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Fuel and Greenhouse Gas Emission Reduction Potentials by Appropriate Fuel Switching and Technology Improvement in the Canadian Electricity Generation Sector

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Abstract: Problem statement: In recent years, Greenhouse Gas (GHG) emissions and their potential effects on global climate change have been a worldwide concern. According to International Energy Agency (IEA), power generation contributes more than half of the global GHG emissions. **Approach:** Purpose of this study is to examine GHG emission reduction potentials in the Canadian electricity generation sector through fuel switching and adoption of advanced power generation systems. To achieve this objective, eight different scenarios were introduced. In the first scenario, existing power stations' fuel was switched to natural gas. Existing power plants were replaced by Natural Gas Combined Cycle (NGCC), Integrated Gasification Combined Cycle (IGCC), Solid Oxide Fuel Cell (SOFC), hybrid SOFC and SOFC-IGCC hybrid power stations in scenario numbers 2 to 6, respectively. In last two scenarios, CO_2 capture systems were installed in the existing power plants and in the second scenario, respectively. **Results:** The results showed that Canada's GHG emissions can be reduced by 33, 59, 20, 64, 69, 29, 86 and 94% based on the first to eighth scenarios, respectively. On the other hand, the second scenario is the most practical and its technology has already matured and is available. In this scenario by replacing existing power plants by NGCC power plants, Canada can fulfill more than 25% of its 238,000 kt year^{-1} commitment of GHG emission reduction to the Kyoto Protocol. In addition, the GHG emission reduction potentials for each province and Canada as a whole were presented and compared. Based on the results, Alberta, Ontario and Saskatchewan are the biggest producers of GHG in Canada by emitting 49, 21 and 14% of Canada's GHG emissions, respectively. Therefore, they have higher potential to reduce GHG emissions. The comparison of the results for different provinces revealed that based on efficiency of electricity generation and consumed fuel distribution; specific scenario(s) tend to be suitable for each province. **Conclusion:** The results pointed out that despite of acceptable performance of some provinces, there are still great potentials to reduce GHG emission level in Canada. In addition, the economical analysis showed that some scenarios are economically competitive with current technologies and should be considered when a new power station is to be built.

Key words: Greenhouse gases, GHG, reduction potentials, electricity generation, Canada

INTRODUCTION

Global climate deterioration is a global concern that is caused by high level of Greenhouse Gases (GHGs) in the atmosphere (IPCC, 2007). To address this challenge, in 1992 in Rio de Janeiro and 1997 in Kyoto, there were two major United Nations conferences to reduce GHG emissions in the world. The results of these conferences were international environmental treaties known as United Nations Framework Convention on Climate Change (UNFCCC or FCCC) and Kyoto protocol, respectively. The Kyoto Protocol is an agreement to reduce GHG emissions of certain countries (Annex I Parties) to specified levels below their 1990 emission levels by available options. This target level for Canada is to reduce GHG emissions to 6% below 1990 level by the period between 2008 and 2012 (UNFCCC, 1998). The protocol became formally binding on February 16, 2005 and as of August 26, 2009, 188 countries as well as European Union accepted the protocol, covering about 64% of the emissions addressed by the Protocol (UNFCCC, 2009).

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Table 1: Electricity generation in Canada for different types of consumed fuels in 2006 (International Energy Agency, 2009)

Fuel type	Generated electricity (GWh)	Percent
Hydro	314,230	58.4
Coal	95,050	17.6
Nuclear	92,420	17.2
Natural gas	25,780	4.8
Refined petroleum products	5,140	1.0
Renewable	3,770	0.7
Other	1,870	0.3

The objectives of this study are to introduce and evaluate several scenarios to reduce GHG emissions by fuel switching and adoption of advanced power systems in Canadian electricity generation industry.

Current status of GHG emissions in power generation industry: According to the World Energy Outlook published by the International Energy Agency (IEA), the world's total net electricity consumption will increase dramatically. The world electricity generation was 14,781 billion kWh in 2003 and will increase to 21,699 and 30,116 billion kWh in 2015 and 2030, respectively (International Energy Agency, 2006).

The same report predicted that the share of fossil fuels as energy supplies for electricity generation would remain constant at nearly 65%. Also, GHG emissions from energy industry will increase by 55% between 2004 and 2030. In this period, coal and oil are leading contributors to global energy-related CO_2 emission (International Energy Agency, 2006). It has been shown that more than half of the CO_2 emission of industrial large point sources is from power production industry (Gale, 2005).

According to the Canada's Energy Outlook published by Natural Resources Canada, electricity consumption in Canada will increase to 593 TWh by 2020, growing at average rate of 1.2% annually. However, the GHG emissions of electricity generation industry will increase slightly, from 130 Mt in 2004 to 131 Mt in 2010 (Natural Resources Canada, 2006).

Table 1 shows the status of Canadian electricity generation sector based on type of consumed fuels for electricity generation (Environment Canada, 2008).

These statistics show that electricity generation sector is and will remain a major source of GHG emissions and it is essential to reduce these emissions.

MATERIALS AND METHODS

Different methodologies to calculate GHG emissions: In this study the "2006 IPCC Guidelines for National Greenhouse Gas Inventories (Eggleston *et al*., 2006)" will be used to provide methodologies for estimating GHG emissions.

Table 2: Default emission factors used in Tier 1 (kg of GHG per TJ on a net calorific basis) (Eggleston *et al*., 2006)

Fuel type	CO_2	CH_4	N_2O
Natural gas	56,100	5	0.1
Diesel oil	74,100	10	0.6
Residual oil	77,400	10	0.6

Table 3: Default emission factors used in the Tier 3 (kg TJ^{-1}) (Eggleston *et al*., 2006)

Fuel and technology type	CH_4	N_2O
Natural gas		
Boilers	1.0	1.0
Gas-fired gas turbines (>3 MW)	4.0	1.0
Combined cycle	1.0	3.0
Gas/diesel oil		
Boilers	0.9	0.4
Residual oil		
Residual fuel oil normal firing	0.8	0.3

Generally, emission of each GHG is estimated by multiplying fuel consumption by the corresponding emission factor.

There are three tiers presented in the 2006 IPCC Guidelines for estimating emissions from fossil fuel combustion for electricity generation. In these tiers, fuel consumption and emission factors are considered as follows (Eggleston *et al*., 2006):

- Tier 1: Tier 1 is a fuel-based method to estimate GHG emissions. In this tier, the quantities of consumed fuel and average emission factors for all relevant direct greenhouse gases are used for GHG analysis. The Tier 1 emission factors are available in IPCC guidelines. Table 2 shows default emission factors for three fuels (Eggleston *et al*., 2006)
- Tier 2: In Tier 2, similar to Tier 1, the quantities of consumed fuel from fuel statistics are used to estimate GHG emissions. But instead of the Tier 1 default emission factors, country specific emission factors are used
- Tier 3: Tier 1 and 2 approaches of estimating GHG emissions necessitate using an average emission factors, either default emission factors in Tier 1 or country specific emission factors in Tier 2. In reality, GHG emissions depend upon the fuel type, combustion technology, operating conditions, control technology, quality of maintenance and age of the equipments. In Tier 3 approach, these parameters are taken into account by using different emission factors for each case (Table 3 (Eggleston *et al*., 2006)). The emission of CO_2 highly depends on the carbon content of the fuel. Therefore, the CO_2 emission factors from Table 2 are sufficient for this tier

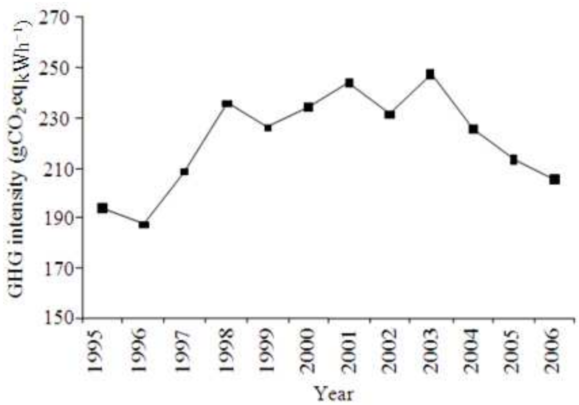

Fig. 1: Average GHG intensity in Canada's electricity generation sector between 1995 and 2005 (Eggleston *et al*., 2006)

All these tiers use the amount of fuel combusted as the activity data. In the energy sector, the activity data are typically the fuel consumption to generate electricity. These data are sufficient for the Tier 1 analysis. In higher tier approaches, additional data are required on fuel characteristics and power generation technologies.

Being one of the Annex I Parties, Canada's annual national greenhouse gas inventory report has been prepared and published by Environment Canada. The calculations of GHG emissions for Canadian electricity generation industry in this study are based on Tier 3 with country specific emission factors and activity data is provided by Environment Canada (2008).

Figure 1 illustrates average GHG intensity in Canada's electricity generation sector between 1995 and 2005 (Environment Canada, 2008). According to the graph, Canada experienced 6% increase in average GHG intensity in this period. In this graph, greenhouse gas intensity is the ratio of GHG emissions to generated electricity. This parameter is used to evaluate the electricity generation performance in terms of GHG emissions.

This indicates that there are great potentials for GHG intensity reduction in the sector. In the rest of this study, some of these potentials will be discussed.

GHG emission reduction scenarios: Despite the problems in fossil fuel-fired power plants, fossil fuels are available on a mid and long-term basis and their continued large-scale and widespread applications in power generation industry are essential in order to maintain current economic growth in the world. The IEA has commented that "numerous technology solutions offer substantial CO_2 reduction potentials, including renewable energies, higher efficiency power generation, fossil-fuel use with CO_2 capture and storage, nuclear fission, fusion energy, hydrogen, biofuels, fuel cells and efficient energy end use. No single technology can meet this challenge by itself. Different regions and countries will require different combinations of technologies to best serve their needs and best exploit their indigenous resources. The energy systems of tomorrow will rely on a mix of different advanced, clean, efficient technologies for energy supply and use" (International Energy Agency, 2009).

Thus, both fossil and non-fossil sources of energy will be needed in the foreseeable future to meet global energy demands. It is, therefore, important that alternative technologies are commercialized to permit the consumption of fossil fuels with significantly reduced GHG emissions and other pollutants.

Based on this, different scenarios to reduce GHG emissions are defined as follows:

Scenario number 1: In this scenario, GHG emission reduction potentials by fuel switching will be investigated. Based on this scenario, all power plants will use natural gas as primary fuel. But technology of power stations will remain unchanged.

Scenario number 2: In the second scenario, there will be fuel switching as well as technology changes. According to this scenario, all power stations will be replaced by Natural Gas Combined Cycle (NGCC). The size of the alternative NGCC power plant is 505 MW. The plant configuration consists of two gas turbines, a heat recovery steam generator, and a condensing reheat steam turbine. In this study, the efficiency of the power plant is considered to be 49% (based on higher heating value, HHV) (Spath and Mann, 2000).

Scenario number 3: In this scenario, it is assumed that all existing coal-fired power stations are replaced by Integrated Gasification Combined Cycle (IGCC). In IGCC technology, gas turbine and steam cycle are incorporated with modern coal gasification plant to use coal for electricity generation with greatly improved efficiency and environmental performance. This technology's advantages can be summarized as their greater than 40% thermal efficiency, high fuel flexibility and very low pollutant emissions. The efficiency of IGCC is considered to be 43% (Topper, 2006) (HHV) in this study.

Scenario numbers 4 and 5: In order to implement these scenarios, all existing power stations will be replaced by Solid Oxide Fuel Cell (SOFC) for the fourth scenario and hybrid SOFC power plants for the fifth scenario. In both cases power plants will be fueled by natural gas.

Fuel cells operation is based on direct and continuous conversion of fuel chemical energy into electrical energy in electrochemical process. Because of this direct energy conversion, their efficiencies are usually higher than conventional electricity generation technologies.

Fuel cells can be classified by their operating temperature and electrolyte compositions, which dictate their suitability for different applications. SOFCs have high operating temperature (between 600-1000°C) which makes them especially suited for stationary power generation, also allowing for internal reforming of different fuels within the cells.

There are numerous demonstrational and semi-commercial units of SOFCs installed around the world with different sizes and configurations (Singhal and Kendall, 2006; Singhal, 2002; Williams *et al*., 2006). But so far, to the authors' best knowledge, there have been three proof-of-concept SOFC hybrid power plants installed in the world (Veyo *et al*., 2002; Mitsubishi Heavy Industries, Ltd., 2009).

Since these technologies have not been commercialized yet, there are no universally accepted efficiency ranges for them. However, for SOFC power generation units, efficiency of 50 to 60% has been reported (Petruzzi *et al*., 2003; Campanari, 2001). In the case of the SOFC hybrid cycle, the efficiency is higher and its range is wider, from 57% to more than 75% (Calise *et al*., 2006; Palsson *et al*., 2002; Song *et al*., 2005). For this study the average efficiencies of 55% for the fourth scenario and 65% for the fifth scenario are considered.

Scenario number 6: This scenario is a combination of the third and fourth scenario. In this case, all existing coal-fired power stations will be replaced by SOFC and IGCC hybrid cycles. The efficiency of cycle is considered to be 50% (Kuchonthara *et al*., 2005; Jansen *et al*., 1994).

Scenario numbers 7 and 8: CO_2 Capture and Storage (CCS) systems are technologies that can be used to reduce CO_2 emission by different industries where combustion is part of the process. A major problem of CCS utilization is their high efficiency penalty in power plants (Metz, 2005).

In the seventh scenario, CCS is installed in the existing power plants with current technologies. For the last scenario, all existing power plants will be replaced by NGCC plants equipped with CO_2 capture system. The CCS system in these scenarios is capable of removing 90% of CO_2 from flue gas but because of consumption of more fuel to compensate plants efficiency reduction, overall, 87% of CO_2 can be captured. The output penalty of 10% is considered for both scenarios.

RESULTS

GHG emission reduction potentials in Canada: Table 4 shows different fuels consumption, electricity production for each fuel and GHG emissions for current situation and eight GHG emission reduction scenarios and reduction potentials as well as GHG intensity for each scenario in Canadian fossil fuel-fired thermal power plants.

In order to perform these calculations, the fuel consumption, electricity production and emission factors for different fuels for each province were used to estimate GHG emission reduction potentials. The latest data publicly available from Environment Canada that has been used in this study is for 1996 (Environment Canada, 2006).

It should be noted that the focus of this study is on GHG emission reduction potentials in fossil fuel-fired thermal power plants. Therefore, other power generation technologies (such as, nuclear, hydro and renewables) are not considered in the estimation of GHG emissions.

Table 4 shows that Canada's GHG emissions can be reduced from almost 100 Mt year^{-1} in the base case (existing case) to 65, 40, 79, 36, 30, 70, 14 and 6 Mt year^{-1} based on the first to eighth scenarios, respectively. This means 33, 59, 20, 64, 69, 29, 86 and 94% reduction potentials in GHG emissions, respectively.

The best solutions are the eighth, seventh and fifth scenarios, respectively. On the other hand, the second scenario is the most practical one and its technology has already matured and is available. This scenario can reduce GHG emissions by almost 60%. This means that just by replacing existing thermal power plants by NGCC plants Canada can fulfill more than 25% of its 238 Mt year^{-1} commitment of GHG emission reduction to Kyoto Protocol (Environment Canada, 2005) (Fig. 2).

Table 5 shows the summary of results for some provinces including Alberta, Ontario, Saskatchewan, Nova Scotia, New Brunswick, British Columbia, Newfoundland and Canada as a whole. Other provinces are not included since they, together, are responsible for only approximately 1% of Canada's GHG emissions from electricity generation. Based on Table 5, Alberta, Ontario and Saskatchewan are the biggest producers of GHG in Canada's electricity generation sector by emitting 49, 21 and 14% of this sector's GHG emissions, respectively. Therefore, they have higher potentials to reduce GHG emissions.

Table 4: Fuel consumption, electricity production, GHG emission reduction potentials and intensity in Canada

	Fuel	Existing	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Fuel consumption	Coal (kt)	46,927	0	0	35,259	0	0	30,322	51,620	0
	Petroleum (ML)	1,692	0	0	1,692	0	0	1,692	1,861	0
	Natural gas (BL)	4,061	34,690	21,368	4,061	18,960	16,043	4,061	4467	23,505
Electricity production (GWh)	Coal	86,150	0	0	86,150	0	0	86,150	86,150	0
	Petroleum	7,115	0	0	7,115	0	0	7,115	7,115	0
	Natural gas	14,577	107,841	107,841	14,577	107,841	107,841	14,577	14,577	107,841
	Total	107,841	107,841	107,841	107,841	107,841	107,841	107,841	107,841	107,841
GHG emissions (kt year^{-1})	Coal	85,421	0	0	66,147	0	0	56,886	12,215	0
	Petroleum	5,202	0	0	5,202	0	0	5,202	744	0
	Natural gas	7,662	65,436	40,138	7,662	35,609	30,131	7,662	1,096	5,740
	Total	98,285	65,436	40,138	79,011	35,609	30,131	69,750	14,055	5,740
Reduction potential (%)	Coal	-	-	-	23	-	-	33	86	-
	Petroleum	-	-	-	0	-	-	0	86	-
	Natural gas	-	33	59	0	64	69	0	86	94
	Total	-	33	59	20	64	69	29	86	94
GHG intensity ($gCO_2eq\ kWh^{-1}$)	Total	911	607	372	733	330	279	647	130	53

Table 5: The GHG emissions and reduction potentials for each scenario in different provinces in Canada

	Existing	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	GHG emissions (kt year^{-1})	GHG emissions (kt year^{-1})	Reduction potential (%)	GHG emissions (kt year^{-1})	Reduction potential (%)	GHG emissions (kt year^{-1})	Reduction Potential %	GHG emissions (kt year^{-1})	Reduction potential (%)
Canada	98,285	65,436	33	40,138	59	79,011	20	35,609	64
Alberta	48,070	31,870	33	18,200	62	37,368	22	16,146	66
Ontario	20,784	13,590	35	10,710	48	19,978	4	9,501	54
Saskatchewan	13,661	9,517	30	3,486	74	7,482	45	3,092	77
Nova Scotia	7,282	4,675	36	3,304	55	6,260	14	2,931	60
New Brunswick	6,055	3,716	39	2,627	57	5,491	9	2,330	62
British Columbia	1,277	1,286	-	1,260	1.5	1,277	-	1,117	12
Newfoundland	1,155	782	32	552	52	1,155	-	490	58
		Scenario 5		Scenario 6		Scenario 7		Scenario 8	
Canada	98,285	30,131	69	69,750	29	14,055	86	5,740	94
Alberta	48,070	13,662	72	32,529	32	6,874	86	2,603	95
Ontario	20,784	8,040	61	17,712	15	2,972	86	1,532	93
Saskatchewan	13,661	2,617	81	6,504	52	1,954	86	498	97
Nova Scotia	7,282	2,480	66	5,475	25	1,041	86	472	94
New Brunswick	6,055	1,972	67	5,099	16	866	86	376	94
British Columbia	1,277	946	26	1,277	-	183	86	180	86
Newfoundland	1,155	415	64	1,155	-	165	86	79	93

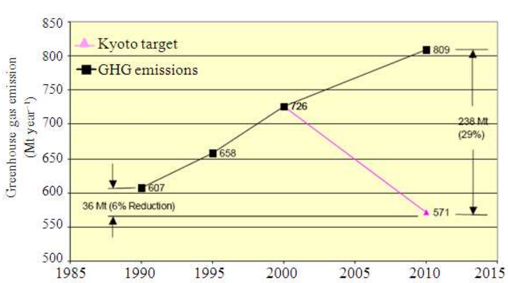

Fig. 2: Canada GHG projection and Kyoto Protocol (Environment Canada, 2005)

In Ontario, for the first scenario (fuel switching to natural gas) there is a 35% reduction potential which is slightly higher than the national average of 33%. For the second, fourth and fifth scenarios, GHG reduction potentials in Ontario are considerably lower than Canadian average with 48, 54 and 61% in comparison with 59, 64 and 69%, respectively. This could be as a result of high efficiency of both natural gas and coal fueled power stations in Ontario.

The same is true for the third and sixth scenarios where Ontario's GHG emission reduction potentials, 4 and 15%, are significantly lower than national average of 20 and 29%, respectively.

For Ontario, it can be concluded that although power generation sector is emitting less GHG in comparison to national average, there are still considerable potentials under these eight scenarios. In addition, the first scenario tends to be the most suitable scenario in short term.

Furthermore, the results point out that the level of GHG emission reduction potentials depends on the share of coal in electricity generation. For instance, share of coal in electricity generation from fossil fuel in Alberta, Ontario and Saskatchewan are 87, 70 and 92%, respectively, during the same period (Environment Canada, 2008). Accordingly, results show that Saskatchewan, Alberta and Ontario have the highest level of GHG emission reduction potentials, respectively, especially for the third and sixth scenarios.

DISCUSSION

Cost of different scenarios: Inevitably, the first question raises about these scenarios is their impacts from economic point of view. The cost of the first scenario is not considerable and the main issue is availability of natural gas at reasonable price.

Since scenario numbers 4, 5 and 6 are not commercialized yet, it is not possible to assess their cost accurately. Therefore, in this study, economic effects of scenario numbers 2, 3, 7 and 8 will be investigated mostly based on Rubin *et al.* (2007).

Investigation of different economical studies (Metz, 2005; Rubin *et al*., 2007; Rao and Rubin, 2002) revealed considerable variation in costs of power generation and CO_2 capture unit, both capital cost and Cost Of Electricity (COE), for all types of power plants due to different assumptions about key parameters, such as fuel properties, fuel cost, plant size, plant efficiency, plant capacity factor, plant financing, and performance of the CO_2 capture unit (Rubin *et al*., 2007).

The general conclusion from studies published prior to 2004 is that the COE, for both configurations with and without CO_2 capture, is the lowest for NGCC plants. For coal-based plants, Pulverized Fuel-fired (PF) for configuration without CO_2 capture and IGCC plants for configuration with CO_2 capture have the lowest COE.

More recent studies showed different pattern because of increase in price of several items (Rubin *et al*., 2007). They showed that PF and IGCC have the lowest COE for configurations without and with CO_2 capture system, respectively. These results were not in agreement with the studies prior to 2004. The reason is that in recent years, the price of natural gas ($3-4.5/GJ in studies prior to 2004 vs. $6/GJ in studies after 2004) as well as many raw materials has increased significantly.

In order to have a clear idea of natural gas price variations, Fig. 3 shows natural gas price in Canadian $/GJ in Canadian market (Energyshop, 2009). As the graph indicates, although $6/GJ is not reflecting the current price of natural gas, it is more reasonable than $3-4.5/GJ.

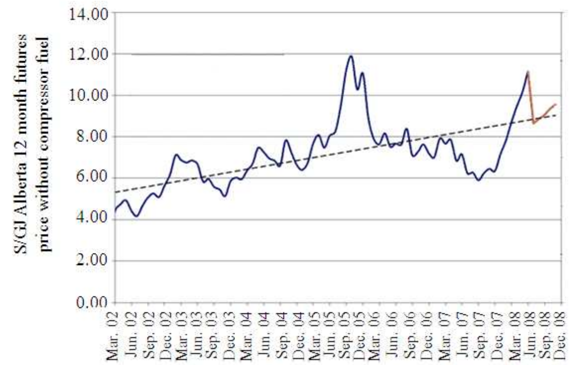

Fig. 3: Natural gas prices in Canadian market (Energyshop, 2009)

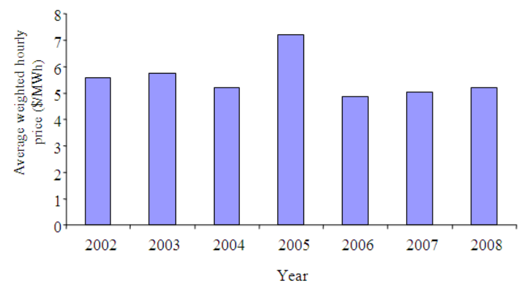

Fig. 4: Annual average weighted prices of electricity reported by Independent Electricity System Operator (IESO) for Ontario, Canada between 2002 and 2008 (Independent Electricity System Operator, 2009)

Moreover, the COEs reported in these studies are comparable with annual average weighted prices of electricity shown in Fig. 4, reported by Independent Electricity System Operator (IESO) for Ontario, Canada between 2002 and 2008 (Independent Electricity System Operator, 2009).

In conclusion, scenario numbers 2 and 3 can compete with existing power plants, especially using IGCC technology, when the current increase in natural gas price is considered. Therefore, when a new power station is to be built these technologies should be considered as main candidates. For scenario numbers 7 and 8, CO_2 capture from power plants is still too expensive but their costs are expected to lower as a consequence of technological improvements.

CONCLUSION

In this study, the GHG emission reduction potentials were investigated under eight introduced scenarios. The results for Canadian power stations showed that there are very high GHG emission reduction potentials. The estimation for GHG emission reduction potentials for different provinces revealed that Alberta, Ontario, and Saskatchewan are responsible for more than 84% of GHG emissions in the electricity generation sector in Canada. Therefore, they have the highest GHG emission reduction potentials. The results pointed out that despite acceptable performance in some provinces, there are considerable potentials to reduce GHG emissions. For instance, the second scenario, being the most practical scenario in Canada, can reduce GHG emissions by almost 60%, which is more than 25% of Canada's commitment of GHG emission reduction to Kyoto Protocol.

The economic analysis showed that when a new power station is to be built, different scenarios should be considered, particularly scenario numbers 2 and 3, because they can compete with existing power plants in terms of cost. Furthermore, CO_2 capture from power plants is still too expensive but their costs are expected to decrease.

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