

## **Supporting Information for Life Cycle Emissions and Cost of Producing Electricity from Coal, Natural Gas and Wood Pellets in Ontario, Canada**

Yimin Zhang<sup>1</sup>, Jon McKechnie<sup>1</sup>, Denis Cormier<sup>3</sup>, Robert Lyng<sup>4</sup>, Warren Mabee<sup>5</sup>,  
Akifumi Ogino<sup>6</sup> and Heather L. MacLean<sup>1,2\*</sup>

<sup>1</sup>Dept. of Civil Engineering, University of Toronto, 35 St. George St. Toronto, Ontario M5S 1A4

<sup>2</sup>School of Public Policy and Governance, University of Toronto

<sup>3</sup>FPIInnovations – FERIC 580 boul. St-Jean, Pointe-Claire, Quebec, H9R 3J9

<sup>4</sup>Ontario Power Generation, 700 University Avenue, Toronto, ON M5G 1X6

<sup>5</sup>School of Policy Studies and Dept. of Geography, Queen's University, 423-138 Union St.

Kingston, ON K7L 3N6

<sup>6</sup>National Agriculture and Food Research Organization, 2 Ikenodai, Tsukuba, Ibaraki 305-0901,  
Japan

\*Corresponding author: phone: (416) 946-5056, fax: (416) 978-3674, e-mail:  
hmaclean@ecf.utoronto.ca

**The supporting information contains 34 pages, including 12 tables and 5 figures.**

### **INTRODUCTION**

#### **Electricity generation in Ontario**

Ontario's electricity generation installed capacity is expected to evolve by the year 2025 from the current mix of nuclear (14,000 MW), renewables (8300 MW, including 7800 MW of hydro), coal (6400 MW), gas and cogeneration (5100 MW) as well as a conservation component (1300 MW) to one that meets the Government of Ontario Supply Mix Directive of June 2006 (1). According to the Directive, the 2025 installed capacity is planned to consist of nuclear (14,000 MW or less), renewables (15,700 MW), gas and cogeneration (9400 MW) and conservation (6300 MW). The Government is still finalizing the exact plans for the 2025 mix.

Ontario's electricity generation sector along with its industrial and transportation sectors are responsible for the largest shares of the Province's greenhouse gas (GHG) emissions. Two components of the Province's overall emissions are directly related to the electricity sector; 'fossil fuel industries' and 'electricity and heat generation.' These components together were responsible for approximately 20% of GHG emissions in 2004 (2). The emissions of the electricity generation sector have increased substantially during the period 1990 to present (3).

The Government of Ontario has a plan for reducing GHG emissions in the province by the year 2020. This plan states that the largest component of emissions reductions (29%) will result from actions in the electricity sector (2). These include the mandated phase out of coal-fired electricity in the province, an increase in the utilization of renewables, and other electricity policies. It is reported that power plant emissions will be reduced 85% from 46 Mt CO<sub>2</sub> equivalent (in 2003) to less than 7 Mt CO<sub>2</sub> equivalent by 2014 when the coal phase out is planned to be completed (3). While these reductions will be significant if achieved, there are considerable challenges to the Ontario plan. Issues to consider include increasing demand for electricity (potentially related to transportation uses such as electric vehicles), the reliance on natural gas for electricity generation (which also results in GHG emissions), the success of renewable generation options and conservation programs, imports of electricity to the province (potentially generated from coal) from other jurisdictions, and the full life cycle implications of electricity generation.

## **METHODS**

### **Pellet supply from Great Lakes St. Lawrence Forest**

In this study, biofibre for pellet production is supplied by forest management units in the Great Lakes St. Lawrence (GLSL) Forest Region. This forest is a transitional forest comprised of a mix of hardwood and softwood species, situated primarily in Ontario and Quebec. It represents 20% of Ontario's forest and is the second largest forest region in the province. The forest contains a large amount of lower quality hardwoods, predominantly soft maples and white birch. While these species are not ideal for sawlog or pulp production, they are well-suited for pellet production (4). Current market conditions and long-term issues related to the pulp and paper sector have led to a situation where the annual allowable harvest is not being fully utilized. Forest growth exceeds industry removals by more than three million m<sup>3</sup>/y in this region (4). This sustainable source of wood could be utilized for pellet production.

Based on the above assumptions, the total harvest volume available for pellets supplied from sustainably managed Crown (public) forest in this region is approximately 1.475 million oven dry tonnes (ODT)/y. The actual biofibre harvest levels would be determined on an annual basis by the forest management planning process for Crown forest land and allocated in approved forest

management plans (5). Allocating this excess of forest biofibre to pellet production would not reduce current harvest quantities for traditional forest products, but instead would create a market for available merchantable logs no longer marketable given the decline in the forest sector in the region. It is not anticipated that there will be any trade-off between traditional forest products and bioenergy outputs in the GLSL.

### **Life cycle activities associated with wood pellet production and transportation**

Figure S-1 is a simplified diagram, which shows the activities included in the life cycle inventory of wood pellet production and transportation. Note that this section considers the life cycle of pellet production as distinguished from the life cycle of electricity generated from pellets which is discussed in later sections.

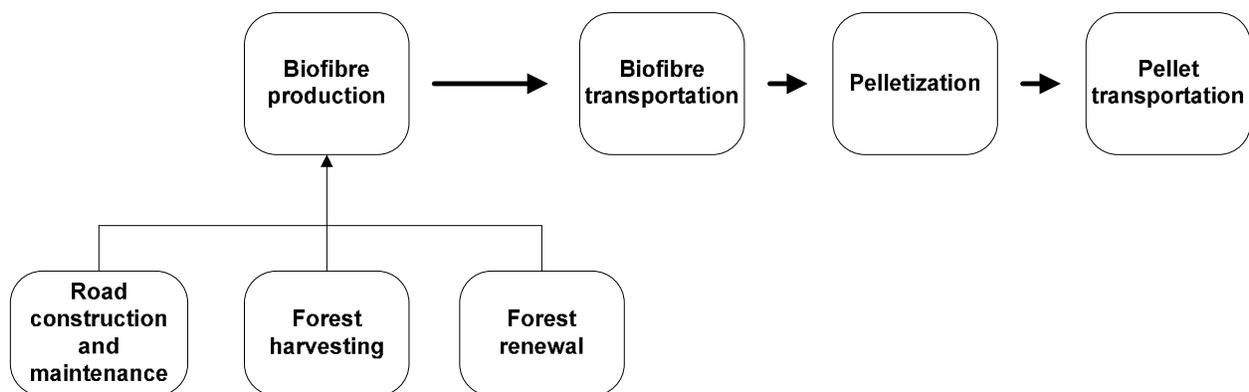


Figure S-1. Schematic diagram of activities within the life cycle of wood pellet production and transportation to electricity generating stations.

## **Forest Harvest Operations**

The data and assumptions on forest harvest operations for the Great Lakes Saint Lawrence (GLSL) Forest are shown in Table S-1. Below we describe additional details about the harvest methods, renewal and road construction.

Harvest methods: Biofibre is provided by three harvest methods. Selection cuts involve marking and harvesting of individual trees within a stand, leaving a thinned or patchy forest landscape post-harvest. Shelterwood cutting is a variation of this method that selects the trees in the overstory or canopy, releasing young saplings in the understory, leaving a younger and thinned forest structure behind. Clear cutting is a method that involves removal of most trees within a prescribed boundary of varying sizes.

Forest stands providing biofibre for pellet production are assumed to provide biofibre for both pellets and traditional forest products. Thus, the harvest volume available for pellet production will vary depending upon stand composition, harvest method, and the physical properties of harvested logs. Tops and branches are assumed to remain in the forest based on the combination of harvest methods assumed and Crown land requirements. Utilization of this material may improve the carbon balance for pellets because a large proportion of harvest residues decay and release CO<sub>2</sub> within a few years of harvest. There are tradeoffs, however, related to soil nutrient loss and impacts on biodiversity if these materials were to be removed.

Impact of forest harvest on soil carbon storage: Forest harvest has been found to have a negligible impact on soil carbon stocks if forest regeneration occurs and intense burning is avoided (6). Carbon stored on the forest floor is reduced due to harvest (7), but this pool is replenished during subsequent forest regrowth. Forest harvest is therefore assumed to have a negligible impact on forest carbon stocks within the time period considered in this analysis.

Renewal: Forest renewal practices vary by harvesting method. Shelterwood and selection cuts are renewed by natural regeneration, in which local seed sources (i.e., remaining trees on the site) are permitted to propagate new growth on the site. On about 25% of selection cut sites and 40% of shelterwood sites, a site preparation stage is required to ensure regeneration. About 20% of these sites are tended during the regrowth phase. By comparison, 50% of clear cut sites are naturally

renewed while the other 50% are planted with seedlings from nursery operations. Site preparation and tending also occurs on 50% of clear cut sites (4). These ratios are relevant to the LCI as diesel fuel inputs are required for all site preparation and tending practices, while herbicides (which are quite energy intensive to produce) are only applied during site tending operations. Fertilizers are not utilized in the forest renewal practices on Crown lands in the GLSL forest and as such their use is not considered in this analysis. Fertilizers may be used on private forest land in the province or in forests outside of Ontario, neither of which are considered as a wood source for this study. A life cycle inventory of pellet production from forests using fertilizers in their regeneration should include impacts from the production and use of fertilizers.

Road construction: Required forest road construction and maintenance has been determined for the entirety of stands necessary to provide the biofibre for wood pellet production as well as for traditional products. Data on the number of stream crossings and total road length to be constructed and maintained were provided by OMNR (4). Fuel use for field and on-road vehicles required to construct and maintain roads was provided by FPInnovations/FERIC (8).

The forest stands are assumed to provide biofibre for both pellets and traditional products. Allocation of inputs for forest harvest, renewal practices, road construction and maintenance is determined by the fractions of harvest volume delivered to each of the product categories. Based on (4), approximately 35% of the maximum sustainable forest harvest volume is available for pellet production. As such, 35% of the total inputs required for forest operations are allocated to this portion of the harvest volume.

Table S-1. Parameters for forest biofibre harvesting

Life Cycle Activity	Forest Harvesting Method			Primary Data Sources and Notes
	Selection cut	Shelterwood cut	Clear cut	
Forest resource				
Harvest method share (%)	25%	25%	50%	(4)
Biofibre yield (m <sup>3</sup> /ha)	30	60	60	(4)
Moisture content (kg <sub>H2O</sub> /kg <sub>wet biomass</sub> )	0.42	0.52	0.48	
Biofibre yield (ODT/ha)	15	25	26	
Forest harvesting				
Diesel use (including harvesting, skidding, slashing) (l/ODT)	7.6	10.4	8.8	(8)
Emissions(g/ODT)				(9-12)
CO <sub>2</sub>	24,753	33,554	28,456	
CH <sub>4</sub>	36	48	41	
N <sub>2</sub> O	9	12	10	
NO <sub>x</sub>	225	305	258	
SO <sub>x</sub>	32	44	37	
Forest renewal				
Diesel (l/ODT)	0.08	0.17	0.30	(4, 8)
Herbicide (l/ODT)	0	0.004	0.010	
Emissions <sup>1</sup> (g/ODT)				(9-11,13)
CO <sub>2</sub>	264	584	1,055	
CH <sub>4</sub>	0.4	0.8	1.5	
N <sub>2</sub> O	0.1	0.2	0.3	
NO <sub>x</sub>	2.4	5.1	9.0	
SO <sub>x</sub>	0.3	0.8	1.4	
Road construction and maintenance				
On-road equipment (1 diesel/ODT)	0.31			(4, 8)
Field equipment (1 diesel/ODT)	0.13			
Emissions (g/ODT)				(9-11) * Zero value due to rounding.
CO <sub>2</sub>	1,400			
CH <sub>4</sub>	2			
N <sub>2</sub> O	0*			
NO <sub>x</sub>	10			
SO <sub>x</sub>	2			

Table S-1 (con't).

Total inputs and emissions for forest operations		
Diesel (l/ODT)	9.7	Fuel use and emissions presented are average values based on volume of biofibre harvest from each harvest method
Herbicide (l/ODT)	0.007	
Emissions (g/ODT)		
CO <sub>2</sub>	31,390	
CH <sub>4</sub>	60	
N <sub>2</sub> O	10	
NO <sub>x</sub>	280	
SO <sub>x</sub>	40	

Notes: In all tables, data taken from other sources are reported based on the number of significant digits in the sources. Totals may not add due to rounding. ODT refers to ODT of biofibre. 1. Data for upstream emissions from production of the herbicide used in forest renewal, glyphosphate acid, were not available. Emissions data for the production of atrazine were obtained from (13).

### Biofibre Pelletization

Logs destined for pellet production are assumed to be transported 115 km to a pellet facility by self-loading pulp truck (4). A schematic of the biofibre pelletization process is shown in Figure S-2 and data, sources and assumptions for pelletization and transportation activities in Table S-2. Additional details on biofibre drying are discussed in the following section.

At the pellet production facility, the logs first pass through an initial grinding stage. A portion of the input biofibre is then diverted from the pellet stream for use as process energy to dry the remaining biofibre. The biofibre destined for pelletization is further ground in a hammermill and then dried. The biofibre is subsequently compressed in a pellet mill to form pellets and cooled. Data on electricity and biofibre consumption during pelletization were provided by a pellet producer in the northeastern United States and reflect requirements for a state-of-the-art facility with a capacity of 12 ODT of pellets/h. These data obtained from the producer were utilized, with one modification (to drying energy use) as discussed below.

Electricity required for the pellet facility is assumed to be provided by the average Ontario generation mix. With respect to the biofibre used as a fuel for drying, the fraction of biofibre diverted from the pellet stream for this purpose is adjusted from that reported by the northeastern

U.S. producer (which uses both roundwood and lower moisture content wood processing residues) to take into consideration the higher moisture content of input biofibre in our study (roundwood only).

### Calculation of biofibre drying energy requirements

Drying energy requirements are assumed to be proportional to drying time requirements. The time-dependency of drying can be represented by Equation S-1 (14):

$$\frac{M_{out} - M_{eq}}{M_{in} - M_{eq}} = e^{-kt} \quad (\text{S-1})$$

Where  $M_{out}$  and  $M_{in}$  are the moisture contents of feedstock at the outlet and inlet of the dryer, respectively (kg H<sub>2</sub>O/kg dry feedstock),  $M_{eq}$  is the equilibrium moisture content of the feedstock and heated air (kg H<sub>2</sub>O/kg),  $k$  is the drying constant (1/min), and  $t$  is time (min). To approximate drying time, this equation can be simplified under the assumption that the equilibrium moisture content is small relative to the moisture content of the feedstock, resulting in:

$$\frac{M_{out}}{M_{in}} = e^{-kt} \quad (\text{S-2})$$

Using this equation, biofibre consumption for drying is adjusted to 0.18 ODT<sub>biofibre</sub>/ODT<sub>pellet</sub> (or 15% of total biofibre supply), as compared to 0.15 ODT<sub>biofibre</sub>/ODT<sub>pellet</sub> reported by the producer.

### Verification of pelletization data

Data for pellet production are limited and generally proprietary. The information provided by the producer that is used in this study was verified by comparing with pellet production data published by Mani (15), based on experimental and numerical modeling, and Bradley (16), based on an analysis of a pellet facility in British Columbia. The producer reported 7% and 56% lower electricity and biofibre consumption, respectively, compared to (16). The source of the higher consumption reported in Bradley is primarily the much higher energy requirements of the drying process and may be related to the age of the facility as well as the different characteristics of the biofibre inputs. Mani (15) also reported lower electricity and biofibre consumption than Bradley (16), showing inputs comparable to the data provided from the northeastern US pellet producer.

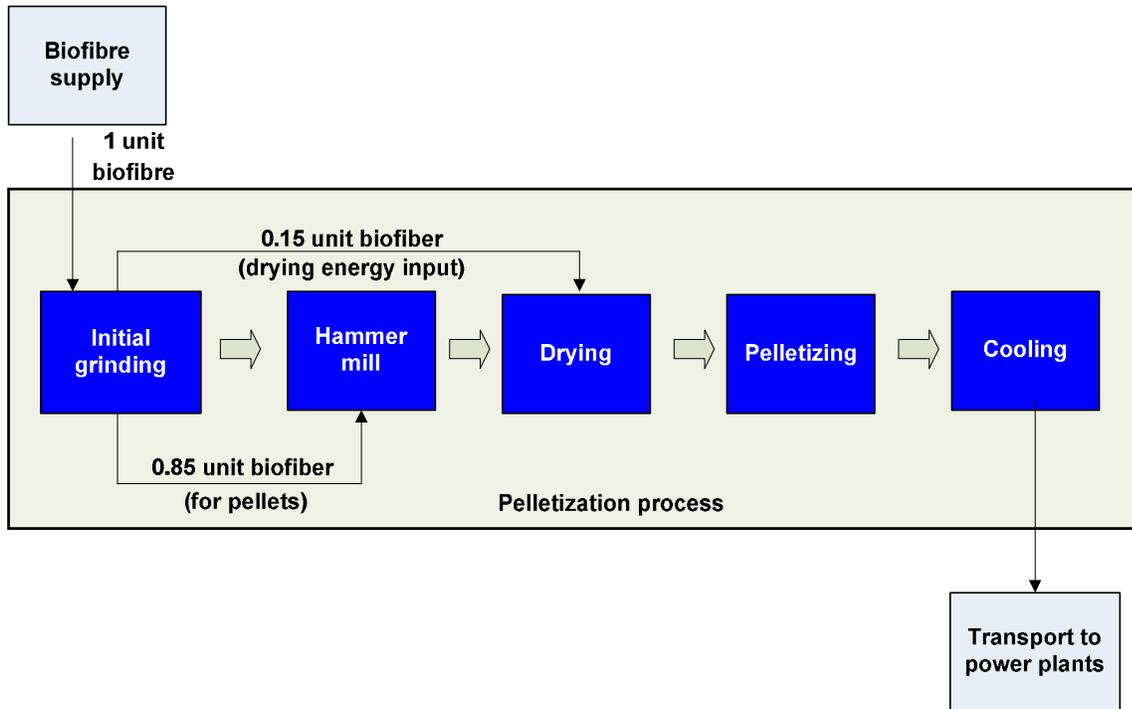


Figure S-2. Schematic diagram of biofibre pelletization process

Table S-2. Parameters for biofibre pelletization

Life Cycle Activity		Primary Data Sources and Notes
Transportation to pelletization facility		
Transport mode and distance	115 km, self-loading pulp truck	Average distance from forest to pellet facility (8)
Diesel use (l/ODT <sub>biofibre</sub> ) <sup>1</sup>	7.8	(8)
Emissions (g/ODT <sub>biofibre</sub> )		(9-11)
CO <sub>2</sub>	25,176	
CH <sub>4</sub>	36	
N <sub>2</sub> O	2	
NO <sub>x</sub>	56	
SO <sub>x</sub>	10	
Pelletization		
Initial grinding energy use (kWh/ODT <sub>biofibre</sub> )	3.75	(8)
Initial grinding emissions (g/ODT <sub>biofibre</sub> )		Emissions from electricity use are based on the average electricity generation mix of Ontario for 2007 (9, 17). * Zero value due to rounding.
CO <sub>2</sub>	870	
CH <sub>4</sub>	1	
N <sub>2</sub> O	0*	
NO <sub>x</sub>	3.5	
SO <sub>x</sub>	6.2	
Biofibre for drying <sup>2</sup> (ODT <sub>biofibre</sub> /ODT <sub>pellets</sub> )	0.18	Northeastern U.S. pellet producer <sup>3</sup> . Adapted for higher initial moisture content in our scenario. Assumes no dry matter loss during pelletization, as per the producer. Material unsuitable for pellets may be diverted to the biofibre stream for drying.
Biofibre drying emissions (g/ODT <sub>pellet</sub> )		Based on emissions from biomass combustion for electricity generation (9) <sup>4</sup> .
CO <sub>2</sub>	0	CO <sub>2</sub> emissions from the combustion of the biofibre during drying are assigned a value of zero as it is assumed that the C released is completely balanced during forest growth.
CH <sub>4</sub>	32	
N <sub>2</sub> O	14	
NO <sub>x</sub>	331	
SO <sub>x</sub>	324	

Table S-2 (con't).

Other pelletization stages energy use (including hammer mill, drying, compression, and cooling and sieving) (kWh <sub>e</sub> /ODT <sub>pellet</sub> )	140		Northeastern U.S. pellet producer <sup>3</sup>
Other pelletization stages emissions (g/ODT <sub>pellet</sub> )			Emissions from electricity use are based on the average electricity generation mix of Ontario for 2007 (52% nuclear, 21% hydro, 18% coal, 7.9% natural gas, 0.1% oil, 1% wind) (9, 17). * Zero value due to rounding.
CO <sub>2</sub>	32,488		
CH <sub>4</sub>	41		
N <sub>2</sub> O	0*		
NO <sub>x</sub>	132		
SO <sub>x</sub>	231		
Transportation to electricity generation facility			
Transport modes and distances	Nanticoke  rail to port (average distance 180 km), and by vessel to Nanticoke (average distance 890 km).	Atikokan  rail from pellet facility (average distance 1,350 km).	(4)  Facilities are assumed to be located near rail lines with access by a short rail spur
Rail energy use (1 diesel / ODT <sub>pellet</sub> )	1.8	5.3	Energy required to load and unload pellets is included. (8)
Vessel energy use (1 bunker oil/ODT <sub>pellet</sub> )	3.7	-	
Emissions			(9-11)
CO <sub>2</sub>	18,809	17,002	
CH <sub>4</sub>	26	25	
N <sub>2</sub> O	2	6	
NO <sub>x</sub>	13	13	
SO <sub>x</sub>	13	13	
Total inputs and emissions for wood pelletization			
Fuel, electricity, and biomass use	Nanticoke	Atikokan	
Diesel (l/ODT <sub>pellet</sub> )	10.9	14.5	
Bunker oil (l/ODT <sub>pellet</sub> )	3.7	0	
Electricity (kWh/ODT <sub>pellet</sub> )	144	144	
Biofibre (ODT/ODT <sub>pellet</sub> )	0.18	0.18	

Table S-2 (con't).

Emissions (g/ODT <sub>pellet</sub> )			
CO <sub>2</sub>	81,940	80,133	
CH <sub>4</sub>	142	141	
N <sub>2</sub> O	19	22	
NO <sub>x</sub>	547	546	
SO <sub>x</sub>	588	588	
Delivered pellet characteristics	Moisture content: 5% Energy content (HHV): 19.5 GJ/tonne S content (% of dry weight) : 0.05 <sup>5</sup>		Moisture content: Northeastern U.S. pellet producer; energy content: (15); S content: (18)

Notes: 1. Transportation energy use by truck includes idling consumption during loading. 2. Biofibre fuel use for drying is removed from input biofibre stream. 3. Name of pellet producer withheld due to confidentiality. 4. The efficiency of 43% reported in (9) is higher than that reported in other literature (approximately 30-35%). However, varying the efficiency within reasonable ranges does not significantly impact the results. 5. The sulfur content ranges from <0.01% to 0.05% (dry weight) for wood pellets as reported by (18). Ontario Power Generation (OPG) specified the sulfur content of pellets to be < 0.2% (dry weight). The upper bound (i.e., 0.05% by dry weight) in (18) is used as an estimate for sulfur content in this study.

### Conversion of coal facilities to use 100% biomass or co-fire at high rates

There is limited experience with retrofits (often termed repowering) of coal-fired generating stations to utilize 100% biomass. We are aware of two facilities that have been retrofitted and are currently operating as well as plans for several others in Europe and the U.S. as noted in the paper. In addition, there are several facilities utilizing high rates of biomass co-firing (greater than 40%). Below we report a few additional details on these projects based on the limited publicly available information.

**100% biomass:** On the lower end of the cost of retrofit, Electrabel (in Belgium) retrofitted a pulverised coal power plant to use pellets as its sole fuel. Modifications were made to storage silos, conveyor belts and burners: filters, hammer-mills and safety devices were installed. The retrofitted system has a capacity of 80 MW (the original system was 120 MW). The total capital cost was \$10 million (19), approximately \$125/kW of biomass capacity. On the higher end, a New Hampshire facility (Schiller Station) replaced one of its 50 MW coal boilers with a 50 MW biomass fluidized-bed boiler (20). The project's total cost was approximately \$75 million (approximately \$1500/kW), including the new fluidized-bed boiler, emissions control system,

covered wood-chip storage facility, wood unloading and handling system, and covered conveyor to deliver chips to the boiler. FirstEnergy is planning to convert its R.E. Burger Power Plant in Ohio into one of the largest biomass-burning operations in the US. The project, slated for completion in 2012, will convert two 156 MW boilers to use 100% biomass (pellets produced from crops) with a capacity up to 312 MW (21). FirstEnergy has estimated they will spend \$200 million on the conversion, which would include modifications to pulverizing and storage equipment. The capital cost is about \$640/kW of biomass capacity if the conversion does not cause capacity loss as is claimed by the company. Antares Group is completing a detailed costing study for EPRI of a Southern Company facility in Georgia (Plant Mitchell) which will be converted from a 164 MW pulverized-coal-fired (PC) boiler to a 101 to 102 MW wood chip fired one, however, the report has yet to be released (22).

**High biomass co-fire rates:** At Hasselbyverket in Stockholm, Sweden, three 100MW coal fired boilers have been converted to burn biomass and low sulfur heavy oil (23). The biomass co-firing rate has reached 80% (by energy). Vasthamnsverket in Helsingborg, Sweden has co-fired pellets with coal at a rate up to 70% (by mass). Energy E2 is retrofitting a pulverized coal/oil fired boiler of Amager Unit 1 in Copenhagen for 40% co-firing. The unit is planned to be in commercial operation this year (2009). It is expected that the yearly biomass consumption will be 40,000 tonnes of wood pellets and 110,000 tonnes of straw pellets, which could substitute for ~ 95,000 tonnes of coal (24).

### **Reference coal pathway**

Nanticoke Generating Station (GS) has eight 490 MW<sub>e</sub> (net) wall-fired natural circulation pulverized coal boilers equipped with low-NO<sub>x</sub> burners, two of which are equipped with selective catalytic reduction (SCR) equipment to reduce NO<sub>x</sub> emissions. The station uses two types of U.S. coal, southern Powder River Basin (PRB) coal and US low sulfur (USLS) coal (25).

Atikokan Generating Station has one 215 MW<sub>e</sub> (net) wall-fired natural circulation pulverized coal boiler equipped with low- NO<sub>x</sub> burners and uses Canadian lignite.

The higher energy use and emissions associated with surface mining and processing in Canada compared to the US (see Table S-3) are likely due in part to the shallower deposits of the PRB

region compared to those in Saskatchewan. Surface coal mining removes biomass and disturbs soil, which results in emissions of CO<sub>2</sub> due to land use change. These along with other mining process emissions are considered in the analysis.

U.S. coals are shipped via rail to ports, and then by vessel to Nanticoke. Canadian coal used in Atikokan is shipped exclusively by rail (25). The net plant coal-to-electricity conversion efficiencies are 35% and 33%, respectively, for the Nanticoke and Atikokan GSs (26). This implies that approximately 0.47 and 0.70 kg coal are required for each kWh of electricity output from Nanticoke and Atikokan, respectively. The difference in coal requirement results from the different properties of the coals used in the two power plants as well as the coal-to-electricity conversion efficiencies. The data and assumptions for the reference coal pathways are shown in Table S-3.

Table S-3. Parameters for reference coal pathways

Life Cycle Activity	Nanticoke		Atikokan	Primary Data Sources and Notes
<b>Coal mining and processing</b>				
Coal type (origin)	Sub-bituminous: Southern PRB (WY), 84% by weight and Bituminous: Central Appalachian USLS (WV, KY), 16% by weight		Lignite: SK	(25)
Mining and processing	PRB: 100% surface mined USLS: 51% surface mined and 49% underground mined		Surface mined	(9, 27)
Energy Use <sup>1</sup> (kJ/tonne)	Surface (U.S.)	Underground (U.S.)	Surface (Canadian)	(9) U.S. data in (9) calculated from U.S. Census statistics. Canadian data based on reports filed by two Canadian mining companies under the Voluntary Challenge and Registry.
Diesel	71,120	12,754	156,460	
Electricity	24,348	60,780	53,566	
Residual fuel	8,487	2,794	18,671	
Coal	7,588	59,743	16,694	
Gasoline	4,651	1,692	10,232	
Natural gas	784	1,233	1,725	
Emissions <sup>1</sup> (g/tonne)				(9)
CO <sub>2</sub>	19,724	21,021	30,654	
CH <sub>4</sub>	624	7,935	372	
N <sub>2</sub> O	1.7	1.7	5.3	
NO <sub>x</sub>	42	42	94.7	
SO <sub>x</sub>	41.6	41.6	76.2	
<b>Coal transportation</b>				
Mode, distance and fuel use	PRB: Rail 1910 km (WY to Superior, WI), vessel 7.08 days (WI to Nanticoke) USLS: Rail 700 km (WV, KY to Ashtabula, OH), vessel 1.38 days (OH to Nanticoke) Rail: 180.4 kJ diesel/tonne-km (includes backhaul) Vessel: 30,000L/day (marine diesel and bunker oil), 27,210 tonnes/trip		Rail: 950 km (SK to Atikokan)  Rail as for Nanticoke	Mode/distance data: (25) Fuel use data: rail (9), vessel (25). Includes fuel required for loading/unloading of vessels.
Emissions (g/tonne)	PRB	USLS		Calculated using (9). Includes emissions from loading/unloading vessels
CO <sub>2</sub>	82,302	20,818	13,870	
CH <sub>4</sub>	122.3	31	20.8	
N <sub>2</sub> O	12.1	4.1	5.1	
NO <sub>x</sub>	1,681	407	232	
SO <sub>x</sub>	77.2	19.6	13.2	

Table S-3 (con't).

Coal-fired electricity generation				
Efficiency <sup>2</sup> (%)	35		33	(26)
Emissions (g/kWh)				Data apply to generation stations only and are not life cycle emissions.
CO <sub>2</sub>	939		1,150	Data Include emissions associated with moving coal and ash at generating station.
CH <sub>4</sub>	0.009		0.014	
N <sub>2</sub> O	0.002		0.011	
NO <sub>x</sub>	1.23		1.82	
SO <sub>x</sub>	3.7		4.6	
Capacity factor (%)	55		34	(26)
Coal properties:	PRB	USLS		(26)
HHV (GJ/tonne)	20.5	29.1	15.6	
Moisture content (%)	28	6	34	
S content (% by wt.)	0.25	0.85	0.35	

Notes: KT = Kentucky, OH = Ohio, SK=Saskatchewan, WI = Wisconsin, WV=West Virginia, WY=Wyoming

1. Because both coal mining and processing occur in the mines, the data for these two activities are aggregated. The GHGenius model (9) assumes that for surface mines, 0.0004 hectares of land are removed per tonne of coal produced, and for underground mines, one quarter of the above rate is disturbed. The model further assumes that 10% of the land disturbed is from forest, 65% from pasture and grass, 20% from desert, and the remaining 5% from agricultural land. Emissions associated with these land use changes are included in the values. 2. Net plant coal-to-electricity efficiencies.

### **Reference natural gas pathways**

The natural gas reference pathway is based on a hypothetical newly constructed natural gas combined cycle (NGCC) electricity generation facility located in Ontario which would receive gas from Western Canada (Alberta). Converting the existing coal GSs to natural gas boiler or NGCC systems were not considered viable options for the study based on discussions with experts at Ontario Power Generation (OPG). Conversion to a natural gas boiler was not economically viable due to the boiler system's relatively low efficiency (~35%) and higher fuel cost. Conversion to a NGCC would pose economic and technical challenges because the GS was originally configured for coal and retrofitting could be more costly than constructing a new NGCC.

This section discusses the NGCC facility and the associated life cycle stages. In the recovery stage, natural gas is collected in gas fields. The gas is then sent to processing facilities, where impurities are removed. The gas is compressed prior to entering the transmission system (28). The transmission systems include some natural gas storage in underground facilities to meet seasonal demand. From the transmission and storage systems, some natural gas goes directly to large-scale consumers such as electric power plants, as modeled in this analysis, while the rest goes into local distribution systems. There are small gas losses at all stages of natural gas production and transportation. The CH<sub>4</sub> emissions associated with these losses are included in the life cycle inventory. The percentages of natural gas lost totals 0.25% during gas recovery, processing and transmission, based on data for Canada (9). NRCan (9) reports a higher gas loss rate for the U.S. (1.32%). As there is not a clear explanation for the differing performance of Canadian and U.S. natural gas upstream activities in (9), we examine the Canadian loss rate as our baseline, but complete an analysis assuming the U.S. loss rate. Net plant natural gas-to-electricity efficiency is assumed to be 53%, for the NGCC facility based on (9). See Table S-4 for additional details of assumptions and data sources.

Table S-4. Parameters for reference natural gas pathway

Life Cycle Activity		Primary Data Sources and Notes
Origin	AB in Western Canada	
Natural gas recovery		
Energy use (kJ/GJ)		(9) <sup>1</sup>
Crude oil	173	
Diesel	1,273	
Residual fuel	497	
Natural gas	17,169	
Electricity	3,443	
Gasoline	555	
Emissions (g/GJ)		(9)
CO <sub>2</sub>	1,443	
CH <sub>4</sub>	27.4	
N <sub>2</sub> O	0.09	
NO <sub>x</sub>	14.9	
SO <sub>x</sub>	2.2	
Natural gas processing		
Energy use (kJ/GJ)		(9)
Diesel	35	
Residual fuel	29	
Natural gas	38,863	
Electricity	2,196	
Gasoline	28	
Emissions (g/GJ)		(9)
CO <sub>2</sub>	1,871 <sup>2</sup>	
CH <sub>4</sub>	21.5	
N <sub>2</sub> O	0.025	
NO <sub>x</sub>	7.7	
SO <sub>x</sub>	4.9 <sup>3</sup>	
Natural gas transmission and storage		
Mode and Energy Use (GJ/GJ transported)	Pipeline: AB to central ON, 0.051	(25)
Emissions (g/GJ)		(9)
CO <sub>2</sub>	1,523	
CH <sub>4</sub>	11.5	
N <sub>2</sub> O	0.05	
NO <sub>x</sub>	14.7	
SO <sub>x</sub>	0.72	

**Table S-4 (con't).**

Natural gas electricity generation		
Efficiency <sup>4</sup> (%)	53	(9)
Emissions (g/kWh)		
CO <sub>2</sub>	340	
CH <sub>4</sub>	0.025	
N <sub>2</sub> O	0.009	
NO <sub>x</sub>	0.77	
SO <sub>x</sub>	0.04	
Natural gas properties:		HHV: (26)
HHV (GJ/tonne)	52.2	Density and carbon
Density (g/L)	0.716	content: (9) (@ 288.7 K
Carbon content (% by wt.)	72	and 1atm)

Notes: AB= Alberta, ON=Ontario. Table reports Canadian data. The percentages of natural gas lost during gas recovery, processing and transmission are 0.11%, 0.09% and 0.05%, respectively, totalling 0.25%. 1. There is some inconsistency in the way the data are presented for natural gas loss during upstream activities in GHGenius 3.12 b (9) according to (29). For example, leaks from transmission and storage are counted in the natural gas recovery stage. However, all of the losses are counted. 2. Value includes CO<sub>2</sub> emissions from process fuel combustion (1,233 g/GJ) and emissions of CO<sub>2</sub> removed from raw gas (638 g/GJ). 3. Value includes SO<sub>x</sub> emissions from process fuel combustion (0.8 g/GJ) and from incineration of H<sub>2</sub>S removed from raw gas (4.1 g/GJ). Above is based on (9). 4. Net plant natural gas-to-electricity efficiency.

### **NO<sub>x</sub> emissions from 100% pellet electricity generation**

Emissions of NO<sub>x</sub> from combustion of coal and pellets are dependent on complex interactions of fuel and combustion characteristics and are therefore difficult to ascribe to a particular fuel or combustion system. Preliminary test data were gathered for 100% wood pellet combustion at the Atikokan GS to approximate the range of NO<sub>x</sub> emissions to be expected with wood pellets used as the sole fuel source (30). Data are extrapolated to the Nanticoke facility by assuming a similar percentage change in emissions would occur at both GSs. NO<sub>x</sub> emissions from wood pellet combustion are compared to limited data available in the literature. A comparison of NO<sub>x</sub> emissions at Atikokan and Nanticoke GS when fueled with coal and 100% pellets and data gathered from the literature is shown in Table S-5.

Table S-5. Comparison of NO<sub>x</sub> emissions from Nanticoke and Atikokan GS when fueled with coal and 100% pellets with data from literature: Direct emissions (not life cycle)

	Average NO <sub>x</sub> emissions (g/kWh)	Range of NO <sub>x</sub> emissions (g/kWh)
Nanticoke GS, coal	1.23	NA
Nanticoke GS, wood pellet	0.49 <sup>1</sup>	0.43 – 0.55 <sup>1</sup>
Atikokan GS, coal	1.82	NA
Atikokan GS, wood pellet	0.73	0.64 – 0.82
Nalco Mobotec (31), wood powder	0.357 <sup>2</sup>	NA
Van Loo and Koppejan (32), wood chips	0.25 <sup>3</sup>	0.25 – 1.2

Notes: <sup>1</sup> Emissions for Nanticoke GS are extrapolated from test firing data at Atikokan assuming a similar percentage change in emissions compared to coal. <sup>2</sup> Emissions are for wood powder combustion using two wall-fired burners totaling 100MW. <sup>3</sup> NO<sub>x</sub> emission rate of 0.25 g/kWh is for a pulverized burner combusting wood chips.

### Cost of electricity production

A life cycle cost model based on annual worth is developed to estimate the cost of electricity generated from the coal, pellet and natural gas combined cycle systems. Capital cost, fixed operating and maintenance (O&M) costs, non-fuel variable O&M costs, fuel costs, conversion system characteristics and financing are considered (see Table S-6 for details). Taxes, subsidies, and profit margins are not considered. The cost of electricity is the ratio of the annualized cost of the GS to the electricity output during the year (Eq. S-3).

$$COE = AC/AE_{output} \quad (S-3)$$

Where COE = cost of electricity (\$/MWh); AC = annual cost (\$/yr), calculated using Eq. S-4; AE<sub>output</sub> = annual net electricity generation (assumed constant for a given system) (MWh/yr) = net capacity of the system × capacity factor × 8600.

$$AC = ACC + AFOM + AVOM + AFC \quad (S-4)$$

Where ACC = annualized capital cost (\$/yr); AFOM = annual fixed O&M cost (\$/yr), estimated based on capacity of a given system; AVOM = annual variable O&M cost (\$/yr), estimated based on annual electricity output; AFC = annual fuel cost (\$/yr), estimated based on annual electricity output, heat rate of a given system, and delivered fuel cost.

To implement 10% or 20% pellet co-firing, the capital cost required for retrofitting the coal-fired system ranges from \$150 and \$300/kW of biomass capacity (33). The annual fixed O&M cost for

co-firing is estimated based on additional operator requirements and retrofit capital cost (32). The fixed maintenance cost is 2% of the original capital cost of the co-firing retrofit. For each 10% co-firing, additional labor costs consisting of a 1.5 and 0.5 full-time equivalent (FTE) are required for Nanticoke and Atikokan, respectively. The variable O&M cost is estimated to be the same as that of coal-only operation (34). Delivered fuel costs for coal and pellets are estimated based on data from (35,36,37).

### **Cost-effectiveness of greenhouse gas emissions reduction**

The cost-effectiveness of reducing life cycle GHG emissions (\$/tonne CO<sub>2</sub> eq.) from the reference coal GS pathways through use of the various alternative pathways is calculated as:

$$\text{Cost-effectiveness of GHG reduction} = - \frac{COE_{\text{alternative}} - COE_{\text{coal}}}{LCE_{\text{alternative}} - LCE_{\text{coal}}} \quad (\text{S-5})$$

Where; COE<sub>alternative</sub> = cost of electricity using alternative pathway (cofiring, 100% pellet firing, or natural gas combined cycle) (\$/MWh); COE<sub>coal</sub> = cost of electricity using reference coal GS pathway (\$/MWh); LCE<sub>alternative</sub> = life cycle GHG emissions of the given alternative pathway (tonne CO<sub>2</sub> eq./MWh); LCE<sub>coal</sub> = life cycle GHG remissions of the coal GS pathway (tonne CO<sub>2</sub> eq./MWh).

### **Technical and financial data for electricity generation pathways**

A summary of key technical and financial data for the baseline coal and natural gas electricity generation pathways and the wood pellet co-firing and 100% pellet pathways are shown in Table S-6.

Table S-6. Key technical and financial data for electricity generation pathways

Parameter	Coal-only	Pellet co-firing (10% and 20% rates)	100% pellet	Natural gas combined cycle
<b>Technical</b>				
Capacity (MW)	Nanticoke: 3948 Atikokan: 215	Nanticoke: 395, 790 (biomass capacity at 10%, 20%) Atikokan: 22,43	Nanticoke: 245 (biomass capacity for 1 unit) Atikokan: 215	400
Capacity factor (%)	Nanticoke: 55 Atikokan: 34	Nanticoke: 55 Atikokan: 34	Nanticoke: 55 Atikokan: 34	55
Heat rate (MJ/kWh)	Nanticoke: 10.3 Atikokan: 10.9	Nanticoke: 10.3 (10%), 10.4 (20%) Atikokan: 11.0, 11.0	Nanticoke: 11.3 Atikokan: 11.5	6.8
Conversion efficiency (%)	Nanticoke: 35 Atikokan: 33	Nanticoke: 34.8 (10%), 34.7 (20%) Atikokan: 32.8, 32.7	Nanticoke: 31.8 Atikokan: 31.4	53
Fuel Properties HHV (GJ/tonne), moisture content (%) in parentheses <sup>1</sup>	Nanticoke: PRB 20.5 (28), USLS 29.1 (6) Atikokan: Lignite 15.6 (34)	Pellet: 19.5 (5)	Pellet: 19.5 (5)	52.2
<b>Financial</b>				
Equity/debt (%), rate/return in parentheses (%)	n.a	50/50 (16, 8)	50/50 (16, 8)	50/50 (16,8)
Loan term (y)	n.a.	10	20	20
Construction period (y)	n.a.	1	2	2
Economic life (y)	n.a.	10	20	20
<b>Costs (U.S. dollars)<sup>2</sup></b>				
Capital cost (\$/kW biomass capacity)	sunk cost	225	640	948 (\$/kW natural gas capacity)
Fixed O&M (\$/kW)	Nanticoke: 28 Atikokan: 62 (38)	Nanticoke (coal): 28 (biomass): Additional 1.5 FTE for each 10% co-firing + 2% of retrofit capital cost (\$/y) Atikokan (coal): 62 (biomass): Additional 0.5 FTE for each 10% co-firing +2% of retrofit capital cost (\$/y) (34)	Nanticoke <sup>3</sup> : 46 Akikokan: 63 (39,40)	13 (39,40)
Variable O&M (\$/MWh)	Nanticoke: 1.9 Atikokan: 4.3 (38)	Nanticoke: 1.9 Atikokan: 4.3 (34)	Nanticoke <sup>3</sup> : 4.3 Atikokan: 5.5 (39,40)	2.2 (39,40)
Delivered fuel cost (\$/unit)	PRB coal (Nanticoke): 1.8/GJ (36/tonne) USLS coal (Nanticoke): 3.3/GJ (95/tonne) Lignite (Atikokan): 1.6/GJ (25/tonne) Pellets <sup>4</sup> : 8.2/GJ (160/tonne) Natural gas: average 7.0/GJ, low 5.0/GJ, high 11.0/GJ (41)			

Notes: FTE = full-time equivalent and assumed to be compensated \$100,000/y, PRB = Southern Powder River Basin, USLS = Central Appalachian Ultra Low Sulfur. Sources for technical parameters are reported in tables S-2-4. <sup>1</sup> Additional fuel properties shown in Tables S-2 and S-3. <sup>2</sup> Exchange rate of 0.85 assumed when converting Canadian to US dollars. <sup>3</sup> Fixed O&M cost is the average of that of coal only operation and that estimated by (39) for an 80 MW dedicated biomass power generation station. Same for variable O&M cost. <sup>4</sup> Pellet delivered cost is

estimated as sum of pellet plant gate price taken from (34,35) plus \$10/tonne for shipping and handling.

## RESULTS AND DISCUSSION

### Greenhouse gas emissions associated with wood pellet production

Life cycle GHG emissions associated with pellet production and delivery to Nanticoke GS are shown in Table S-7 and transportation data for delivery to Atikokan GS are indicated in the notes to the Table.

Table S-7. Greenhouse gas emissions associated with pellet production and delivery

Activity	GHG Emissions (g CO <sub>2</sub> eq./ODT pellet)
Forest harvest	39,190
Forest road construction and maintenance	1,840
Forest renewal	1,380
Transportation to pellet facility	31,330
Pelletization	39,530
Transportation to Nanticoke GS	20,180
Total: pellet production and transportation to Nanticoke Generation Station	133,440

Notes: Transportation to Atikokan results in 19,410 g CO<sub>2</sub> eq./ODT pellet. Results for all other activities are identical to those for Nanticoke. The resulting total emissions for pellet production and transportation to Atikokan are 132,670 g CO<sub>2</sub> eq./ODT pellet.

A sensitivity analysis was completed on several key parameters to examine their impact on the GHG emissions associated with pellet production. The parameters were chosen for sensitivity analysis based on their contribution to LC emissions and their expected variability/ uncertainty. The forest operations (harvest, road construction and maintenance and forest renewal), transport distance from the forest to the pellet facility, drying energy requirements in the pellet facility and the GHG emissions intensity of electricity used in the pelletization process are examined. The parameters were varied +/- 60% from their initial values. All other parameters were held constant at their base values. Results of the analysis for Nanticoke GS are shown in Figure S-3 (results for Atikokan are almost identical). The GHG emissions intensity of forest operations used in the pelletization process has the greatest impact, and drying requirements the least impact. Increasing the GHG intensity of forest operations by 60% resulted in an increase in lifecycle GHG

emissions associated with pellet production of 19%. However, the forest operations data utilized in our study are generally of high quality and based on actual fuel use, etc. in GLSL operations. A 60% increase in drying energy requirement (i.e., 24% of biofibre is diverted to drying) would increase the emissions of pellet production by 9%.

Magelli et al. (42) estimated emissions associated with the production of pellets in British Columbia. The GHG emissions estimated in our study associated with forest operations and pellet production (excluding pellet transportation) of 113,260 g CO<sub>2</sub> eq./ODT pellets, are greater than those calculated by Magelli et al. for an equivalent set of activities [71,010 g CO<sub>2</sub> eq./ODT after adjusting for the 10% moisture content of the pellets as reported in (42)]. The difference arises primarily because upstream emissions (e.g., those associated with the production of diesel fuel and electricity) are omitted in (42).

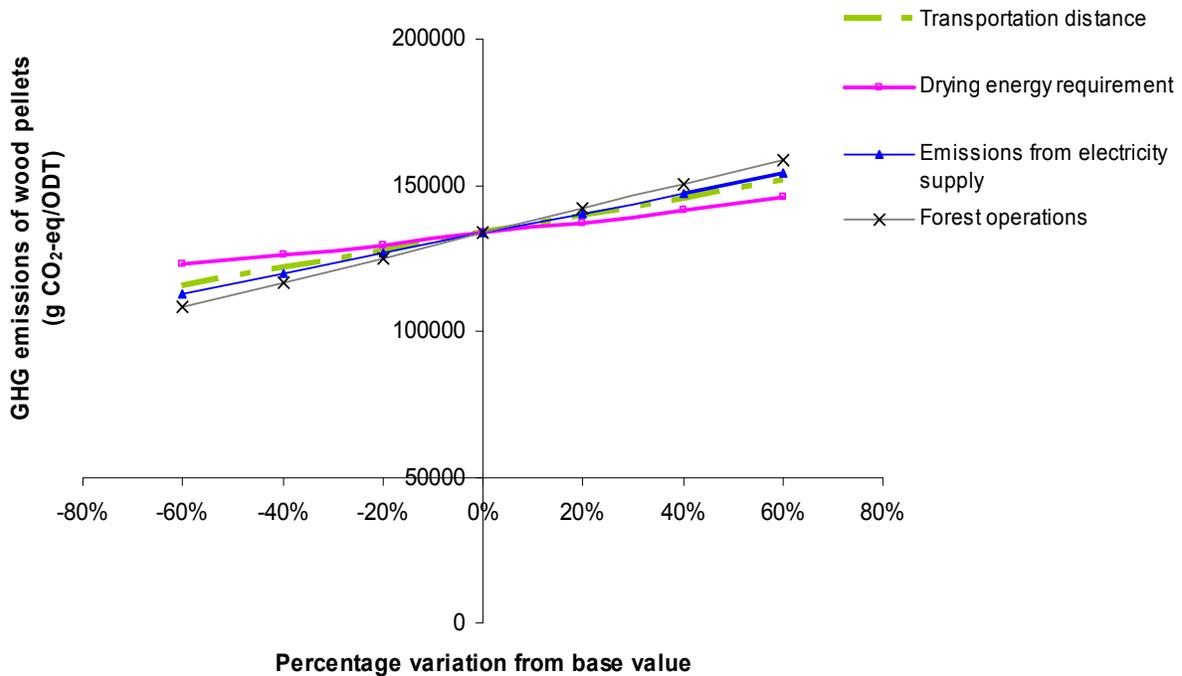


Figure S-3. Sensitivity analysis for pellet production and transportation to Nanticoke GS

### Life cycle inventory results for reference coal pathways

Life cycle emissions for electricity generated from coal in Nanticoke and Atikokan GSs are presented in Table S-8. The production of one kWh of electricity at Nanticoke and Atikokan

results in 1,001 g CO<sub>2</sub> eq. and 1,194 g CO<sub>2</sub> eq, respectively. Emissions resulting from the electricity generation stations (i.e., combustion of the coal) account for 94% and 97% of total life cycle GHG emissions for each kWh of electricity output by Nanticoke and Atikokan, respectively.

Table S-8. Life cycle emissions for electricity produced from coal at Nanticoke and Atikokan Generating Stations

Emissions (g/kWh)	Nanticoke	Atikokan
CO <sub>2</sub>	980	1,180
CH <sub>4</sub>	0.6	0.3
N <sub>2</sub> O	0.01	0.02
GHG (CO <sub>2</sub> eq.)	1,001	1,194
NO <sub>x</sub>	1.9	2.0
SO <sub>x</sub>	3.8	4.7

#### **Life cycle inventory results for reference natural gas pathway**

Table S-9 shows the life cycle emissions associated with electricity produced from the natural gas pathway. Based on the natural gas loss rate for Canada (i.e., 0.25%), the upstream GHG emissions are 43 g CO<sub>2</sub>-eq./kWh for the natural gas combined cycle (NGCC) system. Assuming a higher natural gas loss rate such as that reported for the U.S. (i.e., 1.32%), the upstream GHG emissions increase to 71 g CO<sub>2</sub>-eq./kWh. On a life cycle basis, GHG emissions for the NGCC are 386 and 414 g CO<sub>2</sub> eq./kWh for the 0.25% and 1.32% cases, respectively. Life cycle NO<sub>x</sub> and SO<sub>x</sub> emissions for the NGCC are considerably lower than those of Nanticoke and Atikokan Generating Stations when operating on coal.

Table S-9. Life cycle emissions for electricity produced from NGCC

Emissions (g/kWh)	Electricity produced from NGCC	
	0.25% <sup>1</sup>	1.32% <sup>1</sup>
CO <sub>2</sub>	373	373
CH <sub>4</sub>	0.4	1.5
N <sub>2</sub> O	0.01	0.01
GHG (CO <sub>2</sub> eq.)	386 (Upstream:43; GS:343)	414 (Upstream:71; GS:343)
NO <sub>x</sub>	1.0	1.0
SO <sub>x</sub>	0.1	0.1

Notes: GS = generating station. <sup>1</sup>assumed gas loss associated with recovery, processing, transmission and storage.

### Life cycle air pollutant emissions associated with electricity production

Figures S-4 and S-5 show the life cycle SO<sub>x</sub> and NO<sub>x</sub> emissions associated with the production of electricity through reference, co-firing and 100% pellet-fired pathways. Except for SO<sub>x</sub> emissions at the NGCC GS, the GS (facility) emissions of NO<sub>x</sub> and SO<sub>x</sub> represent the majority of LC emissions for the coal, NGCC, and co-firing pathways. The 100% pellet pathways reduce emissions compared to the coal reference. While the LC SO<sub>x</sub> emissions are higher for the 100% pellet pathway than the NGCC (due primarily to the sulfur in the biomass), the NO<sub>x</sub> emissions are similar. The NGCC lowers LC NO<sub>x</sub> and SO<sub>x</sub> emissions more than would co-firing. With co-firing, SO<sub>x</sub> emissions are reduced slightly more at Nanticoke than Atikokan; the difference is explained by the higher sulfur content of the displaced coal at Nanticoke. NO<sub>x</sub> emissions are just slightly higher for co-firing (0.1 g/kWh) due to a small increase in upstream emissions. However, these results can be considered essentially the same based on the uncertainty in the emissions estimates.

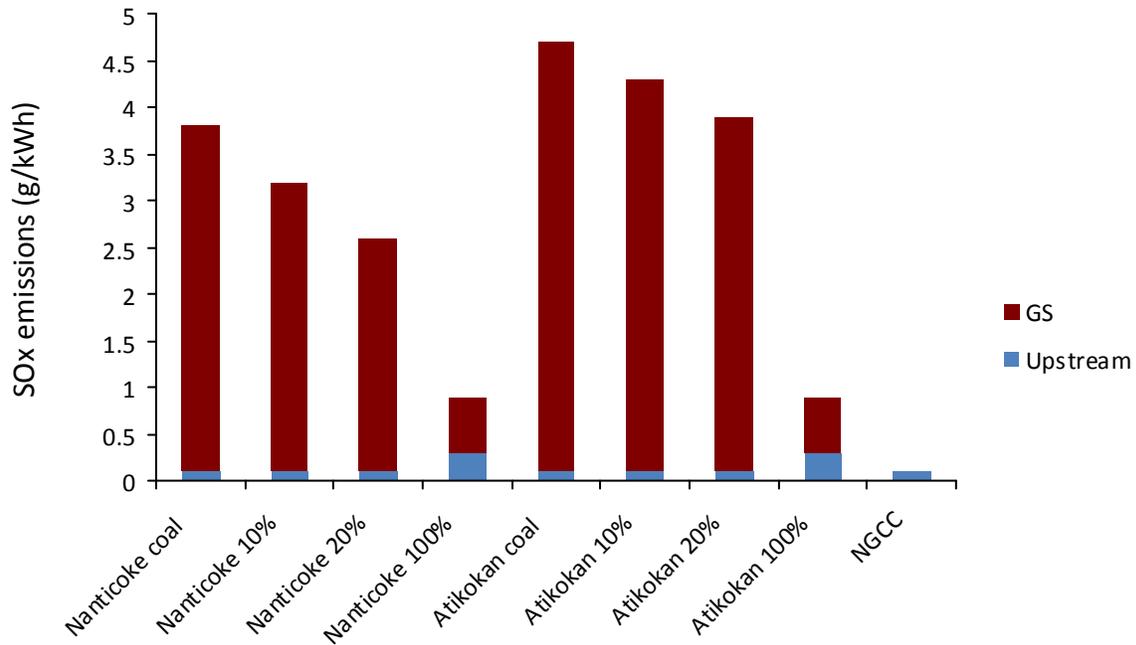


Figure S-4. Life cycle SOx emissions for electricity production pathways  
 Note: Assumes wood pellet sulfur content of 0.05%.

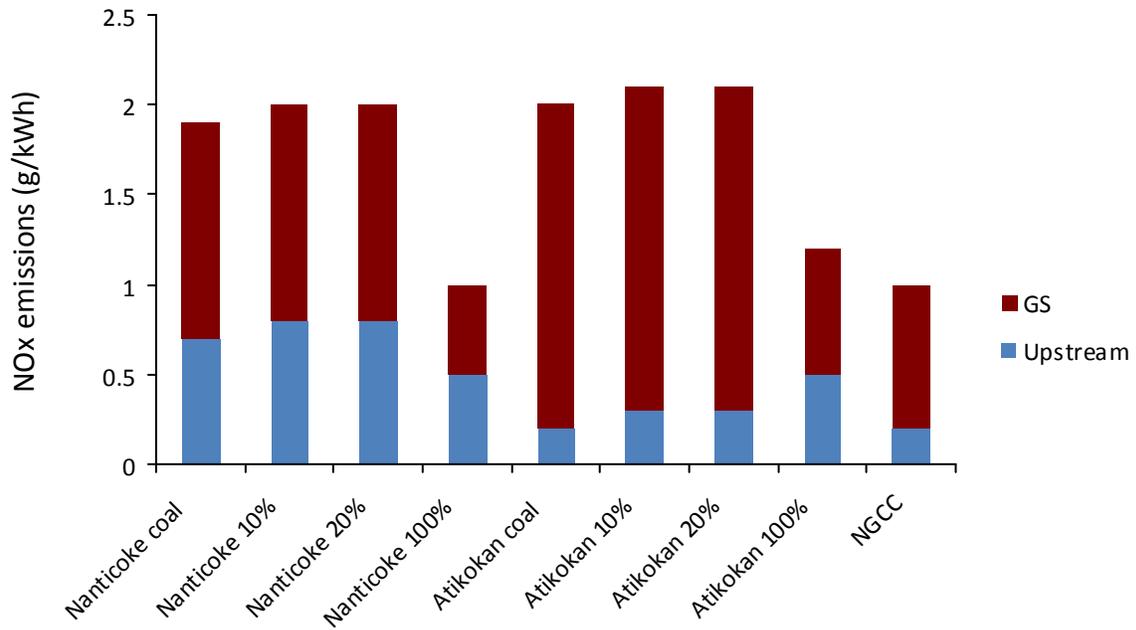


Figure S-5. Life cycle NOx emissions for electricity production pathways

### Cost of electricity production and cost-effectiveness of GHG emissions reductions

Figure S-6 shows the implications on electricity cost (\$/MWh) of varying the values of return on equity, pellet cost, variable cost, fixed O&M cost and capital cost for the Nanticoke GS.

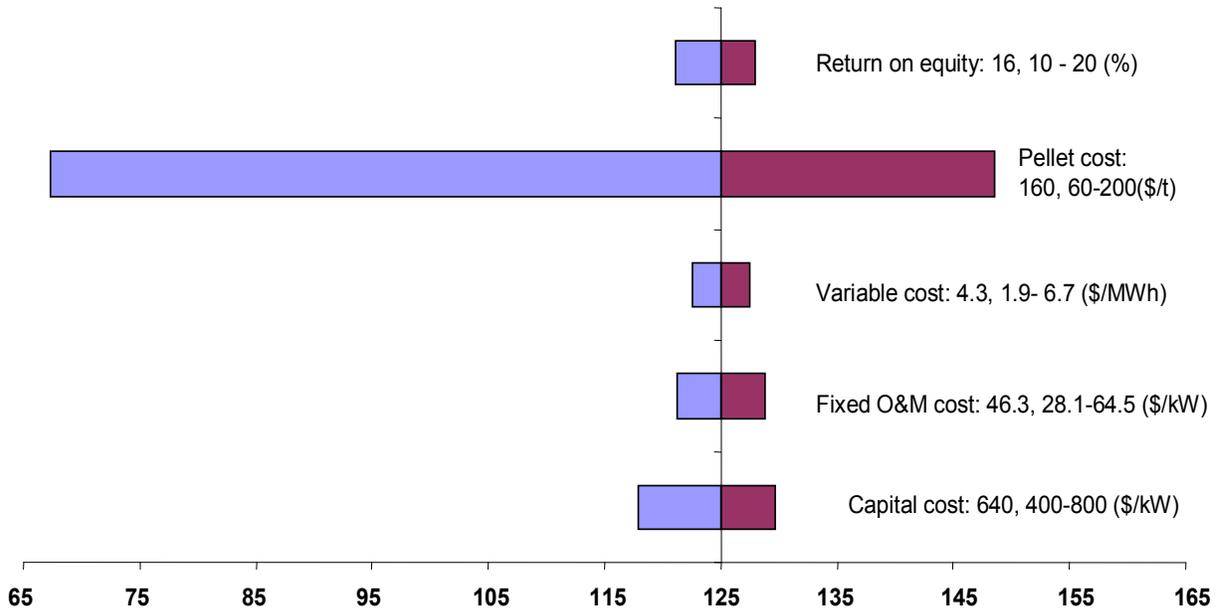


Figure S-6. Sensitivity analysis for electricity cost for 100% pellet firing at Nanticoke Generating Station (\$/MWh). For the y-axis entries, the first value is used for the base case calculation, the second and third values represent the parameter range used in the sensitivity analysis.

Table S-10 reports the cost-effectiveness of reducing NO<sub>x</sub> and SO<sub>x</sub> emissions through pellet co-firing, 100% pellet and the NGCC pathways (natural gas price is the reference price of \$7/GJ). Although all of the pathways have the potential to reduce SO<sub>x</sub> emissions and the 100% pellet and NGCC pathways reduce NO<sub>x</sub> emissions, the costs of mitigation are very high in comparison with market prices for these emissions. Ontario has not yet developed a market for NO<sub>x</sub> and SO<sub>x</sub> emissions transactions, however, in the US, the market prices are on the order of \$100-1000/tonne of SO<sub>x</sub> and \$1000-5000/tonne of NO<sub>x</sub>. In agreement with results of Robinson et al. (33), we find that biomass utilization cannot compete with emissions control methods, which could achieve SO<sub>x</sub> and NO<sub>x</sub> reductions at the market prices.

Table S-10. Cost-effectiveness of air pollutant mitigation (\$/tonne of pollutant)

	Displacing coal at Nanticoke GS		Displacing coal at Atikokan GS	
	NO <sub>x</sub>	SO <sub>x</sub>	NO <sub>x</sub>	SO <sub>x</sub>
10% co-firing	-*	10,300	-*	22,400
20% co-firing	-*	10,400	-*	22,500
100% pellet	107,000	33,100	136,000	28,700
NGCC	57,000	13,800	37,800	8,200

Note: \* The nil results for cost effectiveness of NO<sub>x</sub> reduction in the pellet co-firing scenarios reflect that co-firing was not found to reduce NO<sub>x</sub> emissions relative to coal-only generation.

Figure S-7 reports the cost-effectiveness of GHG emissions reductions for the pellet co-firing, 100% pellet firing and NGCC pathways compared to the coal reference pathways when the pellet price is varied from \$60-200/tonne and the natural gas price from \$5-11/GJ.

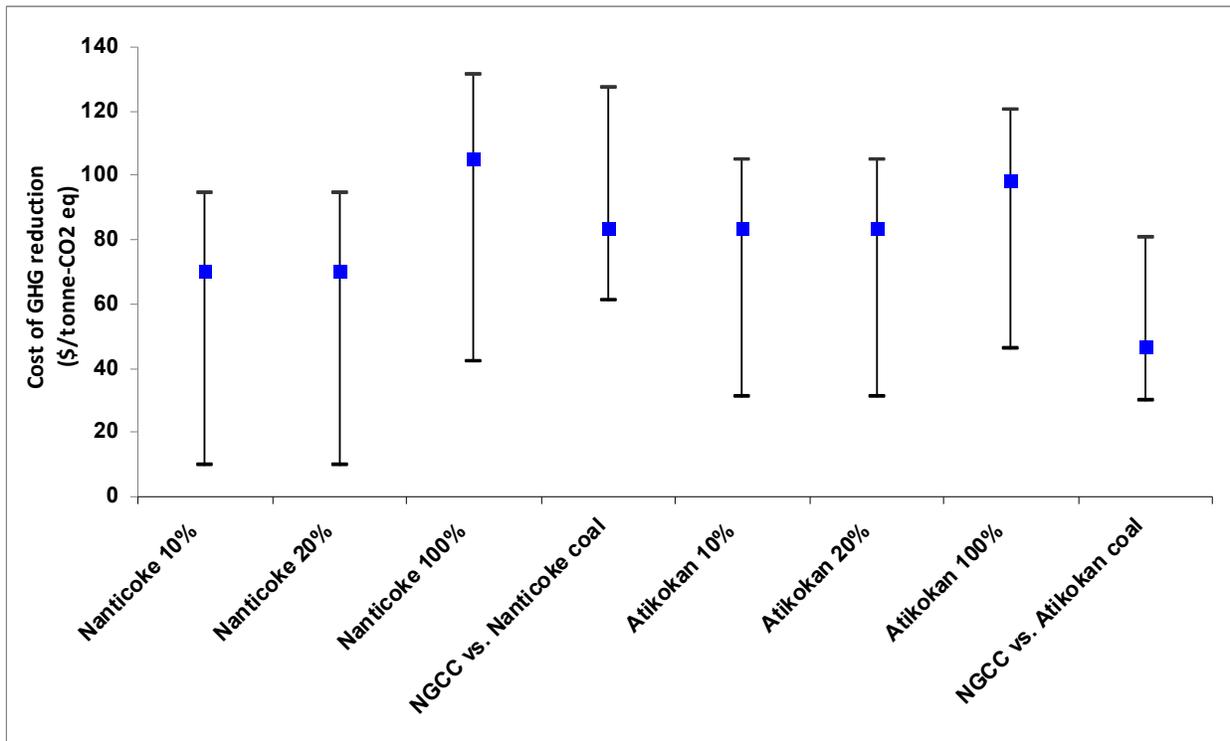


Figure S-7. Cost-effectiveness of GHG emissions reduction compared to coal reference pathways: Impact of varying pellet price from \$60-200/tonne and natural gas price from \$5-11/GJ. Squares represents cost corresponding to \$160/tonne pellet and/or \$7/GJ natural gas.

### **Comparison of life cycle inventory and cost-effectiveness of GHG emissions results with other studies**

We compare GHG emissions reduction results in our study with those of published life cycle studies of electricity generation through biomass coal co-firing (see Table S-11). The form of biomass used in the studies varied, with only one study (43) examining wood pellets.

Unfortunately, the results in (43) are not presented on a comparable basis to those in our study, and due to insufficient detail in the study we are unable to compare the results of the two studies.

Qin et al. (44) assumed CO<sub>2</sub> emissions from biomass combustion are zero because the carbon emitted from combustion is absorbed by switchgrass during its growth. The same method was used by Zhang et al. (45) and by Heller et al.(46) when willow was the only co-fired fuel.

However, when wood residue was used for co-firing, Heller et al.(46) and Mann and Spath (47) did not allocate a carbon credit to the biogenic CO<sub>2</sub> emissions from biomass combustion because the authors assumed the co-fired biomass was not grown for the purpose of co-firing. Rather, the authors assumed the GHG emissions that would have occurred during the normal routes of biomass disposal (i.e., emissions associated with landfill of wood residue) were avoided.

Our results are generally in line with those of the other studies. The GHG emissions reductions, based on a coal reference, for a 10% co-firing rate range from 6.3% to 9.9% in the literature compared to 9% in our study.

Table S-12 reports results of cost of GHG emissions mitigation published in two US studies and one of our prior studies for Ontario, Canada. The studies examine unpelletized biomass.

Robinson et al.(33) estimated the cost-effectiveness of CO<sub>2</sub> reduction (facility only, not life cycle basis) through biomass co-firing with coal in US GSs. At a co-firing rate of 15%, the average costs reported are -\$6 and \$45/tonne CO<sub>2</sub> (biomass at \$0 and \$77/tonne, respectively). Qin et al. (44) reported costs for 10% and 20% (by mass) co-firing and 100% firing of switchgrass in the US (the latter in a stand-alone hypothetical unit) of \$13.8, \$15.9 and \$33/tonne CO<sub>2</sub> eq., respectively (\$34.7/tonne biomass). Our prior study (45) reported \$22 and \$39/tonne CO<sub>2</sub> eq. at 10% (\$50/tonne biomass) and 20% (\$62/tonne biomass) co-firing rates in OPG's GS.

Table S-11. Greenhouse gas emissions reductions reported by life cycle studies of biomass co-firing

Study	Co-firing rate (%) (by energy input)	Biomass utilized for co-firing	Reduction in GHG emissions <sup>1</sup> (%)
Mann and Spath (47)	5	Wood residue	5.4
	15	Wood residue	18.2
Heller et al. (46)	10	Residue/willow	7.4
	10	Willow	9.9
Qin et al. (44)	10 (by mass)	Switchgrass	6.3
Zhang et al. (45)	5	Agricultural residue	4.0
	10	Agricultural residue	7.7
	15	Agricultural residue	6.9

Note: <sup>1</sup>All GHG emissions reductions are calculated based on the respective coal-fired operation reported by the original studies.

Table S-12. Cost of GHG emissions mitigation reported by studies

	Cost of GHG mitigation	Notes
Robinson et al. (33)	On a U.S. national level: GHG reduction cost is \$20/tonne CO <sub>2</sub> (10% co-firing) <sup>1</sup>  Based on U.S. average coal and power plant characteristics, 15% co-firing can reduce GHG emissions at costs of -\$6 and \$45/tonne CO <sub>2</sub> , when the biomass costs are \$0 and \$77/tonne, respectively.	U.S. based study. CO <sub>2</sub> is calculated only for electricity generation, not on a life cycle basis. CH <sub>4</sub> and N <sub>2</sub> O are not included.
Qin et al. (44)	\$13.8/tonne CO <sub>2</sub> eq. (10% co-firing by mass)  \$15.9/tonne CO <sub>2</sub> eq. (20% co-firing by mass)  \$ 33.0/tonne CO <sub>2</sub> eq. (100% switchgrass firing relative to coal-only)	U.S. based study.  CO <sub>2</sub> eq. is calculated on a life cycle basis. Switchgrass price is \$34.7/tonne. SO <sub>x</sub> credit is included in the cost of GHG reduction.  The 100% option is based on a hypothetical stand-alone unit, which has a net conversion efficiency of 21% (heat rate of 17.4 MJ/kWh).
Zhang et al. (45)	\$22/tonne CO <sub>2</sub> eq. (10% co-firing in four OPG coal GS (Ontario). Biomass price is \$50/tonne.  \$39/tonne CO <sub>2</sub> eq. (15% co-firing in four OPG coal GS). Biomass price is \$62/tonne.	Ontario, Canada based study. Efficiency loss due to co-firing unpelletized agricultural residues in this study is higher than co-firing wood pellets in current study.

Note: 1. Co-firing rate is defined on energy input basis unless stated otherwise.

## Literature Cited

1. Ontario Ministry of Energy and Infrastructure. Backgrounder, Ontario's electricity supply mix. Available at [http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&back=yes&news\\_id=134&backgrounder\\_id=105](http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&back=yes&news_id=134&backgrounder_id=105).
2. Jennings, R. Go green and Low Carbon Fuel Standards. National Conference on Low Carbon Fuel Standards for Canada, June 3-4, 2008. Toronto, ON. Available at <http://www.pollutionprobe.org/Happening/pdfs/lowcarbonfuelwkshp/agenda.pdf>.
3. Ontario Ministry of the Environment. Ontario greenhouse gas emissions targets: A technical brief. June 18, 2007. Available at: [www.ene.gov.on.ca/publications/6793e.pdf](http://www.ene.gov.on.ca/publications/6793e.pdf).
4. Spaans, R. Personal communication. June 12, 2008 – August 30, 2008. Ontario Ministry of Natural Resources: Sault Ste. Marie, ON.
5. Ontario Ministry of Natural Resources. Provincial wood supply for potential wood pellet production. Sault Ste. Marie, ON. June 2, 2008.
6. Johnson, D.W. Effects of forest management on soil carbon storage. *Water, Air, and Soil Pollution*. **1992**, 64 (1-2), 83-120.
7. Nave, L.; Vance, E.; Swanston, C.; Curtis, P. The effects of forest harvesting on soil C storage: A meta-analysis. Carbon in Northern Forests. June 10-11, 2009. Traverse City, MI.
8. Forest Engineering Research Institute of Canada. FERIC database. FERIC: Pointe-Claire, Quebec, 2008.
9. Natural Resources Canada. GHGenius – a model for lifecycle assessment of transportation fuels. Version 3.12b. NRCan: Ottawa, ON, 2008. Available at <http://www.ghgenius.ca>.
10. Jaques, A.P. Canada's greenhouse gas emissions: estimates for 1990. Report EPS 5/AP/4. Environment Canada: Ottawa, ON, 1992.
11. SGA Energy Limited. Emission factors and uncertainties for CH<sub>4</sub> & N<sub>2</sub>O from fuel combustion. SGA: Ottawa, ON, 2000.
12. Doan, C. Personal communication. Ontario Ministry of Environment: Toronto, ON. September 15, 2008.
13. Spatari, S.; Zhang, Y.; MacLean, H.L. Life cycle assessment of switchgrass and corn stover derived ethanol fueled automobiles. *Environ. Sci. Technol.* **2005**, 39 (24), 9750-9758.
14. Sun, D-W.; Woods, J.L. Low temperature moisture transfer characteristics of barley: Thin-layer models and equilibrium isotherms. *J. Agric. Eng. Res.* **1994**, 59 (4), 273-283.

15. Mani, S. A system analysis of biomass densification process. Ph.D. thesis. Department of Chemical & Biological Engineering. The University of British Columbia: Vancouver, BC, 2005.
16. Bradley, D. GHG impacts of pellet production from woody biomass sources in BC, Canada. Climate Change Solutions: Ottawa, ON. May 24, 2006.
17. Ontario Ministry of Energy and Infrastructure. Ontario's electricity generation mix. Toronto, ON. Available at <http://www.energy.gov.on.ca/index.cfm?fuseaction=english.electricity>.
18. Oehman, M.; Boman, C.; Hedman, H.; Nordin, A.; Bostroem, D. Slagging tendencies of wood pellet ash during combustion in residential pellet burners. *Biomass Bioenergy*. **2004**, 27 (6), 585-596.
19. World Business Council for Sustainable Development. From coal to biomass. Available at [http://www.wbcsd.org/DocRoot/BWQ8215vu2cevQqR2HPV/suez\\_awirs\\_biomass\\_full\\_case\\_web.pdf](http://www.wbcsd.org/DocRoot/BWQ8215vu2cevQqR2HPV/suez_awirs_biomass_full_case_web.pdf).
20. Peltier, R. PSNH's Northern Wood Power project repowers coal-fired plant with new fluidized-bed combustor. *Power*. **2007**, 151 (8), 37.
21. Energy Business Review. First energy plans to repower RE Burger Plant with biomass. April 6, 2009. Available at [http://www.energy-business-review.com/news/firstenergy\\_plans\\_to\\_repower\\_re\\_burger\\_plant\\_with\\_biomass\\_060409](http://www.energy-business-review.com/news/firstenergy_plans_to_repower_re_burger_plant_with_biomass_060409).
22. O'Connor, D. Personal communication. Electric Power Research Institute: Palo Alto, CA, June 16, 2009.
23. Medin, K.; Hedar, E. Possibilities and limitations when converting a coal fired PF-boiler to co-combustion of biomass and coal. Stockholm Energi AB: Sweden. 2000.
24. Schultz, G. Modern biomass utilization. Energi E2: Denmark. 2008.
25. Drysdale, S. Personal Communication. June 9, 2008 -September 15, 2008. OPG: Toronto, ON.
26. Marshall, L. Personal Communication. May 14 -September 16, 2008. OPG: Toronto, ON.
27. Energy Information Administration. Coal production and number of mines by state and by mine type. Report number: DOE/EIA 0584 (2007). EIA: Washington, DC, 2008.
28. Canadian Energy Pipeline Association (CEPA). Pipeline overview: types of pipelines. Available at [http://www.cepa.com/pipeline101.aspx?page\\_guid=827CCD9F-4EA4-43A9-8261-4C90678938E7](http://www.cepa.com/pipeline101.aspx?page_guid=827CCD9F-4EA4-43A9-8261-4C90678938E7).
29. O'Connor, D. Personal communication. (S&T)<sup>2</sup> Consultants Inc.: Delta, BC, July 1, 2008.

30. Marshall, L. Test data on SO<sub>x</sub> and NO<sub>x</sub> emissions at Atikokan. Personal communication. July 5, 2009. OPG: Toronto, ON.
31. Nalco, M. Available at: [www.mobotecusa.com/projects/hasselbyverket.htm](http://www.mobotecusa.com/projects/hasselbyverket.htm). No longer available on-line, accessed cached page. April 19, 2009.
32. Van Loo, S.; Koppejan, J. *The Handbook of Biomass Combustion and Co-Firing*. EarthScan: London, UK, 2007.
33. Robinson, A.L.; Rhodes, J.S.; Keith, D.W. Assessment of potential carbon dioxide reductions due to biomass-coal cofiring in the United States. *Environ. Sci. technol.* **2003**, *37* (22), 5081-5089.
34. U.S. Department of Energy and Electric Power Research Institute. Renewable energy technology characterizations. TR-109496. Prepared by Office of Utility Technologies, Energy Efficiency and Renewable Energy. DOE: Washington, DC, 1997.
35. United Power. Monthly coal prices between 2006 and 2008. ICAP United Inc.: Boston, MA, 2009.
36. KPMG LLP. Wood pellet plant cost study for the Algoma and Martel Forests in the western portion of the Great Lakes/St. Lawrence Forest. KPMG: Sault Ste. Marie, ON, 2008.
37. Deloitte. 2008. Wood pellet plant cost study for the forests of north eastern Ontario. August 26, 2008. Deloitte & Touche LLP: Toronto, ON.
38. Ontario Ministry of Energy. 2005. Cost Benefit Analysis: Replacing Ontario's coal-fired electricity generation. Available at <http://www.mei.gov.on.ca/wsd6.korax.net/english/pdf/electricity/Cost%20Benefit%20Analysis%20DSS%20Report%20-%20Executive%20Summary.pdf>.
39. Energy Information Administration. Electricity market module. Report number: DOE/EIA-0554(2009). EIA: Washington, DC, 2009.
40. Ontario Power Authority. Economic analysis of gas-fired and nuclear generation resources. EB-2007-0707. OPA: Toronto, ON, 2007.
41. Energy Information Administration. U.S. Natural gas electric power price. Available at <http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm>.
42. Magelli, F.; Boucher, K.; Bi, H.T.; Melin, S.; Bonoli, A. An environmental impact assessment of exported wood pellets from Canada to Europe. *Biomass Bioenergy*. **2009**, *33* (3), 434-441.
43. Damen, K.; Faaij, A. A greenhouse gas balance of two existing international biomass import chains. *Mitigation and Adaptation Strategies for Global Change*. **2006**, *11* (5-6), 1023-1050.

44. Qin, X.; Mohan, T.; El-Halwagi, M.; Cornforth, G.; McCarl, B.A. Switchgrass as an alternate feedstock for power generation: an integrated environmental, energy and economic life-cycle assessment. *Clean Technol. Environ. Policy*. **2006**, 8 (4), 233-249.
45. Zhang, Y.; Habibi, S.; MacLean, H.L. Environmental and economic evaluation of bioenergy in Ontario, Canada. *J. Air Waste Manage. Assoc.* **2007**, 57, 919-933.
46. Heller, M.C.; Keoleian, G.A.; Mann, M.K.; Volk, T.A. Life cycle energy and environmental benefits of generating electricity from willow biomass. *Renewable Energy*. **2004**, 29 (7), 1023-1042.
47. Mann, M.K.; Spath, P.L. A life cycle assessment of biomass cofiring in a coal-fired power plant. *Clean Production Processes*. **2001**, 3(2), 81-91.