an applied-nitrogen basis, organic fertilizer production has been found to have a smaller GHG production profile than that of inorganic fertilizer production [34]. The IPCC nitrogen (ammonia) fertilizer production emissions factor, which is used by Canada, is 1.6 kg CO<sub>2</sub> eq kg<sup>-1</sup> product [35]. This is higher than actual facility emissions reported in the Canadian GHG inventory. For example, Canadian Fertilizers Ltd. reported emissions of 1.2 kg CO<sub>2</sub> eq kg<sup>-1</sup> product [1], although this number excludes upstream emissions associated with natural gas extraction. If upstream natural gas emissions were included [29], the Canadian Fertilizers Ltd. emission factor would be approximately 1.45 kg CO<sub>2</sub> eq kg<sup>-1</sup> product. In organic fertilizer LCAs, emissions associated with the production and storage of the fertilizer have not typically been allocated to the fertilizer itself, since the fertilizer has been considered to be a by-product of production (e.g., manure is a by-product of milk or meat production). The primary emissions considered for organic fertilizer are transportation and spreading of the fertilizer, making them highly site specific [36]. While notable, these emissions will be significantly less than those associated with inorganic fertilizer production, distribution, and spreading. In a comparative LCA of conventional (inorganic) and organic production systems for leeks, GHG emissions were found to be 54% lower for the organic system compared to the inorganic system [36]. However, the study includes other non-fertilizer management practices in the estimate.

## **3.2 Calcined Coke and Thermal Carbon Black**

### **3.2.1 Product Summary**

Calcined petroleum coke (calcined petcoke) is a very high carbon content solid that is produced from the petroleum coke (petcoke) derived from petroleum refining cracker or coking units. Approximately 23% of worldwide petcoke (excluding China, where proportional use in energy is much higher [37]) is used to produce calcined coke, with 75% of that production used to produce anodes for the aluminum industry due to the high carbon purity requirement in their manufacture [38]. The remaining 25% is used in the titanium, steel, and electrochemical industries for processes requiring a very high carbon content solid [39]. Calcined petcoke is very low in moisture and oxygen-containing volatiles.

Thermal carbon black is a very high elemental carbon content (~97%), notably black solid. Approximately 70% of carbon black is used as a black pigment and reinforcer in the production of automobile tires. Non-tire rubber products account for 20% of consumption, while the remaining 10% is used as a pigment in inks and other applications [40]. Thermal carbon black is one of two types of carbon black – the other being furnace carbon black. The distinctive labels are due to the process used in manufacture.

### **3.2.2 Production Facilities**

One calcined petcoke and one thermal carbon black facility operate in Alberta. Although these are both high carbon products, they are produced by very different methods. Petcoke is a by-product of the petroleum refining and chemical production industries. Approximately 4-7% of an ‘average’ barrel of oil remains as petcoke following refining (“bottom of the barrel”), with longer residence times and higher temperature for coking favouring harder coke production. Harder petcoke results in a higher yield of calcined petcoke, which is produced by passing petcoke through a rotary kiln to drive off volatiles and moisture [41]. This results in a low-moisture, high carbon content material. The volatiles from the calcining process are used to provide heat for the kiln at the required temperature of 1300°C. The Rio Tinto Alcan facility in Strathcona receives 250,000 t of ‘green’ coke per year to produce 172,000 t calcined coke [42].

In contrast, thermal carbon black is produced from natural gas by superheating the gas and decomposing it into elemental carbon and hydrogen. The hydrogen gas is typically combusted to provide energy for the process. Thermal production using natural gas is one of two manufacturing processes for producing carbon black – the other being furnace production. In this latter process, heavy oil and tar (from fluid catalytic cracking and ethylene production) are pyrolyzed under controlled conditions and the carbon black particles extracted. Co-products are hydrogen and carbon monoxide [40]. It should be noted that carbon black is not the same as black carbon (soot), which is produced from the incomplete combustion of carbon containing materials and is considered a pollutant.

### **3.2.3 Switching Options**

Input Switching and Product Switching opportunities are available for both calcined petcoke and thermal carbon black. Biocoke, or biomass-based coke, is a high carbon material produced using pyrolysis (heating in the absence of oxygen). Many different pyrolysis technologies exist for transferring heat to the biomass materials but can be classified into two major groups: 1) carbonization, or slow pyrolysis technologies; and 2) fast pyrolysis technologies. The former operate at temperatures above 250°C, require a residency time of minutes to hours, and result in a higher carbon solid with higher temperatures (up to 1300°C) [43]. The latter, as the name implies, are much faster technologies that operate at 400-500°C and require a residency time of only a few seconds. Typically, a longer residence time and lower temperature result in a higher solid product yield. Longer residency time also results in a higher purity carbon solid. Liquid pyrolysis oil is the dominant product of fast pyrolysis, although solid yield can still reach 30-35% [43,44].

The quality of the solid product is of utmost importance if it is to be processed to calcined coke. While most pyrolysis processes produce low-density char (charcoal), biocoke is a denser product, more in keeping with petcoke qualities [45]. The Australian national research organization CSIRO announced in 2011 that they had developed a pyrolysis process to convert biomass into metallurgical grade (for aluminum industry anode production) biocoke [45]. Should the biocoke product require further processing to become calcined biocoke, this would be considered an Input Switching opportunity. Should it meet calcined coke specifications for carbon, moisture, and volatile content without further processing in a rotary kiln, this would be considered a Product Switching opportunity.

A similar pyrolysis process may also be employed to produce bio-based furnace carbon black as a Product Switching opportunity. Although not in commercial operation, technologies have been developed and patented that are intended to produce carbon black from lignocellulosic biomass materials [46]. An example is a multi-stage hydrolysis-carbonization-pyrolysis process that can produce a carbon black product of 95% carbon [47]. Alternatively, a high temperature (>700°C) and multi-hour residency pyrolysis process has also been developed [48]. Overall, to produce bio-based carbon black, pyrolysis and treatment conditions must have a higher temperature and longer residency than traditional fast pyrolysis. It is only under these harsher conditions that the carbon purity is increased to a level that is acceptable for Product Switching.

Input Switching would be possible for the CanCarb thermal carbon black facility through the utilization of biomethane in the place of natural gas. Production of high purity biomethane is discussed in Section 3.5.3, but could include upgrading feedstocks biogas and landfill gas. The biomethane would need to meet natural gas quality methane and trace gas standards prior to use in the production of carbon black. Utilization of biomethane would present a feedstock diversification, Input Switching option to the existing facility rather than production of a competitor product – as would be the case in Product Switching for bio-based carbon black.

### **3.2.4 Scale and Greenhouse Gas Benefits**

The GHG emissions associated with the production (not life cycle) of thermal carbon black are approximately 2.0-2.2 kg CO<sub>2</sub> eq kg<sup>-1</sup>, as evidenced by both the CanCarb facility emissions relative to yearly production capacity of 45,000 t [49] and literature data [50]. Other studies have shown that the GHG impact of H<sub>2</sub> production from the thermal carbon black process is 2.23 kg CO<sub>2</sub> eq kg<sup>-1</sup> H<sub>2</sub> [51], although the H<sub>2</sub> is typically used to provide heat for the production process. Should natural gas be used for heat instead of this by-product H<sub>2</sub>, emissions are estimated to more than double. Utilization of biomethane, sourced from upgraded biogas, could result in large net GHG reductions in thermal carbon black manufacture. The life cycle GHG reduction associated with the production and use of biomethane relative to natural gas is largely dependent upon the feedstock utilized in the anaerobic digester and the upgrading technology. A 10-20% reduction from natural gas was found when utilizing biomethane from anaerobic digestion of bioenergy crops [52]. In another study on biogas upgrading to biomethane, water scrubber-upgraded biogas had reductions of 27-63% relative to natural gas, with the large range due to differing feedstock performance [53]. Relative to a 68 kg CO<sub>2</sub> eq GJ<sup>-1</sup> natural gas baseline [54,29], anaerobic digestion of dairy manure for compressed biomethane resulted in an 80% reduction in GHG

emissions [55], while upgrading and compressing of landfill gas resulted in a reduction of 83% [56]. Other studies have found a more than 100% reduction (i.e., net carbon reduction from use) when using liquid manure due to the reduced methane emissions from unprocessed liquid manure found in the base case [57]. For the CanCarb facility, complete Input Switching from natural gas to biomethane would reduce annual GHG emissions by 9,600 t CO<sub>2</sub> eq for bioenergy crop anaerobic digestion, but 77,000-79,000 t CO<sub>2</sub> eq if a combination of upgraded landfill gas from the Medicine Hat landfill and biogas from anaerobic digestion of manure were utilized (assuming reductions of 80-83%). A mid-range 50% reduction would result in an annual decrease of 48,000 t CO<sub>2</sub> eq.

The most relevant LCAs that have been undertaken for Product Switching of calcined coke and carbon black have focused on biochar. These have typically assessed the GHG benefits of switching biochar for coal in thermal power plants. Roberts et al. (2010) estimated that replacement of coal with biochar in an integrated combined cycle coal power plant would result in GHG reductions of 2.1 kg CO<sub>2</sub> eq kg<sup>-1</sup> biochar (0.6 kg CO<sub>2</sub> eq kg<sup>-1</sup> unprocessed corn stover feedstock) [58]. This is a reduction of approximately 85% from bituminous coal and is based upon a biochar yield of 30% from corn stover. Petcoke, which is used to make calcined coke, constitutes approximately 4-7% of an average product mix of a conventional oil refinery by weight and produces 3.5 kg CO<sub>2</sub> eq kg<sup>-1</sup> coke when combusted [54,59], with total life cycle emissions of 4.7 kg CO<sub>2</sub> eq kg<sup>-1</sup> coke [60]. Assuming the Rio Tinto Alcan facility receives 250,000 t of petcoke coke per year (to produce 172,000 t of calcined coke), the emissions intensity for the facility is 0.4 kg CO<sub>2</sub> eq kg<sup>-1</sup> petcoke or 0.55 kg CO<sub>2</sub> eq kg<sup>-1</sup> calcined coke. Total life cycle emissions would be approximately 5.1 kg CO<sub>2</sub> eq kg<sup>-1</sup> petcoke or 7.4 kg CO<sub>2</sub> eq kg<sup>-1</sup> calcined coke. This compares with life cycle GHG emissions for thermal bituminous coal of 2.4-2.5 kg CO<sub>2</sub> eq kg<sup>-1</sup>, which has approximately 75% the fixed carbon content of calcined coke [61,62]. Therefore, applying an 85% life cycle GHG reduction, as determined for biochar relative coal [58], to petcoke is conservative. Applying this to calcined biocoke (in place of petcoke) production at the Rio Tinto Alcan facility, life cycle GHG emissions could be reduced by 1.1 Mt CO<sub>2</sub> eq.

### **3.3 Cement & Lime**

#### **3.3.1 Product Summary**

Cement is the world's most widely used construction material and its production is responsible for approximately 5% of global GHG emissions [63]. Cement is often mixed with aggregate and additives to form concrete and acts as the binder in this mixture. Cement can be classified into hydraulic, including the common ordinary Portland cement (OPC), and non-hydraulic forms. The former requires water to harden it, but then retains its structural integrity even in wet and, in some cases, underwater conditions. Non-hydraulic cement, including lime, requires dry conditions in order to retain structural integrity.

#### **3.3.2 Production Facilities**

There are two large OPC facilities and one large lime facility in Alberta. Lime is produced by the calcination ('burning') of calcium carbonate (CaCO<sub>3</sub>), the primary component of limestone. Following size reduction (grinding, etc.) of quarried limestone, it is heated in a kiln at 1000-1500°C, producing lime (calcium oxide, CaO) (Equation 3.4). The co-product of CaCO<sub>3</sub> calcination is CO<sub>2</sub> and this process CO<sub>2</sub>

typically represents approximately 50% of the total lime CO<sub>2</sub> emissions [64]. The remainder is from the burning of fossil fuels to provide process heat for the kiln. Newer, high-efficiency facilities tend to have a higher proportion of emissions derived from the calcination (reduction) reaction [65]. In the production of cement, the CaO is reacted with minor materials clay, sand, shale, and iron to produce a product that meets specific application requirements.



Lafarge operates the largest cement facility in Alberta, located in Exshaw (near Canmore), with a capacity of 2.2 Mt per year, although capacity was just 1.3 Mt per year in 2009 [66]. Lehigh cement operates a facility in Edmonton that has a capacity of 1 Mt per year [67]. The cement facilities produced 970,393 t CO<sub>2</sub> eq combined in 2009. Also located in Exshaw is a Graymont Western Canada lime facility with an annual capacity of 180,000 t lime and 60,000t hydrated lime [68]. This facility produced 146,305 t CO<sub>2</sub> eq in 2009. Coal is the typical fuel for heat production, but the Lehigh Cement facility in Edmonton is a large consumer of natural gas.

### **3.3.3 Switching Options**

The production of lime from CaCO<sub>3</sub> via calcination inherently requires the release of CO<sub>2</sub> and does not present opportunities for material switching in the chemical process. However, material switching is possible in the lime and cement production process by using Fuel Switching – substituting biomass for the fossil fuels (e.g., coal, natural gas) used to provide heat for the kiln. Whether this biomass is in the form of virgin fuel such as forest harvest residues, agricultural residues, or dedicated energy crops, or ‘wastes’ such as municipal solid waste or construction debris, the amount of switching that can occur will be dictated by the ability of the fuel to meet process heat and operating regulation requirements. A primary consideration for switching of biomass for coal is the ability of facilities to utilize the resulting fly ash as a blend in production. Coal-derived fly ash is often used as a blending material in cement production to reduce lime requirements and substituting biomass fuels will alter the ability of facilities to blend. The use of fly ash to reduce the cement requirements in concrete production is a major cost consideration when switching to alternative fuels [69].

The second option for reducing GHG emissions associated with cement production and use is Product Substitution by using bio-based building materials, such as lumber and engineered structural wood products such as parallel strand lumber, in place of cement products (such as concrete) in construction applications. While single family housing in Alberta is dominated by wood-frame construction, multi-unit housing and office buildings typically utilize steel and concrete construction. One method of increasing wood use in multi-unit construction is to modify current legislation to permit six or more storey wood construction. Currently, the limit in Canada’s building code is four storeys, which contrasts with the limits in the United States (five to six depending upon jurisdiction), United Kingdom (seven, with exemptions available), and Germany (no limit) [70,71,72]. In the UK, the Stadthaus residential building is nine storeys high, while a 17 storey wood-frame building is planned for Kirkenes in Norway [73,74]. These multi-storey wood-frame buildings allow developers to maximize the quantity of wood used in construction and reduce their use of concrete and steel.



### **3.3.4 Scale and Greenhouse Gas Benefits**

Fuel input switching from gas and coal to biomass to produce process heat is one of the easiest means of causing large GHG reductions. With moderate retrofitting to accommodate fuel with heterogeneous properties, facilities in France, Germany, Netherlands, and Switzerland have co-fired biomass and “waste” at blends of up to 70% with traditional coal fuel [75]. The Sian Cement Company Co. Ltd. of Thailand reduced energy-derived GHG emissions by 90% through material switching of biomass for coal and petcoke [76]. The type of biomass used to blend with coal or natural gas for heat production and the blend percentage will dictate the quantity of GHG emissions reductions. In some instances, co-firing with agricultural or forestry residues or biological components of waste will result in negative GHG emissions due to the avoidance of CO<sub>2</sub> and CH<sub>4</sub> emissions from material decomposition [77]. In addition, transportation-associated emissions for biomass may be less than those of coal [78]. The Pembina Institute prepared a compilation of reports for the Cement Association of Canada in 2005, which identified forestry and agricultural residues as promising materials for fuel switching that require further investigation on delivered cost [79]. In addition, biomass feedstocks such as animal & bone meal and refuse-derived fuel (RDF) have been highlighted for their use as alternative fuels [80]. While Canada averages an 11.3% thermal substitution (of alternative fuels) rate, Alberta trails the country with a 0% substitution rate [80,81]. Assuming an 85% GHG reduction in the thermal GHG emissions of cement production (although many studies find a greater than 90% reduction for fuel switching) [82,83,84,85], a 55% allocation of emissions to thermal sources (i.e., non-process emissions), and a 60% substitution rate on an energy basis, Alberta’s lime and cement emissions could be reduced by 364,000 t CO<sub>2</sub> eq per annum.

When considering Product Switching options – namely wood frame construction for concrete frame – construction practices and building longevity are key factors in determining GHG reductions. However, the end-use of the wood following demolition also has a very large impact on GHG profile. Should the construction debris be used to replace fossil fuels in heat and electricity generation, life cycle GHG reductions for product switching can exceed 95% [86]. Should the materials be landfilled, thereby resulting in methane emissions that are not piped and flared, GHG reductions are only 60% [86]. However, should 50% of the framing materials be re-used for further construction purposes and 50% used to replace fossil fuels in heat and power generation, Product Switching from concrete to biomass results in a 100-200 % reduction (i.e., net reduction from wood use) [86,87]. The net GHG reduction becomes even greater when forest harvest residues (e.g., tops and branches) are utilized as an energy source to displace fossil fuel heat and power generation [88]. In a cradle-to-gate LCA, which includes upstream and production but not end use, of Canadian softwood lumber, it was determined that, on average, four times more carbon is sequestered in the lumber than is released by fossil fuels throughout the production cycle [89]. Therefore, net GHG emissions from the construction sector as a whole can be reduced, while keeping current cement and concrete production/consumption stable, simply by constructing more wood frame buildings. As with all biomass material switching options, these reductions are only possible through sustainable sourcing of biomass materials – in this case, lumber.

Estimates on GHG emissions reduction from wood-frame housing construction are considered to be only modestly accurate due to the large variety of designs, construction techniques, specific geographical and

jurisdiction building requirements, and the impact of weather on building performance. For this report, an estimate on yearly GHG emissions reductions, based upon work by Salazar and Meil (2009) is used for calculations [90]. The authors compared two single-family home alternatives in Ottawa; one of typical design (brick cladding, vinyl windows, asphalt shingles, and fiberglass insulation) and construction and the other of wood-intensive construction (cedar shingles and siding, wood windows, cellulose insulation). The life cycle GHG emissions difference was 69 t CO<sub>2</sub> eq per home, with the wood-intensive home a carbon sink by 5 t CO<sub>2</sub> eq [90]. Given Alberta's current home starts are approximately 16,000 units per year [91], the potential GHG emissions savings by switching to 'wood-intensive' construction would be 1.1 Mt CO<sub>2</sub> eq per year – assuming a constant rate of home starts. This figure does not include the potential for increased wood use in multi-unit housing.

### **3.4 Ethylene & Ethylene Derivatives**

#### **3.4.1 Product Summary**

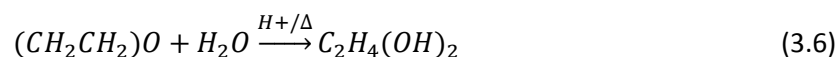
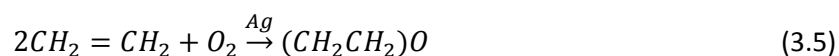
Ethylene (C<sub>2</sub>H<sub>4</sub>), also known as ethene, is the simplest alkene and world's most produced organic chemical by volume, with 2010 production of approximately 115 Mt [92,93,94]. It is the basic building block for some of the most common man-made chemicals and materials in use today, including polyethylene [high-density polyethylene (HDPE), low-density polyethylene (LDPE), and linear low-density polyethylene (LLDP)], the most widely used plastic; ethylene oxide (CH<sub>2</sub>CH<sub>2</sub>O), the feedstock for ethylene glycol (C<sub>2</sub>H<sub>4</sub>(OH)<sub>2</sub>); ethylene dichloride; and ethyl benzene [92].

#### **3.4.2 Production Facilities**

Due to low-cost raw materials, Alberta is a world-scale ethylene production centre, with hubs in Fort Saskatchewan, Joffre, and Prentiss (near Red Deer). Ethylene is produced using steam cracking from the natural gas extraction by-products ethane, propane, and butane, or, in areas with limited natural gas resources, oil refinery-derived naphtha. Kerosene and gas oils are also used as raw materials for ethylene production, although with higher operating costs due to greater catalytic cracking requirements [95].

In steam cracking, long-chain saturated (single bond only) hydrocarbons are diluted with steam and briefly heated in the absence of oxygen. This results in the production of shorter-chain molecules and introduction of double bonds (and thus unsaturated molecules).

The two highest volume ethylene derivatives produced in Alberta are ethylene glycol (via ethylene oxide), also known as monoethylene glycol (MEG), and polyethylene. Ethylene oxide (EO) is produced via direct oxidation of ethylene over a silver catalyst (Equation 3.5) [96,97]. EO is then hydrated to MEG and co-products diethylene glycol (DEG) and triethylene glycol (TEG) (Equation 3.6) [98,99].



Polyethylene is produced using ethylene polymerization reactions radical polymerization, ionic polymerization (anionic and cationic), or coordination polymerization. The reactive double bond is activated and, following reaction between two molecules, becomes saturated [102].

Multiple plants exist at the three ethylene and ethylene derivative production hubs in Alberta. These plants, their products, and production capacities are presented in Table 3.2. Combined, ethylene and ethylene derivative production facilities in Alberta resulted in 4.45 Mt CO<sub>2</sub> eq in 2009 [1], although not all these emissions can be attributed to ethylene and derivatives due to the production of additional products at some of the facilities.

**Table 3.2 Ethylene and ethylene-derivative facilities in Alberta (2011)**

Ref: [13,100,101]

Operator	Site	Facility	Product	Product Capacity (kt)
Dow Chemical	Fort Saskatchewan	Ethylene	Ethylene	1,304
Dow Chemical	Fort Saskatchewan	Polyethylene	Polyethylene	848
Dow Chemical	Fort Saskatchewan	Ethylene dichloride	Ethylene dichloride	1,095
Dow Chemical	Prentiss	Polyethylene	Polyethylene	500
MEGlobal Canada	Fort Saskatchewan	FS 1	Ethylene glycol	340
MEGlobal Canada	Prentiss	Prentiss 1	Ethylene glycol	310
MEGlobal Canada	Prentiss	Prentiss 2	Ethylene glycol	350
NOVA Chemicals	Joffre	E1	Ethylene	726
NOVA Chemicals	Joffre	E2	Ethylene	817
NOVA Chemicals/ Dow (50/50 JV)	Joffre	E3	Ethylene	1,300
NOVA Chemicals	Joffre	P1	Polyethylene	600
NOVA Chemicals	Joffre	P2	Polyethylene	386
Shell Chemicals	Fort Saskatchewan	Ethylene	Ethylene glycol	450

### 3.4.3 Switching Options

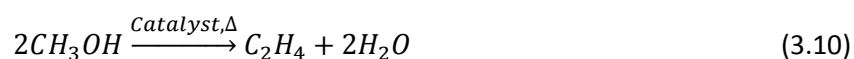
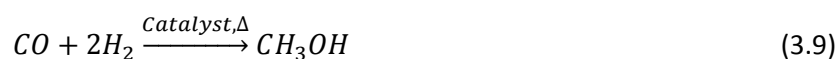
The primary means of material switching in the ethylene sector is Product Switching of bio-based ethylene for ethane-based ethylene. This in turn presents Input Switching opportunities for ethylene derivatives including polyethylene, ethylene glycol, and ethylene dichloride. Commercial bioethylene production is already underway in Brazil, with the largest facility being a 200,000 tonnes per year (tpy) plant operated by Braskem in Triunfo [103]. Electro Cloro, a subsidiary of the Solvay Group in Brazil, commissioned a 6,700 tpy facility in Brazil in 1960 [104], showing that commercial production of bioethylene has had a relatively long history. The route of production used by all commercial facilities to date is ethanol dehydration to ethylene, presented in Equation 3.7. The Braskem Triunfo plant consumes 462 million litres of ethanol per year to produce 200,000 t.



Since ethanol is supplied as a liquid, it must be vaporized and a temperature of 450°C is common. Superheated steam injected on a 1:1 weight proportion with ethanol. Pressures of 1.1 (Electro Cloro facility [104]) and 1.2 (Braskem facility [105]) MPa have been used commercially. Fixed bed or fluidized bed technology may be used for the reaction vessel, with fixed bed technology developed by Scientific Design Company (SD) and currently licensed by Chematur International AB. Lummus has developed an alternative approach with a proprietary catalyst and fluidized bed vessel [106]. The recovery of unconverted ethanol is energy and capital intensive, making 99%+ conversion to ethylene highly desirable [107].

Many different catalysts are available for the dehydration of ethanol to ethylene. The first commercial catalyst, used by ICI in the 1930's and 1940's, was clay loaded with phosphoric acid. This was followed by the development of Al<sub>2</sub>O<sub>3</sub>-MgO/SiO<sub>2</sub>, a multivariate oxide catalyst, in the 1960's by SD. In 1981, SD introduced the non-zeolite SynDol™ catalyst, based upon the 1960's design, while Nankai University in China developed the NKC-03A zeolite catalyst, which was later used in commercial operations, in 1987 [107]. Many researchers are attempting to identify catalysts with high performance, low reaction temperature (lower than the typical 400-450°C), long lifetime and low cost.

Although ethanol dehydration is the most common and commercially-proven option for bioethylene production, an alternative, thermochemical conversion pathway exists. It involves the conversion of bio-based methanol to olefins (dominated by ethylene and propylene) in a methanol-to-olefins (MTO) unit. Biomethanol can be produced using gasification of biomass to syngas (dominated by CO and H<sub>2</sub>), followed by catalytic reformation. This is the technology currently being deployed by Enerkem at the Edmonton Waste Management Centre for conversion of solid waste to methanol [108]. The gasification, methanol synthesis, and methanol-to-olefins reactions are presented in Equations 3.8-3.10, using a basic C-6 sugar as an example feedstock.



Methanol reformation to olefins can result in longer chain hydrocarbons and therefore an olefin cracking process can be included in the facility design to boost ethylene and propylene yields. Methanol can also be produced from biogas or landfill gas-sourced biomethane [109].

Although MTO technology has not been deployed commercially for bio-based methanol, it has been deployed for the conversion of fossil fuel-based methanol for ethylene and propylene production. The world's first commercial-scale MTO facility at Baotou, China opened in 2010 and is operated by China Shenhua Coal to Liquid and Chemical Co., Ltd. Facility capacity is 600,000 tpy of ethylene and propylene from 1.8 Mt methanol and uses SYN Energy Technology Co Ltd. MTO technology and Lummus olefins recovery technology [110,111]. The catalyst is supplied by CHIATAI Energy Materials Dalian Ltd. A similar plant is being constructed in Guizhou province by Sinopec [112].

In July, 2011 Honeywell's UOP announced that their MTO technology (including proprietary catalysts) had been selected by China's Wison (Nanjing) Clean Energy Company for a 295,000 tpy methanol to ethylene and propylene facility [113]. The feedstock for methanol production will be coal. This is one of the world's first facilities employing MTO technology and follows the successful operation of a Total Petrochemicals €45 M, 45,000 tpy technology demonstration facility at Feluy, Belgium [114]. Propylene is the dominant product of the demonstration facility.

Finally, a third option for material switching is Product Switching of ethylene glycol, a large-volume ethylene derivative. Although still at the research stage, direct conversion of cellulose to ethylene glycol may be a promising long-term option for bioethylene glycol production. Ethylene glycol and other low molecular weight polyols are formed from the hydrogenolysis of glucose, while sorbitol, mannitol, and other sugar alcohols are formed from the hydrogenation of glucose [115]. Although several different catalysts and processes have been researched, the most promising at present utilizes a tungsten-carbide catalyst supported on carbon and promoted by a small amount of nickel (2% Ni-30% W<sub>2</sub>C/AC, where AC is activated carbon) [115]. Pure cellulose was completely converted to polyols within 30 minutes at a temperature of 245°C and a pressure of 6 MPa of hydrogen gas. Yields of ethylene glycol have reached 75% wt % [116,117,118]. Although highly unlikely commercially, ethylene glycol can be converted to ethylene by dehydration to ethylene oxide (via chloroethanol) and then reduced to ethylene.

### **3.4.4 Scale and Greenhouse Gas Benefits**

As high volume commodities, ethylene and ethylene derivatives, such as polyethylene, have been the subject of several LCAs. Due to the commercial state of ethanol dehydration to ethylene, comparative LCAs of fossil fuel vs. bio-based ethylene have also previously been prepared. When examining ethanol dehydration to ethylene for material switching, the primary determinant of GHG reductions is the GHG profile of the ethanol used relative to the fossil fuel ethylene feedstock. In a low-density polyethylene (LDPE) LCA comparison of Brazilian sugarcane ethanol-based production with Saudi Arabian oil naphtha-based production, sugarcane ethanol ethylene production had half the life cycle GHG emissions of naphtha-based ethylene production; approximately 1.5 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene vs. 2.7 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene [119]. The production plants were assumed to be located in Brazil and Sweden, respectively, and 1.2 kg of naphtha was needed for each kilogram of LDPE produced. However, should polymerization of ethylene to polyethylene be removed along with oil/ethanol transport, the LCA GHG emissions are reported to drop to 0.8 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene for sugarcane ethanol-based production and 1.9 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene for naphtha-based production. The naphtha-based result contrasts with other naphtha-based LCA results from the Energy Research Centre of the Netherlands of 1.32 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene [120] and Dow Chemical of 1.8 kg CO<sub>2</sub> eq kg<sup>-1</sup> polyethylene (1.2-1.3 kg CO<sub>2</sub> eq kg<sup>-1</sup> with polymerization removed) [121]. Combustion of ethylene would produce 1.57 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene, not including the potential GHG benefits of displacing coal and/or natural gas electricity generation on the electrical grid via ethylene (i.e., solid waste) or bagasse combustion.

The ethylene produced in Alberta is almost exclusively made from natural gas extraction co-product ethane [122]. Assuming an approximate 20% lower GHG intensity of ethane compared to naphtha [54], the production emissions, including upstream gas extraction, are estimated at approximately 1.1 kg CO<sub>2</sub>

eq kg<sup>-1</sup>. This results in base case, ethane-derived ethylene life cycle GHG emissions of 2.7 kg CO<sub>2</sub> eq kg<sup>-1</sup>. Should corn ethanol be used in the place of sugarcane ethanol, GHG emissions will increase due to the higher GHG emissions associated with corn ethanol. Assuming corn ethanol has life cycle GHG emissions of 1.6 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethanol (based upon a 20% GHG reduction on an energy basis relative to U.S. gasoline at 3.2 kg CO<sub>2</sub> eq kg<sup>-1</sup> gasoline (2.3 kg CO<sub>2</sub> eq L<sup>-1</sup> gasoline), assuming a natural gas-fueled dry grind ethanol plant [123,124,125]), and 1.7 kg of ethanol are required for 1 kg of ethylene [103,119], the GHG emissions of ethanol-based ethylene from ethanol alone would be 2.7 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene. Combining 2.7 kg CO<sub>2</sub> eq kg<sup>-1</sup> from the ethanol feedstock with 0.5 kg CO<sub>2</sub> eq kg<sup>-1</sup> from ethanol dehydration [119] results in a corn ethanol-based ethylene profile of 3.2 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene. This is 20% higher than the ethane-based ethylene production GHG profile estimate of 2.7 kg CO<sub>2</sub> eq kg<sup>-1</sup>, although it is important to note that there is a large variability in LCA results for corn ethanol and that older Canadian studies of Ontario corn ethanol have found a 50% GHG reduction relative to a baseline of 3.9 kg CO<sub>2</sub> eq kg<sup>-1</sup> Albertan gasoline (2.8 kg CO<sub>2</sub> eq L<sup>-1</sup> gasoline) [126,127]. This is equivalent to approximately 1.2 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethanol (0.9 kg CO<sub>2</sub> eq L<sup>-1</sup>). If Albertan wheat-based ethanol were used for ethylene production, with life cycle GHG emissions of 1.3 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethanol (1.1 kg CO<sub>2</sub> eq L<sup>-1</sup> ethanol) [127], the ethylene GHG life cycle emissions would be approximately 2.8 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene – very similar to the ethane-produced baseline.

While ethanol-to-ethylene is only attractive from a GHG reduction perspective for non-corn ethanol sources (e.g., sugarcane, lignocellulose, wheat), thermochemical production (via methanol) of ethylene is more promising. Since lignocellulosic biomass, or even solid waste, can be used as the raw material for methanol production, the processing route benefits from a relatively “carbon neutral” feedstock. An LCA prepared by Nouri and Tillman of Chalmers University of Technology in Sweden found a cradle-to-gate (i.e., production) GHG profile of 0.2 kg CO<sub>2</sub> eq kg<sup>-1</sup> olefins (since the thermochemical route produces both ethylene and propylene, the profile is on a ‘total olefins’ basis) for conversion of forest harvest residues [128]. This is an 82% GHG reduction from the ethane-based ethylene production baseline of 1.1 kg CO<sub>2</sub> eq kg<sup>-1</sup> and a 92% reduction for life cycle emissions (including incineration of product following use). Assuming a more conservative 80% reduction in life cycle emissions for ethylene and ethylene glycol (polyethylene is excluded due to the use of ethylene in its manufacture and desire to eliminate double counting) and that all final product is incinerated, the annual life cycle GHG emissions reduction would be 12 Mt CO<sub>2</sub> eq. This is significantly larger than the production emissions due to the inclusion of final product incineration in the estimate. Should only upstream and processing emissions in Alberta be considered, a 70% reduction would be 4.3 Mt CO<sub>2</sub> eq.

## **3.5 Hydrogen**

### **3.5.1 Product Summary**

Hydrogen is the lightest chemical element and, at standard temperature and pressure, is a colourless, odourless, tasteless, and highly combustible diatomic gas. It is given by the formula H<sub>2</sub>. Hydrogen gas is produced industrially in large volumes, typically from steam reforming of natural gas, with the two largest users in Alberta and worldwide being the petrochemicals processing industry and the fertilizer industry.

### 3.5.2 Production Facilities

Air Products Canada Ltd. operates two natural gas-based steam reformers plants (at a single facility) in Edmonton that produce H<sub>2</sub> for use in the petrochemicals refining sector. Plant 1, which was completed in 2006, has a capacity of 2 million cubic meters (Mm<sup>3</sup>) per day and Plant 2, which was completed in 2008, has a capacity of 2.8 Mm<sup>3</sup> per day. The Air Products Canada plants service the Suncor refinery in Edmonton and other industrial customers in the region [129]. H<sub>2</sub> is used in hydrocracking, hydrogenation, hydrodealkylation, and hydrodesulphurization processes. The Air Products Canada complex produced 1,069,164 t CO<sub>2</sub> eq in 2009 [1].

H<sub>2</sub> is produced by steam methane reforming (SMR) by reacting steam with CH<sub>4</sub> at temperatures of 700-1000°C over a nickel catalyst at 0.3-2.5 MPa pressure (Equation 3.11) [130]. Co-product CO is reacted with water in a gas-shift reaction, which produces additional H<sub>2</sub> (Equation 3.12). CO<sub>2</sub> is a product of this reaction and is also produced from the combustion of fossil fuels used to provide heat for the strongly endothermic first reaction [130,131,132]. This is also the process used to produce H<sub>2</sub> for NH<sub>3</sub> production, in which H<sub>2</sub> is reacted with N<sub>2</sub> (see Section 3.1.2).

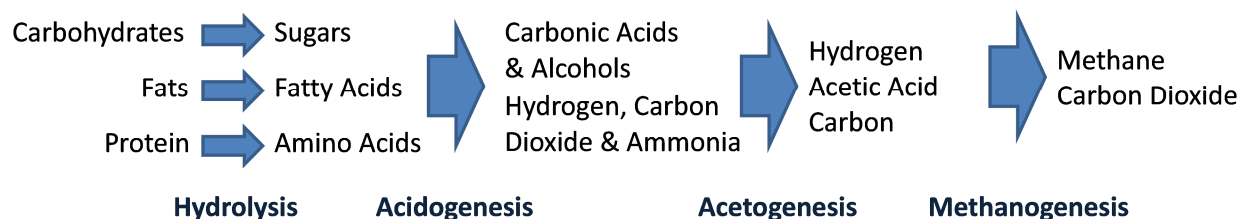


### 3.5.3 Switching Options

Alternative biological sources of H<sub>2</sub>, including syngas derived from biomass gasification, for use in fertilizer production are detailed in Section 3.1.3. This H<sub>2</sub> could also be used in the petrochemical industry as an Input Switching option. Relative to the Air Products Canada H<sub>2</sub> product, utilization of biomass syngas-sourced H<sub>2</sub> would be a competitor and represents a Product Switching option. This section will focus on Input Switching options for the Air Products Canada plants and other steam methane reforming facilities, which would require a source of biologically-based CH<sub>4</sub> for natural gas substitution. This would result in a H<sub>2</sub> product with biological and renewable content.

The two primary methods of obtaining biological CH<sub>4</sub> for conversion to H<sub>2</sub> are directly via anaerobic processes or indirectly via methanation of syngas. CH<sub>4</sub> is the dominant constituent of biogas from anaerobic digestion (AD) of manure, food waste, and other biological materials; landfill gas, which is produced by the breakdown of biological waste materials in landfills; and biogas from the breakdown of biosolids at wastewater treatment facilities. Biogas is produced in anaerobic digesters that often involve stirring action to increase the rate of material breakdown and biogas production [133,134]. Landfill gas is captured by utilizing piping systems running through the landfill and transporting the gas to a central processing facility. CH<sub>4</sub> production by anaerobic breakdown of biological materials includes four primary processes of hydrolysis, acidogenesis, acetogenesis, and methanogenesis. These occur in mesophilic (35 to 42 °C) or thermophilic (45 to 60 °C) temperature conditions and are presented in Figure 3.1 [135,136].

Figure 3.1 Primary processes of anaerobic breakdown



CH<sub>4</sub> content for biogas is typically 55-65% and for landfill gas is 50 – 55% [137,138]. In order for this gas to be utilized for SMR as ‘renewable natural gas’ or ‘biomethane’, the CH<sub>4</sub> content must be increased to approximately 98%, the hydrogen sulphide (H<sub>2</sub>S) content to be reduced to < 1 ppm (from 300-3000 ppm for AD biogas), the siloxanes content to be reduced to < 1 ppm, and the water content of the gas to be reduced from a saturated state to < 1 ppm [139,140,141]. Technologies for biogas treatment include high-pressure water scrubbing, pressure swing adsorption, chemical absorption, cryogenic separation, and membrane separation [140,141].

The second, less traditional, method of obtaining biomethane from biological sources is methanation of syngas (CO and H<sub>2</sub>), produced from the gasification of biomass [142]. This is the reverse reaction of steam reforming. However, since syngas already contains H<sub>2</sub>, it would be inefficient to produce methane from syngas for conversion back to H<sub>2</sub>. Therefore, this route of production is deemed unattractive and will not be discussed further.

### 3.5.4 Scale and Greenhouse Gas Benefits

The GHG reduction potential for biomethane Input Switching for natural gas, as discussed in Section 3.2.4, is largely dependent upon the feedstock, upgrading technology, and business-as-usual use of biomass materials. At the lower end, a 10-20% reduction relative to natural gas is possible when utilizing biomethane from anaerobic digestion of corn and rye produced for dedicated bioenergy use [52]. This modest GHG benefit is more likely when pressure swing absorption is the biogas upgrading technology, as compared to alternatives such as water scrubbing [53]. On the other hand, studies by the California Air Resources Board show anaerobic digestion of dairy manure for compressed biomethane resulted in an 80% reduction in GHG emissions [54,143], while upgrading and compressing of landfill gas resulted in a reduction of 83% [56], relative to a natural gas baseline [54,29]. Other studies have found a more than 100% reduction (i.e., net carbon reduction from use) when using liquid manure due to the reduced CH<sub>4</sub> emissions from unprocessed liquid manure found in the base case [57]. This large range for GHG performance was also found in a study by Pertl et al. (2010) [53], who estimated reductions for biomethane relative to natural gas of 9% to 89%, depending upon feedstock and upgrading technology.

Assuming a 50% reduction in life cycle GHG emissions for biomethane relative to natural gas, complete Input Switching to biomethane at the Air Products Canada plants could result in annual emissions reductions of 535,000 t CO<sub>2</sub> eq.



## 3.6 Isooctane

### 3.6.1 Product Summary

Isooctane is an octane enhancer used to prevent knocking (when fuel combustion does not occur at the optimum point in a four-stroke cycle) in gasoline engines. It has an octane rating of 100. It has a formula of  $(\text{CH}_3)_3\text{CCH}_2\text{CH}(\text{CH}_3)_2$  and is one of the isomers of octane ( $\text{C}_8\text{H}_{18}$ ). Although it is a component of transportation fuel, it is considered here as a chemical fuel additive and within the scope of the report.

### 3.6.2 Production Facility

Isooctane, also known as 2,2,4-trimethylpentane, is produced by Alberta Envirofuels, a joint venture between Neste Oil and Chevron. The production process utilizes field-grade butane, which includes both n-butane and isobutane, as the primary feedstock. n-butane ( $\text{C}_4\text{H}_{10}$ ) is isomerized to isobutane and this is converted into isobutylene. Isooctene is produced via dimerization of isobutylene and then hydrogenated to isooctane [144,145]. The Alberta Envirofuels facility previously produced methyl *tert*-butyl ether (MTBE) by reaction of isobutylene with methanol, but was retrofitted to produce isooctane after the former was banned as a gasoline fuel additive. The Alberta Envirofuels facility at Edmonton produces 560,000 tpy of isooctane and had 2009 GHG emissions of 323,824 t  $\text{CO}_2$  eq [2,146].

### 3.6.3 Switching Options

Several alternatives exist to increase the octane rating of gasoline, including MTBE, tetraethyllead, and ethyl *tert*-butyl ether (ETBE;  $\text{C}_6\text{H}_{14}\text{O}$ ), although the former two options have been banned in North America due to ground water contamination and lead toxicity, respectively. However, the most common octane enhancer in North America is ethanol ( $\text{C}_2\text{H}_5\text{OH}$ ), which is typically produced from corn or, when imported from Brazil, sugarcane. North American ethanol production is currently 52 billion litres (BL), with one plant in Alberta currently operating (feedstocks are wheat, wheat starch, corn, barley, rye and triticale) and several others proposed or under construction [147,148].

ETBE, which is produced from ethanol [(47% volume/volume (v/v)) and isobutylene (53% v/v)], has notable air quality and fuel performance benefits over direct use of ethanol but has a higher production cost. ETBE, unlike ethanol, does not have any azeotropic effects on the distillation curve of gasoline and blends in a smooth fashion. As an ether, ETBE does not have the high water solubility problems of ethanol, which prevent the alcohol from being transported by barge and pipeline due to collection of water in the fuel. It can be handled in a very similar fashion to hydrocarbon-only gasolines [149]. ETBE is used extensively as an oxygenate in Europe [150].

To reduce the life cycle emissions of the current operation, two primary options are available.

- a) Product Switching – Ethanol or ETBE, as fuel additives, could be used to substitute for isooctane and would increase fuel renewable/bio-based content. Canadian fuel blending mandates currently require that renewable fuels constitute 5% of the gasoline pool [151]. Ethanol or ETBE could be used to partially replace isooctane in the Alberta gasoline pool by increasing the

provincial renewable fuel blend requirement beyond the existing 5% renewable alcohol. However, this would likely not result in a decrease in facility point source emissions, as isooctane production at the Edmonton facility could continue with increased product exports to alternate jurisdictions.

- b) Input Switching – Given that the Alberta Envirofuels facility previously produced MTBE, it may be possible to retrofit the facility to produce ETBE from ethanol [152,153]. This would decrease butane/isobutylene consumption and result in a fuel with a 47% (v/v) renewable content. However, ethanol will be a higher-priced feedstock than butane, a fact that must be recognized when designing policy and considering industrial possibilities for GHG reduction. While Europe utilizes significant amounts of ETBE, current legislation and industrial practice favours ethanol as the primary oxygen enhancer in North America, with ETBE penetration very low.

### **3.6.4 Scale and Greenhouse Gas Benefits**

Emissions reductions realized by Product Switching from isooctane to ethanol will be dependent upon the blend percentage of ethanol (with gasoline) and the feedstock for ethanol production. Specific isooctane emissions are estimated to be 4.3 kg CO<sub>2</sub> eq kg<sup>-1</sup> isooctane, based upon upstream butane emissions of 0.6 kg CO<sub>2</sub> eq kg<sup>-1</sup> isooctane [29], facility emissions of 0.6 kg CO<sub>2</sub> eq kg<sup>-1</sup> isooctane [1,146], and combustion emissions of 3.1 kg CO<sub>2</sub> eq kg<sup>-1</sup>. Assuming Alberta-produced wheat ethanol has life cycle GHG emissions of 1.3 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethanol [127], approximately 45% lower than isooctane on a delivered energy basis, replacing the 560,000 tpy isooctane currently produced by Alberta Envirofuels with wheat ethanol would reduce yearly life cycle emissions by 1.1 Mt CO<sub>2</sub> eq per year. Should U.S. corn ethanol, with life cycle GHG emissions of 1.6 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethanol [123,124,125] (35% lower than isooctane on an energy equivalent basis), replace isooctane, life cycle GHG emissions reductions would be 843,000 t CO<sub>2</sub> eq per year. However, this switching option would require the closure of the Alberta Envirofuels facility and development of new ethanol facilities.

GHG reductions from input switching are associated with the replacement of 47% of isooctane production with ethanol production on a volume basis. Instead of a dimerization of isobutylene, isobutylene would be reacted with ethanol to form ETBE. Life cycle emissions could be reduced by 16% if corn ethanol imported from the U.S. was used in ETBE production to displace isooctane (based upon a 35% reduction in life cycle GHG emissions on an energy basis [123,124]), while emissions could be reduced by 21% if Albertan wheat ethanol was used (assuming a 45% life cycle GHG emission reduction) [127]. This would result in annual GHG emissions reductions of 385,000 t CO<sub>2</sub> eq for U.S. corn ethanol or 506,000 t CO<sub>2</sub> eq for wheat ethanol. It is not likely that actual point source facility emissions would be decreased significantly.

## **3.7 Linear Alpha Olefins (LAO)**

### **3.7.1 Product Summary**

Linear alpha olefins (LAOs) are alkenes (unsaturated hydrocarbons) with the chemical formula C<sub>x</sub>H<sub>2x</sub>. Common examples include 1-hexene, 1-octene and 1-decene. LAOs are typically used as intermediates or to assist in the production of other compounds. They are intermediates in the production of polyvinyl

chloride (PVC), used as a feedstock for the production of synthetic lubricant polyalpha olefins (PAOs) and biodegradable surfactants, utilized in synthetic drilling muds, and are applied extensively in the production of polyethylene [154].

### **3.7.2 Production Facility**

There is one large LAO production facility in Alberta, which is located in Joffre and operated by INEOS. The facility has a capacity of 250,000 t per year and produced 112,078 t CO<sub>2</sub> eq in 2009 [1,154]. There are several routes for the production of LAOs including oligomerization of ethylene, Fischer-Tropsch synthesis from syngas (CO and H<sub>2</sub>), and dehydration of alcohols. The Joffre facility, which is partially integrated with the NOVA chemicals ethylene and polyethylene facility, utilizes the oligomerization of ethylene method.

There are several different ethylene-to-LAOs production processes, but the one employed by INEOS, the Ziegler stoichiometric reaction, is a two-stage process [155,156]. In stage one, ethylene is reacted with triethyl aluminium in olefin diluent to lengthen the molecular chain. Triethyl aluminum is recovered in the second stage of the process, when aluminium tri-alkyls are reacted with ethylene again in a displacement reaction at higher temperature but lower pressure. The LAOs produced are used as the olefin diluent in a repeat of the process to lengthen the molecular chain [157]. Alternative processes have been developed by Chevron, Shell, UOP, Idemitsu, DuPont, and SABIC/Linde. Shorter-chain LAOs, such as 1-hexene and 1-octene, are typically more valuable than longer-chain LAOs, but maximizing selectivity can be difficult [158].

Sasol of South Africa uses gasification of coal and Fischer-Tropsch synthesis to produce LAOs and synthetic liquids. Reformation reactions of the H<sub>2</sub> and CO syngas components are carried out over an iron and/or cobalt catalyst, resulting in the production of a mix of chemical products, known as Fischer-Tropsch liquids, including LAOs. Natural gas can also be used as a feedstock for syngas production and Fischer-Tropsch reformation [159,160,161]. Operating temperature and pressure, along with feedstock and catalyst selection, will dictate the ratio of products in the Fischer-Tropsch liquids. Additional cracking reactions and product purification (e.g., fractional distillation) may be necessary to achieve a high concentration of the desired LAO product(s), which are typically shorter-chain molecules (e.g., 1-hexene, 1-octene) [158, 161].

The final commercial method of LAO production is the dehydration of linear fatty alcohols (LFAs). This process would only be used in unusual cases where linear fatty alcohols are priced lower than corresponding LAOs due to geographic or supply issues. LFAs can be produced from either natural sources (see Section 3.7.3) or by oxidation, followed by hydrolysis, of Ziegler reaction-derived compounds. Following the growth reaction, the aluminium tri-alkyls are partially oxidized. These partially oxidized trialkylaluminum compounds are hydrolyzed using sulphuric acid [162]. This produces LFAs that can be dehydrated to LAOs by passing them, in vapour form, over an acidic alumina catalyst.

### **3.7.3 Switching Options**

Several material switching options are available for LAOs, including Input Switching and Product Switching for identical, bio-based 1-hexene, 1-octene, and 1-decene. As an ethylene derivative, LAOs can be produced using bioethylene, the biological production of which is detailed in Section 3.4. Principal routes of bio-ethylene production include ethanol dehydration and methanol conversion in a methanol-to-olefins unit. Input Switching of bioethylene for butane-sourced ethylene in LAO production would enable the existing INEOS facility to continue operations with little retro-fitting of existing equipment. The same Ziegler-based reactions could be utilized.

Biomass gasification, combined with Fischer-Tropsch catalytic reformation of syngas, could potentially be used to produce LAOs and represents a Product Switching opportunity. Also known as biomass-to-liquids (BtL), this process would be similar to the production of LAOs from coal, as practiced by Sasol. However, key differences exist when gasifying biomass compared to coal, including the much higher oxygen content and higher moisture content. This impacts the H<sub>2</sub>:CO ratio and the formation of products in the Fischer-Tropsch process. While methanol has been produced from gasification of biomass feedstocks at both the demonstration- [108] and commercial-scale [163] (for a brief period), production of longer-chain molecules has not been proven commercially. Selectivity of LAOs is also likely to be low. However, this presents a technology development opportunity that has already received significant attention in the public and private sectors [164].

### **3.7.4 Scale and Greenhouse Gas Benefits**

As ethylene-derived compounds, LAOs will have a GHG profile largely dictated by the GHG profile of primary raw material ethylene. As discussed in Section 3.4.4, the GHG profile of ethylene can vary dramatically based upon the feedstock and conversion process utilized, but for this report, base case ethane-derived ethylene life cycle GHG emissions of 2.7 kg CO<sub>2</sub> eq kg<sup>-1</sup> are assumed. Add to this the LAO production emissions of 0.45 kg CO<sub>2</sub> eq kg<sup>-1</sup> (derived from the IEOS facility emissions [1,154]) and life cycle LAO emissions are estimated as 3.15 kg CO<sub>2</sub> eq kg<sup>-1</sup>. Should corn ethanol and dehydration be the basis for bioethylene production, life cycle GHG emissions would be increased. However, should sugarcane or lignocellulosic ethanol-based bioethylene, or MTO-derived bioethylene, be utilized, there will be a notable drop in life cycle GHG emissions from baseline ethane-sourced ethylene. A life cycle reduction to 0.65 kg CO<sub>2</sub> eq kg<sup>-1</sup> LAO (0.2 kg CO<sub>2</sub> eq kg<sup>-1</sup> ethylene and 0.45 kg CO<sub>2</sub> eq kg<sup>-1</sup> for LAO production) would be a reduction of 79%. Assuming a conservative 70% drop in life cycle emissions of LAOs due to MTO-derived bioethylene input switching, the annual life cycle reduction would be 551,000 t CO<sub>2</sub> eq.

Gasification can also be used to produce LAOs directly, rather than via methanol and MTO conversion. However, specificity is likely to be lower. Life cycle assessments of Fischer-Tropsch (FT) liquids provide an indication of the relative life cycle GHG emission reductions possible, given the absence of targeted LCAs on LAOs from biomass. Fischer-Tropsch liquids have been found to provide a 77-80% reduction in life cycle emissions relative to diesel [165,166] and a 90-91% reduction relative to gasoline [167]. In addition, emissions from biomass plantation FT liquids are projected to be 90% lower than those from

coal-based FT liquids [166]. However, since the baseline for LAO production is utilization of ethane as a feedstock rather than diesel, and ethane has GHG combustion emissions approximately 20% lower than diesel and 12.5% lower than gasoline, the relative reduction is estimated as 74-90%. This is in keeping with the MTO-based route and the choice of technology would be dictated by capital and operating costs, along with specificity for desired products. The 70% life cycle GHG reduction estimate used for production of LAOs from MTO-derived ethylene could also be applied to the direct LAO production route.

### **3.8 Lumber and Medium Density Fibreboard**

#### **3.8.1 Product Summary**

Lumber and medium density fibreboard (MDF) are products from the forest sector used in both single- and multi-unit housing and commercial construction. Lumber, produced from sawn timber and available in numerous sizes, is typically used for framing and structural applications, while MDF, a dense board product produced from fine wood particles and glue, has a multitude of applications in construction and furniture production.

#### **3.8.2 Production Facilities**

Two lumber mills and one MDF plant are included in the large emitter list, although many other smaller lumber mills are also operating in Alberta. Both lumber mills reported emissions lower than the 50,000 t CO<sub>2</sub> eq threshold, but are included voluntarily by the operating companies (Tolko Industries Ltd. and West Fraser Mills Ltd.). The greatest source of GHG emissions at the Tolko lumber facility is combustion of natural gas for kiln drying. Once the lumber has been cut, it is dried in a kiln prior to planing and shipping to customers. MDF board production involves mixing glue and refined (pulped) wood fibres, followed by hot compression into board panels. This produces a smooth surface board that can be used in applications for which rough-surfaced plywood or chipboard may not be appropriate [168]. The GHG emissions from the West Fraser Mills MDF plant (Ranger Board) and the West Fraser Mills lumber mill (Blue Ridge Mills) are dominated by nitrous oxide with no net CO<sub>2</sub> emissions.

#### **3.8.3 Switching Options**

Lumber and MDF, as with pulp (see Section 3.11), are already bio-based materials and as such, material switching opportunities are limited. The primary means of reducing net GHG emissions at the facilities is via Fuel Switching for drying and process heat applications. Sawmills typically use natural gas in direct-fired kilns, in which combustion flue gas enters the kiln and dries the lumber directly, due to its clean-burning nature. Flue gas from biomass combustion has a significantly greater concentration of particulate matter than flue gas from natural gas combustion, thereby impeding its use in direct-fired kilns due to the contamination of the lumber product. In these situations, biomass gasification, which can produce flue gas at particulate matter levels consistent with those of natural gas, could be a viable option. In contrast, biomass can readily be substituted for natural gas in indirectly-fired kiln operations, since a thermal energy source (e.g., steam) other than flue gas is used to heat the kiln [169].

Although lumber is 100% biomass, MDF contains glue or resin to hold the wood fibres together. There are a variety of resins that can be used, but the most common is urea-formaldehyde. Alternatives include phenol formaldehyde and melamine resins. Two Input Switching options for MDF production are the use of bio-based urea (see Section 3.1.3) in the manufacture of urea-formaldehyde and the use of biomass lignin-derived resins. Lignin, the ‘glue’ that holds together cellulose and hemicellulose fibres in lignocellulose, can be isolated using pulping technologies. Use of lignin-derived resins in MDF manufacture would result in a 100% bio-based board. Since lignin-rich black liquor is a by-product of kraft pulp production, this could be a potentially attractive resin production feedstock. Alternatively, other pulping processes such as the Alcell process and sulphite pulping produce higher-purity lignin co-products [170]. The performance of lignin as a resin is currently being investigated in Canada by academic researchers, private companies such as Lignol, and academic-government-industry consortiums such as the lignin demonstration plant in Thunder Bay, ON [171,172].

### **3.8.4 Scale and Greenhouse Gas Benefits**

As described in Sections 3.2.4 and 3.5.4, there is a very large range of GHG benefits reported in the literature for biomethane when displacing natural gas. Assuming a 50% reduction from the natural gas baseline for the Tolko lumber mill, emissions could be reduced by 19,000 t CO<sub>2</sub> eq per year. The West Fraser lumber (Blue Ridge) and MDF (Ranger Board) complex at Blue Ridge has already installed a biomass burner to provide process heat for kilns in the place of natural gas [173,174]. This is why emissions are dominated by CH<sub>4</sub> and N<sub>2</sub>O and there are no net CO<sub>2</sub> emissions.

Due to early development stage of lignin-based resins, the potential GHG emissions reductions are not estimated here.

## **3.9 Magnesium Oxide**

### **3.9.1 Product Summary**

Magnesium oxide (MgO), also known as magnesia, is a white solid used in wide variety of industries, from steel and refractory materials, pulp and paper (magnesium bisulphate pulping liquors), construction (magnesia cements), and water treatment, to animal feed (ruminant) and fertilizer. Magnesium compounds production in 2009 was 19 Mt magnesium oxide equivalent [175]. The primary raw material for magnesium oxide production is magnesium carbonate (MgCO<sub>3</sub>), also known as magnesite.

### **3.9.2 Production Facility**

The magnesium oxide production process is very similar to that of lime (calcium oxide, CaO). Mined MgCO<sub>3</sub> is reduced in size by grinding and milling and then added to a kiln. The MgCO<sub>3</sub> is heated to temperatures of 1600-2200°C within the kiln, which results in decarbonisation of the MgCO<sub>3</sub> to magnesia [176]. CO<sub>2</sub> is produced as a by-product in the reaction (Equation 3.13).



For every tonne of magnesia produced, 1.092 tonnes of CO<sub>2</sub> are produced from the decarbonisation reaction [176]. GHG emissions from fuel combustion to provide process heat must be added to this total, with approximately half of total GHG emissions derived from the decarbonisation reaction. The magnesia production reaction requires an energy input ( $\Delta H$ ) of 113 kJ mol<sup>-1</sup> MgO and the GHG emissions are dictated by the GHG profile of the fuel used (e.g., coal, gas, oil) [176]. The Baymag Inc. facility in Exshaw produced 93,694 t CO<sub>2</sub> eq in 2009 with a capacity of 50,000 tpy of MgO [1]. However, this capacity was doubled by the end of 2009 to 100,000 tpy [177], which means GHG production is likely to have also approximately doubled.

### **3.9.3 Switching Options**

The primary material switching option available for MgO production is the same as for CaO: Fuel Switching. Biomass materials, including those from the forest, agriculture, and waste management sectors, could potentially be used in stand-alone or co-firing applications with fossil fuels. A critical component of fuel selection and the maximum co-firing percentage is the ability of fuels to meet process heat demands and temperature requirements, along with any regulatory requirements. As with alternative fuel use for lime and cement production, fuel handling and air emissions systems may need to be modified to accommodate the change in fuel. This is particularly true when heterogeneous materials such as municipal solid waste are utilized. Biomass materials may need to be pretreated to reduce moisture content, drive off volatiles, and increase the fuel energy content. An example would be torrefaction (“roasting”) or carbonization of biomass to increase the proportion of carbon in the fuel.

Due to the large number of uses for MgO, Product Switching options are not assessed here. However, they are likely to be limited due to the specific nature of many magnesia applications. Input Switching (i.e., non-fuel switching) is not a possibility for MgO production.

### **3.9.4 Scale and Greenhouse Gas Benefits**

The process Fuel Switching potential for MgO is very similar to that of CaO. As discussed in Section 3.3.4, a variety of biomass types can be co-fired with coal in ratios up to 70%. While this is high, particularly for North America, it has been proven technically viable in a commercial setting [75]. Maximum rates would need to be assessed on a facility-by-facility basis. Assuming an 85% GHG reduction in the thermal GHG emissions of magnesium oxide production [82,83,84,85], a 45% allocation of emissions to thermal sources (i.e., non-process emissions) based upon similar processing requirements from the cement industry [64,65], and a 60% substitution rate on an energy basis, Baymag’s 2009 emission levels could be reduced by 21,500 t CO<sub>2</sub> eq per annum. However, since capacity has doubled since 2009, a reduction of 43,000 t CO<sub>2</sub> eq per annum may be possible.

## **3.10 Nitrogen & Oxygen Gases**

### **3.10.1 Product Summary**

Nitrogen (N<sub>2</sub>) and oxygen (O<sub>2</sub>) gases are the pure, diatomic forms of these primary air components, typically separated and purified using cryogenic air separation. They are used for a multitude of

industrial and commercial applications. Nitrogen is valued as a non-flammable, relatively inert gas that can also be used in ultra-cold applications (liquid nitrogen). It is used in the production of chemicals, pharmaceuticals, glass and ceramics, steel and other metals, and pulp and paper. It is used in numerous oil refining processes and also the healthcare industry [178]. In contrast, pure oxygen gas is valued for its reactivity and is often used in the place of air as an oxygen source in biological, combustion, and oxygenation reactions. It is used in steelmaking and other metals refining and fabrication processes, in the production of chemicals, pharmaceuticals, and pulp and paper, and for municipal and industrial effluent treatment. As an essential gas for human life, it is also used extensively in the healthcare field [179]. Pure oxygen can be used to produce low-nitrogen syngas in coal and biomass gasification facilities.

### ***3.10.2 Production Facility***

The most common route for production of high-purity N<sub>2</sub> and O<sub>2</sub> gases is cryogenic air separation. In this process, incoming air is filtered, compressed, and cooled. Water and CO<sub>2</sub> are removed by a molecular sieve pre-purification unit. The gas is then cooled to a cryogenic temperature of approximately -185°C, where N<sub>2</sub>, O<sub>2</sub>, and argon (Ar) components are separated by distillation in high and low pressure columns. Should liquefied product be required, an additional refrigeration unit (liquefier) will be included in the plant [180,181,182].

The energy required for cooling and compression is in the form of electricity, with approximately 1 kWh required per cubic meter of N<sub>2</sub> or O<sub>2</sub> product [181]. This results in electricity being a major operating cost for cryogenic air separation facilities. To deal with this electrical demand, Air Liquide Canada Inc. installed an 80 MWe co-generation natural gas power plant, in partnership with TransAlta, at their Scotford Complex facility in 2000 [183]. They also supply electricity and steam to the neighbouring Shell refinery, and utilize CO<sub>2</sub> gas from Shell for use in soft drink carbonation [184]. It is this co-generation plant that is a primary source of Air Liquide's 2009 emissions of 437,984 t CO<sub>2</sub> eq.

### ***3.10.3 Switching Options***

Since electricity generation is a primary source of emissions of the Air Liquide Scotford Complex, and electricity generation is outside the scope of this report, a detailed assessment of switching options is not included. However, it should be noted that biogas and landfill gas can be upgraded to biomethane to meet specifications of natural gas-fired co-generation facilities. This would present an opportunity for reducing the net GHG emissions of the Scotford Complex and would be considered a Fuel Switching opportunity.

### ***3.10.4 Scale and Greenhouse Gas Benefits***

Assuming an 50% reduction in GHG emissions from fuel switching of biomethane for natural gas [52,54,56,185], as per Sections 3.2.4 and 3.5.4, the Air Liquide Scotford Complex annual emissions could be reduced by 219,000 t CO<sub>2</sub> eq.



### **3.11 Pulp (Kraft and Mechanical)**

#### ***3.11.1 Product Summary***

Pulp is the primary wood-based material used to produce paper and cardboard. The quality of the pulp and its application is a combination of the feedstock type, namely softwood or hardwood, and the production technology. Kraft pulp, produced using chemical pulping, is a high quality pulp with low lignin levels. Mechanical pulp, produced using physical fibre separation methods, is typically a lower quality pulp with higher lignin levels. Mechanical pulp is principally used in the newspaper and magazine industry. The quality of mechanical pulp can be improved by combining physical treatment with chemical and thermal treatment; for instance, in bleached chemi-thermo-mechanical (BCTM) pulp.

#### ***3.11.2 Production Facilities***

Alberta is home to four kraft pulp mills and one BCTM pulp mill. Combined, the facilities produced 535,085 t CO<sub>2</sub> eq in 2009, ranking the industry fifth in non-energy sector GHG emissions. The majority of emissions from pulping facilities result from the production of process heat through combustion of natural gas, wood residues, or oil. Over the past two decades, there has been a significant shift in Canada's pulp and paper sector from using natural gas to wood residues for process heat. This has resulted in a net GHG reduction for the sector [186]. In 2009, in response to the black liquor biofuel subsidy in the United States, the Canadian Federal Government established the Green Transformation Program for the pulp and paper sector. This program provides funds to companies to modernize equipment and install boilers to produce biomass-based heat and power [187,188].

#### ***3.11.3 Switching Options***

Since pulp is already a bio-based product, material switching opportunities for GHG reductions are limited to Fuel Switching. However, the four kraft pulp mills in Alberta already consume large quantities of wood residues – 761,000 bone dry tonnes (bdt) in 2004 [169]. This has since risen due to the installation and upgrading of additional power boilers (as opposed to recovery boilers) operating on hog fuel (mill wood residues sawdust and bark). All four kraft pulp mills in Alberta received funding from the Canadian Government's Pulp and Paper Green Transformation Program to reduce their natural gas consumption and produce greater quantities of biomass-based electricity [189,190,191,192,193]. Some natural gas is used in the power boilers for electricity generation to supplement biomass materials, but this is typically consumed to ensure efficient combustion of relatively high moisture-content fuel. Natural gas consumption can be minimized by optimizing biomass fuel consistency (size, energy content, moisture content) and minimizing fuel moisture content.

The Millar Western Forest Products BCTM pulp mill uses natural gas for its heating operations, but sells hog fuel from lumber operations to a separate CHP facility. The company is examining the potential for utilizing harvest residues for heat and power, which could reduce their own consumption of natural gas for process heat [194].

### ***3.11.4 Scale and Greenhouse Gas Benefits***

The use of forest harvest residues or wood pellets in the place of natural gas can reduce life cycle GHG emissions by 75% or more [84, 185,195,196]. Therefore, replacement of 90% of Millar Western Forest products natural gas with forest-sourced biomass for heat production is estimated to reduce annual facility emissions by 38,000 t CO<sub>2</sub> eq.

In order to convert the pulp mills to 100% renewable heat supply, a high-energy fuel is required to replace supplementary natural gas. Upgraded biogas or landfill gas, in the form of biomethane (>97% CH<sub>4</sub>), can directly replace the existing supplementary natural gas and result in life cycle emission reductions exceeding 80% [52,54,56,185]. The most convenient option for supplying biomethane to existing natural gas users is likely via blending in existing pipelines, although compressed biomethane (CBM) could also be considered an option.

## **3.12 Steel**

### ***3.12.1 Product Summary***

Steel is a widely used metal with a vast array of applications from construction and process equipment, to automobiles, tools, ships, and machines [197]. It is largely composed of iron, with a carbon content ranging from 0.2-2% by weight. Steel is often alloyed with elements, including nickel, manganese, chromium, molybdenum, and silicone, to produce metals with a variety of performances and properties [198]. Steel is the most widely recycled material in the world.

### ***3.12.2 Production Facilities***

Alberta does not have any integrated steel production plants that include primary basic oxygen furnaces. These are facilities that produce steel from iron ore, generating large quantities of CO<sub>2</sub> in the process via reduction reactions. However, one steel mill does meet the large emitters list of the National Inventory Report: the AltaSteel Edmonton facility, which produced 77,664 t CO<sub>2</sub> eq in 2009 [1]. This is a mini-mill operation, with both melting and casting facilities and a capacity of 350,000 t steel billet per year [199]. A mini-mill is an electric-arc furnace type mill, which uses electricity for melting steel for re-casting. Approximately 440 kWh are required to melt one tonne of steel. Oxygen is blown (often with natural gas in oxy-fuel burners) into the scrap metal in the electric arc process, resulting in oxygen combustion and the formation of oxides with impurities and CO<sub>2</sub> [200]. Oxidation of additional carbon in the scrap (e.g., in non-steel materials in the charge) also results in the production of CO<sub>2</sub>. To ensure a good quality product, the chemistry of the steel is monitored continuously and reduction reactions involving coke may be required. Slag, which forms on the surface of molten steel, is produced from the addition of CaO or MgO and functions as a blanket where impurities such as silicon, sulphur, and phosphorus can accumulate as oxides. To form billets into steel products, a reheat furnace is utilized that operates on a combination of natural gas and re-circulated waste gases. This is a notable source of CO<sub>2</sub> from the AltaSteel operations [201].

### **3.12.3 Switching Options**

Steel melting and production in an electric-arc furnace operation requires the addition of several different products already discussed, including high-carbon solids, CaO, and MgO. Electric arc furnaces are large consumers of electricity, but within the scope of this project, the primary opportunity for material switching is Fuel and Input Switching. Process inputs CaO, MgO, and O<sub>2</sub> are discussed in Sections 3.3, 3.9, and 3.10, respectively. As discussed in Section 3.2, pyrolysis and carbonization technologies offer the opportunity to produce a high-carbon (>95% C) solid [202]. Although coal-derived coke consumption is significantly smaller in electric arc furnaces, including the mini-mill operated by AltaSteel, than integrated steel mills, it can be utilized to help form the slag [200]. Coke is carbonized coal, with a higher carbon content and reduced level of impurities and volatiles relative to the raw material. It is produced by carbonization (slow pyrolysis) – heating coal in an oxygen-free oven [203]. A similar process can be applied to biomass and the world’s largest producer of industrial charcoal, Brazil, devotes 75% of production to the steel industry [204]. However, North American steel producers typically demand a carbon source that has consistent properties and performance to that of coal-sourced coke [205,206]. Therefore, if bio-coke is to be utilized in an Input Switching capacity, pyrolysis and carbonization technologies must produce a product on par with traditional coke [207].

As with other natural gas Fuel Switching options (e.g., Section 3.13.3), the most straightforward means of integration of bio-based fuel into the system is biomethane from upgraded landfill gas or biogas. Alternatively, solid biomass combustion or gasification could be utilized to provide the heat for the reheat furnace. However, AltaSteel replaced the old reheat furnace with a new one in 2009, which has resulted in a reduction in natural gas consumption of 40% from 2009 to 2010 [201].

### **3.12.4 Scale and Greenhouse Gas Benefits**

As identified in Section 3.2.4, carbonization of biomass can produce a high-carbon biocoke solid to replace fossil fuel-derived carbon, resulting in GHG reductions exceeding 80%. The natural gas used for heating operations at the AltaSteel facility could be replaced by biomethane from upgraded landfill or biogas and result in GHG emission reductions exceeding 50% (see Sections 3.2.4 and 3.5.4). However, some CO<sub>2</sub> is produced from oxidation of carbon in the scrap material itself, which cannot be avoided through material switching. Assuming a facility-wide reduction of 40% through the use of fuel switching and biocoke, the total annual GHG reduction could be 31,000 t CO<sub>2</sub> eq.

## **3.13 Sugar (from Sugar Beet)**

### **3.13.1 Product Summary**

Sugar beet is a temperate, biennial root crop grown in rotation and processed to produce white sugar. Leading producers in 2010 were France (32 Mt), the United States (29 Mt), Germany (24 Mt), and Russia (22 Mt), with Canadian production 508,000 t (35<sup>th</sup> worldwide) [208]. The average global yield is approximately 50 t ha<sup>-1</sup>, but this can vary widely. In order to produce one tonne of sugar, 7.7 tonnes of sugar beet are required [209]. Alberta is Canada’s leading producer of sugar beet, planting 15,700 ha of

the Canadian total 19,488 ha in 2006. All of Alberta's sugar beet is grown in the Taber area, with refined sugar destined for markets in Alberta, Saskatchewan, and Manitoba [210].

### ***3.13.2 Production Facility***

The sugar beet processing plant located in Taber has an annual capacity of 150,000 t of sugar per year and is owned by Rogers Sugar (operated by subsidiary Lantic Sugar). Approximately 400 producers supply the facility with sugar beets [211]. In the sugar extraction process, sliced sugar beets (cosettes) are added to a diffuser for treatment with counter-current flowing water at 70°C for one hour. Remaining sugars are then extracted using a press, which results in an exhausted pulp. The diffusion juice (liquor) is then treated with calcium hydroxide (milk of lime) to remove impurities, which is followed by concentration and crystallization [209].

Unlike sugarcane sugar facilities, which use by-product bagasse for heat (steam) and power generation, sugar beet sugar processors typically rely on fossil fuels (e.g., natural gas, coal) for process heat and grid electricity for power [209]. This is due to the strong animal feed market for sugar beet pulp and also the very high moisture content (>40%) of this pulp, which makes it a relatively unattractive fuel. Therefore, this process heat fossil fuel combustion is the primary source of emissions at the Taber processing plant.

### ***3.13.3 Switching Options***

The primary material switching opportunity at the Rogers Sugar Taber sugar beet processing plant is in Fuel Switching. Process steam could be generated using a biomass boiler operating on solid biomass, or alternatively, the facility could utilize biogas from anaerobically digested animal manure and agricultural residues. This latter option would require less adjustment in existing operations, particularly if the biogas was upgraded to biomethane to meet existing gas boiler fuel specifications.

Due to the short harvest season of sugar beets, processing facilities typically only operate three months per year. This makes effective fuel supply management a critical factor in the ability to switch to alternative fuels. However, it also makes capital investments in energy infrastructure difficult to justify economically without alternative sources of revenue (e.g., sale of electricity to the grid). Therefore, retention of existing natural gas-based equipment would be highly economically advantageous.

### ***3.13.4 Scale and Greenhouse Gas Benefits***

As discussed in Section 3.3.4, solid biomass can replace natural gas in process heat applications. This includes the production of steam. As in Sections 3.3.4 and 3.9.4, an 85% reduction in GHG emissions relative to coal can be assumed. However, for GHG reductions for solid biomass relative to natural gas, a 70% reduction is assumed due to the fact many studies find a 75% or greater GHG reduction [84,185,195,196]. Therefore, the Rogers Sugar processing plant could anticipate GHG reductions of approximately 43,650 t CO<sub>2</sub> eq per year. This option would require switching from a gas to solid fuel boiler. Should the facility have the option of using upgraded biogas or landfill gas (biomethane), a 50% reduction (see Sections 3.2.4 and 3.5.4) [52,53,54,143,185] could result in emission reductions of 31,000 t CO<sub>2</sub> eq per year.

### **3.14 Waste Management**

Unlike the other facilities analyzed in this report, waste facilities typically provide a service rather than a product. However, as point sources of GHG emissions, landfills and wastewater treatment plants have the opportunity to reduce their emissions by producing products such as energy, fuels, and chemicals.

#### ***3.14.1 Service Summary***

Landfills and wastewater treatment plants process and store (in the case of the former) solid and liquid wastes, respectively. Waste management is a critical component of efficient and sustainable operation of urban centres. Solid wastes are typically disposed of in landfills or in waste-to-energy (WtE) plants, which combust the waste and reduce the quantity of solid requiring landfilling 90% by volume [212]. Modern landfills are designed to contain landfill leachate, thereby preserving ground and surface water quality.

Wastewater treatment plants process sewage and other waste water to remove and neutralize contaminants and purify water. During processing, a large volume of CH<sub>4</sub> is released as organic materials are broken down by anaerobic processes. Any screened solids are typically landfilled.

#### ***3.14.2 Processing Facilities***

Three landfills – those of Calgary, Edmonton, and Lethbridge – made the major point source emitters list in 2009. These landfills produce landfill gas, which is approximately 50% methane, as organic materials in the landfill are broken down anaerobically. Combined, the three landfills produced 226,414 t CO<sub>2</sub> eq in 2009, but total Alberta landfill GHG emissions will be greater than this when accounting for landfills in cities such as Red Deer and Medicine Hat. Landfills in both Edmonton and Calgary capture landfill gas and use it to produce electricity [213,214], while the City of Lethbridge is exploring the potential for landfill gas capture and utilization [215]. Landfill gas capture and combustion, including simple flaring, significantly reduce the net CO<sub>2</sub> eq emissions associated with landfills due to the notably lower GWP of CO<sub>2</sub> compared to CH<sub>4</sub>. For all three landfills, GHG emissions were dominated by CH<sub>4</sub> emissions. Since the landfill gas is being used to produce electricity in Edmonton and Calgary, it also reduces the consumption of natural gas and/or coal in other electricity generating facilities.

The wastewater treatment plant in Edmonton is the only such facility included in the large emitters list. The reason that Calgary wastewater treatment is not included in the list is that instead of a single facility treating all the water for the city, as is the case in Edmonton, Calgary has three separate facilities that produce emissions below the reporting threshold of 50,000 t CO<sub>2</sub> eq per year [216,217]. Therefore, consideration should be given to the Calgary facilities as well as the large Gold Bar wastewater treatment plant in Edmonton.

#### ***3.14.3 Switching Options***

As evidenced by the Edmonton and Calgary landfill CH<sub>4</sub> emissions production despite landfill gas capture and utilization, landfilling followed by gas capture is an inefficient means of reducing the GHG emissions associated with waste. Energy and higher value products, such as fuels and chemicals, can be produced

from solid waste in a more efficient manner if the waste is diverted to a processing facility rather than a landfill. The City of Calgary has a plan to divert 80% of solid waste from the landfill by 2020 via recycling, reuse, and compost programs [217]. Edmonton is home to the Edmonton Waste Management Centre (EWMC), considered North America's largest collection of waste processing research and development facilities [218]. This includes a waste-to-chemicals facility currently under construction, that when completed, is expected to convert 100,000 dry tonnes per year of sorted waste into 36 million litres of methanol and ethanol [108]. This Enerkem Inc. facility utilizes gasification and catalytic syngas reforming technology for production of these chemicals, which could be useful in the production of ethylene (see Section 3.4.3).

The primary opportunities for wastewater treatment GHG reduction are in biogas capture and utilization and the use of biosolids as an energy source. Waste water sludge can function as the sole organic material for biogas production using AD at wastewater treatment facilities, or alternatively, microalgae or other organic material can be added to the sludge to increase the solids content and hence biogas production [219,220,221]. When microalgae are introduced to the digester, they utilize the nutrients to grow and once dead and decomposing, contribute to the production of biogas [222,223]. This biogas can be used to provide heat and electricity to the wastewater treatment facility, or alternatively, could be upgraded to pipeline quality biomethane and used in various applications (e.g., see Section 3.5.3) [219]. Algae could also be grown to act as a source of lipids that could be extracted and used to produce fuels and chemicals [224].

#### ***3.14.4 Scale and Greenhouse Gas Benefits***

Many different LCAs have been conducted on the management options for municipal solid waste, with an emphasis on comparing energy production to landfilling [225,226]. Since municipal solid waste (MSW) is a highly heterogeneous feedstock, results will vary tonne by tonne. While incineration of fossil fuel derived materials, such as plastics, results in a net increase in GHG emissions, incineration of biological materials typically results in a net decrease in GHG emissions due to the avoidance of CH<sub>4</sub> emissions from anaerobic breakdown in a landfill. As an average, the U.S. Environmental Protection Agency found a 0.16 kg CO<sub>2</sub> eq kg<sup>-1</sup> solid waste (unsorted) reduction for incineration compared to landfilling [227]. Of this 0.16 kg CO<sub>2</sub> eq kg<sup>-1</sup> solid waste, 0.03 kg CO<sub>2</sub> eq kg<sup>-1</sup> is from reductions in fossil fuel power generation as a result of waste-fired generation and 0.13 kg CO<sub>2</sub> eq kg<sup>-1</sup> solid waste is from avoided CH<sub>4</sub> and CO<sub>2</sub> emissions from base case landfilling. This reduction from avoided landfilling is similar to the estimate of 0.1 kg CO<sub>2</sub> eq kg<sup>-1</sup> solid waste (7,000 t CO<sub>2</sub> eq per year) reduction from avoided landfilling that is predicted for the new methanol/ethanol facility being constructed in Edmonton. This facility will reduce landfilling volume by 71,000 tpy [228].

The City of Edmonton already has a strong waste diversion program in place which, during operation of the methanol/ethanol plant, will have a diversion rate exceeding 90%. Therefore, there is limited scope for GHG reductions from the Edmonton landfill beyond the facility already under construction. On the other hand, Calgary and Lethbridge could also pursue the waste-to-chemicals, fuels, and energy route. Assuming a GHG reduction of 0.1 kg CO<sub>2</sub> eq kg<sup>-1</sup> solid waste and a 90% diversion rate from current landfilling volume of 680,000 tpy [217], Calgary could reduce GHG emissions by an estimated 61,200 t

CO<sub>2</sub> eq per year (assuming current production rate is stable). Lethbridge could reduce GHG emissions by an estimated 15,000 t CO<sub>2</sub> eq per year based upon their current landfilling rate of 165,000 tpy [229].

A comprehensive comparison of biosolids processing and end-use options, including anaerobic digestion, dewatering, drying and landfilling, agriculture fertilizer, composting, and incineration to replace coal in a cement kiln, was prepared by Peters and Rowley (2009) [230]. The greatest GHG reduction from the digester, dewatering, and landfilling baseline was when the final use was replacement of coal in a cement kiln. If biosolids were utilized in the kiln without drying (although after dewatering), there was a greater than 100% reduction in GHG emissions. Even when drying the biosolids with natural gas and then incinerating them in the cement kiln, emissions were reduced by 80%. Assuming a 90% reduction from baseline emissions at the Edmonton Gold Bar wastewater treatment plant due to offsets obtained from reduced coal use at a cement facility and avoided CH<sub>4</sub> emissions, annual emissions could be reduced by approximately 83,500 t CO<sub>2</sub> eq. This management strategy could also be applied to wastewater treatment facilities in Calgary and other Alberta cities.

## 4 Greenhouse Gas Emissions Reduction Critical Analysis

### 4.1 Potential Reductions by Switching Type and Product Category

The potential GHG emissions reductions from material switching in Alberta are summarized in Table 4.1. It is important to note where the GHG reductions occur over the life cycle of the products, as described for each product category in Section 3. These can be generally classified according to the type of material switching type:

- 1) **Input Switching** – GHG emissions reductions must be considered over the lifetime of the primary product, including use and final disposal of that product. An example is bioethylene; while production of bioethylene has limited GHG reductions relative to production of ethane-based ethylene, the greatest GHG benefit occurs when the final product is incinerated. Due to the lower carbon intensity of the raw materials used to produce bioethylene than ethylene, the net GHG production when incinerated is significantly less. Many of the products that have Input Switching opportunities, such as ethylene, isooctane, and LAOs, are exported from Alberta and therefore life cycle GHG emissions reductions must take cross-border emissions allocation into consideration.
- 2) **Fuel Switching** – GHG emissions reductions occur over the life cycle of the fuel used to produce the final product but not the materials of the product itself. Therefore, the use and disposal of the product do not affect the material switching GHG benefits. While point-source facility emissions may stay the same or even increase, the lower carbon intensity of the biomass fuel compared to fossil fuel results in lower net emissions for the production facility. An example is the use of forest biomass in cement kilns to replace coal, which reduces the net GHG emissions from cement production but the use or disposal of cement is not considered in the reductions.
- 3) **Product Switching** – GHG emissions reductions occur due to the substitution of carbon-intensive products with bio-based alternatives. In this case, material switching creates a competitor product and therefore, use of the bio-based product results in avoided point source emissions from the carbon-intensive facility and the upstream and downstream emissions associated with that product. At the extreme, one could consider the closure of a production facility (and avoidance of the point source and product life cycle emissions) due to the production of a bio-based alternative at a separate facility. An example is the use of wood lumber in the place of steel and concrete in building construction, or the use of ethanol in the place of isooctane as a fuel additive.



Table 4.1 Summary of potential greenhouse gas emissions reductions from material switching

Product Category	Material Switching Option(s) <sup>a</sup>	Process & Materials	2009 GHG Emissions (kt CO <sub>2</sub> eq)	Estimated Reduction Potential (%)	Estimated Annual GHG Reductions (kt CO <sub>2</sub> eq)
Ammonia & Fertilizers	1. Input (hydrogen) 2. Product (organic fertilizer)	1. Gasification of lignocellulosic biomass for hydrogen production 2. Organic fertilizers such as manure, biosolids	4,043	1. 80 2. 50	1. 3,817 2. 2,021 (LC) <sup>b</sup>
Calcined Coke & Thermal Carbon Black	1. Product (biocoke) 2. Input (biomethane)	1. Carbonization at high temperature (slow pyrolysis) 2. Biogas/ landfill gas upgrading to replace natural gas	191	1. 85 (LC, CC) <sup>c</sup> 2. 50 (TCB) <sup>d</sup>	1. 1100 (LC) 2. 64
Cement & Lime	1. Fuel (solid biomass) 2. Product (wood construction)	1. Agriculture/forestry residues, animal and bone meal for coal & gas 2. Increased wood-frame construction (particularly multi-storey)	1,588	1. 85 (partial) <sup>e</sup> 2. 80-100+	364 + wood use
Ethylene & Ethylene Derivatives	Product/Input (bioethylene)	Ethylene and olefins produced via biomass gasification, methanol production, and methanol to olefins (grain-based ethanol dehydration has poor GHG reduction potential)	4,545	1. 80 (LC) <sup>b</sup> ; 2. 70 (U&P) <sup>f</sup>	1. 12,089 (LC) <sup>b</sup> 2. 4,310 (U&P)
Hydrogen	Input (biomethane)	Biogas/landfill gas upgrading to replace natural gas	1,069	50	535
Isooctane	1. Input (ethanol) 2. Product (ethanol)	1. Ethanol is reacted with isobutylene to produce ETBE instead of isooctane 2. Ethanol is a fuel octane enhancer	324	1. 30 2. 40	1. 722 (LC) 2. 963 (LC)
Linear Alpha Olefins	1. Input (bioethylene) 2. Product (bio LAOs)	1. Bioethylene, as discussed above, is used to replace ethane-sourced ethylene 2. Identical LAOs produced using biomass gasification and Fischer-Tropsch catalytic reformation	112	70 (same for both)	551 (LC) <sup>g</sup>

Lumber and MDF	1. Fuel (biomethane) 2. Input (lignin resins)	1. Biogas/landfill gas upgrading to replace natural gas 2. Replacement of petroleum resins and glues with lignin-based products	132	50 (partial) <sup>e</sup>	1. 19
Magnesium Oxide	Fuel (solid biomass)	Agriculture/forestry residues, animal and bone meal for coal & gas	94	85 (partial) <sup>e</sup>	22
Nitrogen & Oxygen	Fuel (on-site electricity)	Biogas/landfill gas upgrading to replace natural gas	438	50	219
Pulp	Fuel (solid biomass/biomethane)	Forest harvest residues at one mill Biogas/landfill gas upgrading to replace supplementary natural gas in others	535	75 (partial) <sup>e</sup>	38
Steel	1. Fuel (biomethane) 2. Input (biocoke)	1. Biogas/ landfill gas upgrading to replace natural gas 2. Carbonization at high temperature (slow pyrolysis)	78	40 (across facility)	31
Sugar	Fuel (solid biomass/biomethane)	1. Agricultural residues in a new boiler 2. Biogas/landfill gas upgrading to replace supplementary natural gas in existing	62	2. 50	31
Waste Management	1. Product (waste-to-chemicals) 2. Product (biomethane)	1. Production of chemical, fuels, and/or electricity from waste instead of landfilling 2. Capture of biogas emissions from water treatment as feedstock for biomethane	319	1. 90 2. 90	167
Total			13,530		9,617 + 9,842 (LC)

<sup>a</sup>Additional fuel switching options may also be possible, such as replacement of natural gas for process heat in chemical production facilities

<sup>b</sup>Life Cycle – emission reductions are found when comparing complete life cycles, including final product use. Non-LC reductions are for upstream and production emissions only. Point source emissions may not be reduced.

<sup>c</sup>Calcined Coke

<sup>d</sup>Thermal Carbon Black

<sup>e</sup>Partial – only a portion of the fossil fuels used in production are replaced and biomass resources are using in a co-firing setting

<sup>f</sup>Upstream and production does not include final combustion of the product (i.e., could be landfilled)

<sup>g</sup>Mutually exclusive with ethylene reductions

## **4.2 Biomass Inventories of Alberta**

The ability of Alberta's large non-energy industrial emitters to utilize material switching is largely dependent upon an economically available supply of raw materials. Biomass for bioenergy or biomaterial applications is typically sourced from local (i.e. within several hundred kilometers or less) suppliers, although inter-continental long distance transportation of biomass in the form of wood pellets has proven commercially viable [231]. The emphasis of this report is not an inventory of biomass potential in Alberta, but previous studies provide estimates of the available biomass and these can be compared to the quantities required to realize potential GHG emissions reduction identified in Section 3 and summarized in Table 4.1.

The current and future potential availability of biomass in Alberta has been the subject for several reports, with a large range of estimates due to varying assumptions and study detail. In a 2004 study by Levelton and (S&T)<sup>2</sup> consultants, it was estimated that the current biomass potential is 200 petajoules (PJ) and future potential, including dedicated forest harvest and bioenergy crops, would be 585 PJ [232]. With an average energy content of 17.5 GJ bdt<sup>-1</sup>, these figures are equivalent to 11.4 M bdt and 33.4 M bdt respectively. This contrasts with a 2009 study by the Energy Futures Network that estimates the potential Bioresources amount to 380-420 PJ or 22-24 M bdt [233]. In a more recent assessment of the potential for GHG emissions reductions from biological systems in Alberta, forestry residue availability was estimated at only 17 PJ or approximately 1 M bdt [234]. This is significantly different than the 7 M bdt estimated in the Energy Futures Network report [233] and the approximate 6.5 M bdt estimated for the by Levelton and (S&T)<sup>2</sup> consultants' report [232]. For this report, it will be assumed that 6.5 M bdt of forest residues with an energy potential of 120 PJ and 3 M bdt of agricultural crop residues with an energy potential of 50 PJ are available. Additional lignocellulosic material demand will need to be met by dedicated forest harvest, bioenergy crops, or biomass imports (e.g., wood pellets). Municipal waste resources are assumed to be 33 PJ with volume approximately 3.5 Mt [232].

The biogas potential of Alberta was estimated by the Agriculture and Rural Development of the Government of Alberta. With an estimated annual available biomass quantity of 31.9 Mt (wet) of biomass, dominated by cattle manure, it was determined that the biogas energy potential for the province is 21-39 PJ [235]. This is notably less than the 88 PJ energy potential estimated by Levelton and (S&T)<sup>2</sup> consultants [232], but includes an allowance for recoverable and not total quantities of manure and other biomass materials such as animal fat, animal carcasses, wastewater biosolids, household waste, and straw.

## **4.3 Biomass Availability in Context**

Assuming a 10% loss in energy for upgrading to biomethane [236] (large and therefore conservative for energy availability), the biogas potential of Alberta is equivalent to 19-35 PJ or 510-930 Mm<sup>3</sup> of natural gas. This amount of natural gas, if consumed industrially, would result in point source emissions of 1927 g CO<sub>2</sub> eq m<sup>-3</sup> or 983,000-1,790,000 t CO<sub>2</sub> eq. As illustrated in Table 4.2, natural gas consumption, based upon the previously stated emissions factor, for only a few product categories far exceeds potential

biomethane production. However, biomethane production could potentially meet all the needs of the hydrogen and sugar product categories (two facilities in total).

**Table 4.2 Estimated natural gas consumption for selected product categories (2009)**

Product Category	GHG Emissions (kt CO <sub>2</sub> eq)	Estimated Natural Gas Consumption (Mm <sup>3</sup> )
Ammonia & Fertilizers	4,043	2,100
Hydrogen*	1,069	560
Sugar	62	32
Total	5,174	2,700

\*Excludes hydrogen for ammonia production

Based upon a report prepared by Chalmers University of Technology and other sources, methanol yield can be approximated at 0.53 kg kg<sup>-1</sup> when produced by biomass gasification and reformation [128,26]. For conversion to olefins ethylene and propylene, the production ratio is 3:1, resulting in a final biomass-to-olefins mass balance of 0.178 kg kg<sup>-1</sup> dry biomass [128]. Half of this olefins production is assumed to be ethylene and half propylene. Therefore, with a biomass-to-ethylene mass balance of 0.089 kg kg<sup>-1</sup>, 60-70 M bdt of lignocellulosic biomass would be required to meet Alberta ethylene production volumes on a yearly basis. This far exceeds previous estimates of annual biomass availability [232,233,234]. In addition, a large volume of propylene would be produced and this must be taken into consideration. However, with a current installed polyethylene capacity of approximately 2.3 Mt, 26 M bdt of biomass could produce sufficient ethylene to meet the demand of these existing facilities via ethylene Input Switching. However, this would require virtually all biomass available in the province in addition to development of biomass crops and dedicated forest harvest. Replacing 2.3 Mt of ethylene with bioethylene and assuming an emissions reduction of 80%, as described in Section 3.4.4, would result in annual GHG emission reductions of approximately 5 Mt CO<sub>2</sub> eq. However, due to the low conversion efficiency, this is significantly less than the GHG emissions reductions that could be realized if that 26 M bdt of biomass were used to replace coal in power generation [62,234].

Gasification of biomass to produce H<sub>2</sub> can have a yield of approximately 7% on a mass basis. This is approximately 56% on an energy basis [25,26]. Applying this yield to the 9.5 M bdt of forestry and agricultural crop residues available in Alberta on a yearly basis results in H<sub>2</sub> production of 0.64 Mt H<sub>2</sub>. This is equivalent to approximately 7,000 Mm<sup>3</sup> and compares with the Air Products Canada H<sub>2</sub> plants' combined annual capacity of 1,750 Mm<sup>3</sup>. Assuming an 84% H<sub>2</sub> to NH<sub>3</sub> conversion efficiency [23], the 7,000 Mm<sup>3</sup> could be used to produce approximately 3 Mt of NH<sub>3</sub>. This is sufficient NH<sub>3</sub> to meet all the net NH<sub>3</sub> and nitrogen fertilizer production requirements in Alberta, excluding the Agrium Joffre facility production (which utilizes by-product H<sub>2</sub> and is therefore not considered a large emitter). Including avoided upstream natural gas emissions, fertilizer life cycle emissions reductions of 80% via utilization of bio-based H<sub>2</sub> would result in annual GHG emissions reductions of approximately 3.8 Mt CO<sub>2</sub> eq.

## 5 Recommendations and Gaps

### 5.1 Priorities for Large-Scale Material Switching GHG Reductions

The assessment of potential GHG reductions detailed in Section 3, combined with the critical analysis of these reductions in Section 4, provides the basis for making recommendations on material switching priorities for Alberta. These priorities are selected based upon the potential for large-scale GHG emissions reductions, as dictated by existing emissions, estimated percentage GHG reduction, and availability of acceptable feedstocks. While current industrial technical feasibility and economic viability are key metrics dictating the realism of reductions, these were not considered primary criteria for recommendations. Therefore, recommendations on commercial implementation of any material switching options will require techno-economic analyses that are beyond the scope of this report. The viability of these recommendations is dependent upon the economic attractiveness (including risk) relative to existing practices, the cost of raw materials/fuels, the policy support and barriers for implementation, and the technical challenges to implementation and operation.

The six recommended priorities for large-scale GHG emissions reductions in Alberta are:

#### 1) Intensive Wood-Use Construction

Material Switching: Product Switching – Cement & Lime product category plus other building materials (e.g., aluminum, petroleum products)

Use of wood in construction, whether in multi-storey buildings or single-family homes, results in carbon sequestration that can last decades or centuries. Wood-intensive building construction can result in a net decrease of carbon, thereby offsetting emissions from other sectors. Intensive wood construction, including wood roofing, cladding, insulation, and windows, for single-family homes only could result in annual GHG reductions of 1.1 Mt CO<sub>2</sub> eq.

#### 2) Biomethane for Natural Gas Substitution

Material Switching: Input Switching – Ammonia & Fertilizers, Thermal Carbon Black, and Hydrogen product categories; Fuel Switching – Numerous product categories, including Pulp, Steel, and Sugar

Upgraded biogas and landfill gas can blend with, or substitute for, natural gas in pipelines and directly at large industrial consumers such as producers of ammonia, thermal carbon black, hydrogen, pulp, steel, and sugar. Similar properties of natural gas and biomethane enable blending at any percentage. This is linked to the recommendation 5, since a large quantity of natural gas is currently used to produce hydrogen and biomethane could also fulfill this purpose. The Alberta GHG reduction potential is limited by biomethane feedstock availability. Assuming 725 M m<sup>3</sup> of natural gas could be replaced and a 50% reduction in GHG emissions, annual GHG reductions of 0.7 Mt CO<sub>2</sub> eq could be possible.

**3) Fuel Switching in Cement and Magnesium Oxide Kilns**

Material Switching: Fuel Switching – Cement & Lime and Magnesium Oxide product categories

With fuel handling and facility modifications, alternative fuels can be used at co-firing rates of up to 70% with coal. Alberta is currently lagging other provinces in the use of alternative fuels in lime and magnesia kilns. Use of biomass such as biosolids derived from wastewater has the additional benefit of reducing methane emissions. With a high 60% fuel substitution rate on an energy basis and an 85% reduction in fuel GHG intensity, annual GHG reductions could reach almost 0.4 Mt CO<sub>2</sub> eq.

**4) Biomass gasification for methanol production**

Material Switching: Input Switching – Ethylene Derivatives and LAO product categories

Methanol can be used to produce ethylene and propylene in a methanol-to-olefins facility, resulting in significant GHG emissions reductions. This bioethylene can then be used to produce ethylene derivatives such as polyethylene or LAOs. The alternative pathway of direct conversion of cellulose to ethylene glycol requires further investigation. Biomass availability is the limiting factor in GHG reduction potential, with 26 M bdt of forestry and agricultural residues required to produce 2.3 Mt ethylene and eventually polyethylene. This biomass quantity is at the very high end of previous estimates of biomass availability. An 80% GHG reduction from baseline would result in annual life cycle GHG reductions of 5 Mt CO<sub>2</sub> eq but would leave no other biomass available in Alberta for other applications and it is questionable whether 26 M bdt could be aggregated. A more reasonable estimate would be production of 0.3 Mt bioethylene for life cycle GHG reductions of 0.6 Mt CO<sub>2</sub> eq, requiring 3.4 M bdt of biomass.

**5) Biomass gasification for hydrogen production**

Material Switching: Input Switching – Ammonia & Fertilizer product category

Hydrogen, typically produced from natural gas, is a key input for fertilizer production, oil refining, and chemical production. Gasification of feedstocks such as forest harvest residue, agricultural residues, solid waste, and bioenergy crops has the potential to produce large volumes of bio-based hydrogen to reduce natural gas consumption. As with methanol production, the limiting factor in hydrogen production is biomass availability. All the agricultural and forestry biomass available in Alberta would be required to meet the needs of the Ammonia & Fertilizer producers in the province. However, a more reasonable estimate would be the use of 3.0-3.5 M bdt of biomass to produce 1.0 Mt of ammonia. This could result in production emissions reductions of 0.9 Mt CO<sub>2</sub> eq per year.

**6) Wheat-based ethanol production**

Material Switching: Input Switching – Isooctane, Ethylene Derivatives, and LAO product categories

Ethanol can be used to produce ETBE, a gasoline fuel oxygenate, and bioethylene. Ensuring low life cycle GHG emissions for ethanol is critical if material switching of its derivatives is to result in large GHG emissions reductions. The current limiting factor in emissions reductions is Alberta-based ethanol production. However, ethanol can be readily imported by rail, making the annual 0.7 Mt CO<sub>2</sub> eq reductions (including product use) identified for ETBE production in Section 3.6.4 a possibility.

These recommendations focus on the opportunities for large GHG reductions and can be combined to represent annual GHG reductions of approximately 4.4 Mt CO<sub>2</sub> eq. However, on a per tonne of biomass basis, the most effective use for GHG reductions is dependent upon the fossil fuel being replaced and the relative efficiency of conversion for biomass relative to the fossil fuel. Coal is the most GHG intensive fossil fuel, followed by oil and then natural gas. The greatest GHG reductions will occur when biomass replaces coal and has efficiencies of conversion equal-to or greater-than coal. The replacement of natural gas at efficiencies lower than that of natural gas typically results in the lowest GHG reductions. Biomass form and properties, which partially dictate efficiency of conversion, must also be taken into consideration when choosing a preferred use. For example, high moisture content feedstocks such as food waste and manure are often used for biogas production via AD rather than incineration due to the low efficiency of the latter with high moisture content feedstocks. Biogas will be used in applications that require a gaseous fuel as an input, thereby dictating the preferred use.

**5.2 Gaps for the Material Switching Priorities**

A high-level gap analysis was conducted using a review of the relevant academic, industry, non-governmental organization (NGO), and government literature. The gap analysis results focus upon gaps relevant to the six recommended priorities and are organized by priority and gap type: science, data, and information; policy; technology; demonstration; or GHG quantification metrics. Given the number of priorities and the vast array of potential hurdles to commercial implementation in Alberta, this gap analysis should not be considered a complete list but an identification of some key gaps that need addressing prior to pursuing commercial material switching. Many of the gaps are in Alberta-specific data and this is certainly true for the GHG reduction quantifications throughout this report. Particularly with biological systems, GHG reductions can be highly site-specific, requiring unique LCAs to accurately quantify product GHG profiles.

Table 5.1 Key gaps for biomass material switching in Alberta, arranged by priority area

Priority Area	Gaps				
	Science, Data, & Information	Policy	Technology	Demonstration	GHG Metric
<b>Intensive wood-use construction</b>	<ul style="list-style-type: none"> <li>• Performance of wood-intensive construction in Alberta climate zones</li> <li>• Performance of &gt;4 storey wood-frame buildings in Alberta climate</li> <li>• Performance of wood buildings in Alberta’s forest-fire prone regions</li> </ul>	<ul style="list-style-type: none"> <li>• Building code limits for &gt;4 storey wood-frame construction</li> <li>• Construction/ demolition material requirements to limit landfilling</li> <li>• Economic recognition of GHG advantages of using bio-based building materials, including sequestered carbon</li> </ul>	<ul style="list-style-type: none"> <li>• Novel biomass-based building products/ materials to increase bio-based content and replace plastics, metals, and cement products</li> </ul>	<ul style="list-style-type: none"> <li>• &gt;4 storey wood-frame construction in Alberta weather conditions</li> <li>• Performance of wood-intensive buildings in fire zones</li> </ul>	<ul style="list-style-type: none"> <li>• Alberta-specific LCA comparisons of standard vs. wood-intensive construction</li> <li>• Determination of impact of building design and architecture on LCA results</li> <li>• Quantification of Alberta-specific construction/ demolition material reuse, recycling, landfill, and incineration rates</li> </ul>
<b>Biomethane for natural gas substitution</b>	<ul style="list-style-type: none"> <li>• Detailed mapping of manure, animal offal, food processing residues, and other feedstock availability relative to location of natural gas pipelines</li> </ul>	<ul style="list-style-type: none"> <li>• Small-producer access to large natural gas pipelines</li> <li>• Supply agreements for small biomethane producers</li> <li>• Renewable content opt-ins for gas consumers</li> </ul>	<ul style="list-style-type: none"> <li>• Cost-competitive and efficient biogas/ landfill gas upgrading technologies</li> </ul>	<ul style="list-style-type: none"> <li>• Economically competitive upgrading</li> <li>• Multi-feedstock anaerobic digestion optimization</li> <li>• Capture of landfill gas at Alberta’s smaller landfills</li> </ul>	<ul style="list-style-type: none"> <li>• Alberta-specific LCAs for various anaerobic digestion feedstocks</li> </ul>



<p><b>Fuel switching in cement and magnesium oxide kilns</b></p>	<ul style="list-style-type: none"> <li>• Inventory and cost estimate of low and negative cost alternative fuels in Alberta</li> <li>• Mapping of alternative fuels and proximity to existing facilities</li> </ul>	<ul style="list-style-type: none"> <li>• Incentive to use alternative fuels, recognizing waste disposal and GHG benefits</li> <li>• Permitting for incineration of various alternative fuels, such as specified risk materials</li> </ul>	<ul style="list-style-type: none"> <li>• Alternative fuel fly-ash quality and use in cement/alternative applications</li> </ul>	<ul style="list-style-type: none"> <li>• Determination of maximum alternative fuel firing rates on a plant-by-plant and feedstock-by-feedstock basis</li> </ul>	<ul style="list-style-type: none"> <li>• Alberta-specific LCAs for various alternative fuels, with consideration of business-as-usual waste disposal requirements (e.g., biosolids)</li> </ul>
<p><b>Biomass gasification for methanol production</b></p>	<ul style="list-style-type: none"> <li>• Commercial performance information for MTO technologies</li> <li>• Economies-of-scale for gasification and MTO technologies</li> <li>• Long-term industrial biomass gasification performance</li> <li>• End-use information for plastics produced in Alberta</li> </ul>	<ul style="list-style-type: none"> <li>• Renewable content recognition (e.g., labelling standards) or requirements for plastics</li> <li>• Support for non-energy renewable product technologies and 'Alberta Bio' content</li> </ul>	<ul style="list-style-type: none"> <li>• Cost-competitive syngas scrubbing technologies</li> <li>• Optimization of preferred feedstocks, gasification technology, and methanol formation catalyst</li> <li>• MTO technology methanol purity requirements</li> <li>• Alternative methanol-to-ethylene (or MTO) catalysts to maximize ethylene selectivity</li> <li>• Basic research on direct conversion of cellulose to ethylene glycol</li> </ul>	<ul style="list-style-type: none"> <li>• Reliable, cost effective gasification technology with good feedstock flexibility</li> <li>• Gasification with low-tar syngas and methanol production operational at scale appropriate for biomass availability</li> <li>• Operation of MTO technology at smaller scale than existing facilities</li> </ul>	<ul style="list-style-type: none"> <li>• Alberta-specific LCA on woody and herbaceous biomass gasification and olefins production via methanol</li> <li>• Lack of commercial data on biomass-to-methanol operations</li> <li>• Allocation of emissions to ethylene and propylene based upon performance of MTO technology</li> <li>• Integration of combined heat and power facilities with methanol and MTO production for GHG credits (offset coal power)</li> <li>• Allocation of existing ethylene facility emissions to various ethylene derivatives</li> </ul>

<p><b>Biomass gasification for hydrogen production</b></p>	<ul style="list-style-type: none"> <li>• Long-term industrial biomass gasification performance</li> <li>• Syngas tar impact on H<sub>2</sub> purification</li> </ul>	<ul style="list-style-type: none"> <li>• Renewable content recognition (e.g., labelling standards) or requirements for plastics, chemicals, and fertilizer</li> <li>• Support for non-energy renewable product technologies</li> </ul>	<ul style="list-style-type: none"> <li>• Cost-competitive syngas scrubbing technologies</li> <li>• Optimization of preferred feedstocks and gasification technology</li> <li>• Syngas-derived H<sub>2</sub> gas purification</li> </ul>	<ul style="list-style-type: none"> <li>• Reliable, cost effective gasification technology producing low-tar syngas from low-grade, heterogeneous feedstocks</li> <li>• Biomass feedstock delivery systems to operate at scale consistent with H<sub>2</sub> user demand</li> </ul>	<ul style="list-style-type: none"> <li>• Alberta-specific LCA on woody and herbaceous biomass gasification</li> <li>• Integration of combined heat and power facilities with bio-based H<sub>2</sub> facilities (emissions allocation)</li> </ul>
<p><b>Wheat-based ethanol production</b></p>	<ul style="list-style-type: none"> <li>• Future crop yield variability for long-term feedstock planning</li> </ul>	<ul style="list-style-type: none"> <li>• Renewable content recognition (e.g., labelling standards) or requirements for plastics and chemicals</li> <li>• Support for non-energy renewable product technologies</li> <li>• Recognition of ETBE as effective octane enhancer in North America</li> </ul>	<ul style="list-style-type: none"> <li>• Novel catalysts for low-temperature, low pressure ethanol dehydration to ethylene</li> </ul>	<ul style="list-style-type: none"> <li>• Increased ethanol production in Alberta to supply potential users such as dehydration (to ethylene) facility</li> <li>• Trial of ETBE at isooctane facility</li> </ul>	<ul style="list-style-type: none"> <li>• Updated LCAs on ethanol production in Alberta using recent electricity/fuel supply mix</li> <li>• Allocation of existing ethylene facility emissions to various ethylene derivatives</li> </ul>

### **5.3 Implementation in Alberta**

Many of the industries detailed in this report operate in Alberta specifically due to the abundance of fossil fuels such as natural gas, ethane, coal, and oil. While Alberta is endowed with substantial biomass resources that can make a notable impact on fossil fuel consumption within the province, it must be recognized that fossil fuels will continue to play a central role in operation of Alberta's non-energy industries. However, opportunities do exist for including biological, renewable content in many of Alberta's non-energy industrial products. As a major exporter of products such as ethylene & ethylene derivatives, LAOs, isooctane, and fertilizer, Alberta has the opportunity to take the lead on material switching for products used around the world. In many commodity markets, this could be a point of differentiation. Alberta's image around the world is often one of an oil sands exporter. Aggressive pursuit of material switching and branding of 'Alberta Bio' content could play an important role in highlighting Alberta's environmental credentials while recognizing the current scale and economic benefits of fossil fuel-derived products.

As a leader and innovator in fossil fuel extraction and processing, Alberta could utilize this expertise to pursue development of biomass material switching technologies. This is particularly true for gasification and gas processing technology for the production of H<sub>2</sub> and ethylene (via methanol). Technologies such as circulating fluidized beds, which are the preferred technology for clean coal power generation, can also be utilized for biomass gasification [237]. Catalyst development is also an area that has the potential for excellent cross-over between the fossil fuel and biomass processing sectors. Specific opportunities could include catalysts for ethylene production from coal-, natural gas-, or biomass-derived methanol and catalysts for direct conversion of syngas to chemicals and fuels.

Fuel switching opportunities, including blending biomethane with natural gas and co-firing alternative fuels with coal for cement and magnesium oxide production, may be some of the easiest means of material switching. Alberta lags other jurisdictions in Canada in co-firing alternative fuels in thermal cement kilns [80,81] and therefore has a large opportunity to boost co-firing rates. British Columbia's Terasen Gas biogas upgrading and pipeline access program also provides a good example of how policies can enable biomethane producer access to the natural gas grid [238]. Both fuel switching opportunities identified here as priorities can be implemented commercially with limited technical risk. Economic competitiveness will be the largest hurdle to commercial success.

Although wood is already used extensively in single-family and multi-family home construction in Alberta, the quantity of bio-based materials used in construction can be significantly increased. This includes options such as cellulose insulation, wood windows, and wood cladding/shingles. However, despite the large quantity of carbon that can be sequestered in homes over many decades or even centuries, this long-term benefit is not typically considered when determining GHG balances. Often, as trees are cut down for milling to lumber, the carbon in the tree is considered to be already released into the atmosphere. The long-term benefits of using wood and biomass for construction need to be adequately recognized in order to encourage material switching in this sector.

## 6 Conclusion

Biomass material switching can result in large life cycle GHG emissions reductions for the non-energy large industrial emitters of Alberta. These GHG emissions reductions are largely due to the lower GHG intensity of raw biomass feedstock relative to fossil fuel feedstocks coal, oil, and gas. When acquired from a sustainable source, biomass is a low carbon intensity resource that can be used to displace fossil fuels in products and as a process fuel. While material switching to biomass may not result in large changes in point-source (i.e. facility) emissions, the complete life cycle of products (in the case of Input or Product Switching) or process fuels (in the case of Fuel Switching) requires assessment to quantify and realize the GHG emissions reductions.

Currently, the largest non-energy GHG emitters in Alberta are the (1) ethylene & ethylene derivatives, (2) ammonia & fertilizers, (3) cement & lime, and (4) hydrogen product categories. While coal is the traditional fuel for cement and lime, the other products are produced from Alberta's large supply of natural gas and heavier gaseous hydrocarbons such as ethane.

The six priorities for biomass material switching include wood intensive construction, substituting biomethane for natural gas, fuel switching in cement and magnesium oxide kilns, gasification for the production of H<sub>2</sub> and methanol (with the latter further processed to ethylene), and increased domestic ethanol production for use as a fuel additive and chemical feedstock. Based upon estimates of the available biomass resources in Alberta, life cycle (including use of the final product) emissions reductions from implementing these six priorities could reach 4.4 Mt CO<sub>2</sub> eq. Although point-source facility emissions may not decrease, producers could gain credit for reductions obtained throughout the product life cycle.

The least disruptive means of material switching for these large emitters is utilization of bio-based alternatives with properties very similar or identical to those currently in use. This material switching could be realized by either an Input Switching or Fuel Switching approach, depending upon the product. Due to the large scale of many of the facilities detailed in this report and limited supplies of domestic Albertan biomass, blending (rather than complete replacement) similar or identical biological materials with primary fossil fuels may be a more attractive and reasonable approach. This would enable Albertan products to contain a renewable component and reduce products' GHG emissions profiles. This is equivalent to mixing ethanol with gasoline in transportation fuels or wood pellets with coal for power generation. Examples include biomethane blending with natural gas, bioethylene blending with ethylene in polyethylene production, and H<sub>2</sub> from biomass gasification blending with natural gas-derived H<sub>2</sub>.

This report ranks the opportunities for GHG reduction across key non-energy emitters in Alberta, but does not comment on the relative cost of reduction in each product category. Future work might consider quantifying the cost of reduction in each category on a t CO<sub>2</sub> eq basis, which would allow government to optimize potential trade-offs between economic and environmental benefits. This report should not be interpreted as a definitive assessment on which material switching opportunities *should* be pursued, but which opportunities *could* be pursued.

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