INTERNATIONAL JOURNAL OF ENERGY RESEARCH
Int. J. Energy Res. (2010)
Published online in Wiley InterScience
(www.interscience.wiley.com). DOI: 10.1002/er.1676

Greenhouse gas emission intensity factors for marginal electricity generation in Canada

Amal A. M. Farhat and V. Ismet Ugursal*,†

Department of Mechanical Engineering, Dalhousie University, Halifax, NS, Canada

SUMMARY

In Canada, each province has its own electric utility system, and each system is responsible for meeting the demand of its customer base. Electricity demand in all provinces is highly variable throughout the day, as well as during the year. In order to achieve a good match between electricity demand and generation, a mix of base, intermediate and peaking load power plants is used, which uses different fuel sources. When a renewable energy technology or an energy efficiency measure that results in electricity savings is implemented on a regional, provincial and national scale, the electricity savings reflect in the peak (marginal) electricity generation. Thus, the greenhouse gas (GHG) emission reduction due to the reduction in electricity generation corresponds to the fuel used to generate the electricity at the margin. In Canada, the fuel used for marginal electricity generation varies from province to province and from hour to hour. To estimate the reduction in GHG emissions due to reducing electricity generation at the margin, it is necessary to have information on the fuel mix used to generate the marginal electricity for each province on a suitable time scale. With such information, it is possible to estimate a marginal GHG emission intensity factor for each province, which would provide the amount of GHG emissions produced as result of producing 1 kWh of electricity on the margin. However, such information is regarded confidential by most electric utilities and is not made public. In this paper, methodologies are presented to estimate the GHG intensity factors (GHGIFs) for marginal electricity generation for each province of Canada based on the information available in the public domain. The GHGIFs developed for each province are also presented, which are expected to be valid within the next 5-year horizon. Copyright © 2010 John Wiley & Sons, Ltd.

KEY WORDS: GHG emission intensity; marginal electricity generation; electricity savings

1. INTRODUCTION

In Canada, electricity generation is a substantial source of greenhouse gas emissions because close to a quarter of all electricity generation is from combustion of fossil fuels. In 2005, electricity generation and heat production were responsible for about 17% of the total greenhouse gas (GHG)

*Correspondence to: V. Ismet Ugursal, Department of Mechanical Engineering, Dalhousie University, P.O. Box 1000, Halifax, NS, Canada B3J 2X4.
†E-mail: Ismet.Ugursal@Dal.Ca

Contract/grant sponsor: Natural Sciences and Engineering Research Council of Canada

Received 21 August 2009
Revised 4 November 2009
Accepted 11 December 2009

emissions [1,2]. However, the levels of GHG emissions vary considerably from province to province due to the variance of the availability of energy resources, which is reflected on the electricity generation system.

There are numerous options to reduce the GHG emissions in all sectors of the economy. These include increasing the efficiency of energy consumption and reducing the energy consumption by structural changes and fuel substitution (e.g. using less carbon intensive fuels or renewable energy resources). When a renewable energy technology or an energy efficiency measure that results in electricity savings is implemented on a regional, provincial or national scale, the electricity savings are likely to be reflected in the peak (marginal) electricity generation. Thus, the GHG emission reductions due to a reduction in electricity demand, and consequently marginal electricity generation, correspond to the reduction in GHG emissions produced as a result of the conversion of the fuels used to generate the electricity at the margin. However, the fuels used for marginal electricity generation vary from province to province and from hour to hour, and electric utilities determine the source of marginal electricity to dispatch as the demand for electricity changes using complex and dynamic dispatch rules that take into consideration operational and economic conditions. As these conditions change on a continuous basis, it is practically impossible to predict with precision the magnitude of the marginal generation and the fuel used on a time scale of hours, or even days. Furthermore, the information on the fuel used to generate the marginal electricity in each province as a function of time is regarded confidential by most utilities and is not made public.

Two new methods to estimate the GHG emission intensities from marginal electricity generation in each province are presented here. Both methods rely on publicly available information. One of the methods estimates the GHG emission intensity on an annual basis while the second method provides monthly or seasonal estimates for Alberta (AB), Ontario (ON) and Quebec (QC) because more detailed data are available for these three provinces. A more detailed discussion on the development of the methods and their applications are given in Farhat [3].

2. PERFORMANCE OF THE ELECTRICITY GRID

The performance of the electricity grid can be summarized in three major components: electricity generation, transmission and distribution. The voltage of the electricity generated by power plants is increased using transformers, and the high voltage electricity is delivered through the electricity transmission and distribution lines to transformer stations where the electricity voltage is reduced to a lower level, and transmitted over local distribution grids to the consumers [4].

The demand for electricity changes considerably from hour to hour through the day, as well as throughout the year. In order to satisfy the electrical demand in the most economical fashion, electric utilities use complex rules to dispatch their generating units based on demand forecasts, cost of production, unit availability and export/import considerations. This is known as 'optimal power dispatching'.

Utilities use a mix of base load, intermediate load, and peaking load power plants (or units) to satisfy the variability of the demand while minimizing the cost of generation. Base load power plants are designed to operate at full capacity on a continuous basis, and have high fixed costs and low operational costs, resulting in the lowest cost electricity generation within a utility system. Commonly, coal-fired, nuclear and hydro power plants are used as base load plants. Intermediate load power plants have moderate fixed costs and their operational costs are higher than those of base load units. These power plants run during the daytime, filling the gap in supply between base load and peak load power. Their output can change more easily than base load power plants. Commonly oil, combined cycle natural gas (NG) and hydro plants are used as intermediate load power plants. The most expensive electricity is produced by peaking load power plants that operate only at peak demand periods, which is also known as 'marginal generation'. Thus, power

DOI: 10.1002/er

plants whose output can be changed easily and quickly to match fluctuations in demand are used as peaking plants. They can also be started up and shut down quickly. Peaking power plants have lower capital costs and higher operating costs, and they commonly use NG or oil (in combustion turbine or steam cycle plants), and if available, hydro or pumped hydro. In addition to these kinds of power plants, there are non-dispatchable power plants, which include wind and tidal power plants. These cannot be counted on to produce when the need arises since their output depends on the availability of the energy source. The electricity generated by these power plants is usually fed to the grid whenever it becomes available [4].

3. ELECTRICITY GENERATION AND DISPATCH IN CANADA

In Canada, each province has its own electric utility system, and each system is responsible for meeting the demand of its customer base. A brief review of the information available on marginal electricity generation in each province is presented in the following sections.

3.1. Newfoundland and Labrador

Newfoundland and Labrador (NF) has an installed generating capacity of 1635 MW generated by nine hydroelectric plants, one oil-fired power plant, four NG-fired power plants and 25 diesel plants [5]. The peak demand for electricity in NF is during the winter months. The peaking generation capacity is provided by the province's largest thermal power plant that utilizes heavy fuel oil. This power plant has a generating capacity of 500 MW. At peaking time, this power plant runs at full capacity to meet the peak demand. In addition to the thermal generation, about 900 MW is supplied to the grid by several hydro power plants [6].

3.2. Prince Edward Island

For economic reasons, more than 90% of the electricity supplied in Prince Edward Island (PEI) is imported from New Brunswick. The electricity purchased from New Brunswick is transmitted by using a 200 MW capacity undersea cable [7]. This electricity is primarily generated from nuclear and fossil fuel-fired power plants. The remaining electricity generation is from oil-fired power plants and wind turbines. The peak demand for electricity in PEI is during the winter months. The minimum load is about 100 MW, and the peak load is about 210 MW [8]. The peak demand in the province is supplied by imported electricity in addition to the province's thermal power plant which can be used as supplemental capacity at peak demand, but this power plant is usually idle [9].

3.3. Nova Scotia

Nova Scotia (NS) has 2,300 MW of electric generation capacity, with a generating fleet that includes five thermal power plants (coal, NG and heavy oil fired), one tidal and 33 hydro power plants, as well as four combustion turbines and two wind turbine sites [10]. About 75% of the electricity is produced by coal-fired power plants. NS has a winter peaking load, and the peak load is supplied primarily by heavy oil or NG (depending on the spot market price of these fuels), and when available, by the hydro plants [11].

3.4. New Brunswick

In New Brunswick (NB), electricity is generated from 16 power plants distributed throughout the province. A 635 MW nuclear reactor provides about 25% of New Brunswick's electrical requirements and sells 5% of its energy production to PEI. The remaining 15 power plants with total installed capacity of 3,324 MW include seven hydro, two coal-fired, three oil-fired and three diesel power plants. 1,903 MW of the total capacity is from thermal plants, whereas 895 MW is from hydro, and 526 MW is from combustion turbine [12]. These plants produce 75% of the electricity generation in the province, and export energy to the neighbouring New England, QC, PEI and NS markets. New Brunswick has a winter peaking load, which is primarily generated from a mix of coal and oil [13], while the base load is provided by nuclear, hydro and coal. Heavy oil and Orimulsion are used to provide either base or intermediate load [14].

DOI: 10.1002/er

3.5. Quebec

Quebec (QC) is considered as one of the richer regions in the world for its water and hydroelectricity resources. Over 40% of Canada's water resources are in QC, where the surface water reserves in the province cover about 12% of its territory [15]. Historically QC has relied mostly upon hydro electricity to meet its energy needs. Electricity production in the province is from 60 power plants, 54 of which are hydroelectric. Of the remaining six, one is nuclear, four are thermal and one is wind. The highest demand of the electricity in the province is during the winter months, especially during January's coldest days.

Primarily, hydroelectric power plants are used as base load power plants, with the nuclear power plant also providing base load generation. The thermal power plants, which are fuelled by oil or NG, are used mainly as peak load plants during a few highest load periods. A 600 MW oil-fired thermal power plant is operated two weeks per year on average, whereas a 428 MW NG plant is used for 200 h per year. Other thermal power plants work approximately 20 h per year [16].

3.6. Ontario

Electricity generation in ON comes from three major sources: nuclear, coal and hydro. In 2007, three nuclear power plants with total installed capacity of 11 240 MW provided more than 50% of the generating mix. About 180 hydroelectric plants of sizes varying from less than 1 MW to more than 1400 MW at Niagara Falls account for 21% of the generation mix. Four coal-fired plants with a total installed capacity of 6420 MW provide about 18%, and about 60 NG plants provide approximately 8% of remainder. Wind power provided 1% of the total generation in 2007 [17]. ON's peak demand occurs on hot summer days, when most people rely heavily on air conditioning. ON's base load is generated mainly from nuclear and hydro resource, whereas the intermediate and peak load is supplied by coal, NG, oil and hydroelectric generators with storage [18].

3.7. Manitoba

About 95% of Manitoba's (MB) electricity comes from 14 hydroelectric plants of total generating capacity 4828 MW. The remaining 5% is provided by a combination of two gas-fired and one coal-fired power plants with about 535 MW and electricity imports [19,20]. MB has a winter peaking load which is supplied mainly by hydro resources in addition to the NG power plants and imported electricity in case of low water levels [20].

3.8. Saskatchewan

About 60% of the electricity generation in Saskatchewan (SK) is from fossil fuels (45% coal, 15% NG), while the rest is from renewable resources (23% hydroelectric, and 4.5% wind power) and imports. The total generating capacity is about 3700 MW [21]. SK's base load is normally supplied by coal-fired power plants, while the intermediate load is supplied by hydro and imported power. The highest demand in the province normally occurs in winter months with colder temperatures and early darkness, and during the hottest days of summer. The province's peak load is supplied by NG-fired power plants, hydro and imported power [21].

3.9. Alberta

The majority of Alberta's installed generating capacity comes from thermal sources. About 49% of the electricity in the province is generated from coal-fired power plants. NG accounts for 38% of total generation, hydro 7% and the remainder 6% is from wind and biomass [22]. AB has winter peaking load due to lower temperatures and shorter daylight hours. The electricity demand becomes lower in summer than in fall and spring. The peaking load is supplied mainly by NG and coal power plants, while the remaining is supplied by hydro resources [23].

3.10. British Columbia

The electricity generation system in British Columbia (BC) includes 30 integrated hydroelectric generating plants; one gas-fired thermal power plant and two combustion turbine plants

DOI: 10.1002/er

with a total installed capacity of more than 11000 MW [24]. Over 90% of the total system load is served by hydro facilities. The remaining 10% is served by a combination of NG-fired power plants, and energy imports from AB and the US Pacific Northwest [25]. BC has a winter peaking load. The peak load is primarily provided by hydro resources, NG thermal power plants, and imports [26].

4. GHG INTENSITY FACTORS OF FUEL SOURCES

The primary greenhouse gases emitted during the combustion of fossil fuels are carbon dioxide (CO_2), water (H_2O), methane (CH_4) and nitrous oxide (N_2O). Among these gases only water is not considered an anthropogenic GHG as its atmospheric levels are controlled by temperature resulting in precipitation. GHGs are characterized by a global warming potential (GWP).[1] The GWP is referenced to the strength of CO_2 (i.e. equivalent CO_2, or CO_{2eq}) as it is the dominant gas emitted during combustion. Considering the GWP of CO_2 to be unity, CH_4 and N_2O have 100 year GWPs of 25 and 298 by mass, respectively [27].

In the rest of this work, all GHG emissions and emission intensity factors are expressed in terms of CO_{2eq} emissions. The GHG emission intensity factor, i.e. the total CO_{2eq} GHG emissions generated per unit of electricity generation (g CO_{2eq}/kWh) is a function of the properties of the fuel used to generate electricity and to a lesser extent, on the combustion technology [28]. The GHG emissions factors as a result of combusting fuels used in the electric utility sector are given in Table I. The GHG emissions factor for any given fuel is the amount of CO_2, CH_4 and NO_2 in grams emitted as result of burning 1 unit of that fuel. Using these factors, the GHG emission intensity factor for electricity generation can be determined based on the amount of fuel combusted and the amount of electricity generated.

[1]GWP is a measure of how much a given mass of GHG is estimated to contribute to global warming over a period of 100 years.

The values of the GHG intensity factors (GHGIF) (g CO_{2eq}/kWh_{fuel}) for the fuel sources used for marginal generation in a given province are considerably different from one year to the next, due to changes in the efficiencies of the power plants that operate on margin. There are many factors that affect power plant efficiecncy, such as fuel type, load factor (i.e. full load, part load), and the technology used. Therefore, in the rest of this work, the average GHG emission intensity factors for marginal fuel sources (g CO_{2eq}/kWh_{fuel}) over the years 2004–2006 as shown in Table II are used.

5. PREVIOUS METHODS TO CALCULATE GHG EMISSION INTENSITY FACTORS

Two methods have been used to predict the GHG emission intensity factors [29]. The first method calculates the average GHG intensity factor '$GHGIF_A$', which is as the average amount of GHG emissions produced as a result of generating 1 kWh of electricity:

$$GHGIF_A = \frac{TGHG}{TEG} \tag{1}$$

where

TGHG = total GHG emissions from electricity generation in 1 year (g $year^{-1}$).

TEG = total electricity generation in 1 year (kWh $year^{-1}$).

$GHGIF_A$ method neglects the transmission and distribution losses. $GHGIF_A$ can be calculated for the whole country, or for each individual province. As each province uses a substantially different fuel mix for electricity generation, the $GHGIF_A$ is substantially different from one province to another. Generally, base electrical load is satisfied by large-scale power plants that are difficult to modulate, and produce the least expensive electricity, using energy sources including nuclear and hydro which produce no GHG emissions. Therefore, depending on the fuel mix used, this method may result in highly conservative estimates of GHG emission intensity factors for electricity generated on the margin because it assumes that marginal electricity generation is distributed among all types of power plants.

DOI: 10.1002/er

Table I. GHG emissions due to the conversion of fuels to generate electricity [28].

Fuel used	CO_2 (g/unit of fuel)	CH_4 (g/unit of fuel)	N_2O (g/unit of fuel)
Natural gas (m^3)	1891	0.49	0.049
Heavy fuel oil (L)	3080	0.034	0.064
Light fuel oil (L)	2830	0.18	0.013
Diesel (L)	2730	0.133	0.4
Canadian bituminous (kg)	1852–2254	0.022	0.032
US bituminous (kg)	2288–2432	0.022	0.032
Sub-bituminous (kg)*	1733–1765	0.022	0.032
Lignite (kg)	1424–1476	0.022	0.032
Wood & wood waste (kg)†	0	0.05	0.02
Spent liquor (kg)	0	0.05	0.02
Landfill gas (L)	0	N/A	N/A
Orimulsion (kg)‡	2219	N/A	N/A

*Represents both domestic and imported sub-bituminous.
†CO_2 emissions from biogenic materials are considered as complement of the natural carbon cycle. CO_2 emissions is emitted by the combustion of biogenic materials will return to the atmosphere where it was originally removed by photosynthesis.
‡CO_2 emission for orimulsion is calculated in Farhat [3].

The second method calculates the GHGIF for fossil fuel '$GHGIF_M$' is the amount of GHG emission produced as a result of generating 1 kWh of electricity from only fossil fuel power plants:

$$GHGIF_M = \frac{FFGHG}{FFNEG} \qquad (2)$$

where

FFGHG = GHG emissions from electricity generation from only fossil fuel-fired power plants in 1 year ($g\,year^{-1}$).

FFNEG = net electricity generation from only fossil fuel-fired power plants in 1 year ($kWh\,year^{-1}$).

The net electricity generation from only fossil fuel-fired power plants in one year can be calculated for each province by subtracting the transmission and distribution losses from the total electricity generated from fossil fuel power plants. The overall transmission and distribution losses for each province in Canada are given in Table III.

As in some provinces, and during parts of the year, marginal electricity generation can be from hydro resources, $GHGIF_M$ may provide liberal estimates of GHG emission intensity factors for marginal generation because it assumes that marginal electricity savings come only from the fossil fuel power plants.

To demonstrate the magnitude of the differences between the two methods, the average $GHGIF_A$ and $GHGIF_M$ values, calculated using the latest available Statistics Canada data on electricity generation and fuels used [30–32], for each province over the 2004–2006 period are presented in Table IV. As seen in the table, the difference between the $GHGIF_A$ and $GHGIF_M$ values are substantially different, for some provinces as high as two orders of magnitude, due to the difference in their definitions.

6. METHODOLOGY

Two new methods are presented here to estimate the GHG emission intensity factors from marginal electricity generation in each province:

- Weighted annual marginal GHGIFs.
- Monthly or seasonal marginal GHGIFs estimated based on reported data.

The two methods presented here and the marginal GHGIFs calculated using these two methods reflect the current mix of fuels used in the provinces of Canada for marginal electricity generation. As such, considering the rate at which new power plants are brought on line, the GHGIFs reported in this work are likely accurate in a time frame of about 5 years. It is recommended that the GHGIFs should be recalculated and updated as new data become available.

DOI: 10.1002/er

Table II. Average GHG intensity factors for the marginal fuel sources over 2004–2006 [28–31].

Province	Marginal fuel source	GHG intensity factor (g $CO2_{eq}/kWh_{fuel}$)
NF	Oil	817
PE	Oil	1722
NS	Heavy oil	660
	Natural gas	522
	US bituminous	873
NB	Coal	873
	Oil	814
	Natural gas	474
	Orimulsion*	699
QC	Oil	926
	Natural gas	599
	Wood	4
	Spent liquor*	5
	Landfill gas*	0
	SK lignite	1098
ON	Natural gas	476
	Coal	941
	Oil	737
	SK lignite	1098
	US bituminous	918
MB	Natural gas	751
	Montana sub-bituminous	1125
SK	Natural gas	558
	SK lignite	1098
AB	Natural gas	567
	Coal	1088
	Landfill gas	0
	AB bituminous	1100
BC	Natural gas	445
	Wood	7

*All GHG intensity factors are based on the average values over 2004–2006 except for orimulsion and spent liquor. The detailed data used to calculate the emission factors for these fuels are given in Farhat [3]. For the landfill gas, the CO_2 emission is considered as complement of the natural carbon cycle.

Table III. Overall transmission and distribution losses for each province in Canada.

Province	NF	PE	NS	NB	QC	ON	MB	SK	AB	BC
% losses	9	6	4	6	4	6	12	6	4	3

6.1. *Weighted annual marginal GHGIFs*

Through the information that is made publicly available or has been obtained through personal communication with electric utility officers on electricity generation and fuels used, the mix of fuel sources used to generate the marginal capacity for each province has been identified as shown in Table V.

Table IV. The average $GHGIF_A$ and $GHGIF_M$ values (g CO_{2eq}/kWh) over 2004–2006 period for each province.

	Average over 2004–2006	
	$GHGIF_A$	$GHGIF_M$
NF	26	847
PE	191	1849
NS	733	839
NB	433	810
QC	6	723
ON	199	862
MB	13	1209
SK	789	1061
AB	921	1015
BC	22	462

In the absence of detailed data on the amounts of marginal electricity generated from each fuel, it is assumed that the fuel mix used for marginal electricity generation has the same ratio as the mix of these fuels in the annual generation, i.e.

$$\frac{\mathrm{MEGMF}_i}{\sum_{i=1}^{n}\mathrm{MEGMF}_i} = \frac{\mathrm{TEGMF}_i}{\sum_{i=1}^{n}\mathrm{TEGMF}_i} \tag{3}$$

where

MEGMF_i = marginal electricity generation using marginal fuel i (MWh).

TEGMF_i = total electricity generation using marginal fuel i (MWh).

n = number of fuels used for marginal electricity generation.

The annual marginal GHGIFs are calculated based on the fuel percentages and the GHG emission intensity factors for each fuel as shown in Equation (4):

$$\text{Marginal GHG Intensity Factor}\left(\frac{\mathrm{gCO_{2eq}}}{\mathrm{kWh}}\right) = \sum_{i=1}^{n} \%\ \mathrm{Fuel}_i * \text{GHG Intensity Factor for Fuel}_i\left(\frac{\mathrm{g\ CO_{2eq}}}{\mathrm{kWh_{fuel\ \mathit{i}}}}\right) \tag{4}$$

DOI: 10.1002/er

Table V. Fuels used for marginal electricity generation.

Province	Fuels used for marginal electricity generation	Reference
NF	Oil, hydro	[6]
PE	Oil, imports	[9]
NS	Natural gas, hydro, oil	[11]
NB	Coal, oil	[13]
QC	Natural gas, hydro, oil	[16]
ON	Natural gas, hydro, coal, oil	[18]
MB	Natural gas, hydro, imports	[20]
SK	Natural gas, hydro, imports	[21]
AB	Natural gas, hydro, coal	[23]
BC	Natural gas, hydro, imports	[25]

where

$$\text{GHG Intensity Factor for Fuel}_i = \frac{\text{Emission factor for fuel}_i\left(\frac{\text{g CO}_{2\text{eq}}}{\text{quantity}_{\text{fuel}}}\right) \times \text{Quantity of fuel}_i \text{ consumed}}{\text{Electricity generated by fuel}_i \text{ (kWh)}} \quad (5)$$

Using the latest available Statistics Canada data on electricity generation and fuels used [30–32], and the GHGIFs for each fuel (g CO_{2eq}/kWh_{fuel}) used for marginal generation in each province, the annual marginal GHGIFs for the years 2004–2006 were calculated assuming that imported electricity has no GHG emissions attributable to Canada [3]. Similarly, electricity obtained from hydro resources is assumed to be free from GHG emissions [28].

As the marginal fuel mix was estimated for the years of 2004–2006, and as the electricity supply mix changes from year to year with the new power plants added to the grid whether due to the retirement of the old power plants or the increase in electricity demand, to predict the fuel mix used for marginal generation, a weighted averaging approach, as described in Equation (6), is used here.

$$\%\text{ Fuel mix on margin} = \%\text{ fuel mix in 2004} \times 20\% + \%\text{ fuel mix in 2005} \times 30\% + \%\text{ fuel mix in 2006} \times 50\% \quad (6)$$

This approach assumes that the recent years have a higher contribution to predict the future fuel mix than that of the earlier years. Using the predicted marginal fuel mix according to Equation (6), and the GHGIFs in Table II, the weighted annual marginal GHGIFs were calculated using Equation (4). The annual marginal GHGIFs for the years 2000–2006, as well as the weighted annual marginal GHGIFs are presented in Table VI.

6.2. Monthly or seasonal marginal GHGIFs estimated based on reported data

To predict monthly or seasonal marginal GHGIFs, detailed data are needed from utilities on electricity generation and fuels used as a function of time. However, in Canada data on electricity generation and fuels used are reported by utilities only in AB, ON and QC, and the level of particularization of data varies among these provinces. In the following sections, a brief review of the data available for each one of these provinces is presented, followed by the methods developed based on the reported data to estimate the monthly or seasonal marginal GHGIFs.

6.2.1. Alberta. The deregulated electric utility sector in AB provides detailed data on generation and fuels used through the Alberta Electric System Operator (AESO). AESO has on its website a report that identifies the mix of the fuel sources used for marginal generation [23]. Based on this report, the marginal generation in AB comes mainly from three fuel sources: coal, gas and hydro-power. The seasonal percentages of each fuel source on margin for the period 2004–2006 are given in Table VII.

AESO forecasts that the AB peak load will be substantially increasing over the next 10 years [33]. AB peaking load will increase by 3280 MW from 9580 MW in 2005 to reach 12 860 MW by 2016, as a result of an annual average growth rate of 2.6%. Based on this forecasting and due to the retirement of some power plants, about 2300 MW of additional generating capacity is expected to be added to the grid by 2011 and 4100 MW by 2016.

AB's electricity generation comes mainly from coal, NG, hydro and wind, and in small quantity from small generators. The capacity addition projections provided by AESO [33] for each one of

DOI: 10.1002/er

Table VI. Annual marginal GHG intensity factors over 2004–2006, and the weighted annual marginal GHG intensity factors (g CO_{2eq}/kWh).

	Year	Annual marginal GHG intensity factor	Weighted annual marginal GHG intensity factor
NF	2004	33	22
	2005	26	
	2006	15	
PE	2004	11	6
	2005	7	
	2006	3	
NS	2004	501	360
	2005	459	
	2006	212	
NB	2004	820	837
	2005	835	
	2006	850	
QC	2004	10	7
	2005	4	
	2006	5	
ON	2004	397	407
	2005	435	
	2006	408	
MB	2004	2	1
	2005	0	
	2006	1	
SK	2004	243	225
	2005	254	
	2006	199	
AB	2004	947	937
	2005	905	
	2006	965	
BC	2004	20	18
	2005	19	
	2006	16	

the major fuels over the next 10 years are summarized in Table VIII.

Based on the reported data on the fuel sources used for marginal generation over the period of 2004–2006 (coal, gas and hydro) and the additional capacity predicted to come on line, the marginal generation in AB in the near future is assumed to be generated from coal, gas and hydro. The fuel mix on the margin is estimated using the seasonal marginal fuel mix over 2004–2006 and the weighted averaging approach described in Equation (6).

The seasonal percentages of each fuel source on margin calculated based on Equation (7) are given in Table IX. With this fuel mix and the emission intensity factors for each fuel on margin, the marginal GHGIFs (g CO_{2eq}/kWh) for each season can be calculated using Equation (7). The resulting seasonal marginal GHGIFs are given in Table X.

Table VII. Seasonal percentages of the fuel mix used on margin over 2004–2006 in Alberta [23].

	Summer (%)		Winter (%)		Shoulder (%)	
	Peak	Off peak	Peak	Off peak	Peak	Off peak
2004						
Coal	20.1	54.0	34.8	64.3	23.9	54.1
Gas	78.2	44.5	64.7	34.8	75.8	45.6
Hydro	1.7	1.5	0.6	1.0	0.3	0.3
2005						
Coal	42.8	71.4	32.0	62.4	39.9	71.6
Gas	51.5	25.6	66.4	36.9	59.6	27.9
Hydro	5.7	3.0	1.6	0.7	0.5	0.4
2006						
Coal	37.0	65.6	51.8	73.6	36.9	68.8
Gas	59.7	33.4	47.7	26.2	61.7	30.6
Hydro	3.2	1.0	0.6	0.2	1.4	0.6

Note: Summer months include June, July, August and September, whereas winter months include November, December, January and February. The rest of the year comprises the shoulder months. Peak periods are business days (21 days per month), whereas off peak periods include all other times.

Table VIII. Current and the new projected generation capacity in Alberta by 2016 [33].

Source	Projected additional capacity (MW)	Year
Coal	80	2011
	80	2016
Gas	300	2011
	100	2016
Hydro	100	2012
Wind	600	2011
	600	2016
Other	50	2011
	50	2016
Oil sands	50	2011
	100	2016

$$\begin{aligned}&\text{Marginal GHG intensity factor (g } CO_{2eq}/\text{kWh)}\\&=\left\{21\times\sum_{i=1}^{n}\%\,\text{fuel}_i\text{ on peak}\right.\\&\quad\times\text{emission intensity for fuel}_i\ (\text{g } CO_{2eq}/\text{kWh}_{\text{fuel } i})\\&\quad+9\times\sum_{i=1}^{n}\%\,\text{fuel}_i\text{ off peak}\\&\quad\left.\times\text{emission intensity for fuel}_i\ (\text{g } CO_{2eq}/\text{kWh}_{\text{fuel } i})\right\}\Big/30\end{aligned}\qquad(7)$$

DOI: 10.1002/er

Table IX. Predicted seasonal percentages of the fuel mix used on margin in Alberta.

	Summer (%)		Winter (%)		Shoulder (%)	
	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
Coal	35.4	65.0	42.5	68.4	35.2	66.7
Gas	60.9	33.3	56.7	31.1	63.9	32.8
Hydro	3.7	1.7	0.9	0.5	0.9	0.5

Table X. Predicted seasonal marginal GHG intensity factors (g CO_{2eq}/kWh) for Alberta.

Season	Summer	Winter	Shoulder
Marginal GHG intensity factor	769	591	785

where
21 = number of peak days per month.
9 = number of off-peak days per month.
30 = number of days per month (peak days plus off-peak days).

6.2.2. Ontario. In ON, the independent electricity system operator (IESO) forecasts the provincial electricity demand to ensure that the existing and the proposed generation are sufficient to meet ON's electricity needs.

ON base load is generated mainly from nuclear and hydro resources, while the intermediate and peak loads are supplied by coal, NG, oil and hydroelectric generators with storage. However, ON's government is committed to replace the existing coal capacity in the province starting in 2007 and ending in 2014 [34,35]. The new generation capacity that is planned to be added to the system by 2010 is summarized in Table XI.

In addition to forecasting electricity demand of the province, the IESO publishes on its website the hourly data on electricity generation and fuels used [36]. The hourly data has been obtained over the period of 2007–2008 through a personal communication with IESO [37]. To visualize the hourly data on electricity generation and fuels used, the data for the period of 1–8 April 2008 obtained from ON's IESO are plotted in Figure 1.

The hourly data for the 2007–2008 period were analysed to determine the contribution of each fuel source to a change in the total electrical output. The following conditions were assumed to identify the marginal energy sources:

Table XI. Ontario's current and the new projected generation capacity (MW) by 2010 [36].

Source	Projected additional capacity by 2010 (MW)
Nuclear	1500
Hydro	100
Oil & natural gas	2800*
Wind	600
Import	750

*The additional 2800 MW will be generated from only natural gas power plants.

- The minimum change in the total electricity generation in ON from one hour to the next was set to 250 MW for consideration of marginal sources. If the change is less than 250 MW, the change is ignored. The choice of 250 MW is to eliminate the wind generation from the margin where its output can be variable from 0 MW up to 250 MW from hour to hour depending on the availability of the wind.
- A marginal energy source must contribute at least 20% of the change in total generation to be considered of significance and to eliminate possible noise.
- During the periods when total generation remains constant, the previously determined marginal energy sources are considered to remain on the margin.
- If the generation from a fuel source changes in the opposite direction to the change in the total generation (i.e. not following load), that fuel source is not considered to be on the margin.

Based on these assumptions, the hourly marginal energy sources were averaged over individual days for the period of 1–8 April 2008 to identify the significant components. These daily average marginal generation energy source components are shown in Figure 2. As it can be seen, both coal and hydro play a significant role in providing electricity on the margin. NG (Other) is not on the margin on April 6, in agreement with the constant NG output shown in Figure 1. As expected, at no

DOI: 10.1002/er

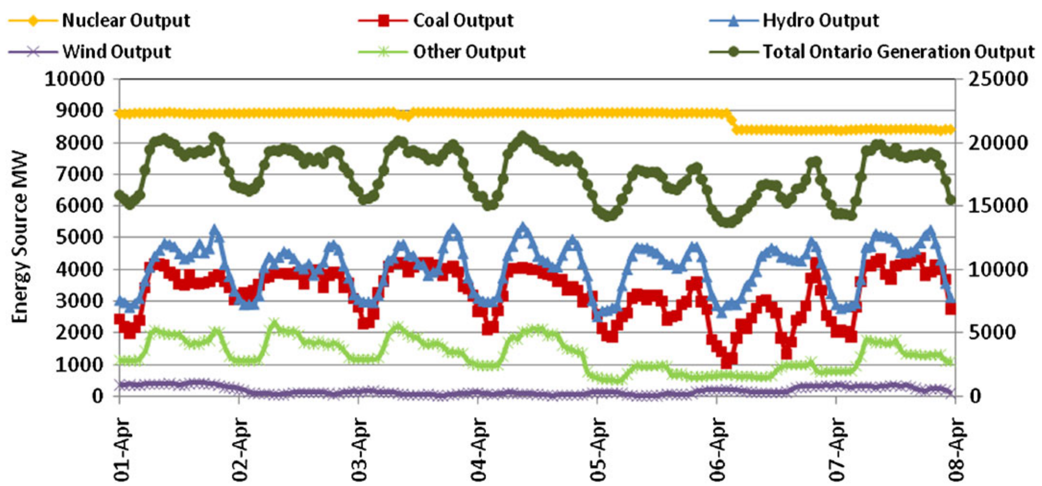

Figure 1. Electrical generation energy source components for Ontario for 1–8 April 2008 [37] ('other' denotes natural gas).

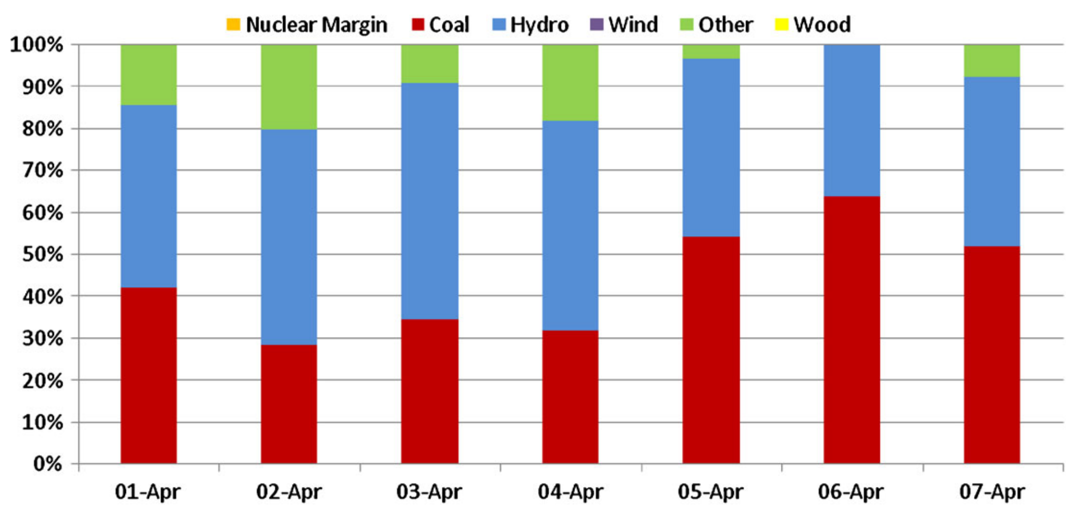

Figure 2. Energy sources for the marginal electricity generation in Ontario for 1–7 April 2008 ('other' denotes natural gas).

point during the period of 1–8 April 2008 is nuclear or wind on the margin.

The same technique was applied to the data over 2007–2008 to identify the energy sources that are on the margin. The results obtained from this analysis were analogous to the result obtained for 1–8 April 2008 with coal and hydro providing a significant portion of the marginal generation, and the remainder coming from NG. The hourly marginal generation for each energy source was averaged over individual months to identify the monthly fuel mix on the margin. The monthly average marginal generation energy source components, as well as the marginal GHGIFs (g CO_{2eq}/kWh) calculated using Equation 4 over the period of 2007–2008, are given in Table XII. As it can be seen, nuclear appears as a part of the marginal generation; however, its contribution is very small (two percent or less) and can be neglected. Therefore, coal, hydro and NG are considered to be on the margin.

On numerous occasions during the past two years, the Government of ON has indicated that ON is committed to replacing the existing coal-fired

DOI: 10.1002/er

Table XII. Monthly average marginal generation energy source components and marginal GHG intensity factors for Ontario (g CO_{2eq}/kWh) over 2007–2008.

	2007					2008				
Month	Hydro (%)	Nuclear (%)	Natural gas (%)	Coal (%)	Marginal GHG intensity factor	Hydro (%)	Nuclear (%)	Natural Gas (%)	Coal (%)	Marginal GHG intensity factor
January	54	1	14	32	366	51	0	10	39	415
February	57	0	24	19	293	52	1	11	36	391
March	57	2	20	21	293	55	1	13	31	354
April	52	2	8	38	396	42	0	8	50	509
May	50	1	9	40	419	39	0	4	57	555
June	38	1	16	45	500	35	0	19	46	523
July	45	1	12	42	452	37	0	17	46	514
August	35	0	27	38	486	44	0	7	49	494
September	40	0	18	42	481	47	0	13	40	438
October	39	1	21	39	467	46	0	12	42	452
November	47	1	17	35	410	52	0	20	28	359
December	49	1	19	31	382	52	0	19	29	363

Table XIII. Predicted marginal fuel sources and the marginal GHG intensity factors for Ontario, Scenario ♯1.

Month	Hydro (%)	Nuclear (%)	Natural Gas (%)	Coal (%)	Marginal GHG intensity factor
January	52	0	11	36	395
February	54	1	16	29	352
March	56	1	16	27	329
April	46	1	8	45	463
May	43	0	6	50	501
June	36	0	18	46	514
July	40	0	15	44	489
August	40	0	15	45	491
September	44	0	15	41	455
October	43	0	16	41	458
November	50	0	19	31	379
December	51	0	19	30	371

generating stations by NG, hydro and renewable. The time frame for the replacement is reported to be the end of 2014. Based on that, two scenarios are used here to predict the marginal monthly GHG intensities for ON.

Scenario 1: The fuel mix on the margin is estimated using the monthly average marginal fuels mix over 2007–2008 and the weighted averaging approach described in Equation (8).

$$\begin{aligned}&\%\text{ monthly fuel mix on margin}\\&= \%\text{ fuel mix in 2007} \times 40\%\\&\quad + \%\text{ fuel mix in 2008 } * \text{ } 60\%\end{aligned} \tag{8}$$

Using the predicted fuel mix according to Equation 8 and the GHGIFs for marginal fuel sources in Table II, the monthly marginal GHGIFs (g CO_{2eq}/kWh) were calculated using Equation 4. The predicted marginal fuel sources, as well as the marginal GHGIFs (g CO_{2eq}/kWh), are given in Table XIII.

Scenario 2: The Government of ON has announced to replace the existing coal capacity starting from 2007 and to end by 2014, and to add about 5000 MW of new generating capacity to the grid by 2010 with 2800 MW from NG and 100 MW from hydro resources. Based on this information, the marginal coal capacity will be assumed to be replaced by NG and hydro resources

DOI: 10.1002/er

by the end of 2014. The contribution of NG and hydro in replacing the coal capacity on margin will be based on their additional capacity as shown in Table XIV.

Therefore, 3.4% of the predicted marginal coal capacity in Table XIII will be replaced by hydro resources, and 96.6% will be replaced by NG by the end of 2014. Based on these assumptions, the marginal fuel mix and the marginal GHGIFs (g CO_{2eq}/kWh) calculated using Equation 4 are given in Table XV.

6.2.3. Quebec. In QC, the development of hydro resources is continuing at a steady pace, with new hydro projects constructed in the last few years and some still under construction or under study. About 4000 MW of wind capacity is expected to be added to the grid between 2006 and 2015 to represent about 10% of the installed capacity [38]. Thus, the new generation capacity that will be added to the system in QC by 2019 is summarized in Table XVI.

Table XIV. New additional capacity in Ontario from hydro and natural gas.

Fuel source	MW	NG: Hydro
Hydro	100	0.034
Natural gas	2800	0.966
Total	2900	1

Table XV. Predicted marginal fuel sources and the marginal GHG intensity factors for Ontario, Scenario #2.

Month	Hydro (%)	Nuclear (%)	Natural Gas (%)	Marginal GHG intensity factor
January	53	0	46	221
February	55	1	44	211
March	57	1	42	199
April	48	1	52	246
May	45	0	54	259
June	38	0	62	294
July	42	0	58	276
August	42	0	58	276
September	46	0	54	259
October	45	0	55	262
November	51	0	49	231
December	52	0	48	227

Based on the reported data on marginal electricity generation and fuels used, the marginal generation comes primarily from hydro resources for most of the year except during the coldest days of the year which is in January, when oil and NG-fired thermal generating stations are used with hydro to meet the peak demand. The latest available Statistics Canada data on electric power statistics [39] for January 2008 shows the components of the electricity generation (MWh) during this month, which is mainly hydro, nuclear, and thermal generation. The electricity generation (MWh) and the percentages generated from each source are shown in Table XVII.

Based on this information, the contribution of the thermal generation (oil and NG) on January's marginal capacity was liberally assumed to be five times of the thermal generation contribution during this month. As the rest of the marginal capacity comes from hydro resources the marginal generation capacity for January is assumed to be as follows:

Thermal generation $= 5 \times 0.7\% = 3.7\%$
Hydro generation $= 100–3.7\% = 96.3\%$

The contribution of oil and NG to the thermal marginal generation in January is based on their contribution to annual electricity generation. Using the Statistics Canada data on electricity

Table XVI. Current and the new projected generation capacity in Quebec by 2019 [38].

Source	Projected additional capacity (MW)	Year
Hydro	2015	2010
	3173	2019
Wind	4000	2015

Table XVII. Electricity generation (MWh) for January 2008 in Quebec [39].

Source	MWh	% Generation
Hydro	16 844 688	96.6
Nuclear	425 985	2.4
Thermal	128 755	0.7
Wind	43 260	0.2
Total	17 431 612	100

DOI: 10.1002/er

Table XVIII. MWh generated from oil and natural gas in Quebec in 2006 [28].

Fuel source	MWh	Oil:NG
Oil	135 020	0.08
Natural gas	1 471 377	0.92
Total	1 606 397	1

Table XIX. Predicted marginal fuel mix and the associated marginal GHG intensity factors for Quebec.

Month	Oil (%)	Natural gas (%)	Hydro (%)	Marginal GHG intensity factor
January	0.3	3.4	96.3	23
February–December	—	—	100	0

generation and fuels used for 2006 [29], the ratio of oil generation to NG generation is calculated as shown in Table XVIII. Based on this, the mix of oil and NG in the marginal generation for January is as follows:

Oil on margin $= 3.7 \times 0.08 = 0.30\%$
NG on margin $= 3.7 \times 0.92 = 3.40\%$

The marginal GHGIF for January can be calculated based on the predicted marginal fuel mix and their GHGIFs, using Equation (5). For the rest of the year, the marginal generation is 100% from hydro resources with zero GHG emissions. The predicted marginal fuel mix and the associated marginal GHGIFs for QC are given in Table XIX.

7. RESULTS AND DISCUSSION

In this work, four different methods to predict the marginal GHG emission intensity factors due to electricity savings in the residential sector of each province of Canada were presented and discussed. These methods are

- Average GHG intensity factor ($GHGIF_A$),
- GHG intensity factor from fossil fuel power plants ($GHGIF_M$),
- Weighted annual marginal GHGIFs,
- Monthly or seasonal GHGIFs estimated based on reported data.

The first two methods are based on a previous work that utilized the $GHGIF_A$ and the $GHGIF_M$ to calculate the GHG emission from electricity generation [29]. The other two methods proposed and developed in this work are based on the available data on fuel sources used for marginal electricity generation in each province on an annual, seasonal and monthly basis. A qualitative comparison of all four methods is presented Table XX. To demonstrate the magnitude of the differences between these methods, the values of the GHGIFs calculated based on each method are presented in Table XXI.

Based on these results the following observations are made

1. Newfoundland: Marginal electricity generation, like the total electricity generation comes mainly from hydro resources, which has zero GHG emissions, and a small proportion from oil. Therefore, the magnitudes of both the $GHGIF_A$ and the GHGIF predicted using the weighted annual marginal method are close to each other, while $GHGIF_M$ is not applicable. The use of the weighted annual marginal GHGIF is recommended.
2. Prince Edward Island: More than 99% of the marginal generation comes from imported electricity with zero GHG emissions, and the remainder is from oil; therefore, $GHGIF_M$ is not applicable. The use of the weighted annual marginal GHGIF is recommended.
3. Nova Scotia: $GHGIF_A$ and $GHGIF_M$ are close to each other since electricity generation relies heavily on fossil fuels. The GHGIF predicted using the weighted annual marginal method is lower than both because about 45% of the marginal generation comes from hydro resource, and the rest from heavy oil and NG. As the weighted annual marginal GHGIF takes into consideration the actual mix of fuels used for marginal generation, the use of the weighted annual marginal GHGIF is recommended.
4. New Brunswick: Although more than 40% of the total electricity generation is from nuclear and hydro resoures with zero GHG emissions, the marginal generation comes mainly from coal and oil which have the highest GHG

Table XX. Comparison of the methods that can be used to predict the GHG emission reductions due to electricity savings in the residential sector.

		Methods proposed in this work		Previously available methods	
		WeightedAnnual Marginal GHGIF	Monthly or Seasonal GHGIF Estimated Based on Reported Data	$GHGIF_A$	$GHGIF_M$
Provinces included		All provinces	Alberta, Ontario, Quebec	All provinces	All provinces
Fuel type on margin	NF	Oil, hydro	—	Fossil fuels, wood, nuclear, hydro	Fossil fuels
	PE	Oil, imports	—		
	NS	Natural gas, hydro, oil	—		
	NB	Coal, oil	—		
	QC	Natural gas, hydro, oil	Natural gas, hydro, oil		
	ON	Natural gas, hydro, coal, oil	Natural gas, hydro, coal, oil		
	MB	Natural gas, hydro, imports	—		
	SK	Natural gas, hydro, import	—		
	AB	Natural gas, hydro, coal	Natural gas, hydro, coal		
	BC	Natural gas, hydro, imports	—		

emission factors among the fossil fuels. Therefore, the magnitudes of $GHGIF_M$ and the GHGIF predicted using the weighted annual marginal method are close to each other. The use of the weighted annual marginal GHGIF is recommended.

5. Quebec: Marginal electricity generation, like the total electricity generation comes mainly from hydro resources with zero GHG emissions, and a small proportion from NG and oil. Therefore, the magnitudes of both the $GHGIF_A$ and the GHGIF predicted using the weighted annual marginal method are very close, and $GHGIF_M$ is not applicable. Based on the latest available information on marginal fuels used, two marginal GHGIFs are recommended; one for January, and another for the rest of the year.
6. Ontario: About 75% of the electricty generation on ON comes from nuclear generation and hydro resources which have zero GHG emissions, the rest comes from fossil fuels. Therefore, the GHGIFs predicted using the $GHGIF_A$ and $GHGIF_M$ methods are substantially different. Considering the higher level of accuracy of the hourly data, it is recommended to use the monthly marginal GHGIFs determined using the hourly data. As it is not known whether the ON government will retire coal-fired power plants as it was announced, the user should decide which one of the two scenarios to use in the prediction.
7. Manitoba: More than 90% of the total electricity generation in MB comes from hydro resources, while more than 99% of the marginal generation comes from hydro resources and imported electricity with zero GHG emissions, and the remainder of the marginal generation coming from NG. Consequently, there is a substantial difference between $GHGIF_M$ and $GHGIF_A$, and $GHGIF_M$ is not applicable for marginal generation. As hydro electricty and imports constitute more than 99% of marginal generation, the weighted annual marginal GHGIF produces a more realistic value and its use is recommended.
8. Saskatchewan: Although a substantial part of the total electricity generation in SK is from

DOI: 10.1002/er

Table XXI. Marginal GHG intensity factors (g CO_{2eq}/kWh) using the four methods presented.

Method	Weighted annual marginal GHGIF	$GHGIF_A$	$GHGIF_M$
NF	22	26	847
PE	6	191	1849
NS	360	689	786
NB	837	433	810
QC	7	6	723
ON	407	199	862
MB	1	13	1209
SK	225	789	1061
AB	937	921	1015
BC	18	22	462

Method		Monthly or seasonal GHGIF estimated based on reported data											
Month		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AB		591	591	785	785	785	769	769	769	769	785	591	591
ON	♯1	395	352	329	463	501	514	489	491	455	458	379	371
	♯2	221	211	199	246	259	294	276	276	259	262	231	227
QC		23	0	0	0	0	0	0	0	0	0	0	0

Table XXII. Recommended marginal GHG intensity factors (g CO_{2eq}/kWh) for each province.

	NF	PE	NS	NB	QC	ON Scenario ♯1	ON Scenario ♯2	MB	SK	AB	BC
January					23	395	221			591	
February					0	352	211			591	
March					0	329	199			785	
April	↑	↑	↑	↑	0	463	246	↑	↑	785	↑
May					0	501	259			785	
June					0	514	294			769	
July	22	6	360	800	0	489	276	1	225	769	18
August					0	491	276			769	
September	↓	↓	↓	↓	0	455	259	↓	↓	769	↓
October					0	458	262			785	
November					0	379	231			591	
December					0	371	227			591	
% losses	9	6	4	6	4	6	6	12	6	4	3

fossil fuels, marginal generation comes mainly from hydro resources and imported electricity with zero GHG emissions, and a small amount from NG which has lower GHG emissions compared with coal. Therefore, both the $GHGIF_A$ and $GHGIF_M$ are unrealistically high and should not be used. The weighted annual marginal GHGIF takes into consideration the mix of fuels used for marginal generation and its use is recommended.

9. Alberta: Electricity generation relies heavily on fossil fuels; therefore, the $GHGIF_A$ and $GHGIF_M$ are close to each other. However, the GHGIFs determined using actual seasonal data on marginal fuels used have a higher level of accuracy and their use is recommended.
10. British Columbia: Marginal electricity generation, like the total electricity generation, comes mainly from hydro resources and imported electricity which have zero GHG emissions,

DOI: 10.1002/er

and a small proportion from NG. Therefore, the magnitudes of both the $GHGIF_A$ and the GHGIF predicted using the weighted annual marginal method are close to each other, and $GHGIF_M$ is not applicable. The use of the weighted annual marginal GHGIF is recommended.

8. CONCLUSION

Based on the results and discussion presented above, the recommended marginal GHGIFs for each province are given in Table XXII. The last row in Table XXII gives the overall transmission and distribution losses for each province in Canada. These values should be used to determine the GHG emission reductions from marginal electricity generation in each province with the help of following equation:

$$\text{GHG emission reduction} = \left(\frac{\text{Reduction in on} - \text{site electricityconsumption (kWh)}}{1 - \frac{\%\ \text{losses}}{100}}\right) \times \text{GHGIF} \qquad (9)$$

It should be noted that the marginal GHG emission intensity factors presented in this work reflect the current situation, and are likely valid in the next 5 year horizon. Thus, they need to be updated periodically as new data on electricity generation and fuels used become available. If more detailed data on marginal generation and fuels used (similar to the data available for ON) were to be made public by other electric utilities, more precise estimates of marginal GHGIFs can be developed.

NOMENCLATURE

AB = Alberta
AESO = Alberta Electric System Operator
BC = British Columbia
FFGHG = GHG emissions from electricity generation from only fossil fuel-fired power plants in 1 year (g year^{-1})
FFNEG = Net electricity generation from only fossil fuel-fired power plants in 1 year (kWh year^{-1})
GHG = Greenhouse gas
GHGIF = Greenhouse gas intensity factor
$GHGIF_A$ = Average GHG intensity factor ($\text{g } CO_{2eq}/\text{kWh}$)
$GHGIF_M$ = GHG intensity factor for fossil fuel ($\text{g } CO_{2eq}/\text{kWh}$)
GWP = Global warming potential
IESO = Independent electricity system operator
MB = Manitoba
$MEGMF_i$ = Marginal electricity generation using marginal fuel i (MWh)
NB = New Brunswick
NF = Newfoundland and Labrador
NG = Natural gas
NS = Nova Scotia
ON = Ontario
PEI = Prince Edward Island
QC = Quebec
SK = Saskatchewan
TEG = Total electricity generation in 1 year (kWh year^{-1})
$TEGMF_i$ = Total electricity generation using marginal fuel i (MWh)
TGHG = Total GHG emissions from electricity generation in 1 year (g year^{-1})

ACKNOWLEDGEMENTS

A. A. M. Farhat gratefully acknowledges the scholarship provided by the Libyan Ministry of Education for her graduate work. The authors are grateful for the financial support provided to this project through the Solar Buildings Research Network funded by Natural Sciences and Engineering Research Council of Canada.

REFERENCES

1. Government of Canada. Canadian Environmental Sustainability Indicators 2007, 2007. Available from: http://www.ec.gc.ca/environmentandresources/CESIFeature2007/Feature2007_e.cfm [Last access: November 3 2009].

2. OEE. Energy use data handbook—1990 and 1998 to 2004, 2006. Office of Energy Efficiency, Natural Resources Canada, Ottawa.
3. Farhat AMF. A new methodology for predicting the GHG emission reductions due to electricity savings in the residential sector. *MASc Thesis*, Department of Mechanical Engineering, Dalhousie University, Halifax, Canada, 2009.
4. Canadian Electricity Association. Power Generation in Canada: A Guide, 2006. Available from: http://www.canelect.ca/en/Pdfs/HandBook.pdf [Last access: 3 November 2009].
5. Newfoundland and Labrador Hydro. Hydro Generation. Available from: http://www.nlh.nl.ca/hydroweb/nlhydroweb.nsf/TopSubContent/Operations-Hydro%20Generation?OpenDocument [Last access: 3 November 2009].
6. Blackler T, Iqbal MT. Pre-feasibility study of wind power generation in Holyrood, Newfoundland. *Renewable Energy* 2006; **31**:489–502.
7. Environment Canada. Backgrounder: PEI Electricity Transmission System, 2005. Available from: http://atlantic-web1.ns.ec.gc.ca/newsreleases/default.asp?lang = En&n = 78079B82-[Last access: 3 November 2009].
8. Piedmont Biofuels. PEI Leads the Way, 2007. Available from: http://www.biofuels.coop/windblog/?p = 147 [Last access: 3 November 2009].
9. Committee on Knowledge Assessment, National Research Council. Background, Lighting the Way: Knowledge Assessment in Prince Edward Island. The National Academies Press, 1999. Available from: http://books.nap.edu/openbook.php?record_id = 6413&page = 92 [Last access: 3 November 2009].
10. Nova Scotia Power. Generation. Available from: http://www.nspower.ca/about_nspi/generation/ [Last access: 12 November 2008].
11. Nova Scotia Power. Dispatching Generating Plants. Available from: http://www.nspower.ca/about_nspi/generation/dispatching.shtml [Last access: 12 November 2008].
12. NB Power. NB Power Group. Available from: http://www.nbpower.com/html/en/about/operating/operating_companies.html [Last access: 12 November 2008].
13. Personal Communication: Trenholm, Arden, March 25, 2008. NB Power. E-mail: ATrenholm@nbpower.cam.
14. Legislative Assembly of New Brunswick. NB power. Available from: http://www.gnb.ca/legis/business/committees/previous/reports-e/nbpowerbp/bus_unit-e.asp♯generation [Last access: 12 November 2008].
15. Hydro Quebec. Power Generation. Available from: http://www.hydroquebec.com/learning/production/pourquoi/index.html [Last access: 12 November 2008].
16. Personal Communication: Lebrun-Pare, Felix, 5 March 2008. Hydro Quebec. E-mail:Accueil2.Siege.Social@hydro.qc.ca.
17. Ontario Ministry of Energy and Infrastructure. Electricity. Available from: http://www.mei.gov.on.ca/english/energy/electricity/?page = nuclear-electricity-supply [Last access: 16 July 2008].
18. IESO. 10-Year Outlook Highlights (January 2006 to December 2015). The Independent Electricity System Operator, Ontario. Available from: http://www.ieso.ca/imoweb/siteShared/pubs_library.asp?sid = bi [Last access: 3 November 2009].
19. Manitoba Hydro. Role of the Selkirk Generation Station. Available from: http://www.hydro.mb.ca/regulatory_affairs/selkirk/role.shtml [Last access: 3 November 2009].
20. Manitoba Hydro. Need for and alternatives to the Wuskwatim Project, 2003. Available from: http://www.hydro.mb.ca/regulatory_affairs/wuskwatim/submissions_nfatt.shtml [Last access: 3 November 2009].
21. SaskPower. Electricity Basics. Available from: http://www.saskpower.com/aboutus/corpinfo/electricity_basics/ [Last access: 3 November 2009].
22. AESO. Powering Albertans. Alberta Electricity System Operator, 2008. Available from: http://www.aeso.ca/ourcompany/39.html [Last access: 3 November 2009].
23. AESO. Percentage of Time Each Fuel Type is 'On the Margin'. Alberta Electricity System Operator. Available from: http://www.aeso.ca/downloads/Percent_of_Time_Each_Fuel_Type_is_on_the_Margin.pdf [Last access: 3 November 2009].
24. BC Hydro. Our Facilities. Available from: http://www.bchydro.com/about/our_system/generation/our_facilities.html [Last access: 3 November 2009].
25. Personal Communication: Gaspard, Jim, 10 March 2008. BC Hydro. E-mail: Jim.Gaspard@bchydro.com.
26. Personal Communication: Gaspard, Jim, 15 September 2008. BC Hydro. E-mail: Jim.Gaspard@bchydro.com.
27. Forster P, Ramaswamy V, Artaxo P, Berntsen T, Betts R, Fahey DW, Haywood J, Lean J, Lowe DC, Myhre G, Nganga J, Prinn R, Raga G, Schulz M, Van Dorland R. 2007. Changes in atmospheric constituents and in radiative forcing. In *Climate change 2007*: *The Physical Science Basis*. *Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, Solomon S, Qin D, Manning M, Chen Z, Marquis M, Averyt KB, Tignor M, Miller HL (eds). Cambridge University Press: Cambridge, U.K., New York, NY.
28. Environment Canada. National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada, Ottawa, 2007. Available from: http://www.ec.gc.ca/pdb/ghg/inventory_report/2005_report/tdm-toc_eng.cfm [Last access: 3 November 2009].
29. Guler B. Impact of energy efficiency retrofits on residential energy consumption and associated GHG emissions. *MASc Thesis*, Department of Mechanical Engineering, Dalhousie University, Halifax, Canada, 2000.
30. Statistics Canada. Electric Power Generation, Transmission and Distribution 2004. Catalogue no. 57-202-XIE, Ottawa, 2006.
31. Statistics Canada. Electric Power Generation, Transmission and Distribution 2005. Catalogue no. 57-202-XIE, Ottawa, 2007.
32. Statistics Canada. Electric Power Generation, Transmission and Distribution 2006. Catalogue no. 57-202-X, Ottawa, 2008.
33. AMEC Americas Limited. Alberta 10 Years Generation Outlook. Prepared for Alberta Electricity System Operator, 2006. Available from: http://www.aeso.ca/files/FINALAESOGeneration.pdf [Last access: 3 November 2009].
34. OPA. Integrated Power System Plan EB-2007-0707 ont. Ontario Power Authority, 2008. Available from: http://www.powerauthority.on.ca/IPSP/Page.asp?PageID = 924&SiteNodeID = 320 [Last access: 3 November 2009].

35. Cleantech Group. Ontario Aim to Kick out Coal by 2014, 2007. Available from: http://cleantech.com/news/1683/ontario-aims-to-kick-out-coal-by-2014 [Last access: 3 November 2009].
36. IESO. Hourly generator output & capability report. Independent Electricity System Operator, Ontario. Available from: http://www.theimo.com/imoweb/marketdata/GenDisReports.asp [Last access: 3 November 2009].
37. Personal Communication: Lafoyiannis, Peter, 2 January 2009. IESO. E-mail: peter.lafoyiannis@ieso.ca.
38. Hydro Quebec. Sustainability Report 2006, 2006. Available from: http://www.hydroquebec.com/publications/en/enviro_performance/index.html [Last access: 3 November 2009].
39. Statistics Canada. Table 127-00021 Electric power generation, by class of electricity producer, monthly (megawatt hour) Available from: http://estat.statcan.ca/cgi-win/cnsmcgi.pgm?Lang = E&ArrayId = 1270002&Array_Pick = 1&Detail = 1&ResultTemplate = ESTAT/CII___&RootDir = ESTAT/ [Last access: 3 November 2009].